Constellation Energy
Nine Mile Point Nuclear Station

P.O. Box 63
Lycoming, NY 13093

October 24, 2005
NMP1L 1989

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555-0001

SUBJECT: Nine Mile Point Unit 1
Docket No. 50-220
Facility Operating License No. DPR-63

Submittal of Revision 19 to the Final Safety Analysis Report (Updated) (UFSAR), 10 CFR 50.59 Evaluation Summary Report, Changes to the Quality Assurance Program Description, and Technical Specifications Bases Changes

Gentlemen:

Pursuant to the requirements of 10 CFR 50.71(e), 10 CFR 50.54(a)(3), 10 CFR 50.59(d)(2), and the Nine Mile Point Unit 1 (NMP1) Technical Specifications (TS) Bases Control Program (TS 6.5.6), Nine Mile Point Nuclear Station, LLC (NMPNS) hereby submits the following:

- Revision 19 to the NMP1 Final Safety Analysis Report (Updated) (UFSAR), including changes to the Nine Mile Point Quality Assurance Topical Report (UFSAR Appendix B),
- The NMP1 10 CFR 50.59 Evaluation Summary Report, and
- NMP1 Technical Specifications Bases Changes.

One (1) copy of the UFSAR Revision 19 pages is enclosed (Enclosure A). The UFSAR revision contains changes made since the submittal of Revision 18 in October 2003. The revision reflects all changes up to and including June 21, 2005. The 10 CFR 50.59 Evaluation Summary Report (Enclosure B), covering the same time interval as the UFSAR revision, contains a brief description of changes, tests, and experiments, and includes summaries of the associated 10 CFR 50.59 evaluations. None of the 10 CFR 50.59 evaluations involved obtaining a license amendment as defined in 10 CFR 50.59(c)(1).

Enclosure C provides the identification, reason, and basis for each change to the quality assurance program description in accordance with 10 CFR 50.54(a)(4)(ii).

A053

One (1) copy of revised Technical Specifications Bases pages (Enclosure D) is also enclosed, which incorporates changes made since April 23, 2003. The corresponding summaries of the changes to this document are provided in Enclosure E.

If you have any questions regarding this submittal, please contact James A. Hutton, Director Licensing, at (315) 349-1041.

Very truly yours,

Timothy J. O'Connor
Plant General Manager

TJO/DEV/sac

Enclosures:
A. Final Safety Analysis Report (Updated) – Revision 19
B. 10 CFR 50.59 Evaluation Summary Report – 2005
C. Identification of Changes, Reasons and Bases for Quality Assurance Program Topical Report (Unit 1 UFSAR Appendix B)
D. Revised Technical Specifications Bases Pages – 2005
E. Technical Specifications Bases Change Summary – 2005

cc: Mr. S. J. Collins, NRC Regional Administrator, Region I
Mr. L. M. Cline, NRC Senior Resident Inspector
Mr. T. G. Colburn, Senior Project Manager, NRR (2 copies)

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
Nine Mile Point Nuclear	)	
Station, LLC	)	Docket No. 50-220
	)	
(Nine Mile Point Nuclear	)	
Station Unit 1)	)	

CERTIFICATION

I, Timothy J. O'Connor, being duly sworn, state that I am Nine Mile Point Plant General Manager; and that I am duly authorized to execute and file this certification on behalf of Nine Mile Point Nuclear Station, LLC. In accordance with 10 C.F.R. §50.71(e)(2), to the best of my knowledge and belief, I certify that the information contained in the attached letter and the Final Safety Analysis Report (Updated) accurately presents changes made since the previous submittal necessary to reflect information and analyses submitted to the Commission or prepared pursuant to Commission requirements and contains an identification of changes made under the provisions of §50.59 but not previously submitted to the Commission.

By: ______________________
Timothy J. O'Connor
Plant General Manager

Subscribed and sworn to before me this 24th day of October, 2005.

Notary Public in and for Oswego County, New York

My Commission Expires: 10/25/05

Sandra A. Oswald

SANDRA A. OSWALD
Notary Public, State of New York
No. 01OS6032276
Qualified In Oswego County
Commission Expires 10/25/05

Enclosure A to
NMP1L 1989

NINE MILE POINT UNIT 1

UPDATED FINAL SAFETY ANALYSIS REPORT

REVISION 19

Docket No. 50-220
License No. DPR-63

Enclosure B to
NMP1L 1989

NINE MILE POINT UNIT 1

10CFR50.59 EVALUATION SUMMARY REPORT

2005

Docket No. 50-220
License No. DPR-63

50.59 Evaluation No.: 2000-007

Implementation Document No.: Modification N1-98-008

UFSAR Affected Pages: X-51

System: Reactor Vessel, RWCU

Title of Change: Noble Metal Chemical Addition

Description of Change:

Operation of reactor recirculation pumps is controlled by Procedure N1-OP-01 during all operating conditions. This procedure requires a minimum of two unisolated recirculation pumps to comply with Technical Specification 3.1.7.f, Recirculation Loops. A minimum of one pump is required to prevent thermal stratification. The Noble Chem application condition is Hot Shutdown.

This modification will reduce the required number of operating recirculation pumps from 5 to 3. Revision of the Noble Chem application procedure will be revised accordingly.

50.59 Evaluation Summary:

Partial loop operation has been evaluated for power operations. This application, with the reactor shut down and all control rods inserted, is bounded by the evaluation.

Reducing the number of operating recirculation pumps to three is within the current licensing and design basis of the plant and is covered by existing procedures.

Based on the evaluation performed, it is concluded that these changes do not require prior NRC approval.

50.59 Evaluation No.:	2004-001
Implementation Document No.:	Sargent & Lundy Report No. SL-008240
UFSAR Affected Pages:	III-12a
System:	Control Room Envelope
Title of Change:	Use of Potassium Iodide as the Compensatory Measure for Addressing Excessive Control Room Unfiltered In-Leakage

Description of Change:

In the event the Control Room tracer gas testing identifies unfiltered in-leakage greater than that required to maintain Control Room Operator doses within 10CFR50 GDC 19 limits, potassium iodide (KI) will be used as an interim measure for addressing Control Room envelope integrity until the excessive Control Room unfiltered in-leakage can be corrected.

50.59 Evaluation Summary:

Use of KI as the compensatory measure to meet GDC 19 for addressing excessive control room unfiltered in-leakage is an alternate method of evaluation. The Nuclear Regulatory Commission (NRC) has endorsed use of KI as an interim compensatory measure as long as key considerations, as described in NEI 99-03 Revision 0, Appendix F, are adequately addressed. As defined in Procedure NAI-DSE-01, "10 CFR 50.59 Resource Manual," an alternate method of evaluation is allowed if NRC has approved the method for the intended application. NMP1 has provided administrative controls to meet these considerations.

Based on the evaluation performed, and since this is an accepted alternate method of evaluation, it is concluded that these changes do not require prior NRC approval.

Enclosure C to
NMP1L 1989

IDENTIFICATION OF CHANGES, REASONS AND BASES FOR NINE MILE POINT NUCLEAR STATION, LLC, QUALITY ASSURANCE PROGRAM TOPICAL REPORT, NINE MILE POINT NUCLEAR STATION - UNIT 1 (UFSAR APPENDIX B)

Docket No. 50-220
License No. DPR-63

ENCLOSURE C

IDENTIFICATION OF CHANGES, REASONS AND BASES FOR
QUALITY ASSURANCE PROGRAM TOPICAL REPORT (UNIT 1 UFSAR APPENDIX B)

UFSAR Appendix B Page/Section	Identification of Change	Reason for Change	Basis for Concluding that the Revised Program Continues to Satisfy 10CFR50 Appendix B and Commitments Previously Approved by the NRC
Page B.2-3 / Section B.2.8	Clarification of implementation of Quality Assurance elements applicable to radwaste handling and shipping. Specifies that QA provides oversight of radwaste handling through audits and inspections and quality inspectors are trained on DOT and NRC radwaste handling requirements.	Clarify implementation of Quality Assurance requirements for radwaste shipping and handling.	This change clarifies the implementation of the QA program applicable to radwaste shipping and handling, by specifically requiring training on applicable DOT and NRC regulations for quality inspectors. This change has no material impact on the QA plan or its implementation.
Page B.2-6 / Section B.2.2.16	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Page B.2-7 / Section B.2.2.16	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Page B.2-8 / Section B.2.2.16	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Page B.2-8 / Section B.2.2.16	Audit frequencies of several functional areas changed to 24 months.	Establish consistent audit frequencies among CGG nuclear stations to facilitate scheduling and implementation of coordinated fleet audits of functional areas.	Functional area audit frequencies are consistent with NRC regulations and those approved by the NRC in issued Safety Evaluation Reports for the QA programs of other nuclear power plants.

UFSAR Appendix B Page/Section	Identification of Change	Reason for Change	Basis for Concluding that the Revised Program Continues to Satisfy 10CFR50 Appendix B and Commitments Previously Approved by the NRC
Page B.2-9 / Section B.2.2.16	Audit frequencies of several functional areas changed to 24 months. Frequency of the FFD audit listed separately as 12 months to conform to current NRC regulations.	Establish consistent audit frequencies among CGG nuclear stations to facilitate scheduling and implementation of coordinated fleet audits of functional areas.	Functional area audit frequencies are consistent with NRC regulations and those approved by the NRC in issued Safety Evaluation Reports for the QA programs of other nuclear power plants.
Page B.2-9 / Section B.2.2.16	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Page B.2-10 / Section B.2.2.17	Changing titles of SORC members.	Consistent with changes in organizational titles.	This change reflects a change in title only and still reflects the required functional composition of the SORC. This change has no material impact on the QA plan or its implementation.
Page B.2-11 / Section B.2.2.17	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Page B.2-12 / Section B.2.2.17	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Page B.5-4 / Section B.5.2.9	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.

UFSAR Appendix B Page/Section	Identification of Change	Reason for Change	Basis for Concluding that the Revised Program Continues to Satisfy 10CFR50 Appendix B and Commitments Previously Approved by the NRC
Page B.5-5 / Section B.5.2.9	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Page B.17-2 / Section B17.2.2	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Page B.17-3 / Section B.17.2.5	Establishes the ability to store records as electronic images on optical disks.	Incorporates NRC guidance on the use of optical disk technology for records storage.	This change incorporates NRC guidance on the use of optical disk technology for storing records as electronic images on media that does not allow deletion or modification of record images. This change has no material impact on the QA plan or its implementation.
Page B.18-1 / Section B18.2.4	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Page B.18-1 / Section B18.2.4	Extension provisions for audit frequency periods were established for audits where frequency is not specifically established by an NRC regulation.	Establish flexibility of audit frequencies among CGG nuclear stations to facilitate scheduling and implementation of coordinated fleet audits of functional areas.	Functional area audit frequencies extension periods are consistent with those approved by the NRC in issued Safety Evaluation Reports for the QA programs of other nuclear power plants.

UFSAR Appendix B Page/Section	Identification of Change	Reason for Change	Basis for Concluding that the Revised Program Continues to Satisfy 10CFR50 Appendix B and Commitments Previously Approved by the NRC
Page B.18-2 / Section B18.2.11	Adds the definition of audit finding and clarifies requirements for follow-up of audit issues identified as findings.	Establish consistency with NQA-1 by adding the definition of a finding for NMP audit-identified problems requiring follow-up.	This change improves the consistency of the QA plan with its basis standard, NQA-1, by establishing a definition for an audit finding for NMP audit-identified problems requiring follow-up as required by NQA-1. This change has no material impact on the QA plan or its implementation.
Page B.18-3 / Section B18.2.12	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Table B-2, Page 4 of 9	Change name of Safety Review and Audit Board (SRAB) to Nuclear Safety Review Board (NSRB).	Establish consistent terminology for the offsite review board among all CGG nuclear units.	The change is for the name of the board only and does not affect the composition, function or responsibilities of the offsite review board. This change has no material impact on the QA plan or its implementation.
Table B-2, Page 4 of 9	Lead Auditor qualifications were revised to take exception to requirements for the completion of participation in five audits, and a requalification extension period of 90 days was established to provide flexibility in scheduling and administering requalification requirements.	Establish consistency with Lead Auditor qualification and administration requirements among all CGG nuclear units.	Lead Auditor qualification requirements and the scheduling and administration of lead auditor requalification are consistent with those approved by the NRC in issued Safety Evaluation Reports for the QA programs of other nuclear power plants.

Enclosure D to
NMP1L 1989

NINE MILE POINT UNIT 1

REVISED TECHNICAL SPECIFICATIONS BASES PAGES

2005

Docket No. 50-220
License No. DPR-63

INSERTION INSTRUCTIONS

TECHNICAL SPECIFICATIONS BASES

The following instructions are for the insertion of revised Bases pages into the Nine Mile Point Unit 1 Technical Specifications Bases.

Remove pages, tables, and/or figures listed in the REMOVE column and replace them with the pages, tables, and/or figures listed in the INSERT column. Dashes (---) in either column indicate no action required.

REMOVE	INSERT
LEP-1 through LEP-04	LEP-1 through LEP-4
95	95
126	126
142	142
150	150
---	150a
250	250
---	250a
251	251
251a	251a
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NMP1 FACILITY OPERATING LICENSE (FOL) AND
TECHNICAL SPECIFICATIONS (TS)

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FOL Page 2	A172	27b (B)	R7
FOL Page 3	A172	27c (B)	R7
FOL Page 4	11/18/04	27d (B)	R7
FOL Page 5	A172	27e (B)	R7
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iv	A176	35	A142
v	A181	36	A180
vi	A181	37 (B)	R5
		37a (B)	R5
1	A142	37b (B)	R5
2	A143	37c (B)	R5
3	A142	38 (B)	A142
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5	A142	40 (B)	A142
6	A176	41 (B)	R4
7	A176	42 (B)	A142
8	A181	43 (B)	R5
9	A168	44	A142
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65	A143	104 (B)	A142
66	A143	105	A173
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68	A142	107 (B)	R2
69	A142	108	A181
70	A142	109	A142
70a	A153	110	A145
71 (B)	A142	111 through 114	Not Used
72 (B)	A142	115 (B)	R6
73 (B)	A142	116	A142
74 (B)	A153	117	A154
75 (B)	A142	118	A152
76	A142	119 (B)	A152
77	A142	120	A142
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79 (B)	A142	122 (B)	R1
80	A142	123	A170
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82 (B)	A142	125	A185
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86	A183	129 (B)	A142
87	A183	130 (B)	A142
88	A183	131	A182
89	A183	132	A159
90	A183	133	A159
91	A183	134 through 139	Deleted
92	A183	140 (B)	A142
93	A183	141 (B)	A159
94	A183	142 (B)	R8
94a	A183	143	A170
94b through 94d	Deleted	144	A142
95 (B)	R12	145	A145
96	A169	146 through 149	Not Used
97	A169	150 (B)	R12
97a	A163	150a (B)	R12
98 (B)	A172	151	A170
98a (B)	A169	152	A142
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158 (B)	A142	202	A186
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168	A170	212	A142
169 (B)	A142	213	A153
170	A170	214	A142
171	A170	215	A142
172 (B)	A170	216	A142
173	A179	217	A142
174	A171	218	A142
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178	A179	222	A142
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183	A142	227	A153
184	A142	228	A186
185 (B)	A142	229	A186
186	A142	230	A186
187 (B)	A142	231	A186
188	A142	232	A186
189	A142	233	A186
190 (B)	A142	234	A142
191	A176	235	A142
192	A176	236	A142
193 (B)	A142	237	A142
194	A142	238	A148
195	A143	239	A142
196	A176	240	A142
197	A143	241	A142
198	A142	242	A142
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(1) (B) denotes Bases page.

NMP1 FACILITY OPERATING LICENSE (FOL) AND
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245	A142	296 (B)	A176
246	A161	297	A176
247	A161	298 through 338 (B)	Deleted
247a	A161	339	A142
248 (B)	A142	340	A142
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250a (B)	R10	343	A172
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251a (B)	R13	345	A142
252 (B)	R13	346	A167
253 (B)	R13	347	A181
254 (B)	R13	348	A181
255	A142	349	A181
256	A179	350	A181
257	A142	351	A182
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259	A175	353	A182
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261	A175	355	A182
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263	A142	357	A181
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266	A142	361	A181
267 (B)	A142	362	A181
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269	A142	364	A181
270	A142	365	A176
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272	A142	367	A181
273 (B)	A142	368	A181
274	A142	369	A176
275	A142	370	A181
276 (B)	A142	371	A181
277	A155	371a	A181
278	A155	371b	A181
279	A155	372	A181
280	A142	372a	A181
281 (B)	A155	373	A181
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283 through 294 (B)	Deleted	375	A181
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[1] (B) denotes Bases page.

BASES FOR 3.2.2 AND 4.2.2 MINIMUM REACTOR VESSEL TEMPERATURE FOR PRESSURIZATION

Figures 3.2.2.a, 3.2.2.b, 3.2.2.c, and 3.2.2.d are plots of pressure versus temperature for heatup and cooldown rates of up to 100°F/hr. maximum (Specification 3.2.1). Figure 3.2.2.e is the plot of pressure versus temperature for leakage and hydrostatic testing. When the heatup rate to the minimum test temperature for leakage and hydrostatic testing is maintained $\leq$ 10°F/hr, the thermal gradient across the vessel wall is negligible, however, if the heatup rate exceeds 10°F/hr, a thermal soak is required. These curves are based on calculations of stress intensity factors according to Appendix G of Section XI of the ASME Boiler and Pressure Vessel Code 1989 Edition and Code Case N-640. In addition, temperature shifts due to fast neutron fluence at twenty-eight effective full power years of operation were incorporated into the figures. These shifts were calculated using the procedure presented in Regulatory Guide 1.99, Revision 2. Reactor vessel flange/reactor head flange boltup is governed by other criteria as stated in Specification 3.2.2.d. The pressure readings on the figures have been adjusted to account for instrument uncertainties and to reflect the calculated elevation head difference between the pressure sensing instrument locations and the pressure sensitive area of the core beltline region. The temperature readings on the figures have been adjusted to account for instrument uncertainties.

The reactor vessel head flange and vessel flange in combination with the double "O" ring type seal are designed to provide a leak-tight seal when bolted together. When the vessel head is placed on the reactor vessel, only that portion of the head flange near the inside of the vessel rests on the vessel flange. As the head bolts are replaced and tensioned, the vessel head is flexed slightly to bring together the entire contact surfaces adjacent to the "O" rings of the head and vessel flanges. Both the head and vessel flanges have an NDT temperature of 40°F and they are not subject to any appreciable neutron radiation exposure. Therefore, the minimum vessel flange and head flange temperature for bolting is established at 40°F + 60°F or 100°F.

Figures 3.2.2.a, 3.2.2.b, 3.2.2.c, 3.2.2.d, and 3.2.2.e have incorporated a temperature shift due to the calculated fast neutron fluence. The neutron flux at the vessel wall is calculated based on Regulatory Guide 1.190 compliant methods using a plant specific model validated to flux monitors installed inside the vessel. The curves are applicable for up to twenty-eight effective full power years of operation.

BASES FOR 3.3.1 AND 4.3.1 OXYGEN CONCENTRATION

The four percent by volume oxygen concentration eliminates the possibility of hydrogen combustion following a loss-of-coolant accident (Section VII-G.2.0 and Appendix E-II.5.2)*. The only way that significant quantities of hydrogen could be generated by metal-water reaction would be if the core spray system failed to sufficiently cool the core. As discussed in Section VII-A.2.0*, each core spray system will deliver, as a minimum, core spray sparger flow as shown on Figure VII-2*. In addition to hydrogen generated by metal-water reaction, significant quantities can be generated by radiolysis. (Technical Supplement to Petition for Conversion from Provisional Operating License to Full Term Operating License).

Inerting the primary containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and deinerted as soon as possible in the plant shutdown. The probability of an event that generates hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these "windows," when the primary containment is not inerted, are also justified. The 24 hour time period is a reasonable amount of time to allow plant personnel to perform inerting or deinerting.

If oxygen concentration is greater than or equal to four percent by volume at any time while in the power operating condition, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration must be restored to less than four percent by volume within 24 hours. The 24 hour completion time is allowed when oxygen concentration is greater than or equal to four percent by volume because of the low probability and long duration of an event that would generate significant amounts of hydrogen occurring during this period.

If oxygen concentration cannot be restored to within limits within the required completion time, reactor coolant pressure must be reduced to less than or equal to 110 psig within 10 hours.

At reactor pressures of 110 psig or less, the reactor will have been shutdown for more than an hour and the decay heat will be at sufficiently low values so that fuel rods will be completely wetted by core spray. The fuel clad temperatures would not exceed the core spray water saturation temperature of about 344°F.

The primary containment is normally slightly pressurized during periods of reactor operation. Nitrogen used for inerting could leak out of the containment but air could not leak in to increase the oxygen concentration. Once the containment is filled with nitrogen to the required concentration, no monitoring of oxygen concentration is necessary. However, at least once a week, the oxygen concentration will be determined as added assurance that Specification 3.3.1 is being met.

*FSAR

The Type A test follows the guidelines stated in ANSI/ANS-56.8[8] and/or the Bechtel Topical Report.[4] This program provides adequate assurance that the test results realistically estimates the degree of containment leakage following a loss-of-coolant accident. The containment leakage rate is calculated using the Absolute Methodology.[8]

The specific treatment of selective valve arrangements including the acceptability of the interpretations of 10 CFR 50 Appendix J requirements are given in References 5, 6, and 7. Core Spray and Containment Spray suction valves will be tested in accordance with the IST Program.

References:

(1) FSAR, Volume II, Appendix E

(2) UFSAR, Section VI B.2.1

(3) TID-20583, Leakage Characteristics of Steel Containment Vessels and the Analysis of Leakage Determinations

(4) BN-TOP-1 "Testing Criteria for Integrated Leakage Rate Testing of Primary Containment Structures for Nuclear Power Plants," Revision 1, Bechtel Corporation, November 1, 1972

(5) NRC Safety Evaluation Report dated May 6, 1988, "Regarding Proposed Technical Specifications and Exemption Requests Related to Appendix J."

(6) Niagara Mohawk Letter dated July 28, 1988, "Clarifications, Justifications & Conformance with 10 CFR 50 Appendix J SER."

(7) NRC Letter dated November 9, 1988, "Review of the July 28, 1988 Letter on Appendix J Containment Leakage Rate Testing at Nine Mile Point Unit 1."

(8) ANSI/ANS - 56.8 - 1994, "Containment System Leakage Testing Requirements."

BASES FOR 3.3.4 AND 4.3.4 PRIMARY CONTAINMENT ISOLATION VALVES

The list of primary containment isolation valves is contained in the procedure governing controlled lists and have been removed from the Technical Specifications per Generic Letter 91-08. Revisions will be processed in accordance with Quality Assurance Program requirements.

Double isolation valves are provided on lines penetrating the primary containment and open to the free space of the containment. Closure of one of the valves in each line would be sufficient to maintain the integrity of the pressure suppression system. Except where check valves are used as one or both of a set of double isolation valves, the isolation valves shall be capable of automatic initiation. Automatic initiation is required to minimize the potential leakage paths from the containment in the event of a loss-of-coolant accident. Details of the isolation valves are discussed in Section VI-D.[(1)] For allowable leakage rate specification, see Section 3.3.3/4.3.3.

It is not intended that compliance with Technical Specification actions would prevent changes in modes or other specified conditions that are part of a shutdown of the unit. Accordingly, since Limiting Condition for Operation (LCO) 3.3.4 (in addition to LCO 3.2.7) applies to the shutdown cooling system containment isolation valves, if during a plant shutdown any shutdown cooling containment isolation valve becomes inoperable for closing while placing shutdown cooling in operation, it is recommended <u>not</u> to take the action specified in 3.3.4.b to isolate one valve in the line having the inoperable valve within 4 hours. This is because, once the line is isolated, the Technical Specifications preclude unisolating the line unless: 1) it is for the purpose of demonstrating operability of the inoperable valve or 2) the inoperable valve is no longer required to be operable (i.e., reactor coolant temperature less than 215°F). It is, therefore, recommended to take the action specified in 3.3.4.c within 4 hours (instead of the action specified in 3.3.4.b) and proceed with the shutdown actions using shutdown cooling as necessary to reduce reactor coolant temperature to less than 215°F within the following 10 hours. An inoperable shutdown cooling containment isolation valve may be opened with the shutdown cooling permissives met (reactor pressure ≤ 120 psig and temperature ≤ 350°F) in order to comply with the shutdown actions specified in 3.3.4.c.

For the design basis loss-of-coolant accident fuel rod perforation would not occur until the fuel temperature reached 1700°F which occurs in approximately 100 seconds.[(2)] The required closing times for all primary containment isolation valves are established to prevent fission product release through lines connecting to the primary containment.

For reactor coolant system temperatures less than 215°F, the containment could not become pressurized due to a loss-of-coolant accident. The 215°F limit is based on preventing pressurization of the reactor building and rupture of the blowout panels.

The test interval of once per operating cycle for automatic initiation results in a failure probability of 1.1×10^{-7} that a line will not isolate (Fifth Supplement, p. 115).[(3)] More frequent testing for valve operability results in a more reliable system.

In addition to routine surveillance as outlined in Section VI-D.1.0[1] each instrument-line flow check valve will be tested for operability. All instruments on a given line will be isolated at each instrument. The line will be purged by isolating the flow check valve, opening the bypass valves, and opening the drain valve to the equipment drain tank. When purging is sufficient to clear the line of non-condensibles and crud the flow-check valve will be cut into service and the bypass valve closed. The main valve will again be opened and the flow-check valve allowed to close. The flow-check valve will be reset by closing the drain valve and opening the bypass valve depressurizing part of the system. Instruments will be cut into service after closing the bypass valve. Repressurizing of the individual instruments assures that flow-check valves have reset to the open position.

(1) UFSAR

(2) Nine Mile Point Nuclear Generation Station Unit 1 Safer/Corecool/GESTR-LOCA Loss of Coolant Accident Analysis, NEDC-31446P, Supplement 3, September, 1990.

(3) FSAR

a. The set points included in the tables are those used in the transient analysis and the accident analysis. The high flow set point for the main steam line is 105 psi differential. This represents a flow of approximately 4.4×10^6 lb/hr. The high flow set point for the emergency cooling system supply line is ≤ 11.5 psi differential. This represents a flow of approximately 9.8×10^5 lb/hr at rated conditions.

Emergency Cooling Initiation

The emergency cooling initiation logic is separated into two trip systems which use a one-out-of-two taken twice logic configuration. The actuation of a single trip system will cause a half emergency cooling system initiation. A trip system for the emergency cooling initiation parameter provides the protective action of de-energizing one of the two DC solenoid valves for each of the two air-operated condensate return isolation valves. A high reactor pressure or low-low reactor water level signal from an instrument channel will de-energize its corresponding time delay relay after 12 seconds. If either of the two time delay relays in a trip system times out, the two control circuits associated with that trip system will change state causing one of the two DC solenoid valves for each of the two condensate return isolation valves to de-energize. This results in the insertion of a half emergency cooling system initiation signal where the condensate return isolation valves do not open. A full initiation will occur when at least one time delay relay in each of the two trip systems times out, and all four control circuits change state to de-energize both DC solenoid valves for each of the two condensate return isolation valves, thereby opening both valves. It is important to recognize that pulling the fuses for (or otherwise de-energizing) the DC solenoid valves for the condensate return isolation valves will affect the isolation capability on a high steam flow isolation signal.

Emergency Cooling Isolation

Automatic isolation of the emergency cooling systems (loops) occurs on a high steam flow isolation signal from the four ΔP transmitters connected to the steam supply lines (two transmitters per steam line). Each ΔP transmitter provides the sensor inputs to its respective instrument channel. Automatic isolation of an emergency cooling system involves closure of both motor-operated steam supply isolation valves and the condensate return isolation valve in the affected system. [Note that the requirements of Table 3.6.2c do not apply to the drain and vent valves since the isolation function of these valves is to prevent bypass leakage.] For the high steam flow isolation parameter, each emergency cooling system is required to have two tripped or operable trip systems, with two operable instrument channels per operable trip system. Both instrument channels for a given emergency cooling system provide isolation trip signals to both of the system's trip systems in a one-out-of-two logic configuration for each trip system. The trip of either trip system will initiate an isolation of the affected system. A trip system for the high steam flow isolation parameter provides the protective action of closing one of the two steam supply isolation valves and energizing one of the two DC solenoid valves to close the condensate return isolation valve.

The high level in the scram discharge volume is provided to assure that there is still sufficient free volume in the discharge system to receive the control rod drives discharge. Following a scram, bypassing is permitted to allow draining of the discharge volume and resetting of the reactor protection system relays. Since all control rods are completely inserted following a scram and since the bypass of this particular scram initiates a control rod block, it is permissible to bypass this scram function. The scram trip associated with the shutdown position of the mode switch can be reset after 10 seconds.

The condenser low-low-low vacuum and the main steam line isolation valve position signals are bypassed in the startup and refuel positions of the reactor mode switch when the reactor pressure is less than 600 psig. These are bypassed to allow warmup of the main steam lines and to provide a heat sink during startup.

The set points on the generator load rejection and turbine stop valve closure scram trips are set to anticipate and minimize the consequences of turbine trip with failure of the turbine bypass system as described in the bases for Specification 2.1.2. Since the severity of the transients is dependent on the reactor operating power level, bypassing of the scrams below the specified power level is permissible.

Although the operator will set the setpoints at the values indicated in Tables 3.6.2.a-1, the actual values of the various set points can differ appreciably from the value the operator is attempting to set. The deviations include inherent instrument error, operator setting error and drift of the set point. These errors are compensated for in the transient analyses by conservatism in the controlling parameter assumptions as discussed in the bases for Specification 2.1.2. The deviations associated with the set points for the safety systems used to mitigate accidents have negligible effect on the initiation of these systems. These safety systems have initiation times which are orders of magnitude greater than the difference in time between reaching the nominal set point and the worst set point due to error. The maximum allowable set point deviations are listed below:

Neutron Flux

The APRM and IRM scram and rod block setpoints have been derived based on GE setpoint methodology as outlined in NEDC-31336, "GE Instrumentation Setpoint Methodology." In this methodology, the setpoints are defined as three values, Nominal Trip Setpoints, Allowable Values, and Analytical Limits. The established analytical limits are listed in Specification 2.1.2a and 2.1.2b. The derived allowable values are listed below:

APRM

The minimum of:

<u>For W ≥ 0%</u>:

$S \leq (0.55W + 64.46\%)\ T$ with a maximum value of 119.5%
$S_{RB} \leq (0.55W + 59.46\%)\ T$ with a maximum value of 114.5%

AND:

<u>For 14.42% ≤ W ≤ 45%</u>:

$S \leq (1.287W + 16.6\%)$
$S_{RB} \leq (1.287W + 9.312\%)$

WHERE:

S or S_{RB} = The respective scram or rod block allowable value
W = Loop Recirculation Flow as a percentage of the loop recirculation flow which produces a rated core flow of 67.5 MLB/HR
T = FRTP/CMFLPD (T is applied only if less than or equal to 1.0)
FRTP = Fraction of Rated Thermal Power where Rated Thermal Power equals 1850 MW
CMFLPD = Core Maximum Fraction of Limiting Power Density

IRM

IRM Upscale Scram, allowable value is ≤ [121.55/125] divisions of full scale
IRM Upscale Rod Block, allowable value is ≤ [114.2/125] divisions of full scale
IRM Downscale Rod Block, allowable value is ≥ [5.61/125] divisions of full scale

The APRM downscale rod block setpoint has been derived based on GE setpoint methodology as outlined in NEDC-31336, "GE Instrumentation Setpoint Methodology." In this methodology, the setpoint is defined as three values, Nominal Trip Setpoint, Allowable Value, and Analytical Limit. Table 3.6.2g shows the nominal trip setpoints. The corresponding allowable value is as follows:

APRM Downscale Rod Block, allowable value is ≥ [4.24/125] divisions of full scale

Reactor Pressure, ±15.8 psig

Containment Pressure ±0.053 psig

Reactor Water Level, ±2.6 inches of water

Main Steam Line Isolation Valve Position, ±2.5% of stem position

Scram Discharge Volume, +0 and -1 gallon

Condenser Low Vacuum, ±0.5 inches of mercury

High Flow-Main Steam Line, ±1 psid

High Flow-Emergency Cooling Line, ±1 psid

High Area Temperature-Main Steam Line, ±10°F

High Area Temperature-Clean-up and Shutdown, ±6°F

High Radiation-Main Steam Line, +100% and -50% of set point value

High Radiation-Reactor Building Vent, +100% and -50% of set point

High Radiation-Refueling Platform, +100% and -50% of set point

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with NEDC-30851P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," MDE-77-0485, "Technical Specification Improvement Analysis for Nine Mile Point Nuclear Station, Unit 1," and Generic Letter 91-04, "Changes in Technical Specification Intervals to Accommodate a 24-Month Fuel Cycle."

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with NEDC-30851P-A Suppl 2, "Technical Specification Improvement Analyses for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," and with NEDC-31677P-A, "Technical Specification Improvement Analyses for BWR Isolation Actuation Instrumentation.". Because of local high radiation, testing instrumentation in the area of the main steam line isolation valves can only be done during periods of Station shutdown. These functions include high area temperature isolation and isolation valve position scram.

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with NEDC-30936P-A, "BWR Owners' Group Technical Specification Improvement Methodology (with Demonstration for BWR ECCS Actuation Instrumentation)," Parts 1 and 2 and RE-003, "Technical Specification Improvement Analysis for the Emergency Core Cooling System Actuation Instrumentation for Nine Mile Point Nuclear Station, Unit 1."

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R. D. Binz IV from C. E. Rossi dated July 21, 1992).

Testing of the scram associated with the shutdown position of the mode switch can be done only during periods of Station shutdown since it always involves a scram.

b. The control rod block functions are provided to prevent excessive control rod withdrawal so that MCPR is maintained greater than the SLCPR. The trip logics for these functions are 1 out of n; e.g., any trip on one of the eight APRM's, eight IRM's or four SRM's will result in a rod block. The minimum instrument channel requirements provide sufficient instrumentation to assure the single failure criteria is met. Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with NEDC-30851P-A Suppl 1, "Technical Specification Improvement Analyses for BWR Control Rod Block Instrumentation," GENE-770-06-1, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," as approved by the NRC and documented in the SER (letter to R. D. Binz IV from C. E. Rossi dated July 21, 1992), and Generic Letter 91-04, "Changes in Technical Specification Intervals to Accommodate a 24-Month Fuel Cycle."

The APRM rod block trip is flow biased and prevents a significant reduction in MCPR especially during operation at reduced flow. The APRM provides gross core protection; i.e., limits the gross core power increase from withdrawal of control rods in the normal withdrawal sequence. The trips are set so that MCPR is maintained greater than the SLCPR.

The APRM rod block also provides local protection of the core; i.e., the prevention of critical heat flux in a local region of the core, for a single rod withdrawal error from a limiting control rod pattern. The trip point is flow biased. The worst case single control rod withdrawal error has been analyzed and the results show that with the specified trip settings rod withdrawal is blocked before the MCPR reaches the SLCPR, thus allowing adequate margin. Below ~60% power the worst case withdrawal of a single control rod results in a MCPR > SLCPR without rod block action, thus below this level it is not required.

The IRM rod block function provides local as well as gross core protection. The scaling arrangement is such that trip setting is less than a factor of 10 above the indicated level. Analysis of the worst case accident results in rod block action before MCPR approaches the SLCPR.

BASES FOR 3.6.2 AND 4.6.2 PROTECTIVE INSTRUMENTATION

A downscale indication on an APRM or IRM is an indication the instrument has failed or the instrument is not sensitive enough. In either case the instrument will not respond to changes in control rod motion and the control rod motion is prevented. The downscale rod blocks are set at 5 percent of full scale for IRM and [5.28/125] divisions of full scale for APRM (APRM signal is generated by averaging the output signals from eight LPRM flux monitors).

Enclosure E to
NMP1L 1989

NINE MILE POINT UNIT 1

TECHNICAL SPECIFICATIONS BASES
CHANGE SUMMARY

2005

Docket No. 50-220
License No. DPR-63

Revision 8	Bases for Sections 3.3.3 and 4.3.3 (Page 142) were revised to reflect changes to the testing requirements for the core spray and containment spray systems suction valves to be tested in accordance with the In-Service Testing (IST) Program.
Revision 9	Bases for Sections 3.3.2 and 4.2.2 (Page 95) were revised to reflect License Amendment 183. License Amendment 183 revised the reactor coolant system pressure-temperature limit curves and tables in Section 3.2.2/4.2.2, "Minimum Reactor Vessel Temperature for Pressurization."
Revision 10	Bases for Sections 3.6.2 and 4.6.2 (Page 250) were revised to clarify minimum requirements and required actions associated with the instrumentation control logic associated with the emergency cooling system initiation and isolation functions.
Revision 11	Bases for Sections 3.3.1 and 4.3.1 (Page 126) were revised to reflect License Amendment 185. License Amendment 185 revised the Technical Specifications (TS) to allow 24 hours to restore oxygen concentration to within the limit and also allow continued plant operation at less than or equal to 15 percent power with oxygen concentration above the limit.
Revision 12	Bases for Sections 3.2.2 and 4.2.2 (Page 95) were revised to reflect License Amendment 184. License Amendment 184 deleted the TS surveillance requirement regarding reactor vessel material surveillance capsule withdrawal, and deleted the requirement to submit the Special Report for Reactor Vessel Material Surveillance Specimen Examination. Bases for Sections 3.3.4 and 4.3.4 (Page 150) were revised to provide guidance for compliance with the required actions during a plant shutdown with a shutdown cooling containment isolation valve inoperable for closing.
Revision 13	Bases for Sections 3.6.2 and 4.6.2 (Pages 251, 251a, 252, 253 and 254) were revised to reflect License Amendment 186. License Amendment 186 revised the TS to allow a 24-month surveillance frequency for the Source Range Monitor (SRM) and Intermediate Range Monitor (IRM) Instrumentation.

U.S. NUCLEAR REGULATORY COMMISSION
DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

OCTOBER 2005

REVISION 19

INSERTION INSTRUCTIONS

The following instructions are for the insertion of the current revision into the Nine Mile Point Unit 1 FSAR (Updated).

Remove pages listed in the REMOVE column and replace them with the pages listed in the INSERT column. Dashes (---) in either column indicate no action required.

Vertical bars have been placed in the margins of inserted pages and tables to indicate revision locations.

INSERTION INSTRUCTIONS

LIST OF EFFECTIVE PAGES

REMOVE	INSERT
EP i	EP i
EP 1-1	EP 1-1
EP 2-1	EP 2-1
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EP 4-1	EP 4-1
EP 5-1	EP 5-1
EP 6-1	EP 6-1
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EP 8-1 thru EP 8-2	EP 8-1 thru EP 8-2
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EP 16-1 thru EP 16-3	EP 16-1 thru EP 16-3
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EP 18-1	EP 18-1
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INSERTION INSTRUCTIONS

VOLUME 1

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xxv/xxvi	xxv/xxvi
xxvii/xxviii	xxvii/xxviii
xxxiva/xxxivb	xxxiva/xxxivb
xxxv/xxxvi	xxxv/xxxvi
xliii/xliv	xliii/xliv
xlv/xlvi	xlv/xlvi
I-21/-	I-21/-
T I-2 Sh 1 thru 5	T I-2 Sh 1 thru 5
III-9/10	III-9/10
III-11/12	III-11/12
III-12a/12b	III-12a/12b
III-13/14	III-13/14
III-41/42	III-41/42
III-43/44	III-43/44
IV-31/32	IV-31/32
V-5/6	V-5/6
V-11/12	V-11/12
V-13/14	V-13/14
V-15/16	V-15/16
V-21/-	V-21/-
T V-3/T V-4	T V-3/T V-4
F V-1	F V-1

INSERTION INSTRUCTIONS

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xxv/xxvi	xxv/xxvi
xxvii/xxviii	xxvii/xxviii
xxxiva/xxxivb	xxxiva/xxxivb
xxxv/xxxvi	xxxv/xxxvi
xliii/xliv	xliii/xliv
xlv/xlvi	xlv/xlvi
VI-17/18	VI-17/18
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F VII-15	F VII-15
F VII-16	F VII-16
VIII-3/4	VIII-3/3a
---	VIII-3b/4
VIII-29/30	VIII-29/30
VIII-55/-	VIII-55/-
T VIII-3 Sh 7/8 thru Sh 10a/-	T VIII-3 Sh 7/8 thru Sh 10a/-
T VIII-4 Sh 2	T VIII-4 Sh 2
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F VIII-2	F VIII-2
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IX-9/10	IX-9/10
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INSERTION INSTRUCTIONS

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xxv/xxvi	xxv/xxvi
xxvii/xxviii	xxvii/xxviii
xxxiva/xxxivb	xxxiva/xxxivb
xxxv/xxxvi	xxxv/xxxvi
xliii/xliv	xliii/xliv
xlv/xlvi	xlv/xlvi
X-3/4	X-3/4
X-7/8	X-7/8
X-9/10	X-9/10
X-23/24	X-23/24
X-25/26	X-25/26
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X-31/32	X-31/32
X-39/40	X-39/40
X-40a/40b	X-40a/40b
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10A-9/10	10A-9/10
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10A-45/46	10A-45/46
10A-49/50	10A-49/50
10A-51/52	10A-51/52
10A-61/62	10A-61/62
10A-63/64	10A-63/64
10A-81/82	10A-81/82
10A-108a/-	10A-108a/-
10A-110/-	10A-110/-
10A-119/-	10A-119/-
10A-126/-	10A-126/-
10A-127/-	10A-127/-
10A-127a/-	10A-127a/-
F 10A-4	F 10A-4
10B-37/38	10B-37/38
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10B-69/70	10B-69/70
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10B-74/-	10B-74/-
10B-77/78	10B-77/78
10B-88/-	10B-88/-
10B-94/-	10B-94/-
10B-101/-	10B-101/-
10B-107/-	10B-107/-
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10B-139/-	10B-139/-
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10B-165/-	10B-165/-
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XII-21/22 thru XII-27/28	XII-21/22 thru XII-27/28
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T XIII-1	T XIII-1
---	T XIII-2
F XIII-1 thru XIII-5	F XIII-1 thru XIII-5

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xxi/xxii	xxi/xxii
xxv/xxvi	xxv/xxvi
xxvii/xxviii	xxvii/xxviii
xxxiva/xxxivb	xxxiva/xxxivb
xxxv/xxxvi	xxxv/xxxvi
xliii/xliv	xliii/xliv
xlv/xlvi	xlv/xlvi
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XVI-13/14	XVI-13/13a
---	XVI-13b/14
XVI-19/20	XVI-19/20
XVI-21/21a	XVI-21/21a
XVI-123/124	XVI-123/124
T XVI-9/-	T XVI-9/-
B.2-3/4 thru B.2-9/10	B.2-3/4 thru B.2-9/10
---	B.2-10a/10b
B.2-11/12	B.2-11/12
B.5-3/4 thru B.5-5/-	B.5-3/4 thru B.5-5/-
B.17-1/2 thru B.17-3/-	B.17-1/2 thru B.17-3/-
B.18-1/2 thru B.18-3/-	B.18-1/2 thru B.18-3/-
T B-2 Sh 4/-	T B-2 Sh 4/-
---	T B-2 Sh 4a/-

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DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

VOLUME 1

OCTOBER 2005

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E. REFERENCES

1. USAEC Press Release H-252, "General Design Criteria for Nuclear Power Plant Construction Permits," November 22, 1965.

2. 0000-0017-3629-SRLR, Revision 0, "Supplemental Reload Licensing Report for NMP1, Reload 18, Cycle 17," March 2005.

3. GE Fuel Bundle Designs, General Electric Company Proprietary, NEDE-31152P, Revision 5, June 1996.

TABLE I-2

ABBREVIATIONS AND ACRONYMS USED IN UFSAR

ACI	American Concrete Institute
ADS	Automatic depressurization system
AISC	American Institute of Steel Construction
ALARA	As low as reasonably achievable
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOV	Air-operated valve
APRM	Average power range monitor
ARI	Alternate rod injection
ARMS	Area radiation monitoring system
ASTM	American Society for Testing and Materials
ATWS	Anticipated transient without scram
BOC	Beginning of cycle
BOP	Balance of plant
BPWS	Banked position withdrawal sequence
BTP	Branch technical position
BWR	Boiling water reactor
BWROG	Boiling Water Reactor Owners' Group
CAD	Containment atmosphere dilution (device)
CEO	Chief Executive Officer
CFR	Code of Federal Regulations
CGCS	Combustible gas control system
CHF	Critical heat flux
CIV	Combined intermediate valve
CND	Condensate demineralizer
CO_2	Carbon dioxide
COLR	Core Operating Limits Report
CPR	Critical power ratio
CRD	Control rod drive
CRDA	Control rod drop accident
CRPI	Control rod position indication
CRS	Control Room Supervisor
CRT	Cathode ray tube
CSO	Chief Shift Operator
CST	Condensate storage tank
DAC	Dominant area of concern
DBA	Design basis accident
DBE	Design basis earthquake
DCRDR	Detailed control room design review
DEC	Department of Environmental Conservation
DER	Deviation/Event Report
DER	Double-ended rupture
DG	Diesel generator
DOP	Dioctylphthalate
DOT	Department of Transportation

TABLE I-2 (Cont'd.)

ECCS	Emergency core cooling system
ECP	Electrochemical corrosion potential
EDG	Emergency diesel generator
EFPY	Effective full-power years
EIC	Energy Information Center
EOC	End of cycle
EOF	Emergency Operations Facility
EOL	End of life
EOP	Emergency operating procedure
EPA	Environmental Protection Agency
EPDM	Ethylene-propylene-diene-monomer
EPG	Emergency procedure guideline
EPRI	Electric Power Research Institute
ESF	Engineered safety feature
ESW	Emergency service water
FA	Fire area
FCV	Flow control valve
FHA	Fire Hazards Analysis
FMEA	Failure modes and effects analysis
FSA	Fire subarea
FSAR	Final Safety Analysis Report
FZ	Fire zone
GDC	General Design Criterion
GE	General Electric Company
GL	Generic Letter
HAZ	Heat-affected zone
HCU	Hydraulic control unit
HEM	Homogeneous equilibrium model
HEO	Human engineering observation
HEPA	High-efficiency particulate air/absolute (filter)
HPCI	High-pressure coolant injection
HVAC	Heating, ventilating, and air conditioning
HWC	Hydrogen water chemistry
HX	Heat exchanger
I&C	Instrumentation & control
ID	Inner diameter
IGSCC	Intergranular stress corrosion cracking
ILRT	Integrated leakage rate test
INPO	Institute of Nuclear Power Operations
ISEG	Independent Safety Engineering Group
ISI	Inservice inspection
IST	Inservice testing
LCO	Limiting condition of operation
LHGR	Linear heat generation rate
LLD	Lower limit of detection

TABLE I-2 (Cont'd.)

LLL	Low-low limit
LOCA	Loss-of-coolant accident
LOFW	Loss of feedwater
LOOP	Loss of offsite power
LPCS	Low-pressure core spray
LPRM	Local power range monitor
LPSP	Low power setpoint
LPZ	Low population zone
LSSS	Limiting safety system setting
LTC	Load tap changer
M&TE	Measuring and testing equipment
MAPLHGR	Maximum average planar linear heat generation rate
MCC	Motor control center
MCPR	Minimum critical power ratio
MG	Motor generator
MLHGR	Maximum linear heat generation rate
MOV	Motor-operated valve
MSIV	Main steam isolation valve
MSL	Main steam line
MSLB	Main steam line break
NDT	Nil ductility transition
NDT	Nondestructive testing
NDTT	Nil ductility transition temperature
NFPA	National Fire Protection Association
NMPC	Niagara Mohawk Power Corporation
NPSH	Net positive suction head
NRC	Nuclear Regulatory Commission
NRV	Nonreturn valve
NSRB	Nuclear Safety Review Board
NSSS	Nuclear steam supply system
NVLAP	National Voluntary Laboratory Accreditation Program
NYPA	New York Power Authority
NYPP	New York Power Pool
OBE	Operating basis earthquake
OEA	Operating experience assessment
OL	Operating license
OOS	Out of service
OSC	Operational Support Center
OT	Operational transient
PA	Public address (system)
PASS	Post-accident sampling system
PCI	Pellet-cladding interaction
PCT	Peak cladding temperature
p.f.	Power factor
P&ID	Piping and instrumentation diagram

TABLE I-2 (Cont'd.)

PP/PA	Page party/public address (system)
PSAR	Preliminary Safety Analysis Report
PSTG	Plant-specific technical guideline
P-T	Pressure-temperature
PVC	Polyvinyl chloride
QA	Quality assurance
QATR	Quality Assurance Topical Report
RBCLCW	Reactor building closed loop cooling water
RBM	Rod block monitor
RCA	Radiologically-controlled area
RCPB	Reactor coolant pressure boundary
RCS	Reactor coolant system
RG	Regulatory Guide
RIP	Reactor internals protection
RMS	Radiation monitoring system
RO	Reactor Operator
RPIS	Rod position information system
RPS	Reactor protection (trip) system
RPT	Recirculation pump trip
RPV	Reactor pressure vessel
RSP	Remote shutdown panel
RSS	Remote shutdown system
RTD	Resistance temperature detector
RT_{NDT}	Reference temperature nil ductility transition
RWCU	Reactor water cleanup
RWE	Rod withdrawal error
RWM	Rod worth minimizer
RWP	Radiation work permit
SAP	Severe accident procedure
SAR	Safety analysis report
SAS	Secondary alarm system
SBO	Station blackout
SCBA	Self-contained breathing apparatus
SDM	Shutdown margin
SDV	Scram discharge volume
SER	Safety Evaluation Report
SFC	Spent fuel pool cooling and cleanup
SIL	Service Information Letter
SJAE	Steam jet air ejector
SM	Shift Manager
SOE	Sequence of events
SOP	Special operating procedure
SORC	Station Operations Review Committee
SOV	Solenoid-operated valve
SPDS	Safety parameter display system
SR	Surveillance requirement
SRAB	Safety Review and Audit Board

TABLE I-2 (Cont'd.)

SRLR	Supplemental Reload Licensing Report
SRM	Source range monitor
SRO	Senior Reactor Operator
SRP	Standard Review Plan
SRV	Safety/relief valve
SRVDL	Safety/relief valve discharge line
SSA	Safe Shutdown Analysis
SWEC	Stone & Webster Engineering Corporation
SWP	Service water system
TAF	Top of active fuel
TBCLCW	Turbine building closed loop cooling water
TCV	Turbine control valve
TDH	Total developed head
TIP	Traversing in-core probe
TLD	Thermoluminescence dosimeter
TMI	Three Mile Island
TSC	Technical Support Center
TSVC	Turbine stop valve closure
TVD	Test, vent and drain
UBC	Uniform Building Code
UHS	Ultimate heat sink
UL	Underwriters' Laboratories Inc.
Unit 1	Nine Mile Point Nuclear Station - Unit 1
Unit 2	Nine Mile Point Nuclear Station - Unit 2
UPS	Uninterruptible power supply
URC	Ultrasonic resin cleaning
U.S.	United States
USBM	U.S. Bureau of Mines
USLS	U.S. Land Survey
UT	Ultrasonic testing
VWO	Valve wide open

B. CONTROL ROOM

The control room is located in the southeast corner of the turbine building at el 277. It is bounded by the administration building offices on the south and east, the turbine room on the west, and the control room break area, instrumentation and control (I&C) office area, and diesel building on the north.

1.0 Design Bases

1.1 Wind and Snow Loadings

The wind and snow loadings for the control room are the same as for the turbine building.

1.2 Pressure Relief Design

There are no special pressure relief requirements for the control room.

1.3 Seismic Design and Internal Loadings

The structural design for the control room, as well as the auxiliary control room below at el 261, is Class I seismic based on the maximum credible earthquake motion outlined in the introduction to Section III. Components whose functional failure could cause significant release of radioactivity, or which are vital to safe shutdown and isolation of the reactor, are also designed as Class I. The seismic analysis resulted in the application of acceleration factors of 20.0 percent gravity horizontal and 10.0 percent gravity vertical. These acceleration factors were calculated from the dynamic analysis of the turbine building.

Although the control room is structurally a part of the turbine building, functional load stresses when combined with stresses due to earthquake loading are maintained within the established working stresses* for the structural material involved.

1.4 Heating and Ventilation

Heating and air conditioning are provided for personnel comfort and instrument protection. The ventilating system also provides clean air to the control room following an accident.

1.5 Shielding and Access Control

Normal access to the control room is provided from the administration building through security-controlled doors.

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* Also see Section XVI, Subsection G.

Shielding is supplied to allow continuous occupancy during any reactor accident. The most limiting accidents are the main steam line break (MSLB) accident and the loss-of-coolant accident (LOCA) without core spray, which are described in Section XV.

The shielding also meets the design gamma dose rate for personnel in the control room such that the exposure guidelines of 10CFR50 Appendix A, General Design Criterion (GDC) 19, will not be exceeded in the course of the LOCA. In addition, the cumulative dose from any design basis accident (DBA) would also meet GDC 19 limits. Credit is taken for automatic initiation of the control room air treatment system for the MSLB and LOCAs. If air outside the building is contaminated, the ventilating system will be controlled to assure that contamination within the control room is minimized and kept within the above limits, as shown in Section 3.0, following.

2.0 Structure Design

Plans showing location and principal dimensions are shown on Figures III-4, III-5, and III-6.

2.1 General Structural Features

The structural steel enclosing the control room and the auxiliary control room below is supported on concrete walls and concrete foundations bearing on and keyed into sound rock. Actual rock bearing pressures are less than one-third of the allowable working bearing pressure. Lateral earthquake forces or wind loads are transmitted to the concrete foundations by the combination of structural steel bracing and concrete walls.

The control room walls, roof and floors are framed with structural steel. The west and north interior walls are 12-in solid reinforced concrete. The east wall is enclosed with insulated metal wall panels made up of FK-16 x 16 metallic-coated interior liner elements, 1 1/2-in insulation and 16 B & S gage F-2 porcelainized aluminum exterior face sheets, as manufactured by H. H. Robertson Company. The wall panel joints are sealed with a synthetic elastomer caulking material. This wall is separated from the administration building extension by a 3-in rattle space. The south interior wall consists of 8-in concrete blocks laid with steel-reinforced mortar joints. An interior metal partition wall parallel to the south wall forms a 6'-6" corridor and is provided with windows for observing the control room operations from the corridor.

The slab immediately above the control room at el 300 is pinned to the walls and provides radiation shielding, and consists of 8 1/2-in thick poured-in-place reinforced concrete supported on structural steel beam framing. Two-thirds of this slab area has a roof above at el 333 which is made up of 3-in deep metal decking, 2 in of insulation and a 5-ply roof with slag surface. The remaining third of the slab area provides a shielding roof

over the control room and consists of the 8 1/2-in thick poured-in-place reinforced concrete slab to which is applied 1 1/2 in of rigid insulation and a 5-ply roof with slag surface.

The control room floor is poured-in-place reinforced concrete on 14-gauge metal decking. The gross depth of the floor slab is 8 in and the average depth of concrete is 5 3/4 in.

2.2 Heating, Ventilation and Air Conditioning System

The ventilation system shown on Figure III-14 is designed to provide outside and recirculated air to the control room and auxiliary control room areas during normal and emergency conditions.

In the normal ventilation mode, outside air enters the system through a louvered intake after which it passes through a 15-kW duct heater and normal supply isolation dampers, which are interlocked with the emergency ventilation inlet dampers. Outside air is needed to recoup air from leakage and losses and to maintain a habitable environment for personnel. The outside air then flows through an outside air mix damper and is then mixed with recirculated control room return air from the recirculation damper, which is set to maintain a positive pressure in the control room. The total amount of air (14,500 cfm minimum) then passes through a two-element dust filter and redundant cooling coils where it will be cooled, if necessary, to ensure the control room temperature does not exceed the maximum calculated temperature of 80.5°F. The cooled air enters the control room circulation fan for distribution to various areas through ducts. Air will circulate through the control room to the return ductwork for recirculation and mixing with additional outside air. In order to prevent infiltration of potentially contaminated air, doors are weather-stripped and penetrations are sealed to maintain a positive pressure to the turbine building of 1/16 in of water.

The emergency ventilation system is automatically initiated on high radiation signal from the intake radiation monitors, LOCA and/or MSLB signal from the reactor protection system (RPS), or manually initiated when required by procedures. The normal supply isolation dampers will be automatically closed, and the emergency ventilation inlet dampers will be opened. The outside air will then flow through a 15-kW duct heater and one of the full capacity control room emergency fans. The design flow rate for the control room emergency ventilation system is 2250 cfm ±10%. Air then passes through a manual throttling damper, a high efficiency particulate filter, and an activated charcoal filter unit. This filtered air will then join the normal supply ductwork and mix with control room return air to be circulated by the normal control room circulation fan. The design flow rate for the emergency ventilation system outside air is determined as that necessary to maintain a positive pressure of 1/16 in of water to the turbine building, administration building, and

outside atmosphere, and is a function of control room boundary leakage. The design flow rate of 2250 cfm ±10% is within the required range of 1000 to 3750 cfm which is based on minimum required fresh air for personnel and maximum filter capability.

The emergency ventilation fans may be manually started for periodic testing.

Heating is provided by thermostatically-controlled ventilation duct heaters. Cooling is provided by two chiller units. Both the temperature control valve and/or the bypass valve for the chilled water system may be open without overcooling the control room.

Tests and inspections on the control room emergency ventilation filters are done in accordance with Technical Specifications.

2.3 Smoke and Heat Removal

To assist in maintaining a habitable atmosphere in the control room and auxiliary control room, a smoke purge capability is provided from two independent fans, one 6000-cfm makeup fan and one 8000-cfm exhaust fan (Figure III-14).

2.4 Shielding and Access Control

Normal personnel access to the control room is provided by three controlled access doors all located on el 277. The north door opens into the control room break area, the south door opens into the administration building, and the west door opens into a corridor, giving access to the administration building at el 277 and also making available the stairway to el 261 of the administration building.

In addition to the above, a stair is provided within the control room (northwest corner) down to the auxiliary control room on the ground floor, shown on Figure III-4. In case of a reactor accident, personnel access to or from the control room would be from the southerly extreme of all buildings and approximately 400 ft from the center of the reactor.

The walls, roof and floors are designed to have concrete thicknesses which provide shielding during the design basis accident (DBA).

3.0 Safety Analysis

The control room is designed for continuous occupancy by operating personnel during normal operating or accident conditions. Concrete shielding provided in the roof and floors above and in the walls facing the reactor building is more than sufficient to ensure the exposure guideline values of General Design Criterion (GDC) 19 will not be exceeded in the course of a LOCA. Maintaining positive pressure inside the control room and

regulating the filtered outside air supply prevents the concentration of radioactive materials and ensures that the cumulative dose from the main steam line break (MSLB) and LOCA accidents would be within the exposure guideline doses of GDC 19.

In addition, supplied air respirators and potassium iodide (KI) are available in the control room for use if necessary.

Both normal and emergency lighting are provided in the control room together with communications, air conditioning, ventilation, heating and sanitary plumbing facilities. If normal electric power service is not available, provision has been made to power the cooling, ventilating and heating units from the emergency diesel generators.

Building components and finish materials are noncombustible and combustible materials are not stored in the control room.

The minimum distance of the control room to the centerline of the reactor is 330 ft and there are no direct connections from passageways, ventilating ducts or tube connections between the reactor building and the control room.

The floor of the control room is 16 ft above yard grade and 28 ft above maximum lake level (el 249). Therefore, the possibility of flooding or inundation is incredible.

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C. WASTE DISPOSAL BUILDING

1.0 Design Bases

1.1 Wind and Snow Loadings

Wind and snow loadings for the waste disposal building are the same as for the turbine building.

1.2 Pressure Relief Design

There are no special pressure relief requirements for this building.

1.3 Seismic Design and Internal Loadings

The waste disposal building and major components whose functional failure could cause significant release of radioactivity, or which are vital to safe shutdown and isolation of the reactor within are designed as Class I structures. The analysis of stress levels used the following earthquake design coefficients.

	Percent Gravity	
	Horizontal	Vertical
Elevations 225 and 229	11.0	5.5
Elevation 236-6	11.5	5.5
Elevations 246-6, 247 and 248	12.2	5.5
Elevation 261	17.0	7.33
Elevation 277 (276-6)	30.7	7.33
Roof Elevation 289	30.7	7.73

Exterior walls of the substructure are designed for an earth pressure at any depth equal to the depth in feet times 90 psf.

The exterior walls of the substructure and the base slab are designed to resist hydrostatic pressure and uplift due to exterior flooding to el 249.

Except where concentrated loading due to the handling and placement of equipment requires construction of greater strength, the substructure floors are designed for dead loads plus the following:

Elevations	Live Loads Pounds Per Sq Ft
225 and 229	Unlimited
236-6, 237 and 248	350
241 and 247	250

The grade floor at el 261, including the concrete shielding plugs which close hatchways over equipment in the substructure, is designed for a uniform live load of 450 psf; or in the loading area a concentrated loading pattern produced by an AASHO* H20 loading, or 1000 psf, whichever requires the stronger construction.

1.4 Heating and Ventilation

Heating and ventilation is provided for personnel comfort, equipment protection and for controlling possible radioactivity release to the atmosphere.

1.5 Shielding and Access Control

Shielding is provided around tanks and equipment to maintain dose rates as described in Section XII.

Normal access to the waste disposal building is from the turbine building.

2.0 Structure Design

Floor and roof plans, exterior elevations, sections showing interior walls, and architectural details of the building are shown on Figures III-2 through III-6 and Figure III-11.

2.1 General Structural Features

The poured-in-place reinforced concrete building substructure is founded on firm Oswego sandstone.

The maximum bearing pressure on the rock as recommended by consultants is 40 tons/sq ft. This results in a safety factor of 18 based on actual unconfined compressive strength tests on selected specimens of rock core extracted from test borings.

The building has a flat roof consisting of a cellular metal deck covered with insulation and a bitumen and felt roofing membrane. The exterior facing of the superstructure walls is of sheet metal, attached either to an exterior shielding wall or to insulated cellular sheet metal wall. The interior walls of the

* American Association of State Highway Officials.

access to the building interior is via the waste building extension. Two exterior rollup doors allow access for vehicles to the two truck bays. Four exterior doors are normally locked and provide emergency egress.

2.0 Structure and Design

Floor and roof plans and sections showing interior walls are shown on Figures III-3 through III-8.

2.1 General Structural Features[1]

The RSSB is located to the east of, and is adjacent to, the existing offgas building, waste disposal building, and waste building extension of Unit 1. The arrangement of the RSSB can be considered as follows: process, handling and storage areas.

This section is rectangular in shape and approximately 277 ft long below grade, 330 ft long above grade (north-south), and 61 ft wide (east-west). The majority of the primary structural components are reinforced concrete. The foundation mat is generally founded on top of bedrock. The finish grade and truck entrance and exit openings are at el 261'-0". The roof elevation is located at el 301'-2 1/2", with the material handling crane running longitudinally underneath the roof at el 292'-6 1/2". With the exception of a few feet around the perimeter, the crane can service the entire interior area of this section. Those portions of the RSSB which are classified as seismic-resistant elements are designed to maintain their structural integrity during and after all credible design loading phenomena, including OBE. Those items which are classified as seismic-resistant elements are the foundation base mat, structural concrete walls, floors and roof. Nonseismic-resistant structural elements are designed to maintain their structural function for all anticipated, credible design loading conditions encountered during construction, testing, operation, and maintenance of the facility. Those compartments containing large tanks (over 2,000 gal) of radioactive liquids are lined with steel to contain 1.5 tank volumes in the event of a tank rupture during a seismic event. During normal operation, maintenance, and loading and unloading operations, the structure provides sufficient environmental isolation to ensure that the exposure of plant operating personnel and the general public to radiation is ALARA.

2.2 Heating, Ventilation and Air Conditioning[2]

Fresh air is filtered and conditioned and supplied to the control and electrical rooms, which are maintained at a slightly positive pressure with respect to other areas of the RSSB and the adjoining radwaste building. Air from other portions of the RSSB is not recirculated back to these areas. Air is recirculated within the RSSB and is processed through a filter system prior to reconditioning and redistribution. The recirculation filter

system is comprised of the following primary filtration components:

1. Prefilters to remove larger particles to reduce dust loading on the high-efficiency particulate air (HEPA) filters.

2. HEPA filters with an individual efficiency of at least 99.97 percent.

All RSSB ventilation exhaust air is processed through a filter train prior to discharging into the stack. The filter is comprised of the following primary filtration elements:

1. Prefilter to remove larger particles to reduce loading of the HEPA filters.

2. HEPA filters with an individual efficiency of at least 99.97 percent.

3. Two carbon adsorber sections for the removal of radioactive iodine from the exhaust stream. (Note: The charcoal adsorption capability provides added insurance that any release of iodine or other halogen activity will not result in offsite dose limits being exceeded. It is considered to be an enhancement, and not mandatory for the current use of the building for storage of waste and not for solidification of waste. Therefore, charcoal adsorption periodic testing is not required.)

4. Final HEPA filters with an individual efficiency of at least 99.97 percent.

Air flow through the process areas of the RSSB is from areas of low radioactive contamination potential toward areas with increasingly higher contamination potential. Air from the two truck bays is ducted to the ventilation exhaust system rather than returned to the recirculating atmospheric cleanup system to prevent recirculation of truck exhaust fumes in the RSSB. The RSSB atmosphere is continuously purged (10,250 cfm) with clean outside air by operation of the fresh air supply and ventilation exhaust systems. Purge air from the process areas of the RSSB replaces the air drawn from the truck bays such that the entire building is purged via the exhaust from the truck bays. Radioactive tank vents are piped directly into the exhaust system upstream of the filter. Heating coils (electrical), cooling (chilled water), and fans are located downstream of the filter components to protect them from radioactive contamination. Supplemental heating is provided for the control and electrical rooms by duct heaters. Stair towers are provided with space heaters. Chilled water is produced in one of two 100-percent capacity water chillers and circulated by one of two 100-percent capacity chilled water pumps. Single failure of any one fan,

heating coil or cooling coil may result in operating variations from the design basis; however, the overall effect with regard to the health and safety of the building occupants or the public will not be compromised. Fresh air inlet and ventilation exhaust penetrations through the RSSB outer walls are each fitted with two series mounted dampers designed to withstand a minimum of 3 psi pressure differential resulting from severe weather pressure conditions. All design and specification requirements are for nonseismic, nonnuclear safety-related systems and components. Instrumentation and control systems are provided to achieve required space temperature conditions and to maintain air flow requirements to provide acceptable building and process area pressure relationships. Relative humidity is not controlled, although it is maintained at reasonable levels by the HVAC system. All operating control functions are automatic. Temperature control systems in the fresh air supply and recirculating atmospheric cleanup systems are independent. Air flow control systems in the fresh air supply system and the exhaust ventilation system include interlock provisions to maintain pressure relationships upon de-energizing an exhaust or supply fan. Air flow controls of the recirculating atmospheric cleanup system are independent of the other systems. Redundant temperature sensing and control loops are provided in the fresh air supply and recirculating atmospheric cleanup system. Local instruments and remote indication and/or annunciation are provided.

2.3 Shielding and Access Control[3]

The RSSB is designed to minimize exposure to plant personnel and the public by its location and design. The RSSB is located within the protected area and is heavily shielded by reinforced concrete.

3.0 Use

The RSSB was constructed with the specific intent of providing onsite storage of low-level radioactive waste (LLW). The need to store LLW onsite is the result of the federal Low-Level Radioactive Waste Policy Act as amended in 1985, which initiated the process by which the three existing LLW disposal sites (Barnwell, SC; Beatty, NV; and Hanford, WA) would no longer be required to receive LLW. Although originally designed to store Unit 1 LLW, the RSSB is capable of providing interim storage of LLW produced at both Unit 1 and Unit 2. From a technical standpoint, the storage of Unit 2 waste at Unit 1 is considered acceptable based on the following:

1. The isotopic distributions of the waste stored in the RSSB from the two units are similar and expected to remain similar as both units have applied noble metals, inject depleted zinc, and inject low levels of hydrogen.

2. The selective storage of the high-activity LLW from both units in the RSSB (and the low-activity LLW at Unit 2) creates the potential for the storage of greater average activity concentration in the building, although not greater volume. However, since the RSSB was designed assuming the storage of incinerated resins which represent a bounding activity concentration, the building design is considered adequate for the combined storage from both units;

3. Total activity in the RSSB will ultimately be controlled per the Site radiation protection program to ensure that both onsite and offsite dose and dose rate limits are maintained; and

4. The transfer of by-product material between Unit 1 and Unit 2 will be conducted in accordance with approved radiation protection implementing procedures.

Radioactive piping is routed through a shielded pipe tunnel and in shielded areas to limit exposure. Major pieces of equipment that can be significant sources of radiation exposure are each provided with a separate shielded cubicle. The storage vaults are shielded with 48 in of concrete in the storage zone (below crane). The roof is 24-in thick. The tank cubicles are shielded by 36 in of concrete. The east-west truck bay is equipped with a retracting shield door in the ceiling which mitigates albedo radiation in the truck bay from the storage vaults. The low-level storage room and the process equipment cubicle are equipped with sliding shield doors.

Access is controlled administratively by the Unit 1 Radiation Protection Program. Physical control of high radiation areas is maintained in accordance with Technical Specifications.

The structural components which guide the control rods have been examined to determine the loadings which would occur in a LOCA (including a steam line break). The core structural components are designed so that deformations produced by accident loadings will not prevent insertion of control rods.

Considerable effort was expended to eliminate possible failures or control instability due to the vibration of reactor internal components. The reactor system was analyzed as a multidegree-of-freedom system. This analysis determined the system's natural frequencies, the resultant vibration mode shapes and the relationship between the vibration amplitudes and the critical stresses in the system, to show that system integrity would be maintained.

7.3 Surveillance and Testing

Rigid quality control requirements assured that the design specifications of the vessel internal components were met. These quality control methods were utilized during the fabrication of the individual components as well as during the assembly process.

Preoperational performance tests and the startup program demonstrated the design adequacy of reactor vessel internals and operability of the core spray spargers.

Periodic testing of the control rod system, i.e., reactivity margin - core loading and stuck control rods; rod scram insertion times and reactivity anomalies, is described in the Technical Specification.

C. REFERENCES

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3. General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A-14-US, June 2000.

4. J. A. Wooley, "Three-Dimensional BWR Core Simulator," NEDO-20953A, January 1977.

5. "Qualification of the One-Dimensional Core Transient Model for BWR's," NEDO-24154, Vol. 1 and 2, and NEDE-24154-P-A, Vol. 3, February 1, 1986.

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12. GENE-523-113-0894, Rev. 1, "BWR Core Shroud Inspection and Evaluation Guidelines," March 1995.

13. BWRVIP-01, Rev. 2, "BWR Core Shroud Inspection and Flaw Evaluation Guideline," October 1996.

14. BWRVIP-07, "Guidelines for Reinspection of BWR Core Shrouds," February 1996.

15. Design Change No. N1-97-033, "Core Shroud Vertical Weld Contingency Repair."

16. GE Marathon Control Rod Assembly, NEDE-31758P-A, October 1991.

1.4 Primary Coolant Leakage

A double O-ring type seal is provided on the reactor vessel head closure. The area between the seals is monitored for leakage. A groove between the inner and outer O-ring communicates through the vessel flange to a line in which is installed a pressure switch between two solenoid valves. The solenoid valves are operated from the control room. The monitoring instrumentation is shown on Figure V-1.

Other primary coolant leakage is detected by monitoring leakage into the drywell floor drain tank for unidentified drywell leakage, and the drywell equipment drain tanks for identified drywell leakage. Unidentified drywell leakage from the CRDs, valve flanges, packing, component cooling water, service water, recirculation pump suction and discharge valve packing leakoff, and any other leakage not connected to the drywell equipment drain tanks, collects in the drywell floor drain tanks. Identified drywell leakage is hard piped to the drywell equipment drain tanks and includes recirculation pump seal leakage. Abnormal leakage rates for the drywell floor and equipment drain tanks are detected and alarmed in the control room.

The excess leakage alarm function for the drywell floor and equipment drain tanks is performed by measuring volume changes in gallons that occur over a predetermined time period and calculating the resultant rate of change. Volume changes are used to determine the rate of change because of the irregular shape of the drywell floor and equipment drain tanks. By using volume change, excess leakage alarm capability is achieved across the entire instrument range with alarm checking occurring upon each recalculation.

The rate of rise alarm function for the drywell floor drain tank is performed by measuring the amount of time between precise level step changes. When a level increase is detected, the change in tank volume and elapsed time since the last change are used to determine the rate of volume change. The rate of volume change is then used to determine the rate of rise. The calculated rate of rise is output to the control room chart recorders and alarm checked.

The rate of rise for the drywell equipment drain tanks is monitored by evaluating the fill rate recorded on the equipment drain tank level chart recorder in the control room. This is performed every 4 hr.

The integrated flow pumped from the drywell floor and equipment drain tanks to the waste disposal system is another means that can be used to determine leakage into the drywell floor or the equipment drain tanks.

Automatic blowdown will not occur for any primary system leak rate below the maximum allowable total operating leak rate of approximately 25 gpm. However, for breaks below about 50 gpm (although the Technical Specification limit is 25 gpm), the triple low-level setting (6 ft 3 in below minimum normal) would not be reached and automatic blowdown of relief valves would not be initiated. If normal Station offsite power were lost, both CRD hydraulic system pumps would be automatically loaded on the diesel generators to maintain water level in the vessel above the automatic blowdown trip level. It is assumed that only one CRD system is operating. The flow rate of one CRD system pump is 50 gpm at 1000 psig reactor vessel pressure and 180 gpm at zero psig reactor vessel pressure. If both pumps were operating, the flows would be greater.

For much larger leak sizes, the time to reach the automatic blowdown trip level is shown in Table V-5. This table is conservatively based on only one diesel generator and its associated CRD system pump being available.

1.5 Coolant Chemistry

The RCS is not designed to use inhibitors. Limits are set on chlorides, solids and gross coolant radioactivity during normal Station operation.

Hydrogen water chemistry (HWC) injection and noble metal chemical addition (NMCA or NobleChem) systems are installed to reduce the potential for intergranular stress corrosion cracking (IGSCC) of the stainless steel reactor vessel components and recirculation piping. The zinc injection system is installed to reduce Cobalt 60 buildup in the primary piping corrosion films. This has the major benefit of reducing radiation dose rates in the drywell, reducing radiation exposure during outages. Hydrogen injection is provided through the feedwater/condensate systems; NobleChem is periodically added through the recirculation pump differential pressure transmitter lines, and zinc injection is provided through the feedwater system.

2.0 Reactor Vessel

An isometric drawing of the reactor vessel is shown on Figure IV-9. Vessel penetrations are shown on Figure V-2 and data for the reactor vessel in Table V-1. The reactor vessel is a vertical cylindrical pressure vessel. The base plate material is high-strength alloy carbon steel SA-302, Grade B. The vessel interior is clad with Type 308L to produce a 304 composition stainless steel following application by weld overlay.

The head closure is designed for easy removal and reassembly, being bolted to the vessel with high-strength studs. Removable stud bushings are furnished in the body flange to facilitate repair of damaged threads.

Protective Devices	Redundancy
High Neutron Flux	Also incorporated in the same manner in the RPS are high neutron flux scrams initiated by the average power range monitor (APRM) system. There are a total of eight APRM signals, four in each logic channel. The trip of only one of four in each channel will produce a scram. As discussed in Section XV, rapid operational transients of pressure and neutron flux are usually coincident. Considering the coincidence of the signals and the large amount of instrumentation provided, considerable redundancy to produce a scram exists.
Solenoid-Actuated Relief Valves	Six independently-actuated relief valves are provided to limit overpressure below the setpoint of the safety valves for events of moderate frequency (MSIV closure with scram), as discussed in Section XV.
Safety Valves	A total of 9 safety valves will limit the pressure to below 110 percent of design pressure for the MSIV closure (safety valve actuation overpressurization) event.

The emergency cooling system has not been included here as a pressure-limiting device. Its capacity in terms of heat removal is only a few percent of rated capacity and cannot be utilized to reverse rapid pressure transients following isolation. The main purpose of the emergency cooling system is to assure long-term core cooling during isolation situations by maintaining coolant inventory.

3.0 Design Heatup and Cooldown Rates

The pressure vessel was fabricated in accordance with ASME Section I-1962. The nominal design temperature of the primary system corresponds to the saturation pressure of 1250 psig. Short-term temperature transients corresponding to 1375 psig, the safety limit, are also considered. Design temperature in the recirculation piping corresponds to saturated conditions at 1200 psig with short-term transients to 1375 psig also.

Of all the malfunctions considered in Section XV, only the malfunction of the initial pressure regulator leads to a more rapid blowdown than the design blowdown rates of Section V-B.1.3 above. However, analyses indicate that the strains incurred are well within the 4-percent limit permitted by ASME Section

III-1965 for up to ten times during the vessel lifetime. These and other extensive design analyses which determine the maximum heatup and cooldown rates are included in Section XVI.

4.0 Materials Radiation Exposure

4.1 Pressure-Temperature Limit Curves

The fracture toughness requirements for the pressure vessel for testing and operational conditions are specified in Section IV of 10CFR50 Appendix G. The pressure-temperature (P-T) limit curves were developed using the methodology specified in ASME Code Case N-640, as well as 10CFR50 Appendix G, and the 1989 Edition of ASME Section XI, Appendix G. The bases for the technical requirements of the ASME Code are discussed in Welding Research Council (WRC) Bulletin 175. Appendix G to 10CFR50 requires that the effects of neutron irradiation on the nil ductility reference temperature (RT_{NDT}) of the beltline materials must be included in the P-T curve calculations. Revision 2 to Regulatory Guide (RG) 1.99 is used for this purpose. Calculated adjusted reference temperature (ART) values and temperature limits are given in this section for limiting locations in the reactor vessel. Code Case N-640 permits fracture toughness curve K_{Ic}, as found in ASME Section XI, Appendix A, to be used in lieu of curve K_{IA} of ASME Section XI, Appendix G, for development of P-T limit curves. The P-T limit curves are presented in the Technical Specifications.

The boltup limits for the flange and adjacent shell region are based on a minimum metal temperature of the RT_{NDT} of the flange and adjacent shell region (40°F) plus 60°F. The maximum throughwall temperature gradient from continuous heating or cooling at 100°F/hr was used. The safety factors applied were as specified in the ASME Code, Section XI, Appendix G.

P-T curve calculations are performed on the beltline material which has the highest ART over the period for which the P-T curves are valid. Therefore, ART calculations were performed using RG 1.99 Revision 2 for the limiting material, plate G-307-4/5.

4.2 Temperature Limits for Boltup

The reactor vessel head flange and vessel flange, in combination with the double O-ring type seal, are designed to provide a leak-tight seal when bolted together. When the vessel head is placed on the reactor vessel, only that portion of the head flange near the inside of the vessel rests on the vessel flange. As the head bolts are replaced and tensioned, the vessel head is flexed slightly to bring together the entire contact surfaces adjacent to the O-rings of the head and vessel flange. Both the head and vessel flanges have a RT_{NDT} of 40°F and they are not subject to any appreciable neutron radiation exposure. Therefore, the minimum vessel head and head flange temperature for bolting the head flange and vessel flange is established at

40°F + 60°F, or 100°F. The flanges and adjacent shell are required to be warmed to this minimum temperature of 100°F before they are stressed by the required bolt preload. A minimum temperature of 100°F is also required for the closure studs.

4.3 Temperature Limits for In-Service System Pressure Tests

The fracture toughness analysis for in-service system pressure tests with fuel in the vessel resulted in a revised set of P-T limits shown in the Technical Specification. The calculated adjustment to the RT_{NDT}, based on Revision 2 of RG 1.99, is used in the analysis to account for the effect of fast neutrons.

4.4 Operating Limits During Heatup, Cooldown, and Core Operation

The fracture toughness analysis was done for the assumed heatup or cooldown rate of 100°F/hr. The temperature gradients and thermal stress effects corresponding to this rate were included.

In order to assess the ART at the 1/4T and 3/4T positions, RG 1.99 requires an assessment of the peak fast (E>1Mev) neutron flux at the inner diameter (ID) surface of the pressure vessel. These data were determined using RG 1.190 compliant plant-specific methods benchmarked to Unit 1 flux monitors that had been removed and tested. The peak vessel ID surface fast flux is 3.054 x 10^9n/cm^2/sec.

4.5 Predicted Shift in RT_{NDT}

The allowable internal vessel pressure for a specific coolant temperature is a function of several key variables including the ART. The ART for the vessel beltline region enters the P-T calculations directly via the reference fracture toughness curve (K_{Ic}). Therefore, it is necessary to provide reasonable and conservative estimates of the shift in RT_{NDT} for the period of time for which the P-T calculations will be used. The ART was calculated using Revision 2 to RG 1.99.

The vessel material surveillance program is outlined in Section XVI.

4.6 Neutron Fluence Calculations

Reactor vessel neutron fluence has been evaluated using a method in accordance with the recommendations of RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," dated March 2001. Future evaluations of reactor vessel fluence will be completed using a method in accordance with the recommendations of RG 1.190 (as noted in Reference 5). NRC approval of the Unit 1 neutron fluence calculational methodology is documented in Reference 6.

5.0 Mechanical Considerations

5.1 Jet Reaction Forces

The RPV and support structures are designed to withstand the forces that would be created by full area flow of any vessel nozzle with the RPV at design pressure. Thus, even if one line ruptured, the vessel would not be moved by jet reaction forces sufficiently to cause rupture of other connected pipes.

5.2 Seismic Forces

The reactor primary system is designed and constructed in accordance with performance objective 1 for seismic design, as described in Section III.

6.0 Safety Limits, Limiting Safety Settings and Minimum Conditions for Operation

Safety limits are appropriate for maximum pressure and heatup and cooldown rates for the RCS. The pressure is automatically limited by devices for which limiting safety system settings are

required. These settings include safety valve actuation, reactor high-pressure scram, and reactor high-flux scram.

Minimum conditions for operation are appropriate for both the devices which have limiting safety system settings and for other pertinent operating parameters. These minimum conditions for operation include the number of operable reactor safety valves, the number of operable solenoid-actuated relief valves, maximum permissible values for various coolant chemical parameters and allowable heatup and cooldown rates.

D. TESTS AND INSPECTIONS

1.0 Prestartup Testing

The RCS was given a system hydrostatic test in accordance with Code requirements prior to initial reactor startup. Before pressurization, the system was heated to RT_{NDT} + 60°F, i.e., 100°F. Piping and support hangers were checked while thermal expansion was in progress. Further details of initial tests are given in Section XIV.

2.0 Inspection and Testing Following Startup

Tests and inspections of the safety and relief valves are covered by the Inservice Inspection (ISI) and Inservice Testing (IST) Programs. Reactor pressure and flux scram components are tested as per the Technical Specifications. Visual inspections are also performed as covered in the ISI Program. In addition, the following tests and inspections are performed.

2.1 Pressure Test

A leakage test at operating pressure is made on the primary system following each removal and replacement of the reactor vessel head. The system is checked for leaks and abnormal conditions are corrected before reactor startup. The minimum vessel temperature during the leakage test is at least 60°F above the highest RT_{NDT} of the material in the vessel closure flange region (40°F) prior to pressurizing the vessel.

2.2 Pressure Vessel Irradiation

Vessel material surveillance samples are located within the reactor vessel to enable periodic monitoring of material properties with exposure. The vessel material surveillance program is outlined in Section XVI.

F. REFERENCES

1. NRC Standard Review Plan, Section 5.2.2, Overpressurization Protection - NUREG 75-087.

2. 0000-0017-3629-SRLR, Revision 0, "Supplemental Reload Licensing Report for NMP1, Reload 18, Cycle 17," March 2005.

3. K. Shure and D. J. Dudziak, "Calculating Energy Release by Fission Products," AEC Report WAPD-T-1309, March 1961.

4. K. Shure, "Fission Product Decay Heat," AEC Report WAPD-BT-24, December 1961.

5. NRC Letter to NMPNS dated November 8, 2004, "Nine Mile Point Nuclear Station Unit Nos. 1 and 2 - Issuance of Amendments RE: Implementation of the Reactor Pressure Vessel Integrated Surveillance Program (TAC Nos. MC1758 and MC1759)."

6. NRC Letter to NMPNS dated October 27, 2003, "Nine Mile Point Nuclear Station, Unit No. 1 - Issuance of Amendment Re: Pressure-Temperature Limit Curves and Tables (TAC No. MB6687)."

TABLE V-3

FATIGUE RESISTANCE ANALYSIS

Region of Vessel	Usage Factor
Closure Studs	0.205
Basin Seal Skirt Weld	0.782
Feedwater Nozzles	
With Repair Cavities	0.489
Without Repair Cavities	0.163
Control Rod Drive Penetrations	0.060
Lower Vessel Head, Vessel Support Skirt and Core Support Cone	0.0833
Reactor Recirculation Nozzles	0.006

TABLE V-4

CODES FOR SYSTEMS FROM REACTOR VESSEL
CONNECTION TO SECOND ISOLATION VALVE

	Piping Vessel Nozzle to Second Isolation Valve	Isolation Valves
Shutdown Cooling Cleanup	ASA B31.1-1955; ASME Sec I-1962 and Articles N324 and N460 to N469 of ASME Sec III-1965; ASME Sec III, Appendix F, 1986 Edition*	ASME Sec I-1962
	ASA B31.1-1955; ASME Sec I-1962 and Articles N324 and N460 to N469 of ASME Sec III-1965; ASME Sec III, Appendix F, 1986 Edition*	ASA B31.1-1955, certain requirements of ASME Sec IIIA-1965, and ASME Sec III-1986 (IV-38-13)
Feedwater Core Spray	ASA B31.1-1955; ASME Sec I-1962 and Articles N324 and N460 to N469 of ASME Sec III-1965	ASME Sec I-1962
	ASA B31.1-1955; ASME Sec I-1962 and Articles N324 and N460 to N469 of ASME Sec III-1965; ASME Sec III, Appendix F, 1986 Edition*	ASA B31.1-1955 and certain requirements of ASME Sec IIIA-1965
Liquid Poison	ASA B31.1-1955, ASME Sec I-1962 and Articles N324 and N460 to N469 of ASME Sec III-1965	ASME Sec I-1962

* For analyzing thermally-induced overpressurization conditions between isolation valves.

REACTOR EMERGENCY COOLANT SYSTEM

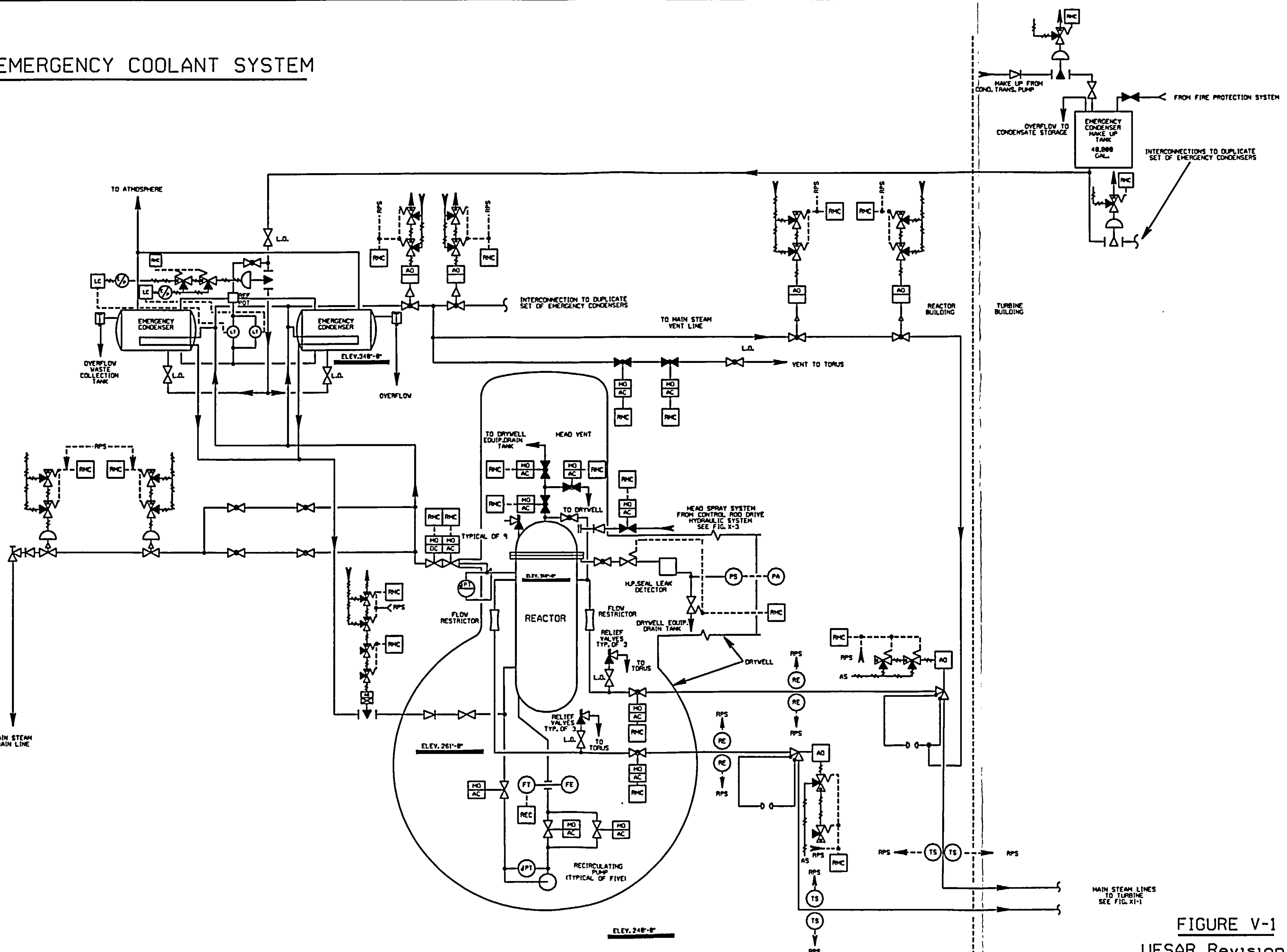

FIGURE V-1

UFSAR Revision 19
October 2005

U.S. NUCLEAR REGULATORY
COMMISSION
DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

VOLUME 2

OCTOBER 2005

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metal wall area of approximately 2,400 sq ft has been attached with bolts that are designed to fail with an internal pressure of approximately 65 psf of wall area. Relief of pressure through this area in case of an energy release will prevent excessive internal pressure on the superstructure walls, roof and their supports, which would fail at an internal pressure in excess of 80 psf. Subsequent calculations were performed in accordance with the AISC Manual of Steel Construction, Load & Resistance Factor Design (LRFD), First Edition, to compute the failure load of the building superstructure, and was determined to be at least 117 psf.

1.3 Seismic Design

The reactor building and its contents whose functional failure could cause significant release of radioactivity, or which are vital to safe shutdown and isolation of the reactor, are designed as Class I structures using the maximum credible earthquake ground motion of 11 percent of gravity. As discussed in Section III, dynamic analyses determine the earthquake acceleration applicable to the various elevations of the reactor building. All equipment whose functional failure could cause significant release of radioactivity, or which are vital to safe shutdown and isolation of the reactor in the reactor building, is designed to withstand these forces.

Functional load stresses (normal operation), when combined with stresses due to earthquake loading, are within the established code stresses.

1.4 Shielding

The reactor building shielding is discussed in Section XII-B, and is designed to limit the radiation level in accessible areas during power operation.

2.0 Structure Design

The reactor building houses the refueling and reactor servicing equipment; fresh and spent fuel storage facilities; and other reactor auxiliary or service equipment, including the emergency cooling system, reactor cleanup system, liquid poison system, CRD hydraulic system equipment, core and containment spray systems, and components of electrical equipment. The equipment arrangement and principal dimensions are shown on Figures III-2 to III-8.

2.1 General Structural Features

The poured-in-place reinforced concrete building substructure is founded on firm Oswego sandstone. The substructure begins 68 ft

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* Also see Section XVI, Subsection G.

below grade and extends upward 147 ft to the operating floor. The maximum bearing pressure on the rock is 40 tons/sq ft. This results in a safety factor of 18 based on actual unconfined compressive strength tests on selected specimens of rock core extracted from test borings. The maximum actual bearing pressure on the rock is 14 tons/sq ft. The superstructure above the operating floor is 57 ft high and consists of structural steel framing supporting the roof system, insulated metal panel siding, and a 125-ton overhead crane. The reactor building is enclosed from el 193 (68 ft below grade) to el 340 (operating floor level), with poured reinforced concrete walls varying in thickness from 1 ft 4 3/4 in to 4 ft 0 in. The superstructure (approximately 57 ft high) above the operating floor is enclosed with insulated metal wall panels and a metal roof deck covered with a 5-ply tar and felt built-up roof. The metal wall panels of the superstructure use caulking of demonstrated leak-tightness. Air infiltration tests on joints between panels sealed with the caulking were conducted at the Housing Research Laboratory, University of Miami, in accordance with the recommended specifications of the National Association of Architectural Metal Manufacturers, and showed no measurable air leakage at pressure differentials ranging from 0.3 to 2.0 in of water. The metal panels, insulated precast concrete wall panels, and the related caulking materials, doors and access openings have been carefully analyzed to assure that resultant leakage will be within specifications.

Precast concrete slabs (el 261 to 285) and uninsulated metal wall panels (el 285 to 340) are applied to the exterior of the reinforced concrete walls of the reactor building for esthetic purposes. However, these slabs and panels do not form a part of the building support or provide any additional measure of leak-tightness for the building.

Fiberglass thermal insulation is provided for the superstructure walls. Thermal insulation properties of the concrete walls, metal wall panels and roofing provide very adequate weather and thermal protection for the reactor building. All materials meet ASTM specifications and are in accordance with Fire Underwriters' requirements.

The exterior of the reactor building below grade is provided with a peripheral drain for collection of groundwater seepage; the drain discharges into a sump pit with two 150-gpm submersible pumps located at the southwest corner of the building. The reactor building grade floor at el 261 is 12 ft above maximum lake level (el 249). Protection of the building from possible inundations, ice accumulation and lake wave action is provided by a rock dike 1,000-ft long at the shoreline.

Specific codes that are complied with include American Institute of Steel Construction, American Concrete Institute, New York State Building Code and the Uniform Building Code (UBC).

E. CONTAINMENT VENTILATION SYSTEM

1.0 Primary Containment

1.1 Design Bases

During normal Station operation, heat is released to the drywell as heat losses from the reactor, motors, hot pipes and other equipment. The drywell is equipped with six water-cooled heat exchanger fan units, which remove heat generated within the drywell and maintain ambient temperature below 150°F during normal operation, to protect equipment not required under accident conditions.

During normal operation, the primary containment vessels--drywell and pressure suppression chamber--are purged with nitrogen (to a pressure of approximately 1.5 psig--see Section VI-B) to maintain less than a 4-percent oxygen concentration, which renders the containment atmosphere nonflammable in the event of hydrogen release from a metal-water reaction following a LOCA.

1.2 System Design

A piping and instrumentation diagram (P&ID) for the ventilation system is shown on Figure VI-23. The six heat exchanger fan units used to cool the drywell are rated at 500,000 Btu/hr each. Their combined rated cooling capacity is sufficient to maintain the drywell ambient temperature at 135°F maximum with all units in operation, and 150°F maximum with one unit out of service (OOS). The 150°F is the design basis maximum temperature limit for the drywell bulk ambient temperature under normal operation. The minimum drywell bulk average temperature limit is 115°F. This value is adopted as the minimum to bound the acceptable temperature range in which all analysis results and equipment performance is assured. The minimum drywell bulk average temperature is based on providing acceptable accuracy of RPV level instrumentation and to ensure compliance with reactor head safety valve setpoint tolerance, as well as its use as an input to EOP calculations.

The coolers are located in the lower portion of the drywell, with ductwork provided on the suction side of the units to draw warmer gases from the upper section of the drywell. The cooled gas is discharged into the lower part of the drywell. The reactor building closed loop cooling water (RBCLCW) system supplies water to the heat exchangers. The RBCLCW system has a backup cooling water supply from the emergency service water (ESW) system.

Three coolers can be powered from each diesel generator. The drywell ambient temperature is indicated in the main control room.

Since the cooling system forms a closed loop inside the containment, only one isolation valve is included, as discussed in Section VI-D.

The design of the combustible gas control system (CGCS) is discussed in Section VII-G.

A line is routed to the suppression chamber from between the isolation check valves and the outer motor-operated valves (MOVs) to permit flow testing. During these tests, the outer MOV is closed and the valve in the test line to the suppression chamber is opened. Pumps can be started and the flow routed to the suppression chamber. The test return line can also be used for extended minimum recirculation flow to support continuous pump set operation, with or without injection, to support throttling of the inboard isolation valves and the shutdown cooling water seal.

Each core spray loop has a high-point vent and a keep-full system to allow testing of isolation valves at full power. During normal operation the high-point vent system is isolated. Keep-full system operation will be continuous during normal operation through normal operation of the condensate pumps. Keep-full isolation or loss of keep-full does not result in an inoperable core spray system. Reasonable judgments may be made to assess keep-full functions, as well as reasonable attempts to maintain the piping filled with water. Prior to the quarterly core spray valve operability test and monthly, the two high-point vent valves will be opened. To verify that the core spray system is solid up to the inner isolation valve, a check to see that flow is present to the equipment drain tank will be made. The vent valves will then be closed and the inside core spray valves operated.

A seal water supply line originates from the topping pump discharge header in each core spray loop to pressurize and provide a supply of seal water to the shutdown cooling system isolation valves to meet Appendix J. The shutdown cooling system MOVs will be administratively controlled by closing the valves and then removing power during normal reactor operation, except when shutdown cooling system is required to be placed in service.

2.2 Operator Assessment

All instrumentation and controls necessary for the Operator to assess the operation of the system are located on the main control room panel. Each core spray loop has separate and independent flow indication and header pressure indicators. Isolation valve control switches and position indicator lights are provided for each isolation valve. The isolation valve positions are also indicated on the isolation valve mimic on the main control panel. Each core spray pump and topping pump has its own control switch with indicating lights and motor ammeters on the control room panels.

An indication of suppression chamber level and pressure is also provided in addition to alarms for high and low values for each.

Each core spray pump has pressure switches to monitor core spray pump suction pressure. The pressure switches will alert the Operator to a clogged suction strainer.

Pressure switches on each loop header are outside the drywell; they will alarm on low core spray header pressure if the system has been called upon to operate.

These alarms are sounded on the control room annunciator and the Station computer.

All sensing instrumentation is in accessible areas and is provided with suitable valving for in-place testing at any time.

Differential pressure indicators are installed to monitor the condition of the core spray piping between the reactor vessel wall and the shroud inside the reactor vessel. The instrumentation is designed to provide a control room alarm if the core spray piping between the reactor vessel and shroud suffers a loss of integrity.

3.0 Design Evaluation

It is necessary to maintain continuity of core cooling subsequent to a postulated LOCA to prevent fuel damage. This continuity of cooling is emphasized in the design of the core spray system. The design provides, as a minimum, a flow rate as shown in Table XV-9a for each loop.

For large breaks, the core spray system can keep the PCT below 2200°F without assistance from the ADS system. From the largest break down to about 0.30 sq ft, the reactor depressurizes sufficiently fast for the core spray to achieve rated flow before the cladding begins to melt.

Small breaks, i.e., breaks below about 0.30 sq ft, are those which fall outside the range of the core spray system. In the event of such a break, substantial coolant loss could occur from the reactor vessel while it was still at relatively high pressure. The ADS system is provided which, in conjunction with the core spray system, will prevent significant fuel damage for all sized line breaks. The ADS system is capable of depressurizing the vessel either manually or on a simultaneous low-low-low water level and high-pressure signals. The LOCA analysis, described in Section XV-C, shows the capability to maintain adequate core cooling under the entire range of breaks analyzed.

Core spray distribution tests were conducted in air with simulated updraft effects and are the basis for flows and nozzle location. A report on these tests is included in the General Electric Company (GE) Report APED-5458. The effect of steam environments on the spray distribution has been evaluated in NEDE-30241.

4.0 Tests and Inspections

Each core spray loop was tested initially during preoperational testing with water under full-flow conditions. Data on flows and pressures at various points in the flow lines was obtained. The nozzle spray pattern was observed as far as practical with the reactor head off. Each loop was also operated bypassing the water to the suppression chamber and the corresponding flow and pressure data obtained.

Subsequently, the core spray and topping pumps are periodically operated, and the water pumped from the suppression chamber through the appropriate supply lines to the outer system isolation valve, then returned to the suppression chamber. Flow into the reactor vessel is not attempted since this would introduce relatively impure water into the reactor coolant. Data on the flow rate and pressure at various points for each supply loop are obtained for comparison with the previously established normal conditions. Interlocks are provided such that the valve in the test line cannot be opened unless the motor-operated containment system isolation valves both inside and outside the drywell are closed. These valves cannot be reopened until the test valve is closed. The MOVs on the pump discharge lines to the reactor vessel are periodically opened fully and the time to open is recorded. These valves shall be fully open within 22.5 sec (valve stroke time) after the signal is given to assure that, under accident conditions, the total delay in achieving full core spray flow is less than 37 sec. The safety valves on the core spray lines outside the second system isolation valve are periodically removed and tested for setpoint, as recommended by the ASME Code, Section III-B-1965. These valves are also containment isolation valves and are subject to Appendix J Type B and C testing.

The pumps and valves are tested quarterly by recycling water to the suppression chamber.

During each refueling outage, condensate water is introduced into the pump suction and automatic initiation of the pumps and valves is tested.

At least once per month verification is made that the keep-full system piping is filled with water.

Once each quarter during the scheduled operability test, the system is visually inspected for leakage, and maintenance is performed as required.

B. CONTAINMENT SPRAY SYSTEM

1.0 Licensing Basis Requirements

The following regulatory documents are applicable to the containment spray system (CSS) and, in general terms, form the basis on which the system is designed and operated.

1.1 10CFR50.49 - Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

An EQ program for electrical equipment has been conducted in accordance with 10CFR50.49. Consequently, electrical equipment important to safety in the CSS system has been qualified to operate in the LOCA environment.

1.2 10CFR50 Appendix A - General Design Criteria for Nuclear Power Plants

The Technical Supplement to Petition for Conversion from Power Operating License to Full Term Operating License covered the Unit 1 positions relative to the General Design Criteria (GDC). Those portions of the documentation that cover both the description of the requirements and NMPC's positions relative to these requirements, as they pertain directly to the CSS system, have been extracted and are shown below:

Criterion 16

Containment Design Reactor containment and associated systems shall be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment, and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

A pressure suppression containment system consisting of a drywell, suppression chamber (torus), and interconnecting vent piping is the primary containment for the main coolant system. During normal operation, the reactor building, containing the pressure suppression system, provides a secondary containment barrier.

To ensure the integrity of the primary containment, integrated leak tests were performed prior to Station operation and periodically thereafter, as provided in the Technical Specifications. The results demonstrated that the containment met the design leak rate of 0.5 percent per day at a pressure of 35 psig and, therefore, provides an essentially leak-tight barrier. The design basis LOCA was evaluated at the primary containment maximum allowable accident leak rate of 1.9 percent per day at 35 psig. The analysis demonstrates that the offsite

The CAD system is designed as a seismic Class 1 system and in accordance with United States Atomic Energy Commission (USAEC) RG 1.7-1972 and 1.26-1974, ASME Section III-1965 Class 2 and IEEE-279.

3.2 Design Evaluation

The hydrogen and oxygen concentrations as a function of time after occurrence of a design basis LOCA are shown on Figure VII-14. From this figure it can be seen that nitrogen injection should begin at 7.2 hr after the accident. Figure VII-15 shows the nitrogen addition requirements as a function of time after a LOCA. Since nitrogen gas is being added to the containment, which is a fixed volume, an increase in pressure, proportional to the amount of gas added, occurs. Figure VII-16 shows containment pressure as a function of time after a LOCA assuming zero containment leakage. It can be seen that the pressure limit of the suppression chamber (35 psig) is reached at approximately 100 days (delivery of nitrogen can be continued for containment pressures in excess of 40 psig). The EOPs provide the required post-accident actions for primary containment when placing the CAD system into operation. In the above analysis, zero containment leakage was assumed for conservative purposes. However, pressures will be less than those on Figure VII-16 as a result of the diminishing need for nitrogen as a function of time, plus the normal containment leakage rates.

4.0 Tests and Inspections

At least once per week the oxygen concentration is determined.

Once each operating cycle all CAD systems undergo a leak test using a helium tracer, followed by repairs and retest, if required.

H. EMERGENCY VENTILATION SYSTEM

1.0 Design Bases

The emergency ventilation system is designed to filter particulates and iodines from the reactor building atmosphere prior to exhausting to the stack during secondary containment isolation conditions. Accident analyses indicate that the most severe release of fission products to the reactor building would be for the refueling accident discussed in Section XV. However, to be conservative, a release corresponding to the TID-14844 accident is used as the design basis for this system.

Only small amounts of particulates would be released from the containment during an accident, and approximately 6.5 percent of the total iodines are available for leakage from the containment to the reactor building.

The filtering system has been designed to accommodate the expected total heat load of approximately 936 W resulting from the decay of deposited radioactive material. The filter heating values are based on a LOCA using TID-14844 fission product release fractions from the fuel, and leakage rates of 1.5 percent per day for the containment, and a fan discharge rate equivalent to 100 percent of the reactor building volume per 24 hr. Adequate provisions are available to cool the filters to maintain their effectiveness.

Immediate operation of the emergency ventilation system can be automatically initiated upon detection of a high radiation signal at the refuel platform when required (typically for fuel handling-related activities). In addition, the reactor building exhaust duct is monitored for high radiation by two monitors. The monitors are electrically connected in a one-out-of-two taken once logic. High radiation must be detected by at least one monitor for a period of 2 to 3 sec to produce an actuation signal. This time delay reduces spurious actuations while ensuring a valid actuation occurs.

An EQ program for electrical equipment has been conducted in accordance with 10CFR50.49. As a result of this program, electrical equipment in the emergency ventilation system important to safety has been qualified to operate in the environment to which it is exposed.

2.0 System Design

A schematic piping and instrumentation diagram (P&ID) of the emergency ventilation system is included as part of the reactor building ventilation system diagram, Figure VI-24.

The system consists of a common supply header taking suction from the normal reactor building ventilation discharge before the inlet isolation valves, an electric heater (10 kW) located on the

I. HIGH-PRESSURE COOLANT INJECTION

1.0 Design Bases

The high-pressure coolant injection (HPCI) system is an operating mode of the feedwater system available in the event of a small reactor coolant line break which exceeds the capability of the CRD pumps (0.003 ft^2). HPCI, along with one emergency cooling system, has the capability of keeping the swollen reactor coolant level above the top of active fuel (TAF) for small reactor coolant boundary breaks up to 0.063 ft^2 for at least 1000 sec. The HPCI system, with one of the two emergency cooling systems and two core spray systems, will provide core cooling for the complete spectrum of break sizes up to the maximum design basis recirculation discharge line break (5.446 ft^2). Its primary purpose is to:

1. Provide adequate cooling of the reactor core under abnormal and accident conditions.

2. Remove the heat from radioactive decay and residual heat from the reactor core at such a rate that fuel clad melting would be prevented.

3. Provide for continuity of core cooling over the complete range of postulated break sizes in the primary system process barrier.

HPCI is not an engineered safeguards system and is not considered in any LOCA analyses. It is discussed in this section because of its capability to provide makeup water at reactor operating pressure.

2.0 System Design

The HPCI system utilizes the two condensate storage tanks (CST), the main condenser hotwell, two condensate pumps, condensate demineralizers, two feedwater booster pumps, feedwater heaters, two motor-driven feedwater pumps, an integrated control system and all associated piping and valves. The system is capable of delivering 6840 gpm into the reactor vessel at reactor pressure when using two trains of feedwater pumps. The condensate and feedwater booster pumps are capable of supplying the required 3420 gpm at approximately reactor pressures up to 332 psig*. Above 332 psig, a motor-driven feedwater pump is necessary to provide the required flow rate.

The feedwater system pumps have recirculation lines with air-operated flow control valves to prevent the pumps from operating against a closed system. In the event of loss of air pressure, these valves open, recycling part of the HPCI flow to

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* 332 psig provides for system pump degradation of 10 percent.

the hotwell. HPCI flow would be reduced to approximately 2600 gpm at a reactor pressure of 1,150 psig and 3420 gpm at a reactor pressure of 940 psig.

Condensate inventory is maintained at an available minimum volume of 180,000 gal.

3.0 Design Evaluation

During a LOCA within the drywell, high drywell pressure due to a line break will cause a reactor scram. This automatic scram will cause a turbine trip after a 5-sec delay. Feedwater flow would be available for considerable time from the shaft-driven feedwater pump. The shaft-driven feedwater pump would coast down while the electric motor-driven condensate pumps and feedwater booster pumps would continue to operate. The coastdown time to reach 3420 gpm delivery to the core is approximately 3.2 min (Figure VII-17), since both the condensate and feedwater booster pumps will continue to operate on offsite power. The curve on Figure VII-17 shows how flow from the shaft-driven feedwater pump decreases as the main turbine is coasting down following a trip. The curve is a representation of the feedwater capability of the shaft-driven pump after a turbine trip at a set of finite conditions. The margin to reach the 3.2-min coastdown time is governed by the turbine coastdown rate and the shaft-driven pump, not system resistance such as flow control valve (FCV) position.

The turbine trip will signal the motor-driven feedwater pump to start. The signal will be simultaneous with the start of the shaft pump coastdown. The motor-driven feedwater pump will be up to speed and capable of supplying 3420 gpm in about 10 sec. As a backup, low reactor water level will also signal the motor-driven pump to start. The initiation signal transfers control from the normal feedwater to the HPCI instrumentation and controller which has been continuously tracking the normal feedwater control signal. To maximize the NPSH to the motor-driven feedwater pumps when operating in HPCI mode, #11 flow control valve (FCV11) for #11 motor-driven feedwater pump (FWP11) does not open if there is sufficient total feedwater flow into the reactor. FCV11 remains closed until total feedwater flow into the reactor drops below 4.5×10^6 lbm/hr (9000 gpm). This logic is bypassed if FWP12 is not running or locked out. In addition, the level setpoint setdown controller (ID66B) limits the controller output to 70 percent of maximum following HPCI actuation. Feedwater flow will continue to be provided by the shaft-driven feedwater pump during turbine coastdown. Thus, there will be a continuous supply of feedwater to the reactor.

The HPCI single element control system will attempt to maintain reactor vessel water level at 65 in or 72 in (depending upon which pump, 11 or 12, respectively, is in service) with a design basis feedwater flow of 3420 gpm.

Figure VII-14. Controlled Hydrogen and Oxygen Concentrations – Inerted Containment

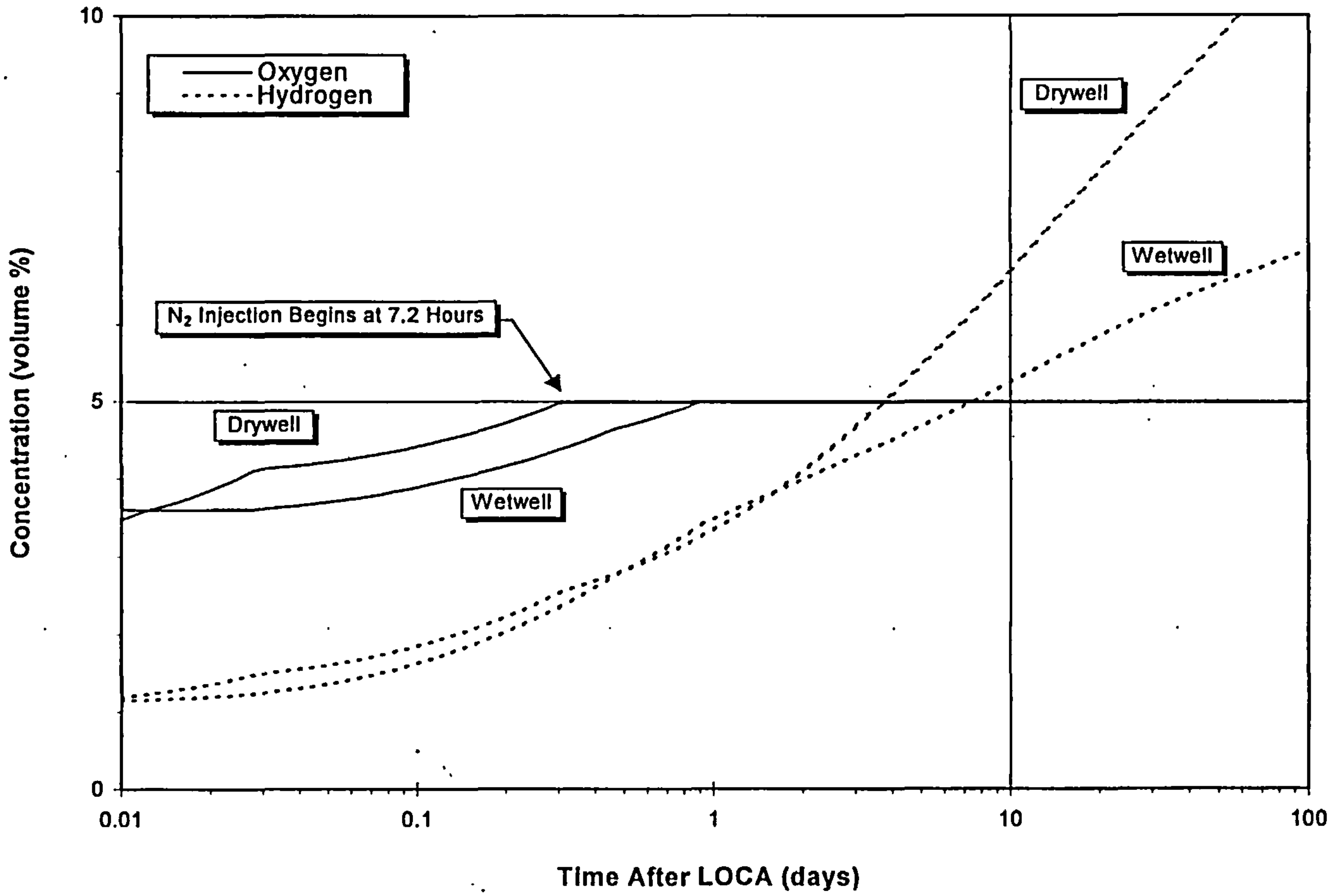

FIGURE VII-14
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Figure VII - 15. Integrated post-LOCA Nitrogen Volume Requirement – Inerted Containment

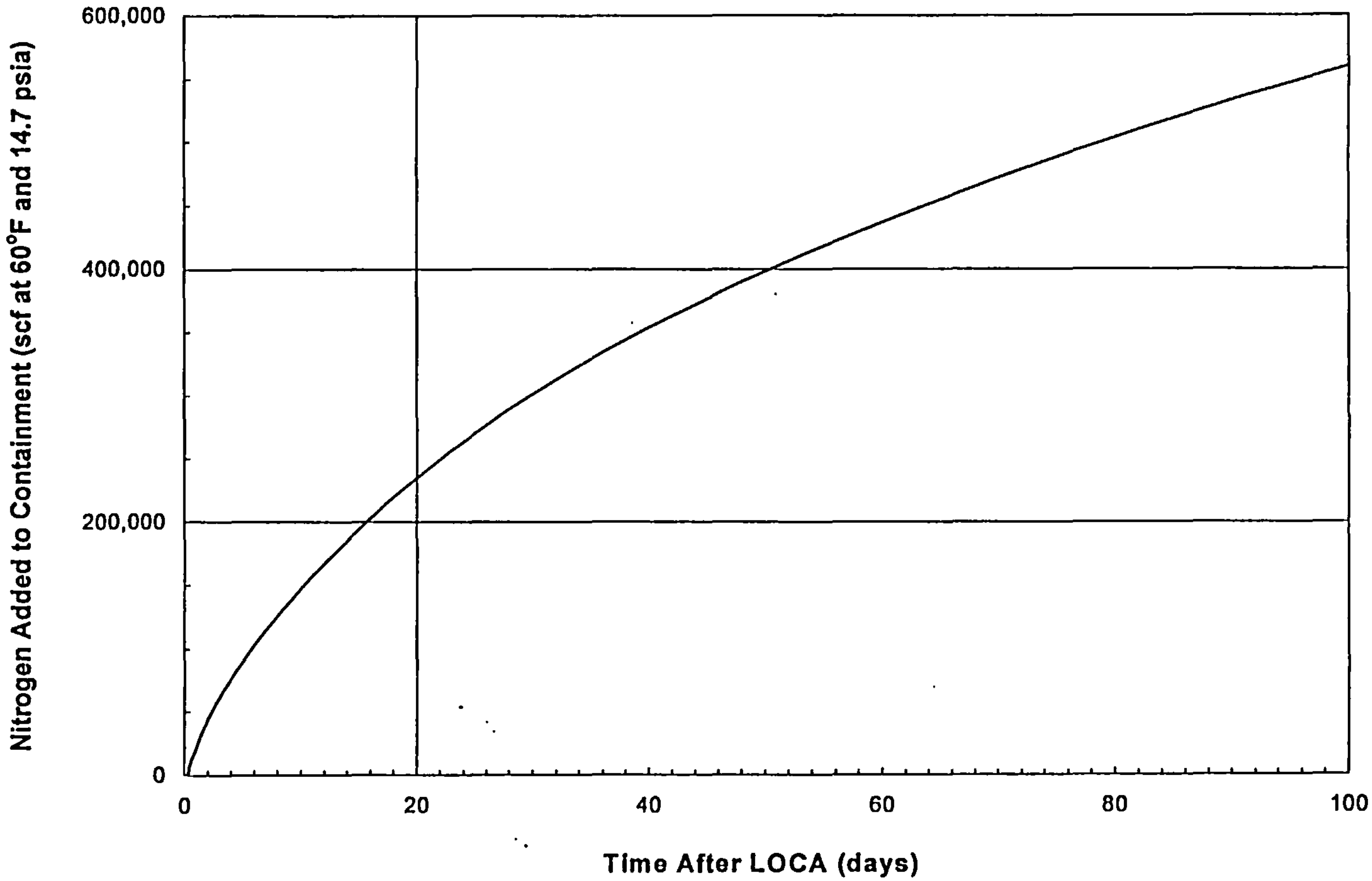

Figure VII - 16. Containment Pressure Following CAD Actuation – Inerted Containment

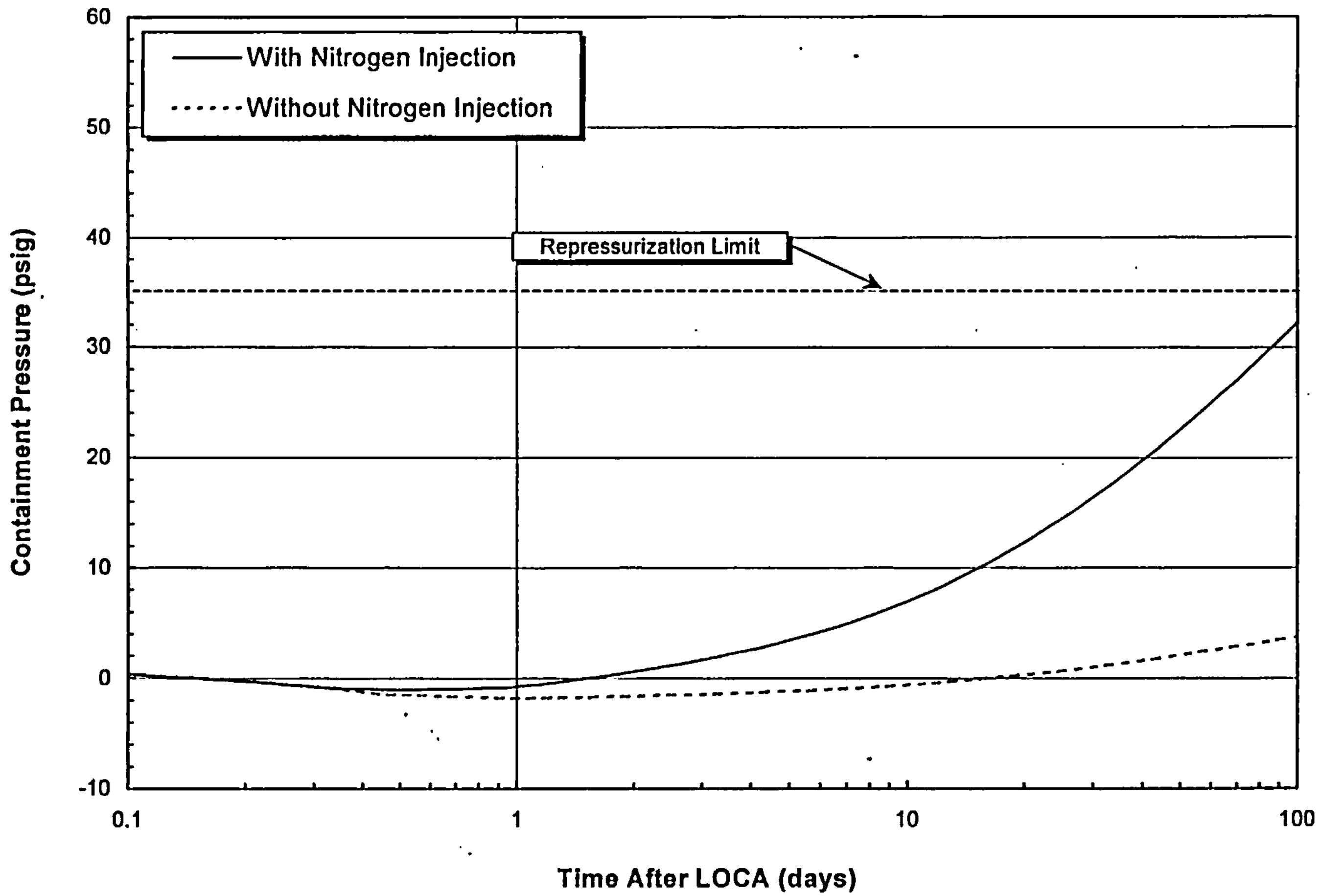

FIGURE VII-16
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3. Liquid poison injection system - manually.

4. Emergency ventilation system is initiated by high radiation level in reactor building ventilation system exhaust, or high radiation at the refueling platform if the bypass switch is in the refuel mode.

The emergency cooling system is initiated manually or automatically by high reactor pressure if the high-pressure condition persists for 12 sec, or by low-low reactor water level after a 12-sec time delay (to assist in depressurization for small breaks). High steam flow on the condenser tube side, indicative of an emergency cooling system line break, automatically isolates the affected set emergency condensers (EC). High radiation in the vent line or high area temperature provide alarm function only. Operator action is required to isolate one set of emergency cooling condensers.

Control rod withdrawal is prohibited by the following conditions:

1. Fuel hoist loaded with fuel and over the reactor.

2. Rod worth minimizer (RWM) below a preset power level if established withdrawal sequence is not followed.

3. High neutron flux (setpoint varied with recirculation flow).

4. Neutron monitoring instrumentation off-normal.

5. Mode switch in shutdown.

6. Withdrawal of more than one rod is prohibited with mode switch in the refuel mode.

7. Bypass of high water level scram in scram dump volume.

The control rod withdrawal block instrumentation limiting conditions for operation (LCO) and surveillance requirements (SR) for the source range monitor (SRM), recirculation flow, and scram dump volume water level scram bypass functions are given in Table VIII-5. The LCOs and SRs for these instrumentation functions were relocated from the Unit 1 Technical Specifications to the UFSAR based on evaluations which demonstrated that the LCOs do not satisfy the four screening criteria defined in 10CFR50.36(c)(2)(ii) for retention in the Technical Specifications[35,36]. Accordingly, the LCOs and SRs for these instrumentation functions are controlled under the 10CFR50.59 program and 10CFR50.71(e).

Offgas and vacuum pump isolation is initiated by the following:

1. Offgas

   a. High radiation from offgas line.

   b. Manually.

2. Vacuum Pump

   a. High radiation from MSL.

   b. Manually.

Diesel generators are initiated by the loss of ac voltage to power boards (PB) 102 and 103, or by a persistent degraded voltage condition to these power boards.

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High-pressure coolant injection (HPCI) is initiated by either of the following:

1. Low reactor water level.

2. Automatic or manual turbine trip.

The control room emergency ventilation system is initiated manually or automatically by any one of the following conditions:

1. Low-low reactor water level.

2. High drywell pressure.

3. High steam flow in MSL.

4. High temperature in MSL tunnel.

5. High radiation in the air intake.

The protective system components and their associated electrical cables located within the primary containment were designed to operate in an environment of 150°F and 100-percent relative humidity. The components and electrical cables which are required to function during and following loss-of-coolant accident (LOCA) are expected to withstand the accident conditions. The environmental qualification (EQ) of system components is controlled through the equipment qualification program. The seismic criterion observed in the design of the protective system components was that equipment would successfully withstand forces resulting from acceleration factors of 0.20g horizontal and 0.10g vertical.

1.2 Anticipated Transients Without Scram Mitigation System

A redundant anticipated transient without scram (ATWS) mitigation system is designed to mitigate the effects of an ATWS event. This supplementary protection system utilizes alternate rod injection (ARI) and reactor RPT which will increase the reliability of the present scram system, thereby decreasing the probability of an ATWS event.

ATWS is initiated automatically by the following conditions:

1. Low-low reactor water level, or

2. High reactor pressure

separate sensing lines from the proper elevations on the vessel shell.

These transmitters are separate from the level sensors inputting to the RPS. Each level signal is corrected independently to compensate for water density and is indicated and/or recorded in the control room.

A backfill system is installed on the reference leg of the level transmitters. The system provides a metered flow of water from the CRD system to the leg. The flow has a negligible effect on the performance of the instrumentation. The backfill is designed to prevent the accumulation of noncondensible gases in the reference leg. These gases can produce erroneous level measurements when reactor pressure is reduced.[1]

Feedwater flow is monitored by three flow transmitters coupled to three flow nozzles in the feedwater lines. The total feedwater flow is the summation of the signals from the three feedwater lines.

Steam flow is monitored by two flow transmitters coupled to two flow nozzles in the steam lines. Each steam flow signal is corrected to compensate for errors due to pressure of the steam. The total steam flow is the summation of the signals from both steam lines.

The three signals, water level, feedwater flow and steam flow, are inputs to the controller. The controller regulates the opening of the valves in the feedwater lines to maintain reactor water level at the desired elevation. During steady-state operation, feedwater flow exactly matches steam flow and the water level is maintained. A change in steam flow is immediately sensed and the controller adjusts the opening of the feedwater control valves to balance the two flows and maintain level.

The level signal input is connected through a manual transfer switch so that either of two levels may be used as the input to the controller. In the event of a feedwater controller failure, the feedwater valves will fail "as is" due to a loss of signal. A backup manual control to the feedwater valves is provided.

2.1.3 Other Nonnuclear Process Instruments

<u>Reactor Vessel Temperature Monitoring</u>

Thermocouples are attached to the pressure vessel to read the vessel temperature at many points. The points are chosen so as to include thick, thin, and transitional sections. These thermocouples are fed to the computer. The thermocouples are copper constantan, glass insulated, and clad with stainless steel. They are clamped under pads welded to the reactor vessel.

In operation, the rate of heating or cooling is controlled so that the stress set up between two sections of the vessel is held to an allowable limit. The stress is computed from the temperature difference between the various points. Other temperatures (from resistance temperature detectors [RTD]) are recorded on the data logger.

Vessel Flange Leak Detection

Integrity of the seal between the vessel body and head is continuously monitored at the drain lines connected to the flange face between the two large concentric O-rings. The drain line is normally closed. Leakage from the reactor vessel through the inner O-ring collects in a chamber. Pressure buildup is annunciated. A valve permits draining the leak system piping.

Reactor Vessel Pressure

Pressure transmitters to the ATWS mitigation system are located on the two RPS pressure sensor lines.

Also provided are six pressure switches to the main steam power-operated pressure relief valves, and two pressure switches to the shutdown cooling isolation valves.

Reactor Vessel Water Level

A compensated vessel level system is provided to monitor reactor water level from the bottom of the active fuel to normal water level. This system is temperature and pressure compensated. This system provides a monitoring function only and will not activate any safety systems.

A backfill system is installed on each level instrument reference leg. The system provides a metered flow of water from the CRD system to each leg. The flow has a negligible effect on the performance of the instrumentation. The backfill is designed to prevent the accumulation of noncondensible gases in the reference legs. These gases can produce erroneous level measurements when reactor pressure is reduced.[1]

Level transmitters to the ATWS mitigation system and the turbine trip circuit are located on the RPS level sensor lines.

Containment Pressure

Instrumentation is provided to monitor the containment pressure from -5 psig to 250 psig (four times containment design pressure). This instrumentation provides a monitoring function only.

29. NMPC letter to the NRC, NMP1L 0851, dated August 23, 1994, documenting commitment change regarding drywell water level recorder.

30. NRC (Office of Nuclear Reactor Regulation) letter to NMPC, dated October 26, 1994, "Proposed Deletion of Commitment to Install Drywell Level Strip-Chart Recorder for Nine Mile Point Nuclear Station Unit 1."

31. General Electric Company Nuclear Energy Report, GENE B2400005-01-01, "Nine Mile Point 1 Relief Valve Setpoint Tolerance Relaxation Evaluation," March 1999.

32. General Electric Company, GENE J11-03433-16-01-00, "Pressure Regulator Out-of-Service Calculations for Nine Mile Point Unit 1 Cycle 14," March 2001.

33. General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A (latest approved revision).

34. NRC (Office of Nuclear Reactor Regulation) letter to Nine Mile Point Nuclear Station, LLC, dated September 11, 2002, "Nine Mile Point Nuclear Station, Unit No. 1 - Use of the Offgas Effluent Stack Monitoring System to Meet Regulatory Guide 1.97, Revision 2, and NUREG-0737 Guidance (TAC No. MB2443)."

35. NMPNS letter to the NRC, NMP1L 1828, dated April 19, 2004, "License Amendment Request Pursuant to 10CFR50.90: Revision of Intermediate Range Monitor Surveillance Frequency and Relocation of Selected Instrumentation Requirements to a Licensee-Controlled Document."

36. NRC (Office of Nuclear Reactor Regulation) letter to NMPNS, dated January 25, 2005, "Nine Mile Point Nuclear Station, Unit No. 1 - Issuance of Amendment Re: Intermediate Range Monitor and Control Rod Withdrawal Block Instrumentation (TAC No. MC2734)."

37. General Electric Company, SIL-42, "RPV Head Flange Leakage Monitoring System," December 1973.

TABLE VIII-3 (Cont'd.)

NOTES (Cont'd.)

The Category 3 instrument designation for this variable at Unit 1 has been reviewed and accepted by the NRC in the SER addressing Unit 1 conformance to RG 1.97 (Revision 2) dated November 19, 1986.

5. DELETED.

6. Direct monitoring of reactor coolant radioactivity concentration is not implemented at Unit 1 for the following reason:

   - The purpose stated RG 1.97 (Revision 2) for this variable is "detection of breach." Timely detection of a breach in fuel cladding integrity is able to be fully accomplished through monitoring of other variables. Specifically, these include containment radiation level (Item 21 in the Table), and analysis results from grab samples of reactor coolant (Item 56 in the Table).

   The Unit 1 decision not to directly monitor this variable is consistent with the associated BWROG evaluation, conclusion, and recommendation (Ref: BWROG submittal to the NRC regarding RG 1.97, dated April 6, 1983), and has been reviewed and accepted by the NRC in the SER addressing Unit 1 conformance to RG 1.97 (Revision 2), dated November 19, 1986.

   The following core damage assessment capabilities are incorporated into Unit 1 procedures, as documented in License Amendment No. 174 (issued by NRC letter dated August 26, 2002):

   - Contingency plans for obtaining and analyzing highly radioactive samples from the reactor coolant system, suppression pool, and containment atmosphere.

   - The capability for classifying fuel damage events at the Alert level threshold at radioactivity levels of 300 μCi/gm dose equivalent I-131.

   - I-131 site survey detection capability, including an ability to assess radioactive iodines released to offsite environs, by using effluent monitoring systems or portable sampling equipment.

7. Included under Item 57 in the Table.

TABLE VIII-3 (Cont'd.)

NOTES (Cont'd.)

8. Included under Item 47 in the Table.

9. "Indication of primary containment breach" is the purpose stated in RG 1.97 for monitoring this variable, and RG 1.97 recommends designating Category 2 instrumentation for this variable. The Unit 1 position is that secondary containment area radiation level is not the most appropriate parameter to use for assessing primary containment leakage or detecting significant releases, and therefore designates Category 3 instrumentation for this variable at Unit 1.

   The change from Category 2 to Category 3 instrumentation for this variable is consistent with the associated BWROG evaluation, conclusion, and recommendation (Ref: BWROG submittal to the NRC regarding RG 1.97, dated April 6, 1983).

   The Category 3 instrument designation for this variable at Unit 1 has been reviewed and accepted by the NRC in the SER addressing Unit 1 conformance to RG 1.97 (Revision 2), dated November 19, 1986.

10. The design of the containment spray system at Unit 1 is such that, upon initiation, system flow is directed simultaneously to both the drywell and the suppression chamber (torus), with a fixed proportion of the pump flow distributed to each header. Containment spray pump discharge flow rate is therefore monitored rather than flow rate in the separate (drywell and torus) spray headers.

    In the SER addressing Unit 1 conformance to RG 1.97 (Revision 2), dated November 19, 1986, the NRC stated that, based on the identified plant-specific system design features, the currently installed flow monitoring instrumentation is acceptable (i.e., separate monitoring of flow rate in each [drywell and torus] spray header is not necessary).

11. Unit 1 does not have this system and, therefore, monitoring of this variable is not applicable.

12. Included under Item 18 in the Table.

13. At Unit 1 the HPCI function is performed by the feedwater pumps. Refer to Item 25 in the Table.

14. Liquid poison system flow rate is not directly monitored at Unit 1. Proper functioning of the liquid poison system can be verified by monitoring pump discharge pressure (Item 66

TABLE VIII-3 (Cont'd.)

NOTES (Cont'd.)

in the Table), storage tank liquid level (Item 38 in the Table), neutron flux level (Items 1, 12, and 13 in the Table), and squib valve status (Item 67 in the Table). Therefore, monitoring system flow rate is not considered to be necessary.

In the SER addressing Unit 1 conformance to RG 1.97 (Revision 2), dated November 19, 1986, the NRC stated that the identified instrumentation is valid as an acceptable alternative indication of liquid poison system flow rate.

15. At Unit 1 the shutdown cooling system is the functional equivalent of the residual heat removal (RHR) system. However, shutdown cooling system flow rate is not directly monitored. Shutdown cooling system flow rate is adjusted as required to control reactor coolant cooldown rate (heat removal) within applicable limits. The following parameters are monitored to verify proper shutdown cooling system operation:

    - Reactor vessel water level (Item 2 in the Table).
    - Shutdown cooling system pump discharge pressure (Item 68 in the Table).
    - Shutdown cooling system heat exchanger tube side (reactor coolant) inlet and outlet temperatures (Item 40 in the Table).
    - Shutdown cooling system heat exchanger shell side (cooling water) inlet and outlet temperatures (Item 69 in the Table).
    - Shutdown cooling system valve position - flow path from and to the reactor vessel (Item 70 in the Table).

    Additionally, the shutdown cooling system is not expected to be operated during accident or immediate post-accident conditions. It would be operated only in the long term after the unit is in a normal stable shutdown condition.

    In the Safety Evaluation Report (SER) addressing Unit 1 conformance to RG 1.97 (Revision 2), dated November 19, 1986, the NRC stated that, based on the identified alternate instrumentation and the design function of the shutdown cooling system, the deviation from the recommended flow monitoring instrumentation is acceptable.

TABLE VIII-3 (Cont'd.)

NOTES (Cont'd.)

16. Cooling water flow and cooling water temperature for the core spray and containment spray pumps are not directly monitored. The cooling water is recirculated pump discharge flow. Pump suction is normally from the suppression pool, thus torus water temperature (Item 4 in the Table) provides indication of the temperature of the cooling water supplied to the pumps.

    In the SER addressing Unit 1 conformance to RG 1.97 (Revision 2), dated November 19, 1986, the NRC stated that, based on the identified plant-specific system design features, the deviation from the recommended cooling water flow and temperature monitoring instrumentation is acceptable.

17. In the SER addressing Unit 1 conformance to RG 1.97 (Revision 2), dated November 19, 1986, the NRC determined that, because Revision 3 to RG 1.97 recommended a Category 3 classification for this variable, no deviation in Category exists. The NRC concluded that the use of Category 3 instrumentation for this variable is acceptable.

18. Included under Item 47 in the Table.

19. Included under Item 51 in the Table.

20. The ability to determine/monitor bulk average temperature is necessary for this EOP Key Parameter.

21. Criteria specified in NEDO-31558-A[26] apply in lieu of those specified in RG 1.97. See NMPC letters NMP1L 0765[13] and NMP1L 0813[27], and NRC letter dated February 10, 1994[28], for additional information.

22. Neutron flux level below the APRM range is not a key variable for accomplishing mitigative actions for any DBA or transient (including those anticipated operational occurrences required to be considered in the implementation of the ATWS Rule [10CFR50.62]); required Operator actions specified in the plant EOPs for such events can be accomplished without reliance on reactor power information below the APRM range. On this basis, the designation of Category 3 instrumentation (in lieu of Category 1 instrumentation as recommended by RG 1.97) is appropriate for monitoring intermediate range and source range neutron flux.

23. Operator actions based on drywell water level would be a contingency action and, therefore, do not meet the

TABLE VIII-3 (Cont'd.)

NOTES (Cont'd.)

definition of a Type A variable. Since drywell water level is not a RG 1.97 Revision 2 recommended variable, the drywell water level recorder does not need to meet the Category 1 criteria. Therefore, a drywell water level recorder is not needed.[29,30]

24. RG 1.97 recommends that noble gas effluent monitoring instrumentation be designed with a range of 1E-06 μCi/cc to 1E+03 μCi/cc. The range of the offgas effluent stack monitoring system (OGESMS) is 1E-07 μCi/cc to 1 μCi/cc (Xe-133). The OGESMS lower limit of detection of 1E-05 μCi/cc meets the NUREG-0737, Item II.F.1, Attachment 1, Position (2) criterion of the instrumentation range beginning at normal conditions (as low as reasonably achievable (ALARA)). The OGESMS upper range limit of 1 μCi/cc (Xe-133) provides a safety margin greater than a factor of two for the site-specific design basis effluent release which occurs at NMP1 from a LOCA.

    RG 1.97 recommends particulates and halogens instrumentation be designed with a range of 1E-03 μCi/cc to 1E+02 μCi/cc, with a 30-min sampling time for detection of significant releases, release assessment, and long-term surveillance. With the use of OGESMS, the particulate samples would be collected by OGESMS and taken to an onsite facility. The onsite analysis facility has a range of 1E-03 μCi/cc to 0.1 μCi/cc with a 30-min sampling time. The onsite analysis facility's upper range of 0.1 μCi/cc provides a safety margin of two for a design basis effluent release from a LOCA. Using NMP1's design basis effluent release from a LOCA, in lieu of 1E+02 μCi/cc as specified in NUREG-0737 and RG 1.97, to determine doses to personnel working with the sampling media during an accident, the results in estimated exposures would be less than the GDC 19 limits.

    In summary, OGESMS meets the objective and purpose of the NUREG-0737 and RG 1.97 guidance. The deviations from NUREG-0737 and RG 1.97 are acceptable.[34]

		Scram	Trip Recirculation Pumps Out	Trip Core Spray On	Open Isolation Condenser Valves	Open Steam Relief Valves	Open Bypass Valves	Start Containment Spray	Inject Liquid Poison Solution	Close Bypass Valves	De-energize Fuel Hoists	Prevent Rod Withdrawal	Isolate Offgas System	Close Steam Line Isolation Valves	Close Turbine Stop Valves	Close Emergency Cooling Valves	Isolate Cleanup System	Isolate Shutdown System (b)	Isolate Drywell Pressure Maint Sys & Sump & Vent to EGTS	Isolate Building and Start Emergency Vent System	Start Diesel	Isolate Mechanical Vacuum Pump	High-Pressure Coolant Injection	Isolate Vent and Purge Valves	Initiate Control Room Emergency Ventilation
26.	Main Steam Line Isolation Valves Partially Closed	(f)													(f)										
27.	Loss Of Power To Auxiliary Bus Or Startup Transformer																				(e)				
28.	Loss Of Power To Protection System Motor Generator Set	(g)													X										
29.	Rod Worth Minimizer Prohibitive											*													
30.	High Flux - Varied With Recirculation Flow											*													
31.	Turbine Trips	(u)													X								X		
32.	Neutron Monitors Off Normal											*													
33.	Liquid Poison Initiation																X								
34.	Scram (Automatic Only)														X										
35.	High Steam Flow In Main Steam Line													X											X
36.	High Temperature In Main Steam Line Tunnel													X											X
37.	Anticipated Transients Without Scram	X	(bb)																						
38.	High Radiation At Refueling Platform																			X					
39.	High Steam Flow on Cond. Tube Side															X									
40.	High Temp. Heat Exchanger Effluent - Cleanup System																X								
41.	High Pressure At Cleanup Sys. Filters																(a)								
42.	Low Flow Cleanup Pump Suction																(a)								
43.	High Radiation At Stack Monitor																							X	
44.	High Radiation Control Room Ventilation																								X

KEY:

(a) After Time Delay.
(b) A Backup To The Procedures Which Require These Valves To Be Closed At All Times During Plant Operation.
(c) Bypassed On "Refuel" And On "Startup" When < 600 psi.
(d) Permits Withdrawal Of One Rod.
(e) Program Loading On Loss Of Both Auxiliary Buses.
(f) May Be Bypassed On "Startup".
(g) Eight- To Ten-Second Time Delay.
(h) At Higher Drywell Pressure Than Scram Value In Combination With Low-Low Water Level 34-Second Time Delay.
(k) Either IRM Or APRM In Startup And APRM In Run.
(l) Bypass In Refuel Or Shutdown.
(m) SRM, IRM, APRM.
(p) With Reactor Pressure ≤ 365 psig.
(r) Manually Retractable After Short Time Delay.

TABLE VIII-5

NON-TECHNICAL SPECIFICATION INSTRUMENTATION THAT INITIATES CONTROL ROD WITHDRAWAL BLOCK

Limiting Condition for Operation							
				Reactor Mode Switch Position in Which Function Must be Operable			
Parameter	Minimum No. of Tripped or Operable Trip Systems	Minimum No. of Operable Instrument Channels per Operable Trip System(d)	Setpoint	Shutdown	Refuel	Startup	Run
(1) SRM							
a. Detector not in Startup Position	2	2(a)(b)(e)	---		X	X	
b. Inoperative	2	2(a)(e)	---		X	X	
c. Upscale	2	2(a)(e)	$\leq 10^5$ counts/sec		X	X	
(2) Recirculation Flow							
a. Comparator Off Normal	2	1(e)	≤6.8%				X
b. Flow Unit Inoperative	2	1(e)	---				X
c. Flow Unit Upscale	2	1(e)	≤103.7%				X
(3) Scram Dump Volume Water Level Scram Bypass	2	1(e)	---	X	X		

TABLE VIII-5 (Cont'd.)

Surveillance Requirement			
Parameter	Sensor Check	Instrument Channel Test	Instrument Channel Calibration
(1) SRM			
a. Detector not in Startup Position	N/A	Once per week[c]	N/A
b. Inoperative	N/A	Once per week[c]	N/A
c. Upscale	N/A	Once per week[c]	Once per operating cycle[f]
(2) Recirculation Flow			
a. Comparator Off Normal	None	Once per 3 months	Once per 3 months
b. Flow Unit Inoperative	None	Once per 3 months	Once per 3 months
c. Flow Unit Upscale	None	Once per 3 months	Once per 3 months
(3) Scram Dump Volume Water Level Scram Bypass	---	Once during each major refueling outage	---

NOTES:

(a) No more than one of the four SRM inputs to the single trip system shall be bypassed.
(b) This function may be bypassed when the count rate is ≥100 cps.
(c) Within 24 hr before startup, if not performed within the previous 7 days. Not required to be performed during shutdown until 12 hr after entering startup from run.
(d) A channel may be placed in an inoperable status for up to 6 hr for required surveillance without placing the trip system in the tripped condition, provided at least one other operable channel in the same trip system is monitoring that parameter.
(e) If the requirements are not met, no control rods shall be withdrawn.
(f) Neutron detectors are excluded.

REACTOR PROTECTION SYSTEM ELEMENTARY DIAGRAM

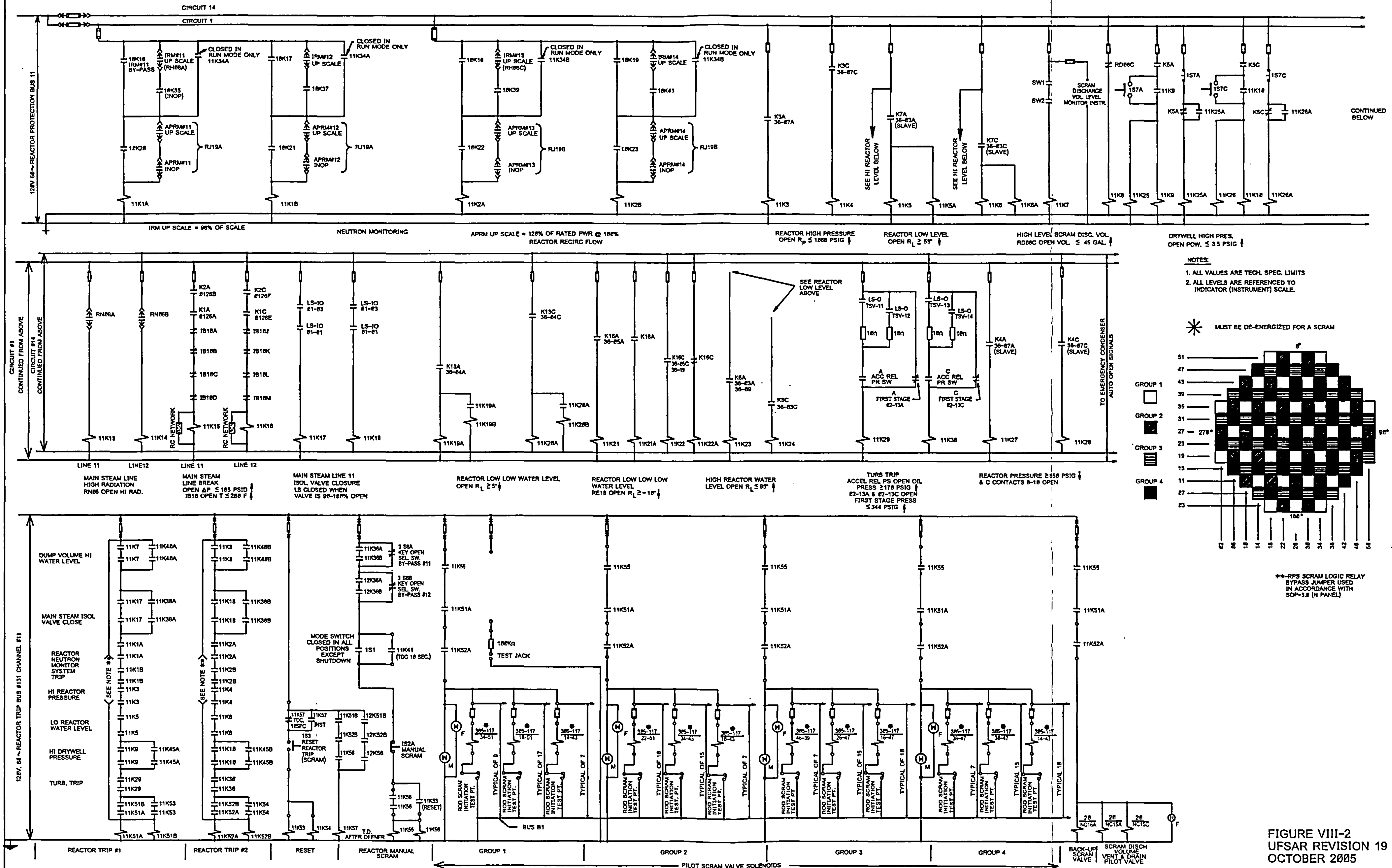

FIGURE VIII-2
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System or Equipment	Malfunction	Effect
		disconnect will be opened automatically. Both breakers will automatically reclose a second time. One of the breakers will thereby energize the unfaulted section of the bus, making offsite power available to one of the redundant engineered safeguards systems at the Operator's discretion.
115-kV bus	One 115-kV bus section faulted.	Under this condition, one group of 4.16-kV power boards, i.e., 11 and 102, or 12 and 103, do not have power available from the 115-kV system. By opening the transformer motor-operated disconnect (8106), this availability can be reestablished via PB 101 through bypass of normal interlocks under procedural control.
Reserve transformer	Transformer faulted.	Transformer protective relays will trip all necessary breakers and open transformer motor-operated disconnect, isolating the transformer from the system. Line breakers will automatically reclose, energizing the 115-kV bus and making offsite power available to one of the redundant engineered safeguards systems at the Operator's discretion.
Reserve transformer	Transformer faulted and isolated from system.	By removing the faulted transformer secondary bus links, power from

System or Equipment	Malfunction	Effect
		the 115-kV system can be made available to all 4.16-kV power boards, as described under the effect associated with the malfunction "One 115-kV bus section faulted" listed previously.
Reserve transformer load tap changer (LTC)	Low or high voltage.	The offsite power system is supervised by the following protective relays: a. overvoltage b. undervoltage These protective relays are set to transfer PB 102 and 103 to their respective onsite diesel power systems if the voltage of the offsite system deviates beyond set limits required for the satisfactory operation of the engineered safeguards systems.
4.16-kV PB 101	Loss of voltage.	Engineered safeguards systems are no longer associated with this power board.
Main generator or normal Station service transformer	Generator trip or transformer fault.	Normal supply breakers will trip and reserve breakers will close by fast automatic transfer, restoring power to PB 11 and 12. The 115-kV reserve bus is not affected.
4.16-kV PB 102 and 103	Loss of voltage.	Bus undervoltage relay circuit will automatically trip (except for one core spray pump) the normal supply breaker, motor

System or Equipment	Malfunction	Effect
		feeder breakers, and will start the diesel generator. The generator breaker will then automatically close, energizing the bus and furnishing power for sequential start of all safeguards systems pumps and 600-V auxiliaries.
All 4.16-kV power boards	Feeder fault--three-phase, phase-to-phase, and phase-to-neutral.	Protective relays will sense high current and trip feeder breaker. No auto reclosing is provided since a transient fault in metal-clad switchgear is unlikely.
All 4.16-kV power boards	Feeder fault--breaker fails to trip.	Supply breaker to PB bus will be tripped selectively. No auto reclosing is provided since a transient fault in metal-clad switchgear is very unlikely. Switches are provided to enable the Operator to turn off the automatic reclosers on the 115-kV and 345-kV line breakers for personnel safety, as necessary.

2.0 Station Distribution System

The basic arrangement of the auxiliary electrical system and the various loads connected to the different power boards are shown on the one-line diagram, Figure IX-1.

In general, auxiliaries smaller than 50 hp are fed from 600-V motor control centers (MCC) which in turn are fed from double-ended metal-enclosed unit substations. Auxiliaries ranging from 50 to 300 hp are fed from the unit substations. Loads 300 hp and greater are fed from the 4160-V metal-clad switchgear.

The major part of the power required for Station auxiliaries is supplied by the normal auxiliary transformer which is connected to the main generator output leads. This normal auxiliary power transformer, transformer 10, steps down from 24 kV (the nominal generator output voltage) to 4160 V and supplies two separate buses, PB 11 and 12.

The Station auxiliary load, other than that fed from PB 101, is divided approximately equally between PB 11 and 12.

PB 101 is supplied from the two reserve transformers 101N or 101S which step down from 115 kV to 4160 V. This bus supplies power to one condensate pump, reactor feed booster pump 12, one of five reactor recirculating pumps, the Energy Information Center, the motor-driven fire pump and the sewage plant feeder.

Transformer 101N supplies PB 11 when transformer 10 is not available, such as during startup, shutdown and refueling. Transformer 101S supplies PB 12 under similar conditions. Transformers 101S and 101N also supply PB 103 and 102, respectively.

Automatic transfer of the auxiliaries from the normal to the reserve source is initiated by low voltage on the auxiliary bus, generator trip, or turbine trip.

The transfer is initiated immediately by the protective relays, causing a generator trip or turbine trip, with no intentional delay between the trip of the normal supply breaker and closure of the reserve supply breaker. A sequential-type fast bus transfer is provided on PB 11 and 12 to trip the normal supply breaker and close the reserve supply breaker. In the sequential-type scheme, the reserve supply breaker closes after the normal supply breaker opens (auxiliary "B" contact closes). The power board bus will be disconnected from both sources for approximately 5.2 cycles.

Low-voltage initiation of transfer is delayed to insure overriding of transient disturbances. In this case, a special relay delays closure of the reserve breaker until the bus voltage has decayed to 20 percent of normal. This is done to preclude reenergizing motors when their residual voltage may be considerably out of phase with the incoming voltage.

PB 102 and 103 have as alternate supply sources diesel generators 102 and 103. Automatic transfer of PB 102 and 103 from offsite power to onsite diesel generator power is initiated by low voltage or degraded voltage. PB 102 and 103 feed the post-accident cooling pumps and, through step-down transformers, 600-V PB 16 and 17. PB 16 and 17 feed the low-voltage auxiliaries that are required for Station safety and are vital to safe shutdown under accident conditions.

PB 102 feeds the "B" bus section of 600-V PB 16, and PB 103 feeds the "B" bus section of 600-V PB 17. PB 16 and 17 are double-ended, metal-enclosed unit substations, each consisting of two 1,000-kVa step-down transformers and two bus sections, "A" and "B," with incoming and bus tie breakers. The "A" bus section of PB 16 is fed by 4160-V auxiliary feeder 11 from PB 11. The "A" bus section of PB 17 is fed by 4160-V auxiliary feeder 12 from PB 12.

The auxiliaries that are required both during normal Station operation and when shut down are duplicated and are connected to the "A" bus sections of PB 16 and 17. If, during shutdown, the 115-kV source is not available to energize PB 11 and 12, the auxiliary feeder secondary breakers will be opened and the bus tie breakers closed with the diesel generators providing the required auxiliary power.

The auxiliaries that are required for post-accident systems and for shutdown systems are duplicated and are connected to the "B" bus sections of PB 16 and 17. Power for these auxiliaries is from either the 115-kV system or the diesel generators described later in Section IX-4.1.

The 4160-V auxiliary feeders 11 and 12 also feed at the "A" and "C" sections, respectively, of PB 13, 14 and 15. These boards are double-ended, metal-enclosed unit substations, each consisting of two 1,000-kVa step-down transformers and three bus sections, "A", "B" and "C", with incoming and bus tie breakers.

The Station electrical distribution system is designed with safety and continuity of service as the primary considerations.

The Station service transformers, both normal and reserve, are located outdoors with barrier walls between, and are connected to the 4160-V metal-clad switchgear by a nonsegregated phase bus duct.

Reserve transformers 101N and 101S are sized, and sufficient facilities are provided, to permit Station startup, shutdown, or operation at reduced load with only one reserve transformer available and the normal transformer OOS. The transformers have automatic load tap changing (LTC) mechanisms on the low-voltage (4160-V) winding. The LTC mechanism is set to automatically maintain voltage on the 4160-V side within a set bandwidth under varying offsite voltage and transformer loading conditions. Manual operation of the LTC mechanism is also controlled from the main control room. Each transformer also has a no-load tap changer on the primary winding.

PB 11 and 12 are physically separated for reliability. If either PB 11 or 12 was OOS, the auxiliaries supplied by the other would permit operation at reduced load. PB 101 is located on the floor above PB 11 and 12 for isolation.

The low-voltage power boards, 13, 14 and 15, and the MCCs, where feasible, consist of three bus sections with the duplicated auxiliaries on the end sections and the one-of-a-kind auxiliaries on the middle section, which is fed from either end. The 1,000-kVA transformers are all interchangeable, and each is large enough to carry the entire power board load with one transformer disconnected. Either auxiliary feeder 11 or 12 can carry the entire balance of plant low-voltage Station load.

The 1,000-kVA transformers themselves are the sealed, dry type and are highly reliable.

The substation distribution arrangement is selectively coordinated, using fully-rated breakers with long-time and short-time trip characteristics, to delay the opening of the main circuit breaker until the faulted feeder has had an opportunity to clear. This provides service continuity for all but the faulted circuit.

Metal barriers are placed between the bus sections of the metal-enclosed switchgear to confine a bus fault to its own bus section.

Switchgear other than MCCs use 125-V dc power for control of the electrically-operated circuit breakers. This is so the breakers may be operated if ac power is lost. Dual feeds are provided to the dc control bus on each power board for added reliability, one each from either battery 11, 12 or 14.

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All equipment that is essential to safety is duplicated, and each duplicated auxiliary system has a cable route for power, control and instrumentation separate and isolated from its counterpart. Many auxiliaries not essential to safety are also duplicated for added reliability and, where possible, have separate cable routes.

Included within the scope of the Station auxiliary electrical system are a number of special purpose, limited capacity power sources. These sources are to supply power to the various instrumentation and control, surveillance, computer and alarm systems which are required for both normal and emergency Station conditions.

The design basis for each supply, exclusive of obvious voltage, current and quality requirements, as dictated by the nature of the connected load, is mainly concerned with the degree of external electrical system isolation, both long and short term, which it requires because of its associated load.

As such, the power sources range from those which are essentially isolated from any external system influence for an extended period of time (hours) to one which is more or less directly coupled to the external system. These supplies, shown on Figure IX-2, include the following.

2.1 Two ±24-V Dc Systems

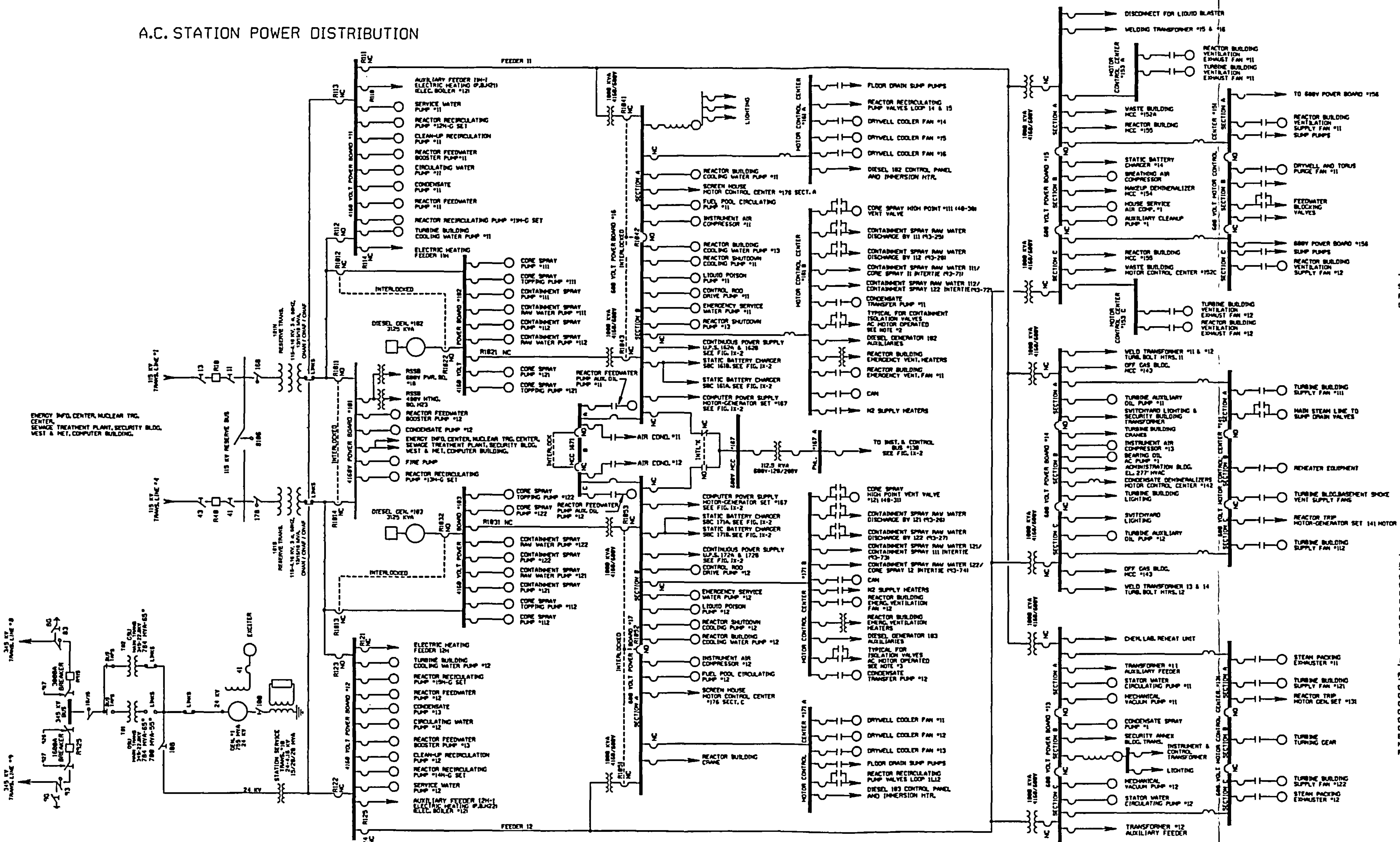
Each ±24-V dc system consists of two 24-V battery chargers (plus and minus) and one 48-V, center-tapped, grounded neutral battery. Each system is intended to supply electrical energy to its assigned part of the source and intermediate range neutron monitoring systems as well as to certain process radiation monitors. When external system power is available, the chargers actually supply the required energy to the connected loads as well as to maintain the battery in a fully-charged condition. Should, for any reason, some or all of the charging capability become unavailable, the battery will inherently and automatically supply the connected load for a minimum of 4 hr.

2.2 Two 120-V, 60-Hz, Single-Phase, Uninterruptible Power Supply Systems

Each reactor protection system (RPS) is supplied power by an uninterruptible power supply (UPS) system. Each UPS system is made up of two UPSs. Each UPS alone is capable of providing power to one RPS power panel. This provides redundant power supplies for each RPS channel.

A manual mechanical make-before-break transfer switch selects which one of the two UPSs in each channel will provide power to the associated RPS power panel. In addition, each UPS has an automatic static transfer switch at its output which will transfer to a bypass power source upon sensing either a UPS

A.C. STATION POWER DISTRIBUTION



NOTE #1

SELECTED LOADS ARE SHOWN ON THIS DRAWING. FOR ADDITIONAL LOADS SEE THE FOLLOWING ONE-LINE DIAGRAMS C-19409-C SHEETS 2-11.

PB*101	SH.2
PB*102	SH.3
PB*103	SH.3
PB*11	SH.2
PB*12	SH.2
PB*13	SH.4
MCC*131	SH.4,4A
PB*14	SH.5
MCC*141	SH.5
PB*15	SH.6
MCC*151	SH.7
MCC*151	SH.7
MCC*152	SH.7A
PB*153	SH.6
MCC*154	SH.7
MCC*155	SH.6
MCC*156	SH.12
PB*16	SH.8
MCC*161	SH.8
PB*167	SH.10
PB*1671	SH.11
PB*17	SH.9
MCC*171	SH.9
MCC*176	SH.10

NOTE #2

POWER BOARD 161B ISOLATION VALVES

CORE SPRAY SUCTION ISOLATION VALVE / 111 (81-21)
CORE SPRAY DISCHARGE ISOLATION VALVE / 111 (40-11)
CORE SPRAY SUCTION ISOLATION VALVE / 121 (81-01)
CORE SPRAY DISCHARGE ISOLATION VALVE / 121 (40-01)
CLEAN UP SUPPLY ISOLATION VALVE / 11 (33-02R)
CONTAINMENT SPRAY SUCTION ISOLATION VALVE / 111 (80-01)
EMER. CONDENSERS STEAM ISOLATION VALVE / 121 (39-10R)
MAIN STEAM ISOLATION VALVE / 111 (01-01)
FEEDWATER ISOLATION VALVE / 11 (31-07)

NOTE #3

POWER BOARD 171B ISOLATION VALVES

CORE SPRAY SUCTION ISOLATION VALVE / 112 (81-22)
CORE SPRAY DISCHARGE ISOLATION VALVE /112 (40-10)
CORE SPRAY SUCTION ISOLATION VALVE / 122 (81-02)
CORE SPRAY DISCHARGE ISOLATION VALVE / 122 (40-09)
CLEAN UP RETURN ISOLATION VALVE /1 (33-01R)
CONTAINMENT SPRAY SUCTION ISOLATION VALVE /122 (80-22)
EMER. CONDENSER STEAM ISOLATION VALVE / 111 (39-09R)
MAIN STEAM ISOLATION VALVE /121 (01-02)
FEEDWATER ISOLATION VALVE / 12 (31-08)

FIGURE IX-1
UFSAR REVISION 19
OCTOBER 2005

FILE NAME: C19489C_001B

U.S. NUCLEAR REGULATORY
COMMISSION
DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

VOLUME 3

OCTOBER 2005

REVISION 19

B. REACTOR CLEANUP SYSTEM

1.0 Design Bases

The purpose of the reactor cleanup system is to maintain high reactor water purity in order to:

1. Minimize deposition on fuel surfaces by reducing the amount of waterborne impurities in the primary system.

2. Reduce the secondary sources of beta and gamma radiation resulting from the deposition of corrosion products, fission products and impurities in the primary system.

2.0 System Design

The cleanup system, shown on Figure X-2, continuously purifies a portion of the recirculation flow and reactor bottom head flow with a minimum of heat loss from the cycle. It can be operated during startup, shutdown, and refueling modes, as well as during normal power operation.

Water is normally removed at reactor pressure from one of the reactor recirculation loops and from the reactor bottom head drain line, and cooled in regenerative and nonregenerative heat exchangers, reduced in pressure, filtered, demineralized, and pumped through the shellside of the regenerative heat exchanger to the reactor through the feedwater system. Whenever reactor pressure is insufficient to maintain suction pressure at the main cleanup pumps, an auxiliary pump is used.

Two full-size filters and demineralizers of 380,000 lb/hr capacity each are provided to permit continuous operation. Normally, one of these units is in a standby condition. The cleanup filters are pressure-precoat type, and the demineralizers are mixed-bed type. Spent cleanup resins may not be regenerated because of the radioactivity of the impurities removed from the reactor coolant, but may be sluiced from the demineralizer vessels directly to the spent resin tank in the waste disposal system for processing, storing, and eventually offsite disposal.

Y-type post-strainers on the inlet and outlet of each of the two demineralizers prevent resins from entering the reactor system in the event of a resin support failure.

The regenerative heat exchanger transfers heat from the water leaving the reactor to the water which returns to the reactor. The nonregenerative heat exchanger cools the water further to a normal temperature of 120°F by transferring heat to the RBCLC system at a design rate of 40,000,000 Btu/hr. The nonregenerative heat exchanger is capable of maintaining this low temperature, and not exceeding a maximum of 140°F during blowdown

of a portion of the cleanup flow, when effectiveness of the regenerative heat exchanger is reduced. Blowdown is normally used during reactor operation only to remove excess water from the reactor. This blowdown provision is also used as an alternate route for removing refueling water back to the condensate storage tanks (CST) via the main condenser and condensate demineralizers (CND).

A cleanup surge tank is provided to assure continuous submergence for the cleanup pumps and to provide a path for the pump recirculation flow.

The equipment in this system is designed and constructed in accordance with ASME Pressure Vessel Code, Section III-1965, Class C, ASME Section III-1963, Class C, or ASME Section VIII-1965 with Code Case 1270N. Piping, valves other than those for isolation, and fittings are built to the requirements of ASA B-31.1-1955 with nuclear interpretations. Isolated piping sections considered susceptible to thermal overpressurization are analyzed in accordance with the criteria of the ASME Boiler & Pressure Vessel Code, Section III, Appendix F, 1986 Edition.

All equipment in the cleanup system is designed to withstand earthquake acceleration factors of 0.20g horizontal and 0.10g vertical. The equipment and the piping subject to reactor water are constructed of stainless steel, rubber-lined carbon steel, or carbon steel. The primary side of the system subject to the reactor pressure is designed to withstand a pressure of 1300 psig and temperature of 575°F.

Operation of the cleanup system is controlled from the main control room. Conductivity of the water entering the cleanup filters and leaving the cleanup demineralizers is recorded in the control room. Filter backwash and resin sluicing operations are controlled from a local panel. Filters are automatically backwashed but are precoated by remote manual operation.

All equipment is shielded with concrete except for the main cleanup pumps, surge tank, flow control valve, filter aid tanks and pumps, and precoat tank. The bases for shielding design were determined by the estimated frequency of operating, inspecting and maintaining the various equipment and devices. The shielding is designed to reduce the radiation levels in the valve corridors to 30 mr/hr, and the levels in the access corridors around the cleanup system complex to 5 mr/hr. The unshielded equipment is located in controlled access areas.

The hydrogen water chemistry (HWC) and noble metal chemical addition (NMCA or NobleChem) monitoring systems require a continuous supply of reactor coolant at rated reactor pressure and temperature conditions provided from the reactor cleanup system. The monitoring systems include two electrochemical corrosion potential (ECP) monitoring locations, material coupons (durability monitor) for monitoring the noble chemistry coating

series and the outlet of the third stage exhausts to the reactor vessel. Therefore, both these pressure stages will vary with reactor pressure changes. The second pressure stage is adjusted to hold a differential pressure, nominally 250-270 psi above reactor pressure, and supplies water for normal drive operation. The third stage supplying cooling water to the drive mechanism is adjusted to maintain approximately 28-44 gpm in the cooling water header. These three supply pressures plus reactor vessel pressure in the exhaust water header are the four operating pressures of the CRD hydraulic system.

2.1 Pumps

Two full-capacity centrifugal pumps (one spare) pressurize the system. Normal operation is with one pump running. Switching from one pump to the other is a manual operation. One pump is rated at 85 gpm at a head of 3,760 ft, with a 250-hp motor. The other is rated at 87 gpm at a head of 3,740 ft, with a 250-hp motor. Each pump is installed with a suction strainer and appropriate isolation valves to permit pump maintenance.

A minimum flow bypass connection between the discharge of the pump and the CSTs prevents the pump from overheating if the pump discharge valve is inadvertently closed. The pump discharge pressure is indicated at the pump by a pressure instrument.

Electric power for this system is normally available from the reserve transformer. Automatic initiation is provided to start each pump from its respective diesel generator in case offsite power is lost.

2.2 Filters

The two parallel filters remove 99 percent of foreign material larger than 40 microns from the hydraulic system water. Either filter can be drained, cleaned, and vented for reuse while the other is in service. A differential pressure indicator and alarm monitor the filter element as it collects foreign material. Strainers in the filter discharge lines guard the hydraulic system in the event of a filter element failure.

2.3 First Pressure Stage

The first-stage pressure is maintained automatically by a flow-sensing controller (44-145, 44-146, 44-146B) and by an air-operated flow control valve (44-149 and 44-154). By throttling 44-149 or 44-151 to maintain constant flow through 44-145, the pump is caused to operate at the point on its characteristic curve which corresponds to the required pressure. A parallel spare valve is provided with isolation valves to permit maintenance of the noncontrolling valve. During cold shutdown and normal power operation, the CRD system flow control valves, which are normally in automatic mode, may be operated manually. This first pressure stage supplies water to the

accumulator charging header. The pressure in this header is monitored in the main control room with a pressure indicator and low and high pressure alarms.

2.4 Second Pressure Stage

The second-stage pressure is automatically maintained at approximately 250-270 psi above the reactor vessel pressure by the combined operation of 44-04, 44-179 and 44-178. Valve 44-04 is manually adjusted from the control room so that the flow through it to the reactor produces a drop of approximately 240 psi. When this valve is adjusted, both 44-179 and 44-178 are open. The flow through these valves bypasses 44-04. The bypass flow is adjusted, using flow meter 44-187, to correspond to the flow required by a drive when moving the flow through 44-179 (corresponding to the flow while inserting), and the flow through 44-178 (corresponding to the flow while withdrawing). Electrically, 44-179 is connected so that it closes when the "insert" valves for any drive are actuated, while valve 44-178 closes when the "withdraw" valves for any drive are actuated. In this manner, the flow through these valves always balances the flow to the drives through the 1-in drive water header, the flow through 44-04 is substantially constant, and the required pressure is maintained in the 1-in drive header. The variation in flow requirements between drives is small enough that the corresponding pressure variation is within acceptable limits. Second-stage pressure may be lowered less than 250 psid to compensate for CRD seal leakage or hydraulic control unit (HCU) valve leakage.

A standby pair of bypass valves (44-181 and 44-182) are provided along with a manual backup pressure control valve (44-157) used during maintenance on the normal pressure control valves.

Filters are installed before the bypass valves to prevent fouling of the bypass valves. Isolation valves are provided for maintenance on the bypass valves. A flow element and an indicator (44-07 and 44-187) are installed for measuring the flow through the bypass valves so that the valves can be adjusted to provide the required flow for normal drive operation.

The flow element and the indicator (44-158 and 44-191A) located in the drive water header are used to measure flow to the drives for adjustment and testing. A differential pressure indicator in the main control room shows the differential pressure between the reactor vessel and the drive water header. This pressure indicator is used when adjusting the second-stage pressure with the motor-operated pressure control valve.

2.5 Third Pressure Stage

The third-stage pressure is automatically maintained at a pressure above reactor vessel pressure to supply a total of approximately 28-44 gpm cooling water to the drives. The

pressure drop which maintains the pressure for this stage is developed by a motor-operated pressure control valve. This valve is manually adjusted from the main control room, and is provided with isolation valves and a manual bypass valve for maintenance. The flow through this valve and the second-stage pressure control valve is substantially constant and the valves, therefore, act to maintain a constant differential above reactor pressure. Changes in the setting of these valves are required only to adjust for changes in the cooling requirements of the drive mechanism as the seal characteristics change with time, and for changes in pump flow characteristics.

The cooling water is monitored by a flow indicator. A differential pressure indicator indicates the difference between reactor pressure and cooling water pressure.

2.6 Exhaust Header

The exhaust header takes water discharged by the drives during operation and by the third-stage pressure controller and conducts this water to the reactor. The piping is sized to maintain a low differential (approximately 5 psi) above reactor pressure in this header. A check valve permits isolating this line from the reactor vessel and automatically prevents reactor water from flowing into this line should the supply pressure fail. A flow element and an indicator permit measuring the exhaust line flow during Station operation. A bypass line from the pump output to a point upstream of this flow meter allows checking of pump flows.

2.7 Accumulator

The accumulator on each drive is an independent source of stored energy to scram that drive. The top of the accumulator contains water; the bottom is initially precharged to approximately 600 psi with nitrogen.

To assure that it is always capable of producing a scram, the accumulator is continuously monitored for water leakage and for nitrogen pressure. A float-type level switch will actuate an alarm if water leaks past the nitrogen-water barrier and collects in the bottom of the accumulator. A pressure indicator and a pressure switch are connected to the accumulator to monitor nitrogen pressure. During normal operation the accumulator barrier has virtually zero pressure drop across it. If there should be any loss of nitrogen, the barrier will move onto a stop and further loss will cause a decrease in the nitrogen pressure. The accumulator barrier will not move down beyond the stop and, therefore, will not compress the reduced amount of gas back up to pressure. A decrease in nitrogen pressure will actuate the pressure switch and sound an alarm. An isolation valve allows each of the accumulator instruments to be isolated and serviced. A connection on the accumulator provides for precharging and bleeding.

The charging line allows isolation of the accumulator for maintenance and prevents backflow from the accumulator to the charging header. It assures that the accumulator will retain its charge even if the supply subsystem fails.

2.8 Scram Pilot Valves

During normal operation, each of the two parallel branches of the RPS energize one of the two three-way solenoid scram pilot valves associated with each drive mechanism. During normal operation, these pilot valves are energized and supply instrument air to the operators of both the inlet scram valve and the outlet scram valve, holding both scram valves closed. During a full scram, both of the RPS branches are de-energized and both pilot valves open, venting the scram valves' operators and allowing the scram valves to open. To protect against spurious scrams, the pilot valves are interconnected so that both pilot valves must be de-energized to vent the scram valves' operators. On the other hand, failure of either electric power to both solenoids or instrument air will produce a scram. The pilot valves are selected based on simplicity of design, a minimum of moving parts, fast opening time (approximately 0.050 sec), and satisfactory statistical operating history on similar units.

For added protection, the instrument air header to all the pilot valves has a pair of backup scram pilot valves. Upon a scram signal these three-way solenoid valves close off the air supply and vent the instrument air header. This will scram any drive should either of its scram pilot valves fail to vent.

A diverse reactor trip system, alternate rod injection (ARI), has been added to provide an alternate and diverse method of venting the instrument air header. An ARI initiation signal, high reactor pressure, or low-low water level will actuate the ARI system.

2.9 Scram Valves

The inlet scram valve is a globe valve which is opened by the force of an internal spring and closes when air pressure is applied on top of the diaphragm operator. The opening force of the spring is approximately 700 lb. Each valve has a position indicator switch which energizes a light in the control room as soon as the valve starts to open. The scram valve is selected based on high operating force, fast opening time (approximately 0.1 sec) and satisfactory operating history on similar units.

Both the inlet and outlet scram valves are similar, except that the inlet scram valve is an angular pattern while the outlet scram valve is a globe pattern. The internal spring preload in the outlet scram valve is slightly greater than the inlet scram valve to provide a faster opening characteristic.

downstream to maintain the set temperature less than or equal to 95°F.

Two temperature-controlled flow control valves regulate the volume of TBCLCW entering the heat exchangers. Operating in tandem, one valve will admit TBCLCW to the cooling water heat exchanger supply manifold, and the other will divert the TBCLCW to the discharge header. As flow to the supply manifold is diminished, the diverted water flow is increased. A temperature element in the TBCLCW discharge manifold from the heat exchangers actuates the SWP and TBCLCW control valves. The SWP control valves located in the SWP discharge manifold can be bypassed by manual control.

To evaluate radiation hazards as a result of leakage from equipment into the cooling water system, the outlet of each major component on this system is provided with a grab sampling station.

High temperature alarms and temperature transmitters for major components served by the cooling water system aid in regulating cooling water flow.

Excessive leakage out of the system is noted by a flow switch and alarm in the system makeup line.

4.0 Tests and Inspections

The alternate cooling water pump is exercised periodically to assure its proper operation.

F. SERVICE WATER SYSTEM

1.0 Design Bases

The purpose of the SWP system is to provide strained lake water for cooling the RBCLCW and TBCLCW systems, the steam jet air ejector (SJAE) precooler, ejector vent cooler, the building local air coolers and other building services. Service water also is supplied to the screenwash pumps, the radwaste solidification and storage building (RSSB), and the makeup demineralizer. The system is to be available to cool the reactor building cooling water system under all conditions of operation. The cooling water requirement during the shutdown mode represents the most severe condition and is used as the design basis.

2.0 System Design

The system is shown on Figure X-6. Lake water from the intake tunnel passes through trash racks and traveling screens in the screen and pump house and floods the service water pump well. Two full-capacity (20,000-gpm) vertical sleeve bearing pumps take suction from the well. Each pump is provided with a .03-in mesh automatic self-cleaning strainer. The pump discharges are passed through the self-cleaning strainers and blocking valves and then into two separate headers which deliver water to cooling loads within the plant. A valved crosstie located downstream of the pumps enables either pump to supply either service water header. In the reactor building, the SWP system provides flow to the RBCLC heat exchangers. Downstream of the RBCLC heat exchangers is temperature control valve (TCV) 72-146. This valve regulates the amount of service water flowing through the heat exchangers. The RBCLC system provides the control signal for the valve's position. In parallel with the TCV is bypass valve 72-92R, for use if the TCV is out of service or to increase flow through the heat exchangers during peak loading conditions, as shown on Figure X-4. Listed below are the systems and requirements fulfilled by the SWP system.

RBCLCW Heat Exchangers (Tube Side)	6,200 gpm
TBCLCW Heat Exchangers (Tube Side)	8,000 gpm
Screenwash System Pumps	2,400 gpm
SJAE Precoolers and Vent Cooler	1,000 gpm
Local Building Area Coolers	1,500 gpm
RSSB HVAC Chillers	650 gpm
Makeup Demineralizer	100 gpm
Breathing Air Compressor	7 gpm
Total	19,857 gpm

To provide for future added capacity, the pump header was extended and two valved branches were added.

In the event of a loss of both normal and reserve ac power, the service water pumps would be unavailable. At this time, service water requirements for the RBCLCW heat exchangers would be met by either of a pair of emergency ac power vertical turbine pumps. One of these pumps is connected to PB 16 and the other to PB 17. These power boards are supplied power from the diesel generators if their normal supply fails, as described in Section IX, Electrical Systems. The emergency pumps, each rated at 3,600 gpm, are in the screenhouse and take their suction from the circulating water intake.

Each of the emergency service water pumps is connected to one of the service water supply lines to the RBCLCW heat exchangers in the reactor building. Each emergency service water pump can supply water to any one of the three heat exchangers.

Each of the TBCLCW heat exchangers is serviced by two full-size service water supply lines. During normal operation, both the supply headers on the RBCLC side and TBCLC side are engaged by keeping the blocking valves open; however, to perform maintenance or other plant activities, one of the RBCLC side and one of the TBCLC side blocking valves can be secured.

3.0 Design Evaluation

Either pump has the capacity with the bypass valve opened to provide maximum service water requirements and can be throttled safely to flows as low as 20 percent of design if a need arises to reduce flow for temperature control. With bypass valve 72-92R closed, two normal service water pumps are required to meet the required flow rates for the most limiting mode of system operation.

The two emergency service water pumps increase the reliability of the SWP system and, as previously mentioned, provide service water during loss of normal and reserve ac power. In the unlikely event both emergency service water pumps fail to operate (i.e., due to a fire), an intertie exists between the diesel fire pump and the emergency service water line. The diesel fire pump is capable of handling the additional emergency service water requirements.

The double supply lines to the closed loop cooling water heat exchangers provide 100-percent backup in the event of pipe failure in either building.

A minimum velocity of 4 fps is maintained in both the RBCLCW and TBCLCW heat exchangers tubes to deter sand buildup.

In the event of loss of a SWP pump, low service water header pressure will be alarmed in the control room and the alternate pump will be started manually.

Differential pressure alarms across all strainers signal excessive pressure drop to the Operator in the control room.

IE Bulletin 80-10 requires effluent radiation monitoring for those systems that are normally considered nonradioactive, but could possibly become contaminated by leakage from interfacing systems.

The 42-in reactor building service water return and 10-in turbine building service water return lines are alternately monitored for radiation at 15-min intervals prior to discharge. Other service water return lines, including cooling to the RSSB air conditioning units which have no credible potential for contamination, are not monitored for radiation prior to discharge.

4.0 Tests and Inspections

To assure its availability, the alternate pump is operated once a month.

Both emergency service water pumps are operated quarterly.

3.0 System Evaluation

Operation of the portable makeup system is on demand at routine infrequent intervals to replenish demineralized water in storage tanks. With the system inoperable or when the portable demineralizer skid is not available, the Station can continue operation with makeup water from the CSTs which have a combined capacity of 400,000 gal. Additional makeup water is available from the demineralized makeup water storage tank which has a 40,000-gal capacity.

As an option, Operators may take a supply of water from city water for processing, depending on the plant operating conditions.

City water is an equivalent or better source for makeup than lake water in terms of contaminants, and delivery capacity is within or exceeds the requirements for supply to the demineralized water system.

4.0 Tests and Inspections

The demineralizer effluent is controlled by effluent conductivity, but periodic samples are taken of conductivity, TOC, silica, chlorides, and sulfates.

H. SPENT FUEL STORAGE POOL FILTERING AND COOLING SYSTEM

1.0 Design Bases

This system is designed to remove the spent fuel assemblies' decay heat and the impurities from the pool water so as to maintain the temperature and purity of the spent fuel pool water at acceptable levels, assuring clarity under all anticipated conditions. The pool water temperature is maintained at or below 140°F during maximum anticipated storage conditions. Normal refueling conditions are based on refueling the reactor every 18 to 24 months. During certain instances, it may be necessary to offload the entire core into the spent fuel pool. The maximum heat generation rate was determined by assuming a full core discharge (532 bundles) after 18 to 24 months, with the maximum number of previously discharged fuel bundles (3550) being present in the pool. The greatest portion of the decay heat would be produced by the bundles being discharged from the core, rather than those bundles which have been stored in the spent fuel pool from previous discharges. The long-term decay heat rate for GE11 fuel is essentially the same as for previous fuel designs. Therefore, the decay heat rate used as the basis for the spent fuel storage pool filtering and cooling system design remains unchanged.

Prior to Technical Specification Amendment No. 167, the spent fuel pool was licensed for 2776 storage cells. The north half of the pool contained 1066 nonpoison flux trap storage locations, and the south half provided 1710 locations using Boraflex as a neutron absorber. Currently, the spent fuel pool is licensed, per Technical Specification Amendment No. 167, for 4086 spent fuel storage locations using the neutron absorber material Boral, with 1840 storage locations in the north half of the pool and 2246 locations in the south half. The nonpoison racks in the north half of the pool were replaced with new poisoned racks after the 1999 refuel outage. The reracking of the south half of the pool has been partially completed. Six of the eight existing Boraflex racks have been replaced with new Boral racks, increasing the capacity from 1296 to 1656 storage locations. Two Boraflex racks remain in the south half, providing 414 storage locations. The rerack of the remaining two racks has been deferred until further capacity increase is warranted.

Unit 1 committed to the Nuclear Regulatory Commission (NRC) that refueling and core offloading operations would not begin until it was determined that the spent fuel pool cooling systems were operable, to ensure that the bulk pool temperature limits would not be exceeded.

For a normal (full core offload or core shuffle) refueling, the offload time to the spent fuel pool and the RBCLC temperatures shall be verified to be consistent with a bulk pool temperature not to exceed 140°F with one cooling train operating.

For the case of an abnormal maximum heat load (such as a full core offload shortly after a normal refueling), this would require verifying that offload time and RBCLC temperatures were consistent with a pool temperature <140°F with both cooling trains operating.

Based on past experience, sufficient clarity of the pool water can be achieved by a filter capable of removing particles as small as 25 microns in size.

2.0 System Design

The system is shown on Figure X-8. Two full-capacity (600 gpm) pumps take suction from the pool surge tanks and circulate the pool water through two parallel loops consisting of one filter and one heat exchanger. The water is returned to the pool on the side opposite the surge tank skimmers.

The spent fuel pool cooling (SFC) system is designed as seismic Category 1.

The SFC system bounding design conditions are that, under full core discharge conditions with RBCLC coolant water temperature at its maximum of 95°F, and assuming the SFC heat exchangers are fouled to their design maximum and 5 percent of the tubes are plugged, a pool water temperature of 140°F would be reached if a full core offload began 1008 hr after reactor shutdown, and was completed 1129 hr after reactor shutdown with one of the two redundant cooling trains operating.

A more expedited offload may be performed if the plant conditions exist to maintain the pool water temperature at or below 140°F with one SFC train operating.

Flow control valves regulate the flow in each loop at 600 gpm by use of a controller that may be operated in the auto or manual mode.

Cooling water is supplied to the heat exchangers from the RBCLCW system at temperatures not exceeding 95°F. A sample point is incorporated to determine any tube leakage.

Initial filling and level maintenance in the spent fuel pool and surge tanks was from the condensate transfer system. The total volume of the surge tanks is approximately 2000 cu ft. They will normally run at a level of approximately 1000 cu ft. The

difference in surge tank volume allows for the displacement of water from the spent fuel storage pool when a shipping cask (or any other object) is placed in the pool.

Makeup water is provided by the condensate transfer system. Normally, makeup is directly to the spent fuel storage pool. Makeup to the spent fuel storage pool is automatically initiated when the surge tank volume decreases to 800 cu ft and stops when the volume reaches 1000 cu ft. If the makeup to the spent fuel storage pool is not sufficient to maintain surge tank volume, makeup water can be provided directly to the surge tanks. The condensate transfer system can provide a makeup rate of 75 gpm or more to either the spent fuel storage pool or the surge tanks. Makeup water can also be supplied directly to the spent fuel pool through fire water hoses.

Any particles that enter the pool either sink to the bottom to be removed by a portable vacuum cleaner or float about in the pool and eventually enter the skimmers, surge tanks and filtering loop. Provision is made for transferring water to the liquid waste disposal system for processing if the pool water becomes highly contaminated.

The precoat-type filters use porous carbon elements. Precoat material is powdered/crushed resins. One precoat mix tank and pump serves both filters. The slurry is circulated through the filter vessel and back to the tank until a uniform coating of precoat material covers all the elements. The filter is then placed in service until differential pressure signals the need for backwashing. The backwashing process consists mainly of first valving off and draining the filter, then filling the filter with condensate from the condensate transfer system. All vents are closed during this filling and air is trapped in the filter dome above the elements. When the pressure in the filter dome reaches approximately 80-100 psig, the drain valve is quickly opened and the filter cake, together with trapped impurities, washes into the fuel pool filter sludge tank. From the sludge tank the suspension of impurities and water is pumped to the waste disposal system.

Aside from its normal function of cooling and purifying the spent fuel pool water, the system is also used after reactor refueling to drain the reactor internals storage pit and head cavity. Alternate lines allow transport of the water to either the main condenser or to the waste disposal system for processing. In either case the water is filtered, demineralized and returned to the CSTs. Each major piece of equipment is designed to withstand seismic forces of 0.25g horizontally and 0.125g vertically. The ASME Boiler and Pressure Vessel Code, Section VIII-1965, is specified for pump casings, heat exchanger, filter vessels, and the sludge tank, as well as for the fuel pool surge tanks.

J. FUEL AND REACTOR COMPONENTS HANDLING SYSTEM

1.0 Design Bases

The design of facilities for handling fresh and irradiated fuel and reactor components is based on the following major considerations.

1. Fresh fuel will be received and stored, with or without flow channels, in a manner which precludes inadvertent criticality.

2. Normal reactor refueling will involve replacement of approximately 35-40 percent of the core.

3. Spent fuel is stored onsite in the spent fuel storage pool until offsite disposal is available.

4. The fuel assemblies and other reactor components to be handled are of the size and weight given in Section IV, Reactor.

5. Previously irradiated flow channels should not be installed on fresh fuel bundles; only new channels should be installed on fresh fuel bundles. Irradiated channels normally are not used on different bundles.

6. There will be no release of contamination or exposure of personnel to radiation in excess of 10CFR20 limits.

7. The spent fuel pool is currently licensed for 4086 spent fuel storage locations using the neutron absorber material Boral, with 1840 storage locations in the north half of the pool and 2246 locations in the south half. Reracking of the north half of the spent fuel pool was completed after the 1999 refuel outage, increasing the north half storage locations to 1840. The reracking of the south half of the pool, increasing from 1710 to 2246 storage locations, has been partially completed. Six of the eight existing Boraflex racks have been replaced with new Boral racks, increasing the capacity from 1296 to 1656 storage locations. Two Boraflex racks remain in the south half, providing 414 storage locations. The rerack of the remaining two racks has been deferred until further capacity increase is warranted.

8. It will be possible at any time to perform limited work on irradiated components.

9. Storage space can be provided for irradiated control rods, flow channels and other reactor components.

10. Fuel sipping operations and the temporary installation of fuel sipping equipment.

2.0 System Design

2.1 Description of Facility

The major components of this system are a fresh fuel storage vault, spent fuel storage pool, a cask drop protection system, reactor head cavity, reactor internals storage pit, refueling platform, and other auxiliary equipment, all of which are located on the operating floor (see Figure X-10).

The fresh fuel vault is a reinforced concrete Class I structure, accessible through top hatches and a personnel door. Racks in the vault can hold a maximum of 200 fuel bundles in an upright attitude. The center-to-center spacing of bundles in the racks is 6.6 in by 11 in. There is an open drain in the floor of the vault. An area monitor used as a criticality monitor is installed in the vault (see Section XII-B).

The spent fuel storage pool is a reinforced concrete Class I structure. The interior of the pool is lined with stainless steel plate. Leak detection channels at the liner seams connect to open telltale drains. A stainless steel-lined canal connects the pool to the reactor head cavity for fuel transfer. During normal operation the canal is closed by two sealed aluminum gates in series. An open drain with a flow switch alarm is provided between the gates for leak detection. The depth of water in the pool is 37 ft 10 in. The depth of water in the transfer canal during refueling is 22 ft 9 in. The water in the pool is continuously filtered and cooled by the spent fuel storage pool filtering and cooling system described in Section X-H.

There are two types of spent fuel storage racks in the spent fuel storage pool. Both are designed to maintain an adequate criticality margin (K_{eff} less than 0.95) under all storage conditions. Calculational methodology and the treatment of uncertainties and manufacturing tolerances are described in References 1, 2, and 3. The spent fuel storage pool is currently licensed for 4086 fuel assemblies. After the 1999 refuel outage, 1840 storage locations using the neutron absorber material Boral were installed in the north half of the pool. The reracking of the south half of the pool, increasing from 1710 to 2246 storage locations, has been partially completed. Six of the eight existing Boraflex racks have been replaced with new Boral racks, increasing the capacity from 1296 to 1656 storage locations. Two Boraflex racks remain in the south half, providing 414 storage locations. The rerack of the remaining two racks has been deferred until further capacity increase is warranted. Through the use of the neutron absorber material Boral, the high-density racks in the north end of the pool may contain up to 1840 fuel assemblies, and the south end of the pool may contain up to 2246 fuel assemblies. The remaining Boraflex high-density poison

racks in the south end of the spent fuel pool may hold up to 414 fuel assemblies with a peak design lattice enrichment of 18.13 grams (3.75 weight percent) of U-235 per axial centimeter. The rows are separated by neutron absorber material--boroflex poison, which is a matrix of boron carbide powder in a silicon polymer. Peak design lattice enrichment is arrived at by averaging the rod enrichments on the design drawings for each lattice, and then choosing the highest (peak) lattice average. Manufacturing tolerances are not included. The Boral racks in the north and south ends of the pool have been analyzed for the design basis fuel assembly of a standard 8x8 array of boiling water reactor (BWR) fuel rods containing UO_2 clad in Zircaloy (62 fuel rods with 2 water rods). The GE11 fuel design, a 9x9 array of fuel rods with 8 partial-length fuel rods, has also been analyzed and found to be less reactive for a given enrichment than the GE 8x8 fuel, and that a maximum $k\infty$ of 1.31 in the standard core geometry will encompass the GE11 fuel at all enrichments up to 4.6 percent. Therefore, the fuel assemblies stored in these racks must have a peak lattice enrichment of 4.6 percent or less, and the $k\infty$ in the standard cold core geometry, calculated at the maximum over-burnup, must be less than or equal to 1.31. Any fuel of 3.1 percent average enrichment or less is acceptable regardless of the gadolinium content or the $k\infty$ in the standard core geometry. The racks are designed so that accidental dropping of a fuel assembly will not cause critical geometry. Five mountings for jib cranes are installed around the periphery of the pool. Jib cranes with a 1/2-ton capacity can be installed on these mountings for handling components in the pool, and for transferring fresh fuel from the storage vault to the pool. The northwest corner of the pool is reserved for loading spent fuel shipping casks, and is provided with a cask drop protection system (Section X-J.2.1.1).

The reactor head cavity is completely lined with stainless steel plate. Leak detection channels at each liner seam connect to open telltale drains. A flexible bellows seal connects the liner to the drywell shell. A horizontal steel refueling seal platform inside the drywell shell, and connected to the reactor vessel flange by a second flexible bellows seal, closes off the bottom of the reactor head cavity. During refueling, the cavity is filled

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M. HYDROGEN WATER CHEMISTRY AND NOBLE METAL CHEMICAL ADDITION (NOBLECHEM) SYSTEMS

1.0 Design Basis

The HWC and NMCA systems are provided to mitigate intergranular stress corrosion cracking (IGSCC) of the recirculation piping and the reactor vessel internals. Mitigation of IGSCC in operating boiling water reactors (BWR) can be effectively accomplished by reducing the bulk liquid oxidant (oxygen and hydrogen peroxide). Hydrogen added to the feedwater suppresses the radiolytic generated oxidant concentration in the core regions, and enhances the recombination reactions in the downcomer. The reduction in oxidant level can reduce the ECP significantly and crack initiation and growth also are greatly reduced, even at high bulk liquid oxidant levels. Reducing the ECP requires high hydrogen addition rates which result in increased main steam line radiation levels from volatile ^{16}N compounds. The catalytic behavior of noble metals provides an opportunity to efficiently achieve a dramatic reduction in ECP by catalytically reacting hydrogen with all oxidants at the catalytic surface.

NobleChem employs the reactor coolant as the transport medium to deposit minute amounts of noble metal on all wetted reactor components. With the ratio of hydrogen to oxygen in excess of stoichiometric, the corrosion potential of the reactor vessel and internal components decreases significantly, and crack initiation and growth also are greatly reduced, even at high bulk liquid oxidant levels.

Low hydrogen addition rates are still necessary to provide sufficient excess hydrogen at the surface of NobleChem treated components. Oxidants that diffuse to the component surface will immediately react with the excess hydrogen (molar ratio of hydrogen to oxidant >2) to form water. In this way, the boundary layer of all NobleChem wetted components is depleted of oxidants and a very low corrosion potential is maintained. In summary, NobleChem utilizes very reactive surfaces to maintain oxidant deficient water in contact with reactor components. Therefore, because of the lower operational dose rates, the NobleChem process in conjunction with low hydrogen addition rates is an effective approach to mitigate and prevent IGSCC.

1.1 Noble Metal Chemical Addition System

The NMCA process involves periodic injection of noble metal compounds, containing platinum (Pt) and rhodium (RH), into the recirculation loop(s) and into the reactor vessel, through existing small bore piping connections in the recirculation pump differential pressure transmitter lines. The noble metal compounds are deposited on reactor internal surfaces with the reactor in hot standby condition. The noble metal compounds are distributed by circulating coolant using 3 of 5 recirculation pumps. The resulting coolant flow across the core and core

shroud is relatively uniform enhancing proper deposition on wetted surfaces. Appropriate water level in the reactor vessel is maintained by operating the CRD and the RWCU systems. Normal reactor coolant makeup is available per operations procedures for this hot shutdown condition.

The noble metal deposition process lasts approximately 48 hr, with the coolant temperature maintained between 250°F and 350°F as required by the General Electric-Nuclear Energy (GENE) Application Procedure. The exact temperature during the application within this range is a GENE process decision, as is the rate of chemical injection. During the process period, a combination of the recirculation pumps and shutdown cooling is used to regulate the coolant temperature.

The noble metal compounds are deposited onto all surfaces that come into contact with the moving reactor coolant in the applicable temperature range. For example, at a nominal deposition of $1 \mu g/cm^2$, the uniform coverage is approximately one atom layer of 3 Å thickness (1 Å is 1×10^{-7} mm or 3.94×10^{-9} in). Surface scans of autoclave treated specimens have shown that the noble metal atoms present on the surface do not completely cover the surface, but are distributed randomly across the surface. On an atomic scale, the deposited noble metals are discontinuous. Even with agglomeration, the maximum thickness of Pt and Rh is significantly less than 0.001 in, which is less than the minimum manufacturing tolerances of the vessel components (e.g., the tolerance of the fuel Zircaloy tubes is ±0.003 in and the Zircaloy channels is ±0.004 in).

1.2 Hydrogen Water Chemistry System

The HWC system injects hydrogen into the feedwater system at the suction to the feedwater booster pumps. The injected hydrogen causes a reduction in dissolved oxygen within the reactor internals and recirculation piping and lowers the radiolytic production of hydrogen and oxygen in the vessel core region. Hydrogen addition to the feedwater results in an excess ratio of hydrogen to oxygen at the entrance to the offgas (OFG) system. Therefore, the HWC system also provides an oxygen supply upstream of the OFG recombiner to maintain stoichiometric mixture of hydrogen and oxygen in the recombiner.

With the suppression of radiolysis, the main steam line dissolved oxygen concentration decreases. This can result in lower condensate and feedwater dissolved oxygen concentrations. If the condensate and feedwater dissolved oxygen concentration values are less than 20 ppb, accelerated carbon steel corrosion can occur. Unit 1 has an existing oxygen injection system to add oxygen to the condensate feedwater system. The HWC system has a provision to supply oxygen to supplement the existing oxygen injection system for the condensate feedwater system.

protection of a specific hazard. NFPA Standard 15, Water Spray Fixed Systems, provides guidance on these systems.

2.0 BTP APCSB 9.5-1 APPENDIX A COMPARISON

2.1 OVERALL NUCLEAR PLANT FIRE PROTECTION PROGRAM REQUIREMENTS

The Fire Protection Program is a program to implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report (Updated), and as approved in the Fire Protection Safety Evaluation Report dated July 26, 1979, and in the fire protection Exemption issued March 21, 1983. Noncompliances with the above-described Fire Protection Program that adversely affect the ability to achieve and maintain safe shutdown in the event of a fire shall be reported in accordance with the requirements of 10CFR50.72 and 10CFR50.73.

2.1.1 Personnel

The Senior Constellation Nuclear Officer Responsible for Nine Mile Point has the overall management responsibility for the nuclear fire protection program.

The Site Vice President has the overall responsibility for the fire protection program at the Nine Mile Point site.

The Manager Operations reports to the Plant General Manager and is responsible for managing, overseeing, and coordinating the site's fire protection functional and technical activities.

The Fire Protection Program Manager reports to the General Supervisor Engineering Programs, who reports to the Manager Engineering Services, and is responsible for managing, overseeing, and coordinating the Fire Protection Engineering group.

2.1.1.1 Organizational Responsibilities

The Senior Constellation Nuclear Officer Responsible for Nine Mile Point has management responsibility for the formulation, implementation, and assessment of the effectiveness of the nuclear plant fire protection program.

The Site Vice President shall have the overall responsibility for the fire protection program at the Nine Mile Point site.

The Manager Operations is responsible for implementation of the site fire protection program at Unit 1 and Unit 2.

The Manager Maintenance shall ensure fire-fighting equipment, systems, and fire barrier integrity for each unit is maintained by performance of maintenance and modifications, as required.

The Manager Training Nuclear ensures that Fire Brigade personnel are scheduled to attend the required fire training sessions and ensure that the required fire drills are performed. In addition, they are responsible for any necessary fire protection training of operating Station or contractor personnel.

The Supervisor Fire Protection shall provide technical support to the Fire Brigade for routine daily matters, required surveillance activities, and to support special investigations and projects:

a. Act as the site contact for fire protection matters such as American Nuclear Insurance (ANI) audits, NRC inspections, QA and Constellation Risk Management audits.

b. Act as liaison between Constellation Risk Management, Site Fire Protection Engineer, and Fire Protection personnel.

c. Consult with the Fire Protection Program Manager for interpretations of adequacy on issues concerning compliance with regulatory and/or fire protection program requirements.

d. Coordinate scheduling of required training and fire protection training drills for Stations operating and offsite fire support personnel.

e. Conduct periodic inspection to assess compliance with the Station fire protection program, and ensure unit fire protection system/equipment operability.

f. Ensure fire protection-related surveillances are performed.

g. Evaluate proposed work activities as required, and maintain an awareness of the status of repairs, modifications, or other work affecting fire protection systems and equipment.

h. Ensure notification of fire insurance carrier (ANI) and Constellation Risk Management is performed when

unit fire protection system impairments occur, as required.

The General Supervisor System Engineering shall:

a. Ensure fire protection system support is maintained.

b. Evaluate fire protection system trend data and provide recommendations for corrective actions as necessary.

c. Ensure input into the Operating Experience Assessment (OEA) Program for matters concerning fire protection.

The Manager Operations shall direct the Fire Brigade's day-to-day activities associated with the implementation of the fire protection program.

a. Consult with the Fire Protection Program Manager for interpretations of adequacy on issues concerning compliance with regulatory and/or fire protection program requirements.

b. Direct investigations into fires at the unit, review the determination of cause, and recommend corrective action, as appropriate.

c. Ensure that training is established and scheduled in accordance with program requirements.

d. Evaluate the effectiveness of fire protection training.

e. Direct the inspection and testing of fire protection systems and equipment in accordance with applicable procedures.

f. Ensure a review of inspection and test results is conducted to maintain compliance with license requirements.

g. Ensure that negative performance trends on fire protection systems and equipment are reported to the Supervisor Fire Protection.

The General Manager Nuclear Engineering has overall responsibility for the design and evaluation of fire protection components and systems, and also periodically assessing, through the Nuclear Safety Review Board (NSRB), the effectiveness of the fire protection program for Nine Mile Point Nuclear Station. Specific actions include:

a. Review of modifications to plant systems by selected personnel under the direction and guidance of a Fire Protection Engineer (qualified) for impacts to the site fire protection program.

b. Designing modifications to fire protection systems in accordance with nationally recognized standards. In addition, assessment of impacts to Final Safety Analysis Report (FSAR) commitments, Fire Hazards Analyses (FHA) and NRC Safety Evaluation Reports (SER). Evaluation of deviation impact is performed by selected personnel under the direction and guidance of a Fire Protection Engineer (qualified).

c. Identification and evaluation of proposed changes to the program or systems which impact licensing prior to the change being made.

d. Identification and resolution of deviations from the program in a timely manner.

e. Development of inspection attributes for fire protection equipment.

f. Provision of support in resolution of deficiencies identified within the fire protection program.

g. Development of testing requirements meeting applicable codes for system changes.

h. Definition and maintenance of design records required to support the fire protection program.

A Fire Protection Engineer (qualified) shall provide direction and guidance to selected personnel assigned to evaluate activities and identified deficiencies to the fire protection program for impacts to program documentation, determine path for resolution of open items or questions, review inspection attributes for fire protection system design changes, recommend program improvements as required, and participate in program evaluation on a periodic basis (audit).

The Manager Engineering Services assigns a Fire Protection Program Manager, and ensures audits are conducted per the fire protection Nuclear Division Directive.

The Fire Protection Program Manager provides organization, direction, and guidance concerning the implementation of the fire protection program, and the approach to be taken regarding fire protection issues as they relate to the overall performance and adequacy of the nuclear fire protection program.

Specific duties include:

1. Maintain cognizance of regulatory positions and trends, determine adequacy/sufficiency of programs to satisfy regulatory and program requirements and commitments, and develop programs to resolve deficiencies, insure auditability and implement corrective actions to maintain acceptable levels of fire protection within the nuclear facilities.

2. Coordinate regulatory response and provide program interpretation for fire protection issues and identify potential fire protection modification requirements.

3. Coordinate the prioritization of identified fire protection work items.

4. Coordinate with appropriate training departments to ensure that required training levels are established for personnel performing fire protection engineering activities.

5. Interface and coordinate with the Supervisor Fire Protection regarding matters that impact site fire protection.

6. Provide an overview function to:

   a. Periodically review fire protection engineering evaluations, Appendix R reviews and fire protection reviews.

   b. Ensure that Unit 1 interpretations of regulatory documents and corporate policy are being applied properly and consistently.

   c. Ensure Corporate fire protection philosophy/requirements are transmitted to Nuclear Engineering and that they are implemented in design changes.

The Director Quality and Performance Assessment has overall responsibility for formulating, administering and verifying the effectiveness of the quality assurance program for fire protection (see Section 2.3). The Director Quality and Performance Assessment ensures that the quality assurance program is implemented by planned inspections and scheduled audits, assuring that the results are promptly reported to cognizant management personnel.

Constellation Risk Management has responsibility for assuring adequate fire protection for company facilities and fire personnel training; to verify appropriate measures are taken to prevent or limit losses from any perils resulting from nuclear operations; and for all matters relating to insurance of our facilities.

The Manager Procurement has overall responsibility for preparation, issuing and commercial administration of purchase orders for materials and services in support of fire protection program requirements, and for procedures used for receipt, storage, and handling of materials employed in implementing the fire protection program.

The Supervisor Central Maintenance is responsible for supervising and coordinating measuring and test equipment (M&TE) calibration activities.

Supervisors shall ensure that their department(s) observe good safety practices in the use and control of combustible materials and processes which may serve as an ignition source; in addition to good housekeeping practices, each supervisor shall ensure that activities are carried out in a manner that does not endanger essential Station equipment, cabling, piping or instrumentation necessary for safe operation of the Station.

2.1.1.2 Personnel Qualifications

Appendix R Engineer - an engineer assigned by the Manager Engineering, or designee, who is knowledgeable in the SSA attributes and design implications, and is capable of determining the impacts of modifications on the aforementioned analysis and the fire protection program.

Fire Protection Engineer (FPE) - an engineer assigned by the Manager Engineering, the Manager Engineering Services, or designee, who is a graduate of a curriculum of accepted standing

2.2.3.2 Leak Testing

Open flame or combustion-generated smoke is not used for leak testing or similar procedures such as air flow determination for leak testing.

2.2.3.3 Combustible Material Storage

The storage of combustible supplies in safety-related areas is controlled by administrative procedures. The use of wood in safety-related areas is minimized. In general, only fire-retardant treated wood is permitted in safety-related structures. Isolated instances where untreated wood is utilized is evaluated on a case-by-case basis for program impacts and adequacy of installed fire protection systems.

2.2.4 Local Fire Department Support

The plant Fire Brigade provides primary response to fire emergencies. Upon determination by the Chief Nuclear Fire Fighter that additional fire fighting assistance is required, municipal response from local fire companies will be provided to support Station operations. Support by local fire companies is addressed by the Site Emergency Plan (SEP) and Mutual Aid Agreements.

2.2.5 Fire Brigade

The Fire Brigade is organized, trained and equipped to address fire emergencies at the plant. A variety of protective clothing and equipment, breathing equipment, salvage covers and/or forcible entry and rescue tools are provided in various locations on site in order to effectively respond to expected emergencies.

Guidance in responding to and responsibility of individuals during fire emergencies is defined in SEP procedures.

2.2.5.1 Surveillance and Maintenance

Procedures have been developed which identify required notifications, methodology and inspection attributes to support surveillance testing and periodic maintenance to fire protection equipment. Compensatory measures during system impairments are also addressed in department procedures.

Each surveillance requirement shall be performed within the specified surveillance interval with a maximum allowable extension not to exceed 25 percent of the specified surveillance interval. This permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance (e.g., transient conditions or other ongoing surveillance or maintenance activities). It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed during refueling outages. The limitation of this allowance is based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the surveillance requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

2.2.5.2 Fire Drills

Fire drills are conducted on a quarterly basis to insure that members work together as a team to address a simulated fire event. These drills are evaluated by supervisory personnel to assess leadership effectiveness, knowledge of responsibilities and of equipment. The drills are critiqued following completion to determine any necessary corrective action which may be warranted.

2.2.6 Fire Brigade Training

The training program for the Fire Brigade is maintained under the direction of the Manager Training Nuclear and Supervisor Fire Protection, and meets or exceeds the requirements of Appendix R to 10CFR50.

Fire Brigade members are trained in accordance with approved training procedures to familiarize the individuals with fire protection systems and equipment, plant fire hazards and emergency response. This training program is also intended to ensure that the Brigade leader and at least two members have sufficient training and a knowledge of plant safety-related systems to understand the effects of fire and fire suppression on safe shutdown capability.

This training program for the Brigade members consists of a combination of classroom sessions and in-plant inspection of site-specific applications of classroom sessions.

Members of the Fire Brigade attend the Niagara Mohawk Fire School annually to provide Fire Brigade work experience in actual fire extinguishment and the use of emergency breathing apparatus under strenuous conditions.

Local fire department personnel are periodically trained in the operational precautions of fighting fires at nuclear power plant sites. In addition, orientation is provided regarding radiation protection at the nuclear station.

2.2.7 Training Guidance

Where applicable, Brigade organization, training and the conduction of fire drills follows the guidance provided by applicable standards of the NFPA Codes. Guidance provided by the fire protection industry is also considered in the development of Fire Brigade training lesson plans.

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a. Main Transformer No. 1

b. Main Transformer No. 2

c. Station Service Transformer 10

d. Reserve Transformer 101N

e. Reserve Transformer 101S

Unit 1 utilizes an engineered wastewater treatment facility for runoff from oil spill areas including transformers. The containment of potential oil spills at the sources is accomplished with curbs and basins around the oil spill areas. A system of drainage sewers transports potential runoff from these areas to a retention basin, where the oil is separated from the runoff prior to its release. This design accounts for runoff from rainfall, as well as automatic and manual fire suppression systems. The objective of this system is to treat oily water runoff from the Unit 1 areas that have the potential for oil pollution.

2.4.1.9 Floor Drains

Unit 1 has performed an analysis of standing water damage to safety-related equipment or supporting systems necessary for the safe shutdown of the plant, resultant from automatic fire system operation with manual suppression activities. The conclusion indicated that the combination of floor drains, floor sumps and ponding capability is sufficient to prevent damage to this safety-related equipment resulting from expected fire-fighting water. In certain areas, curbs have been provided or equipment has been installed on pedestals to isolate the equipment from an oil or water spill.

2.4.1.10 Fire Barriers/Penetrations

Unit 1 utilizes primarily 2-hr and 3-hr rated fire barriers to separate fire areas or protect safety-related equipment from exposure fire hazards. These barriers are identified on Figures 10A-2 through 10A-9. The rating of these barriers is determined based on the hazard present and the evaluation of significance of equipment in the area. The barriers identified are all-inclusive of those currently maintained at the Station.

Thermal shield walls are also utilized in specific applications where a hazard cannot be sufficiently bounded by rated construction to be termed as a distinct fire area due to configuration or original plant design. Certain portions of these walls are sealed with configurations which would meet a rated fire barrier to protect important equipment outside the area from a fire inside the area. These walls are also identified on the subject figures and have been evaluated with respect to the protection required.

Penetrations made in fire-rated barriers are sealed with configurations which will maintain the integrity of the barrier. In the main steam isolation valve (MSIV) room, ten penetrations between primary containment and the turbine building are sealed in such a manner to ensure primary containment integrity. Although these penetrations are not a classic rated penetration seal, the configuration has been found to be acceptable in the location utilized.

The fire barriers identified on drawing C-39591-C (M31.1), sheets 1 through 6, separate redundant safety-related areas or provide exposure protection for safety-related areas. The barriers, including cabling, cable penetrations, pipe penetrations, fire doors and fire dampers, shall be intact. The following surveillance requirements are applicable to these barriers.

<u>Action</u>

With one or more of the above required fire barrier penetrations nonfunctional, within 1 hr, implement one of the following actions:

a. Establish a continuous fire watch on one side of the affected penetration, or

b. Verify the operability of fire detectors on both sides of the nonfunctional barrier and establish a daily inspection of the nonfunctional barrier to verify no increase in fire hazards within the vicinity, or

c. Verify the operability of fire detectors on one side of the nonfunctional fire barrier and establish a fire watch patrol, or

d. Implement a preplanned provision(s) in accordance with the assessment of a qualified Fire Protection Engineer.

2.4.1.10.1 Surveillance

The fire barriers, excluding penetration seals, shall be verified to be functional by:

a. A visual inspection at least once per two operating cycles.

b. A visual inspection of a fire barrier penetration after repair or maintenance, prior to restoring the fire barrier penetration to functional status.

Penetration seals shall be verified functional by:

a. A visual inspection at least once per operating cycle of at least 10 percent of each type of sealed penetration. If significant changes in appearance or

abnormal degradation are found, a visual inspection of an additional 10 percent of that type of sealed penetration shall be made for each unsatisfactory finding. This inspection process shall continue until a 10 percent sample with no significant changes in appearance or abnormal degradation is found. Samples shall be selected so that each penetration seal will be inspected at least once every 10 cycles.

b. A visual inspection of a fire barrier penetration after repair or maintenance, prior to restoring barrier penetration to functional status.

2.4.2 Control of Combustibles

2.4.2.1 In Situ Combustibles

Safety-related systems at Unit 1 are protected from in situ combustibles by any one or a combination of the following methods:

a. Fire rated barriers.

b. Automatic fire suppression and detection systems.

c. Spatial separation between the combustible material and the identified equipment.

d. Engineered design provisions to limit potential exposure.

Allowance for transient combustibles, which may increase to the total combustible loading of the area, is included in the FHA Summary Tables (reference Tables 3.1.1-1 to 3.1.1-9).

2.4.2.2 Bulk Gas Storage

Bulk gas storage is not permitted within structures housing safety-related equipment. Bulk hydrogen and nitrogen storage tanks are located outside with their long axes parallel to the turbine building. However, the hydrogen and nitrogen storage tanks are perpendicular to the west wall of the reactor building (reference Section 3.11.1).

The use of compressed gasses inside site structure is controlled.

2.4.2.3 Plastic Materials

Originally-installed cables are largely polyvinyl chloride (PVC) jacketed. The insulation associated with safety-related cables purchased and installed since the middle of 1974 meets the requirements of IEEE-383 flame test. The insulation associated with nonsafety-related cables purchased and installed since the middle of 1974 also generally meets the requirements of IEEE-383

flame test, except those routed totally in conduit. Other requirements of cables and cable trays are discussed in Section 2.4.3. The use of plastic materials in construction for permanent plant facilities is minimized.

2.4.2.4 Flammable Liquids

Flammable liquids are stored in accordance with NFPA 30, Flammable and Combustible Liquids Code. Fire suppression and/or detection systems are provided for identified storage areas.

Generation administrative procedures control the use and storage of flammable and combustible liquids outside the bulk storage areas.

2.4.3 Electric Cable Construction, Cable Trays and Penetrations

2.4.3.1 Cable Trays

Noncombustible materials are used in the construction of cable trays.

2.4.3.2 Cable Spreading Rooms

This room is protected by automatic total-flooding CO_2, preaction sprinkler and smoke detection systems. Manual fire hose stations and portable extinguishers have been provided for this area. See Section 2.6.3 for detailed discussion.

2.4.3.3 Sprinkler Protection

Automatic preaction sprinkler systems are installed to protect open, safety-related cable trays which are stacked more than two trays deep. Early-warning smoke detection is provided to facilitate system operation. Manually-operated hose stations are provided in the vicinity of the protected cable trays. Where identified, safety-related equipment in the vicinity of such cable trays has been protected if damage may occur from sprinkler operation. Specific design requirements of RG 1.75 are not all satisfied. The application of fire-retardant coatings to safety-related cable trays has been limited to those occurrences where sprinkler protection may not be the most desirable means of protection due to the equipment location in the area (i.e., over safety-related power boards). This coating is used primarily to prevent ignition and limit propagation of fire in the application areas. New cables installed in these trays shall be protected by engineering design in lieu of the application of fire-retardant coatings.

Based on the identified design provisions, the level of protection provided should prevent significant fire propagation and assist in cable tray suppression activities.

In the event that a fire occurs which disables ventilation equipment in one of those zones, portable smoke removal fans would be used for smoke removal purposes.

2.4.4.4 Charcoal Filter Protection

Manually-initiated water spray systems are provided for the emergency ventilation charcoal filters of the control room and the reactor building. These systems utilize thermistor wire temperature monitoring. A manually-initiated water spray system is also provided for the radwaste solidification and storage building (RSSB) heating, ventilating and air conditioning (HVAC) exhaust system which utilizes thermal fixed-rate compensated detectors. The temperature monitoring of these systems would alert operations personnel to higher than normal system/filter temperatures. The new TSC (located in fire zone AB2B) emergency ventilation charcoal filter system does not have a suppression system, but is equipped with duct-type smoke detectors.

2.4.4.5 Fresh Air Intakes

Fresh air supply intakes to areas containing safety-related equipment or systems are remote from the exhaust air outlets and any smoke vents of other fire areas.

2.4.4.6 Stairwells

Three stairwells (two turbine building, one reactor building) have been enclosed to minimize smoke infiltration and provide access and egress routes for fire-fighting and Station personnel. Fire dampers provided at the tops of these stairtowers for ventilation purposes close upon detection system operation.

2.4.4.7 Smoke/Heat Vents

Ventilation systems are provided for all interior plant areas. The installed air handling systems are capable of exhausting limited volumes of smoke and heat from the affected fire area. The smoke is generally directed to the outside.

Areas where smoke generation could impair fire-fighting efforts, or immediately impact Station operation, include the turbine building basement, cable spreading room, and the main and auxiliary control rooms. These areas have been provided with engineered smoke removal systems.

The smoke removal system for the control complex and turbine building basement is designed to remove smoke and moderate heat to permit personnel entry, restore visibility and evacuate products of combustion. The smoke removal systems design is based on a minimum of 4 air changes/hr.

The heat and smoke vent system in the turbine building (roof and sidewall vents) is intended to remove a major portion of the heat from the fire to improve conditions for manual fire fighting and to remove heat to preserve the unprotected steel roof structure. The roof vents in the turbine building are sized to provide 1 sq ft of vent/100 sq ft of floor area. This ratio was based on criteria for a "Moderate Heat Release Content" occupancy in NFPA 204, Guide for Smoke and Heat Venting. Although a free-burning massive oil fire in the turbine building would produce more than moderate heat release, the oil spill area is provided with suppression equipment. Heat venting is designed to compensate fire-fighting efforts should there be a partial failure of the suppression equipment resulting in transfer of superheated gasses to the roof area.

2.4.4.8 Self-Contained Breathing Apparatus

Self-contained breathing apparatus (SCBA) and an adequate supply of additional spare bottles are available for control room and fire-fighting personnel. The SCBA packs are located in various areas of the plant to facilitate ease of personnel access to this equipment. A nominal 30-min air supply is maintained by these units.

A breathing air compressor is installed in a clean area of the administration building to facilitate quick replenishment of exhausted cylinders. In the event of loss of power, a cascade system consisting of large pressurized tanks is available to recharge the self-contained breathing units.

2.4.4.9 Gaseous Extinguishing Systems

Upon actuation of total-flooding gaseous fire extinguishing systems, control and/or fire dampers are closed to maintain gas level concentrations in protected areas as required.

2.4.5 Lighting and Communication

2.4.5.1 8-Hour Battery Pack Lighting

Fixed self-contained lighting consisting of sealed-beam units with individual 8-hr minimum battery power supplies are provided in stairways and other access and egress routes, as well as in areas that may need to be manned for safe shutdown procedures.

2.4.5.2 Portable Hand Lights

Battery-powered portable hand lights are available for use during emergency situations.

2.4.5.3 Fixed Emergency Communication

The plant emergency communications consist of a page party/public address (PP/PA) system as a primary means to initiate emergency

Table 2.5.1.1-4

FIRE DETECTION ZONES PROTECTING SAFETY-RELATED EQUIPMENT
LOCAL FIRE ALARM CONTROL PANEL #4

ZONE NO.	LOCATION	TOTAL DETECTORS	MINIMUM OPERABLE
D-2224	TB 277' P.B. 101 Area	24	20[1]
DA-2234	TB 277' Southeast Side	27	22[1]
D-3054	TB 277' Control Room	27	22[1]
D-2194	TB 277' Remote Shutdown Panel 12 Area and Battery Room 14	62	61
D-2304	TB 291' D.C. Valve Board 12 Area	29	28

(1) No two adjacent detectors may be out of service simultaneously.

Table 2.5.1.1-5

FIRE DETECTION ZONES PROTECTING SAFETY-RELATED EQUIPMENT
LOCAL FIRE ALARM CONTROL PANEL #5

ZONE NO.	LOCATION	TOTAL DETECTORS	MINIMUM OPERABLE
D-2345	TB 305' RX Supply Fan Area	13	11[1]
D-2395	TB 300' Control Vent. Area	7	6
D-2445	TB 333' Change Area	4	3
D-2485	TB 369' General Area	4	3

[1] No two adjacent detectors may be out of service simultaneously.

alarms for water flow and low air pressure. The alarms are located on the system's respective LFCP and the MFCP.

The following sprinkler and water spray systems important to safety or protecting safety-related equipment/areas shall be operable as follows:

TYPE	DESCRIPTION	ZONE NO.
Water Spray	Reserve Trans 101N	WD-8082
Water Spray	Reserve Trans 101S	WD-8092
Wet Pipe	Diesel Fire Pump Room	SP-5033
Wet Pipe	TB 277 South Fire Break Zone	SP-2224
Preaction	RB 237 Area	WP-4076
Preaction	RB 261 Area/Trays	WP-4116
Preaction	RB 298/318 Area	WP-4237
Preaction	TB 250 S Trays	WP-2051
Preaction	TB 250 W Trays	WP-2022
Preaction	TB 250 N Trays	WP-2013
Preaction	TB 250 E Trays	WP-2031
Preaction	DG 250 Area	WP-2041
Preaction	TB 250 Cable Spread	WP-3011
Preaction	TB 261 S	WP-2161
Preaction	TB 261 N	WP-2092
Preaction	TB 261 E	WP-2083
Preaction	TB 277 E	WP-2234

Action

With one or more of the above required water spray or sprinkler systems inoperable, within 1 hr implement one of the following actions:

a. Verify the operability of fire detectors within the area protected by the system and establish a daily inspection of the area to verify no increase in fire hazards, or

b. Establish a fire watch patrol with backup fire suppression equipment for the unprotected area, or

c. Implement a preplanned provision(s) in accordance with the assessment of a qualified FPE.

With one or more of the above-referenced preaction systems inoperable, within 1 hr implement one of the following actions:

a. Verify the operability of fire detectors within the area protected by the system and establish a daily inspection of the area to verify no increase in fire hazards, or

b. Trip the system wet (if inoperability is due to automatic system actuation circuit failure), or

c. Establish a fire watch patrol with backup fire suppression equipment for the unprotected area, or

d. Implement a preplanned provision(s) in accordance with the assessment of a qualified FPE.

2.5.3.3.1 Surveillance

The water spray system shall be demonstrated to be operable:

a. At least once per 12 months by verifying that each valve (manual, power operated or automatic) in the flow path is in its correct position.

b. At least once per yr by cycling each manually-operable valve through one complete cycle.

c. At least once per operating cycle:

   1. By performing a system functional test which includes simulated automatic actuation of the system and verifying that the automatic deluge valves in the flow path actuate to their correct positions.

   2. By visual inspection of spray headers to verify their integrity.

   3. By visual inspection of each nozzle to verify no blockage.

d. At least once per 3 yr by performing an air or water flow test through each open head spray header and verifying each open head spray nozzle is unobstructed.

2.5.3.3.2 The wet-pipe sprinkler and preaction sprinkler systems shall be demonstrated to be operable:

a. At least once per operating cycle.

   1. By performing a system functional test which includes simulated automatic actuation of the system.

   2. By visual inspection of sprinkler headers to verify their integrity.

   3. By visual inspection of each nozzle to verify no blockage.

2.5.3.4 Standpipe System Design

Manual hose systems are in compliance with the requirements of NFPA 14, Standard for the Installations of Standpipe and Hose

Table 2.5.3.4-1 (Cont'd.)

STATION NUMBER	BLDG/ELEV	COLUMN
FS-115	TB 256	M 13
FS-408	SH 256	UV16
FS-405	TB 277	H 9
FS-406	TB 256	F 16
FS-401	RB 267	TRACK BAY
FS-422	RB 267	M 12
FS-402	RB 243	P 9
FS-403	RB 243	DRYWELL ENT
FS-404	RB 243	PQ
FS-113	SH 262	R 14
FS-154	TB 306	Aa13

2.5.3.5 Hose Nozzles

Hose nozzles are suitable for the type of hazards listed in the fire hazards analysis for each area. Nozzles are equipped with shutoff handles and adjustable fog nozzles which can be varied down to a 10-degree minimum spray pattern to render them safe for use on energized electrical equipment.

2.5.4 Halon Suppression Systems

2.5.4.1 Halon System Design

Total-flooding Halon 1301 systems are installed to protect several different locations in the plant. These areas include the auxiliary control room, emergency condenser isolation valve (ECIV) room, RSSB control room, RSSB electrical equipment room, and security equipment areas.

Supply for these systems is provided by cylinder assemblies located near the protected area. Each system is provided with a bank of main cylinders with an associated reserve bank to provide 100 percent backup capacity. Upon remote manual or automatic system initiation, an approximate 30-sec predischarge period operates area warning devices so personnel can safely evacuate the area prior to system discharge. System actuation energy is supplied from solenoid valves. In the event of system operation, protection can be restored by manually switching to the reserve bank of cylinders after resetting the detection system. In the event of a power failure or an inoperative detection system, the Halon 1301 systems can be manually tripped by pulling the lock pin on the manual release valve and operating the manual lever. The systems are designed to maintain a 6 percent concentration of Halon 1301 for a 10-min soak time. These systems are designed in accordance with NFPA 12A, Standard for Halon 1301 Fire Extinguishing Systems.

The following Halon 1301 systems protect safety-related equipment and shall be operable with the storage tanks having at least 95 percent of full charge weight (level) and 90 percent of full charge pressure.

System		Zone
TB 261	Auxiliary Control Room	H-3031
RB 298	ECIV Room*	H-4217

* For the ECIV room, this action is not required if the emergency condensers are not required to be operable.

Action

With one or more of the above-required Halon 1301 systems inoperable, within 1 hr implement one of the following actions:

a. Verify the operability of fire detectors within the area protected by the system and establish a daily inspection of the area to verify no increase in fire hazards, or

b. Establish a continuous fire watch with backup suppression equipment, or

c. Implement a preplanned provision(s) in accordance with the assessment of a qualified FPE.

2.5.4.1.1 Surveillance

Each of the required Halon systems shall be demonstrated operable:

a. At least once per 12 months by verifying that each valve (manual, power operated or automatic) in the flow path is in its correct position.

b. At least once per 6 months by verifying Halon storage tank weight (level) and pressure.

c. At least once per 18 months by:

   1. Verifying the system and associated ventilation dampers and fire door release mechanisms actuate manually and automatically.

   2. Performance of a flow test through headers and nozzles to assure no blockage.

2.5.4.2 System Maintenance

The systems are periodically inspected and tested in accordance with NFPA 12A.

2.5.4.3 System Design Considerations

During the system pre-discharge period, prior to agent release, local audible and visual alarms are provided in the protected area for personnel notification purposes. In addition, the auxiliary control room and the ECIV room are provided with a glass flask of wintergreen concentrate attached to the discharge piping to add a distinctly identifiable scent to the discharge gas. This flask ruptures upon operation of the system and must be replaced after each operation.

2.5.5 Carbon Dioxide (CO_2) Suppression System

Fire extinguishment by CO_2 is either by the total-flooding or local application method. In total-flooding, sufficient CO_2 is injected into a closed room or space to inert the atmosphere and suppress combustion. Local application is employed for unenclosed hazards and involves application of CO_2 on the equipment protected to extinguish the fire, with additional discharge to permit cooling and inhibit reflash.

2.5.5.1 Carbon Dioxide System Design

Total-flooding and local application CO_2 systems are installed to protect several different hazards in the plant. Automatic protection is provided for the following hazards:

a. Turbine Oil Tank Room - total-flooding; automatic actuation by rate-compensated thermal detectors.

b. Motor Generator Sets - local application to all five units simultaneously; actuated by rate-compensated thermal detectors located over each unit.

c. Power Boards 102 and 103 - total-flooding; actuation by cross-zoned smoke detectors.

d. Diesel Generator 102 and 103 - total-flooding; actuation by cross-zoned smoke, flame and thermal detectors.

e. Hydrogen Seal Oil Enclosure - total-flooding; actuation by rate-compensated thermal detectors.

f. Turbine Oil Reservoir Room - total-flooding; actuation by rate-compensated thermal detectors.

g. Cable Spreading Room - total-flooding; detection by cross-zoned smoke detectors.

Manual protection is provided for the following:

a. Generator Exciter Housing - total-flooding; actuation by push button station.

b. Turbine Generator Bearings - local application; actuation by push button station.

c. Turbine Oil Tanks - total-flooding of vapor space of tanks only; actuation by push button station.

d. Auxiliary Control Room - total-flooding; backup to Halon 1301 system.

All the above areas are provided with thermal or smoke detectors.

Manual fire protection capability is provided by manual hose stations and portable extinguishers.

2.6.12 New Fuel Storage Vault

The new fuel storage vault is on the refueling floor (el 340'-0") of the reactor building. An automatic fire detection system has been provided for this area. This system alarms at the local fire alarm control panel and in the control room. Manual hose stations and portable extinguishers are provided for this area.

2.6.13 Spent Fuel Pool Area

The spent fuel storage pool is also located at the refueling floor on el 340'-0" of the reactor building. The protection identified in Section 2.6.12 also applies to this area.

2.6.14 Radwaste Building

The radwaste building, designated as the waste building at Unit 1, is separated from other areas of the plant by 3-hr rated fire barriers.

An automatic sprinkler system has been provided for the baler room, truck bay and trash compactor area. A combination of general area and spot detection has been provided for this structure based on a review of hazard location. These systems alarm at a LFCP and in the control room.

The waste building ventilation system is capable of being isolated during a fire. Drains provided in this structure are connected to the waste building drain tanks for processing if required.

2.6.15 Decontamination Areas

The permanent decontamination areas are protected by area wet-pipe sprinkler systems. Flammable liquids are used and stored in accordance with administrative procedures. Automatic smoke detection is provided in the permanent plant decontamination areas. This system alarms at the LFCP and in the control room. The ventilation system provided for the area is capable of being isolated should conditions warrant this action.

Manual hose stations and portable fire extinguishers are available for use in this area.

2.6.16 Safety-Related Water Tanks

Storage tanks that supply water for safe shutdown are located within site buildings. Manual hose stations and portable extinguishers are available for use in protecting this equipment from exposure fires.

2.6.17 Cooling Towers

Cooling tower(s) are not used at Unit 1.

2.6.18 Miscellaneous Areas

In general, storage locations are controlled to minimize exposure to safety-related components. Protection provided may include, depending on level/severity, passive fire protection features (i.e., fire barriers), automatic suppression systems, manual extinguishing systems and/or automatic detection systems. Individual hazards associated with particular areas have been evaluated as part of Section 3.0.

An electric auxiliary boiler is located in the offgas building.

2.7 SPECIAL PROTECTION GUIDELINES

2.7.1 Cutting and Welding, Fuel Gas Systems

Only portable gas bottles are used for cutting and welding in the plant. Cutting and welding activities are controlled by administrative procedures. The storage location for cutting and welding equipment is protected by an automatic sprinkler system. Manual hose stations and portable fire extinguishers are available for use in this storage area.

2.7.2 Dry Ion Exchange Resin Storage

Dry ion exchange resins are stored above the regeneration room located above el 277'-0" of the turbine building. The area has a smoke detection system, manual hose station and portable extinguishers. Floor drains are provided in this area for removal of fire protection water.

2.7.3 Hazardous Chemicals

Chemical storage in the chemistry laboratory is provided in a separate storage room and protected with an automatic sprinkler system. Storage of chemicals in this area is maintained in accordance with NFPA 49, Hazard Chemical Data.

2.7.4 Radioactive Materials

Any material containing radioactivity is transferred to metal drums or containers, as required, and stored in appropriate centralized locations awaiting disposal. Exposure of containers to combustible materials is controlled.

3.0 FIRE LOADING/HAZARD STUDY

3.1 ORGANIZATION

In order to develop data meaningful to the analysis, the plant has been divided into numerous fire areas, and these areas are further subdivided into fire zones. The fire areas and zones are shown on Figures 10A-2D through 10A-9D.

To discretely identify fire hazards posed by features inherent to plant design (i.e., cable tray installations), a summary of each zone's in situ and anticipated transient fire loading is shown in Tables 3.1.1-1 through 3.1.1-9. A brief description of protective features existing in that zone or area is also identified. In addition, a general building-by-building analysis is provided in Sections 3.2 through 3.11.

A complete list of plant suppression systems is provided in Table 3.1-1.

3.1.1 Fire Loading/Hazard Bases

The bases of values found in Tables 3.1.1-1 through 3.1.1-9 include known combustible materials existing in the area and anticipated transient material. The gross calculation of fire loading by fire zones rather than total fire areas provides a closer estimation of localized hazards. It should be realized that the information obtained has its limitations with respect to the description of a fire scenario in a given area due to inherent construction features, fuel configuration, fuel surface area, etc. Therefore, the fire loading study is used primarily as an indicator in the area analysis.

The calorific content of the combustibles and the Btu/sq ft loading for each fire area/zone have been calculated. In order to determine the fire loading, it was necessary to make some assumptions concerning the amount of combustibles in such equipment as motors and control cabinets. The following assumptions, which are based on engineering judgment, were utilized to estimate the weight of combustibles:

Equipment	Weight of Combustible
Cable	.35 lb/ft
Panels/Power Boards	3 lb/ft^2 of floor space
Motor Insulation	1% of overall weight
Pump Lubricating Oil	
Pumps > 1500 gpm	28 gal
Pumps 500-1500 gpm	14 gal
Pumps < 500 gpm	9 gal

Equipment	Weight of Combustible
Storage Area	100,000 Btu/ft^2 of floor space
Office Area	20 lb/ft^2
Locker Room Area	5 lb/locker
Transient Load	24,000 Btu/ft^2

The following calorific values are used for combustible materials. These values are based on vendor data or the NFPA Fire Protection Handbook, and provide good estimates of expected total heat release capabilities for identified materials.

Material	Calorific Values (Btu/lb)
Electrical cables	13,500
Motor insulation	10,000
Lube oil	20,000
General Class A combustibles	8,000
Hydrogen	65,000
Hydraulic fluid	20,000
Epoxy	13,000
Resin	18,000
Fiberglass	13,000
Charcoal	15,000
Styrene	18,000
Diesel fuel	19,000
Asphalt	18,000
Plastic	20,000

The total Btu content of each area or zone is the sum of all combustibles in that zone.

$$\text{Average Fire Load} = \frac{\text{Total Btu content (Btu)}}{\text{Area of Zone (ft}^2\text{) x 80,000 Btu/ft}^2\text{ hr}}$$

$$= \text{Hours of fire load}$$

For the purposes of this evaluation, cable trays are conservatively assumed to be 100 percent full. The construction materials used for roofing were not included in the fire load. Metal deck roofs are Factory Mutual Class 1 and considered noncombustible for the purposes of this analysis.

3.1.2 Building Analysis

The following sections provide the detailed FHA and a summary of the effects of fire in the identified structures. This summary

3.10 ADMINISTRATION BUILDING

3.10.1 Introduction

The administration building is divided primarily into six areas. To satisfy the Appendix R analysis, these areas are grouped into two fire areas (see Table 3.10-1). These fire areas are:

FA12 - New AB 248
FA12 - Old AB 250/261
FA12 - New AB 261
FA12 - New AB 277
FA12 - Old AB 277
FA4 - Foam Room

The building has essentially three levels. In general, floor openings between adjacent elevations are sealed with comparably-rated sealing configurations. The exterior walls below grade are concrete, and those above grade are metal panel or precast concrete panel construction.

Rated fire barriers have been provided for protection of equipment from exposure hazards or enclosed identified hazards in the following primary fire areas.

Technical Support Center	(FA12)
Radiation Records Processing Area	(FA12)
NMP1/NMP2 Access Tunnel	(FA12)
Secondary Alarm Sys (SAS) Cont Area	(FA12)
SAS Computer Room	(FA12)
Foam Room	(FA4)
Storeroom Truck Bay	(FA12)
Storeroom Oil Storage Area	(FA12)
Warehouse	(FA12)
Telephone Equipment Room 1	(FA12)
Telephone Equipment Room 2	(FA12)

Walls of the administration building that are common to other buildings are 3-hr fire rated, with the exception of stairtowers, elevator shafts, and the wall (El 261') separating the men's locker room and the electrical shop, which are provided with at least a 2-hr rated enclosure. The foam room is separated from the rest of the administration building and other areas of the plant with 3-hr rated fire barriers.

Remotely-located stairtowers provide adequate egress and Fire Brigade access to the different areas of this structure. The stairtowers located in the eastern portion of the administration building are provided with 2-hr rated enclosures.

3.10.2 Safety-Related Systems

In general, the administration building does not contain any safety-related equipment. However, a safety-related dc power

board is located in the foam room. Equipment redundant to this power board exists in other areas of the plant. Therefore, loss of equipment and/or cabling in this area will not impact the ability to safely shut down the plant in accordance with the provisions of 10CFR50, Appendix R.

3.10.3 Post-Fire Analysis

A fire in the foam room or other areas of the administration building will not result in loss of capability to achieve safe shutdown. If the installed fire protection systems located within this building were in service, the fire should be contained within the general area of origin and be extinguished by automatic and/or manual means, as applicable.

3.10.4 Radioactive Release Analysis

There is no source of radioactivity in this building.

3.10.5 Fire Detection/Suppression Systems

Early-warning smoke detection systems have been provided for select areas of this structure. The new TSC emergency ventilation system is equipped with duct-type smoke detectors (see FSAR Figure III-18). These zoned detection systems provide alarms locally (LFCPs) and in the control room.

The entire administration building is protected by wet-pipe sprinkler systems, with the exception of certain select areas as follows.

The Systems Engineers' offices located on el 277'-0" are protected by a preaction sprinkler system. Consideration is being given to convert this system to a wet-pipe sprinkler system, as the hazard of water damage in the area no longer merits using a preaction sprinkler system.

A dry-pipe sprinkler system protects the storeroom truck dock.

A manually-operated water spray system provides protection of the old TSC emergency ventilation system charcoal filter, located on the roof of the administration building.

Automatic total-flooding Halon 1301 fire suppression systems are provided for the two telephone switch rooms, CPU/electrical area and SAS computer area.

Manual hose stations and portable extinguishers are provided for manual suppression activities in this building.

TABLE 3.1.1-1 (Cont'd.)

ZONE		FIRE HAZARD								FIRE PROTECTION	
FIRE AREA/ ZONE	NAME	COMBUSTIBLE MATERIAL	QUANTITY		CALORIC VALUE (BTU/lbm)	TOTAL BTUs	SQUARE FEET	FIRE LOAD		DETECTION H OR S	EXTINGUISHING SYSTEMS
			GALLONS	POUNDS				BTU/FT^2	TIME(HRS)		
FA2/ R5B	RB 318 Gen. Floor Area - West	Cable Insulation Class A Motor Insulation Rubber Wire Insulation Plastic Transient Load		651 1,649 5 50 6 1,620	13,500 8,000 10,000 19,000 20,000 20,000 24,000 BTU/ft^2	8,788,500 13,192,000 50,000 950,000 120,000 32,400,000 103,680,000 159,180,500	4,320	36,847	0.46	Smoke	Sprinklers
FA1/ R6A	RB 340 Gen. Floor Area - East	Class A Motor Insulation Rubber Oil Wire Insulation Epoxy Plastic Transient Load	 2	847 56 50 15 16 12,300 360	8,000 10,000 19,000 20,000 20,000 13,000 20,000 24,000 BTU/ft^2	6,776,000 560,000 950,000 300,000 320,000 159,900,000 7,200,000 219,600,000 395,606,000	9,150	43,236	0.54	Smoke	
FA2/ R6B	RB 340 Gen. Floor Area - West	Cable Insulation Class A Motor Insulation Rubber Grease Oil Wire Insulation Epoxy Plastic Storage Load Transient Load	 60 12	50 9,696 57 230 528 84 2 8,200 233	13,500 8,000 10,000 19,000 18,000 20,000 20,000 13,000 20,000 100,000 BTU/ft^2 24,000 BTU/ft^2	675,000 77,568,000 570,000 4,370,000 9,504,000 1,680,000 40,000 106,600,000 4,660,000 48,400,000 137,280,000 391,347,000	5,720	68,417	0.86	Smoke	

TABLE 3.1.1-2 (Cont'd.)

ZONE		FIRE HAZARD								FIRE PROTECTION	
FIRE AREA/ ZONE	NAME	COMBUSTIBLE MATERIAL	QUANTITY		CALORIC VALUE (BTU/lbm)	TOTAL BTUs	SQUARE FEET	FIRE LOAD		DETECTION H OR S	EXTINGUISHING SYSTEMS
			GALLONS	POUNDS				BTU/FT^2	TIME(HRS)		
FA7/ T2E	TB 250 UPS Battery Room	Cable Insulation		325	13,500	4,387,500	289	249,036	3.11	Smoke	
		Styrene		3,366	18,000	60,588,000					
		Wire Insulation		3	20,000	60,000					
		Transient Load			24,000 BTU/ft^2	6,936,000					
						71,971,500					
FA5/ T1	TB 250-300 Turbine Cond/HTR	Rubber		1,000	19,000	19,000,000	32,800	175,554	2.19	Heat and Smoke	Water Deluge, CO_2 Total Flood for Oil Res. Rm. and Gen. Exciter Local App. CO_2 for Gen. Bearings, Water Deluge
		Wire Insulation		99	20,000	1,980,000					
		Fiberglass		50	18,000	900,000					
		Motor Insulation		330	10,000	3,300,000					
		Class A		32	8,000	256,000					
		Plastic		36	20,000	720,000					
		Oil	17,394	126,976	20,000	2,539,520,000					
		Resin		43,860	18,000	789,480,000					
		Epoxy		47,300	13,000	614,900,000					
		Cable Insulation		74,160	13,500	1,001,160,000					
		Transient Load			24,000 BTU/ft^2	787,200,000					
						5,758,416,000					
FA5/ T3A	TB 261 Gen. Floor Area East of MSIV Room and Fire Zone T1	Cable Insulation		100,975	13,500	1,363,162,500	27,410	113,003	1.41	Smoke	Sprinklers
		Class A		23,803	8,000	190,424,000					
		Motor Insulation		710	10,000	7,100,000					
		Rubber		27,134	19,000	515,546,000					
		Grease		35	18,000	630,000					
		FL Liquids		7,106	20,000	142,120,000					
		Epoxy		6,710	13,000	87,230,000					
		Plastic		1,657	20,000	33,140,000					
		Fiberglass		596	18,000	10,728,000					
		Wire Insulation		783	20,000	15,660,000					
		Storage Area			100,000 BTU/ft^2	76,800,000					
		Transient Load			24,000 BTU/ft^2	657,840,000					
						3,100,380,000					

TABLE 3.1.1-6

FIRE HAZARD/FIRE LOADING

FIRE AREA: WASTE BUILDING

ZONE		FIRE HAZARD								FIRE PROTECTION	
FIRE AREA/ ZONE	NAME	COMBUSTIBLE MATERIAL	QUANTITY		CALORIC VALUE (BTU/lbm)	TOTAL BTUs	SQUARE FEET	FIRE LOAD		DETECTION H OR S	EXTINGUISHING SYSTEMS
			GALLONS	POUNDS				BTU/FT^2	TIME(HRS)		
FA15/ WD1	WB 225/229 Gen. Floor Area	Cable Insulation Wire Insulation Motor Insulation Resin Epoxy Oil Transient Load		3,876 12 37 17,200 1,400 795	13,500 20,000 10,000 18,000 13,000 20,000 24,000 BTU/ft^2	52,326,000 240,000 370,000 309,600,000 18,200,000 15,906,000 161,280,000 557,922,000	6,720	83,024	1.04	Smoke	
FA15/ WD2	WB 247 Gen. Floor Area	Cable Insulation Wire Insulation Motor Insulation Rubber Plastic Resin Grease Oil Transient Load		3,348 38 6 216 487 7,095 264 526	13,500 20,000 10,000 19,000 20,000 18,000 19,000 20,000 24,000 BTU/ft^2	45,198,000 760,000 60,000 4,104,000 9,740,000 127,710,000 5,016,000 10,520,000 161,280,000 364,388,000	6,720	54,224	0.68	Smoke	
FA15/ WD3A	WB 261 Gen. Floor Area	Wire Insulation Cable Insulation Motor Insulation Rubber Plastic Resin Fiberglass Oil Transient Load	 2,915	315 88 1 385 55 5,470 100 21,280	20,000 13,500 10,000 19,000 20,000 18,000 13,000 20,000 24,000 BTU/ft^2	6,300,000 1,188,000 10,000 7,315,000 1,100,000 98,460,000 1,300,000 425,600,000 128,880,000 670,153,000	5,370	124,796	1.56	Smoke	Sprinklers

TABLE 3.1.1-9 (Cont'd.)

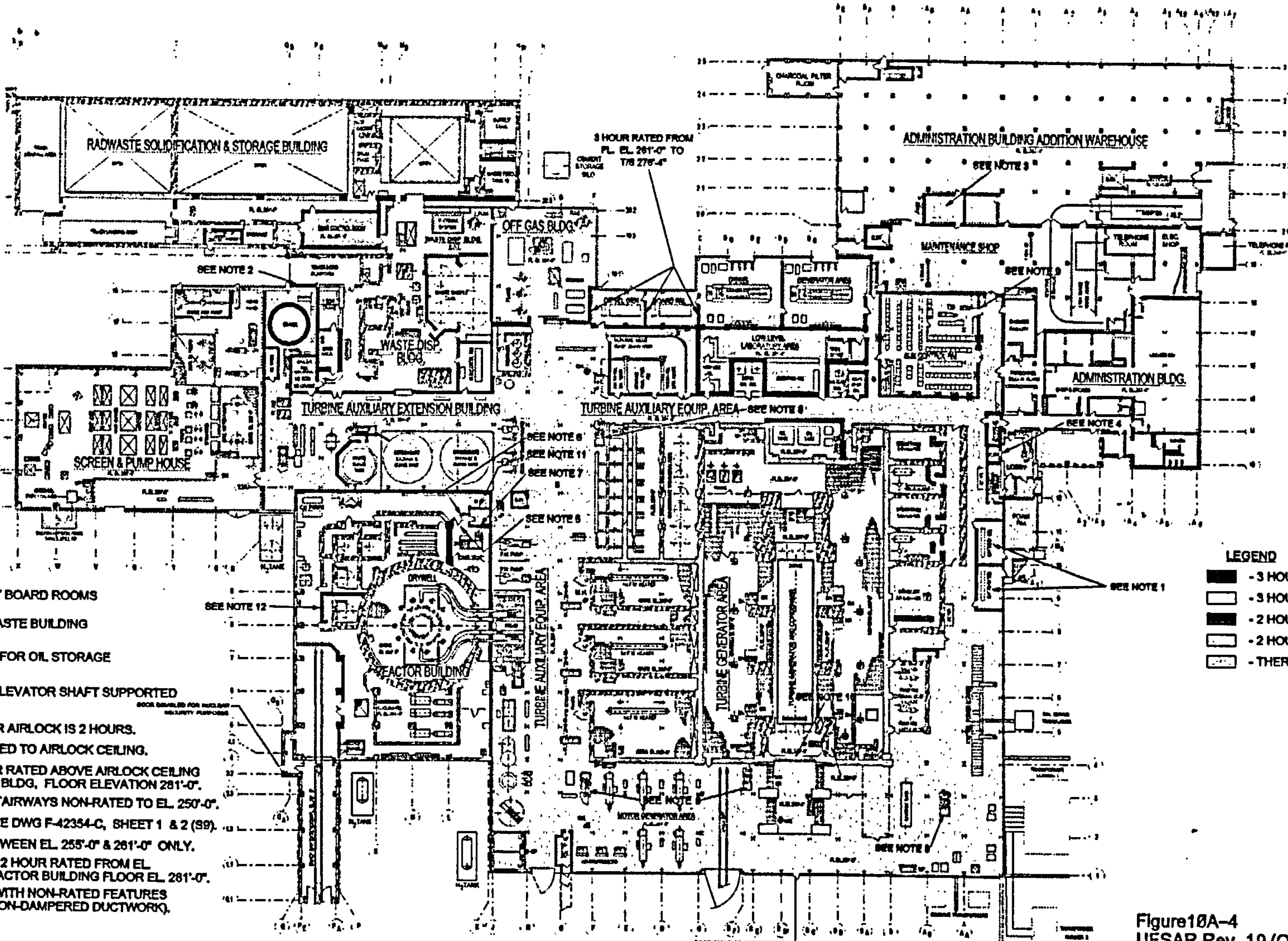
ZONE		FIRE HAZARD								FIRE PROTECTION	
FIRE AREA/ ZONE	NAME	COMBUSTIBLE MATERIAL	QUANTITY GALLONS	QUANTITY POUNDS	CALORIC VALUE (BTU/lbm)	TOTAL BTUs	SQUARE FEET	FIRE LOAD BTU/FT^2	FIRE LOAD TIME(HRS)	DETECTION H OR S	EXTINGUISHING SYSTEMS
FA4/ AB1F	AB 262 Foam Room	Motor Insulation		10	10,000	95,000	450	47,267	0.59	Smoke	
		Wire Insulation		9	20,000	180,000					
		Rubber		94	19,000	1,786,000					
		Plastic		18	20,000	360,000					
		Class A		16	8,000	128,000					
		Fiberglass		121	13,000	1,567,800					
		Cable Insulation		81	13,500	1,093,500					
		Oil	36	263	20,000	5,260,000					
		Transient Load			24,000 BTU/ft^2	10,800,000					
						21,270,300					
FA12/ AB3A	AB 261 Warehouse Area and TSC Charcoal Filter Room	Cable Insulation		317	13,500	4,279,500	24,884	131,738	1.65		Sprinklers
		Motor Insulation		5	10,000	52,500					
		Wire Insulation		35	20,000	700,000					
		Rubber		309	19,000	5,871,000					
		Plastic		50	20,000	1,000,000					
		Class A		53,850	8,000	430,800,000					
		Toluene	120	876	18,000	15,768,000					
		Charcoal		22	15,000	330,000					
		Oil	12	88	20,000	1,760,000					
		Storage (ft^2)		22,204	100,000 BTU/ft^2	2,220,400,000					
		Transient Load			24,000 BTU/ft^2	597,216,000					
						3,278,177,000					
FA12/ AB3B	AB 261 Oil Storage Room (Warehouse)	Grease	60	528	18,000	9,504,000	440	565,055	7.06		Sprinklers
		Oil	1,565	11,425	20,000	228,500,000					
		Wire Insulation		3	20,000	60,000					
		Transient Load			24,000 BTU/ft^2	10,560,000					
						248,624,000					

TABLE 3.1.1-9 (Cont'd.)

ZONE		FIRE HAZARD								FIRE PROTECTION	
FIRE AREA/ ZONE	NAME	COMBUSTIBLE MATERIAL	QUANTITY		CALORIC VALUE (BTU/lbm)	TOTAL BTUs	SQUARE FEET	FIRE LOAD		DETECTION H OR S	EXTINGUISHING SYSTEMS
			GALLONS	POUNDS				BTU/FT^2	TIME(HRS)		
FA12/ AB3C	AB 261 Storeroom Truck Dock	Motor Insulation Wire Insulation Rubber Fuel Oil Transient Load	 330	7 18 1,200 2,607	10,000 20,000 19,000 19,000 24,000 BTU/ft^2	70,000 360,000 22,800,000 49,533,000 48,000,000 120,763,000	2,000	60,382	0.75		Sprinklers
FA12/ AB3D	AB 261 Elect/Mech Shop Area, Office Areas, Locker Rooms	Motor Insulation Wire Insulation Rubber Class A Oil Acetone Cable Insulation Solvent Plastic Transient Load	 348 30 25	9 115 150 17,037 2,437 195 5,351 163 4,419	10,000 20,000 19,000 8,000 20,000 13,000 13,500 20,000 20,000 24,000 BTU/ft^2	85,000 2,300,000 2,850,000 136,293,600 48,740,000 2,535,000 72,238,500 3,250,000 88,380,000 210,240,000 566,912,100	8,760	64,716	0.81	Smoke (Duct Only)	Sprinklers
FA12/ AB3E	AB 261 Telephone Room #1	Cable Insulation Class A Wire Insulation Plastic Transient Load		930 544 216 42	13,500 8,000 20,000 20,000 24,000 BTU/ft^2	12,555,000 4,352,000 4,320,000 830,000 10,800,000 32,857,000	450	73,016	0.91	Smoke	Halon Total Flood
FA12/ AB3F	AB 261 Telephone Room #2	Wire Insulation Class A Transient Load		43 817	20,000 8,000 24,000 BTU/ft^2	860,000 6,536,000 9,600,000 16,996,000	400	42,490	0.53	Smoke	Halon Total Flood
FA12/ AB4A	AB 277 Gen. Office Area	Class A Transient Load		366,400	8,000 24,000 BTU/ft^2	2,931,200,000 439,680,000 3,370,880,000	18,320	184,000	2.30	Smoke	Sprinklers

TABLE 3.1.1-9 (Cont'd.)

ZONE		FIRE HAZARD								FIRE PROTECTION	
FIRE AREA/ ZONE	NAME	COMBUSTIBLE MATERIAL	QUANTITY		CALORIC VALUE (BTU/lbm)	TOTAL BTUs	SQUARE FEET	FIRE LOAD		DETECTION H OR S	EXTINGUISHING SYSTEMS
			GALLONS	POUNDS				BTU/FT^2	TIME(HRS)		
FA12/ AB4B	AB 277 File Room	Class A Transient Load		44,000	8,000 24,000 BTU/ft^2	352,000,000 52,800,000 404,800,000	2,200	184,000	2.30	Smoke	Sprinklers
FA12/ AB4C	AB 277 Records Processing Area	Class A Transient Load		32,000	8,000 24,000 BTU/ft^2	256,000,000 38,400,000 294,400,000	1,600	184,000	2.30	Smoke	Sprinklers
FA12/ AB4D	AB 277 Gen. Office Area	Class A Transient Load		120,000	8,000 24,000 BTU/ft^2	960,000,000 144,000,000 1,104,000,000	6,000	184,000	2.30	Smoke	Sprinklers
FA12/ AB5	AB 290 Penthouse Ventilation Room	Cable Insulation Class A Motor Insulation Fiberglass Rubber Charcoal Wire Insulation Transient Load		45 5,040 3 60 5 11 19	13,500 8,000 10,000 13,000 19,000 15,000 20,000 24,000 BTU/ft^2	607,500 40,320,000 30,000 780,000 99,750 165,000 380,000 15,624,000 58,006,250	651	89,103	1.11	Smoke (Room) Heat (Charcoal)	Sprinklers (Charcoal)



NOTES:

1. CEILING RATING OF BATTERY BOARD ROOMS IS 1.5 HOURS.
2. TWO HOUR RATING FROM WASTE BUILDING TRUCK BAY STORAGE.
3. CEILING AND FLOOR RATING FOR OIL STORAGE ROOM IS 3 HOURS.
4. EAST AND WEST WALLS OF ELEVATOR SHAFT SUPPORTED BY UNPROTECTED STEEL.
5. CEILING RATING OF REACTOR AIRLOCK IS 2 HOURS.
6. DIAGONAL WALL 2 HOUR RATED TO AIRLOCK CEILING.
7. WEST WALL OF AIRLOCK 2 HR RATED ABOVE AIRLOCK CEILING TO UNDERSIDE OF REACTOR BLDG. FLOOR ELEVATION 261'-0".
8. FLOOR SLABS OVER OPEN STAIRWAYS NON-RATED TO EL. 250'-0".
9. 3 HR RATED ENCLOSURE, SEE DWG F-42354-C, SHEET 1 & 2 (S9).
10. 3 HR RATING FOR WALLS BETWEEN EL. 255'-0" & 261'-0" ONLY.
11. WEST WALL OF ELEVATOR IS 2 HOUR RATED FROM EL. 261'-0" TO UNDERSIDE OF REACTOR BUILDING FLOOR EL. 281'-0".
12. THREE HOUR RATED WALLS WITH NON-RATED FEATURES (OPEN PENETRATIONS AND NON-DAMPERED DUCTWORK).

LEGEND

- 3 HOUR RATED WALL
- 3 HOUR RATED SLAB
- 2 HOUR RATED WALL
- 2 HOUR RATED SLAB
- THERMAL SHIELD WALL

REACTOR BUILDING - FL. EL. 261'-0"
TURBINE BUILDING - FL. EL. 261'-0"

Figure 10A-4
UFSAR Rev. 19 (October 2005)
Station Floor Plan
Fire Rated Walls & Slabs
Elevation 261'-0"
Source Documents:
B-40143-C, Sheet 1
Legend - Figure 10A-1

C1

Performance Goals	Remote Shutdown Panels
The reactor coolant makeup function shall be capable of maintaining the reactor coolant level above the top of the core for boiling water reactors (BWR).	Operation of the ECs will maintain the reactor coolant level above the top of the core for a minimum of 8 hr without the need for additional makeup.
The reactor heat removal function shall be capable of achieving and maintaining decay heat removal.	The ECs are designed to handle the removal of decay heat.
The process monitoring function shall be capable of providing direct readings of the process variables necessary to perform and control the above functions.	Each RSP has the following analog indication: a. Drywell pressure b. EC water level c. Reactor coolant level d. Reactor pressure e. Reactor temperature f. Torus temperature g. Drywell temperature
The supporting functions shall be capable of providing the process cooling, lubrication, etc., necessary to permit the operation of the equipment used for safe shutdown functions.	The EC system is capable of operating for a minimum of 8 hr without the need for any support functions or support systems, except for manual throttling of the makeup flow valves to the shellside of the ECs, sometime in the first or second hour of condenser operation. The diesel-driven fire pump is available as a backup water supply for makeup to the EC shellside.

5.10.4 Remote Shutdown Panel Instrumentation

Monitoring instruments provided at the RSP are redundant to and independent from the monitoring instrument in the control complex. The following monitoring instruments are located at each RSP:

a. Reactor temperature
b. Drywell temperature
c. Torus temperature
d. EC water level
e. Reactor pressure
f. Drywell pressure
g. Reactor coolant level

An "all rods in" indicating light located at the RSP, along with a RTS MG set (either 131 or 141) trip switch, verifies that the scram function has been accomplished.

5.10.5 Spurious Operation of the Feedwater System

During a control room fire event and subsequent evacuation, with offsite power available, the potential exists for spurious feedwater system operation due to fire-induced failure of its control system. This may result in a vessel overfill transient and subsequent emergency condenser isolation. An inadvertent emergency condenser isolation during an Appendix R event would invalidate the assumption in the safe shutdown analysis design basis for the continuous operation of the emergency condensers. The control room evacuation procedure provides direction to declutch the turbine-driven feedwater pump 13 (PMP-29-01) prior to control room evacuation, achieve manual control of feedwater control valves, and locally declutch the pump if necessary following control room evacuation. This would eliminate the potential for flooding the emergency condenser lines, thereby isolating the system. Verification of the tripped feedwater pump can be performed by visual inspection at the pump.

FIRE AREA 1 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	N	LI 36-09 AVAILABLE.
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	N	MONITOR IDLE CONT. SPRAY PUMP DISCHARGE PRESSURE (PI 80-54A) AND OPER. CONT. SPRAY PUMP DISCHARGE PRESSURE.

FIRE AREA 2 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	N	LI 36-10 AVAILABLE.
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	Y	
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	N	EC OPER. NOT CREDITED FOR THIS FIRE AREA MONITOR.
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP	N	CONT. SPRAY HX INLET TEMPERATURE TI 80-77B K PANEL FOR TORUS TEMPERATURE.
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

SAFE SHUTDOWN FIRE AREA ANALYSIS

FIRE AREA 4

Foam Room
El. 261'-0"

Fire Zone: AB1F
Detection Zone: D-8151

ADJACENT FIRE AREAS

NORTH	5, 16A
EAST	12
SOUTH	None
WEST	None
BELOW	12
ABOVE	None

SHUTDOWN COMPONENTS IN AREA

Dc Valve Board 11

SHUTDOWN COMPONENT CABLE IN AREA

Emergency Condenser

IV 39-07

DESIGN FEATURES

The north and east boundaries are approximately 12-in thick concrete block walls (3-hr fire cutoff).

The south and west boundaries are described in Section III-E.1.2.1.

The floor slab is a 1'-0" thick concrete slab.

The roof is 16 ft high and consists of a 5-in thick concrete slab.

Cables and pipes which breach the north and east walls are sealed with 3-hr rated fire seals.

EXISTING FIRE PROTECTION

The area is equipped with ionization-type smoke detectors.

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

Manual fire suppression capability is provided by local portable fire extinguishers.

Yard hydrants provide water suppression capability.

MODIFICATIONS/EXEMPTIONS

Pipe and cable penetrations were sealed with 3-hr rated fire seals to establish the foam room as a separate fire area (see Safety Evaluation 83-02).

ANALYSIS

A fire could cause the loss of EC loop 11 due to spurious operation of valve IV 39-07.

Hot and cold shutdown is provided by EC loop 12 and train 12 shutdown systems, respectively.

Instrumentation is adequate to monitor the shutdown process.

FIRE AREA 4 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	Y	
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

SAFE SHUTDOWN FIRE AREA ANALYSIS

FIRE AREA 5

Turbine Building
El. 243'-0" to 369'-0"

Fire Zones:	OG1, T1A, T1, T3A, T3B, T4A, T4B, T5A, T6A, T6B, T6C, T6D, T7A, T8A, T8B
Detection Zones:	DA-2081S, DA-2161E, DA-2161M, DA-2092E, DA-2092W, DA-2162W, DA-2092MG, DA-2083M, DA-2083N, D-2224, DA-2234, D-2345, D-2395, D-2194, D-2304, D-2445, D-2485

ADJACENT FIRE AREAS

NORTH	1, 2, 13
EAST	11, 15, 18, 19, 22, 23, 24
SOUTH	4, 12, 16A, 16B, 17A, 17B
WEST	None
BELOW	6, 7, 9
ABOVE	None

SHUTDOWN COMPONENTS IN AREA

RSP 12

Electrical Distribution

Dc Valve Board 12	SC 171B
MG Set 167	UPS 162A
SC 161A	UPS 162B
SC 161B	UPS 172A
SC 171A	UPS 172B

Emergency Condenser

Makeup Storage Tank 60-10	IV 60-12
Makeup Storage Tank 60-09	BV 60-13
IV 60-11	

SHUTDOWN COMPONENT CABLE IN AREA

Containment Spray

IV 80-15
IV 80-36
PMP 80-04

concrete shield. This annulus air gap communicates with the reactor building (secondary containment) at several locations. Therefore, a potential pathway exists between secondary containment and the turbine building. However, fire, heat and smoke propagation through the air gap is not considered credible due to the large volume of the air gap, the significant available heat transfer surface (heat sink), and virtual nonexistence of any type of combustible loading. Since the potential for fire propagation is considered nonexistent, the need to replace the flexible boots is not justified. Therefore, credit is being taken for the north wall as a 3-hr rated wall with the exception of several nonrated flexible boots.

The stack has been added to FA 6. Consequently, the monolithic stack structure above el 261'-0" has been upgraded to 3-hr fire rating and is a required Appendix R barrier.

EXISTING FIRE PROTECTION

Early-warning, ionization-type smoke detectors are provided to protect trays carrying safety-related cables, SC 161A, 161B, 171A, and 171B, RPS UPS 162A, 162B, 172A, and 172B, the instrument shop, the results shop, the area around the PBs and RSP, all PBs, reactor building ventilation equipment, ventilation/air conditioning equipment, and EC makeup storage tanks 11 and 12.

Detection and automatic suppression are provided to cover the fire break zone on el 277'-0", the low-level laboratory area, the equipment decontamination area, the chemical storage area, the track bay entrance, heavy cable concentrations, and the change area on el 333'-0".

General fire suppression is provided by means of local water, CO_2 hose stations, and portable fire extinguishers.

Cables that pass over PBs are protected by a fire detection system and fire-retardant material.

A manual deluge system and infrared flame detectors are provided to protect the turbine building track bay. Flame detection is also provided for the laydown areas on the turbine building floor.

Certain multitray runs (greater than two trays) are protected by automatic suppression systems.

Each reactor recirculation MG set is provided with its own thermal detection and automatic local application CO_2 suppression system.

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

Manual outside wall water spray systems are provided for the west and southwest walls within 50 ft of the main, reserve and Station service transformers, protecting the unrated wall from a transformer exposure fire.

In the area of electrical equipment, trays are coated with flame-retardant material.

Automatic suppression is provided in the mechanical storage area.

Automatic-flooding CO_2 systems protect the turbine oil storage room, H_2 seal oil unit room, alternate exciter enclosure, turbine oil reservoir room and lube oil reservoir.

Detection is provided in the general storage area between columns 5 and 10 on el 300'-0".

Charcoal filter banks are equipped with manual water spray and thermistor-type detectors.

Automatic water deluge sprinkler systems protect the floor areas beneath the turbine generator unit. Additionally, fixed water spray systems protect the turbine bearings and lube oil piping on the turbine generator unit. A local application CO_2 system also protects the turbine bearings.

MODIFICATIONS/EXEMPTIONS

Spurious blowdown by the reactor head vent was resolved to prevent inventory loss (see Safety Evaluation 83-33).

Spurious blowdown by the ADS was resolved to prevent inventory loss (see Safety Evaluation 84-18).

Spurious isolation of EC loop 11 was resolved to provide for hot shutdown (see Safety Evaluations 84-35 and 84-57).

An exemption was granted for the reactor building/turbine building wall above el 340' not being a 3-hr rated fire barrier (see NRC letter dated March 21, 1983).

An exemption was granted for the (separation) requirements of Appendix R, Section III.G.2, for the redundant 125-V dc cables (11B-1, 11B-2, 12B-1, 12B-2) that feed the battery boards from the Station batteries. The redundant cables are separated by 40 ft, fire detection is provided in this area, and cables in the area are coated with Flamemastic.

ANALYSIS

Both DG 102 and 103 could possibly be lost.

FIRE AREA 6 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	Y	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	

FIRE AREA 7 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	Y	
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

FIRE AREA 9 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	Y	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	

FIRE AREA 10 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	N	LI 36-10 AVAILABLE.
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	Y	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	N	PI 36-32A AVAILABLE.
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	N	MONITOR EC LEVEL AT RSP 11/12.
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	N	TI 201.2-520 AVAILABLE.
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	N	TORUS LEVEL IND. NOT REQUIRED TO MONITOR HEAT TRANSFER FROM VESSEL TO HEAT SINK FOR THIS COLD SHUTDOWN TRAIN.
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	Y	
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	N	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	N	

SAFE SHUTDOWN FIRE AREA ANALYSIS

FIRE AREA 12

Administration Building

Fire Zones:	AB1A, AB1B, AB1C, AB1D, AB1E, AB2A, AB2B, AB2C, AB2D, AB3A, AB3B, AB3C, AB3D, AB3E, AB3F, AB4A, AB4B, AB4C, AB4D, AB5

ADJACENT FIRE AREAS

NORTH	7, 10, 11, 19
EAST	None
SOUTH	None
WEST	4, 5, 10, 11
BELOW	None
ABOVE	None

SHUTDOWN COMPONENTS IN AREA

None

SHUTDOWN COMPONENT CABLE IN AREA

None

DESIGN FEATURES

The north wall adjacent to the diesel generator and control rooms and the west wall adjacent to the foam room are 3-hr rated assemblies.

The south, east, and the remainder of the west walls are exterior walls.

EXISTING FIRE PROTECTION

Wet-pipe sprinkler systems are installed throughout the administration building.

MODIFICATIONS/EXEMPTIONS

None

SAFE SHUTDOWN FIRE AREA ANALYSIS (Cont'd.)

ANALYSIS

Area contains no equipment or cables that would have an effect on shutdown capability.

Safe shutdown barrier analysis (FPEE-1-90-013) has identified fire areas that can be consolidated to form general fire areas for analysis purposes and for the purpose of reducing the Appendix R required fire barriers. As a result, FA 12 has been combined with FA 5, 13 and 15 for analysis purposes only.

FIRE AREA 12 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	Y	
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

FIRE AREA 13 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	Y	
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

FIRE AREA 14 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	Y	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	

FIRE AREA 15 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	Y	
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

FIRE AREA 16A - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	Y	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76B	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	

FIRE AREA 16B - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	Y	
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

FIRE AREA 17A - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	Y	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	

FIRE AREA 17B - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	Y	
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

FIRE AREA 18 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	Y	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	N	PI 36-31A Available
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

For FA 18, 22, and 23, the failure mode of MG Set 172 ac breaker will have to be determined. If the failure mode allows the MG set to coast down, credit cannot be taken for RPS Channel 12. Although MG Set 167 is available to charge 12 battery board, the MG set cannot be started in dc run.

FIRE AREA 19 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	N	LI 36-20 Available
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	Y	
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

FIRE AREA 20 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	Y	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	

FIRE AREA 21 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	Y	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	

FIRE AREA 22 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	N	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	N	PI 36-31A Available
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

Although MG Set 167 is available to charge 12 battery board, the MG set cannot be started in dc run.

FIRE AREA 23 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	N	
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	
LI 36-10	RX LEVEL	0 - 100"	RPS 12	RX LEVEL CH 12	Y	
LI 36-20	RX LEVEL	-34 - 102"	RPS 12	RX LEVEL LLL CH 12	Y	
PI 36-32A	RX PRESS	0 - 1600	RPS 12	ID 76B	N	PI 36-31A Available
LI 60-29A	EC LEVEL	0 - 8'	RPS 12	EM COND 121/122 WATER LEVEL	Y	
TI 201.2-520	TORUS WTR TEMP	30-230	RPS 12	TORUS WATER TEMP CHANNEL 12	Y	
LI 58-05A	TORUS LEVEL	7.0'-15.0'	RPS 12	TORUS H_2O LEVEL #12	Y	

Although MG Set 167 is available to charge 12 battery board, the MG set cannot be started in dc run.

FIRE AREA 24 - SAFE SHUTDOWN INSTRUMENTATION

INDICATOR EPN	PARAMETER MONITORED	INDICATING RANGE	POWER SUPPLY	CONTROL ROOM LABEL	AVAILABLE YES/NO	RESOLUTION
LI 36-09	RX LEVEL	0 - 100"	RPS 11	RX LEVEL CH 11	Y	
LI 36-19	RX LEVEL	-34 - 102"	RPS 11	RX LEVEL LLL CH 11	N	LI 36-09 Available
PI 36-31A	RX PRESS	0 - 1600	RPS 11	ID 76A	Y	
LI 60-28A	EC LEVEL	0 - 8'	RPS 11	EM COND 111/112 WATER LEVEL	Y	
TI 201.2-519	TORUS WTR TEMP	30-230	RPS 11	TORUS WATER TEMP CHANNEL 11	Y	
LI 58-06A	TORUS LEVEL	7.0'-15.0'	RPS 11	TORUS H_2O LEVEL #11	Y	

APPENDIX A

FIRE ZONE DESCRIPTION/CROSS REFERENCES

Fire Area	Fire Zone	Location	Fire Detection Zone(s)
1	R1A	Rx Bldg., 198' Northeast	D-4026
		Rx Bldg., 237' East	DA-4076E
	R1C	Rx Bldg., 237'-340' Southeast	DA-4076E, DA-4116E
	R1D	Rx Bldg., 198'-237' Southeast	D-4046
	R2A	Rx Bldg., 261' East	DA-4116E
	R3A	Rx Bldg., 281' East	D-4156, D-4166
	R4A	Rx Bldg., 298' East	D-4197, D-4207, DX-4217A, DX-4217B
	R5A	Rx Bldg., 318' East	DA-4237
	R6A	Rx Bldg., 340' East	D-4267
2	R1B	Rx Bldg., 198' Northwest	D-4016
		Rx Bldg., 198' Southwest	D-4036
		Rx Bldg., 237' West	DA-4076W
	R2B	Rx Bldg., 261' West	DA-4116W
	R2C	Rx Bldg., 261' West (SDC Room)	DA-4116W
	R3B	Rx Bldg., 281' West	D-4156
	R4B	Rx Bldg., 298' West	D-4197, D-4207
	R5B	Rx Bldg., 218' West	DA-4237
	R6B	Rx Bldg., 340' West	D-4267
3	R1	Drywell	D-4086
4	AB1F	Foam Room	D-8151

APPENDIX A (Cont'd.)

Fire Area	Fire Zone	Location	Fire Detection Zone(s)
5	OG1 T1A T1 T3A T3B T4A T4B T5A T6A T6B T6C T6D T7A T8A T8B	Offgas Building MSIV Room Turbine-Generator Bay Turbine Bldg., 261' East Turbine Bldg., 261' West Turbine Bldg., 277' East Turbine Bldg., 277' West Turbine Bldg., 291' Northeast Turbine Bldg., 305'-6" North Turbine Bldg., 300' East Turbine Bldg., 300' South Turbine Bldg., 300' Southwest Turbine Bldg., 320' South Turbine Bldg., 333'-8"-369' East Turbine Bldg., 369' West	-- -- -- DA-2081S, DA-2083M, DA-2083N DA-2161E, DA-2161M, DA-2092E, DA-2092W, DA-2162W, DA-2092MG DA-2234 D-2224, DA-2234 -- D-2345 D-2395 D-2395 -- -- -- --
6	T2A	Turbine Bldg., 250' Northeast	DA-2013S, DA-2013N
7	T2B	Turbine Bldg., 250' South Turbine Bldg., 250' West	DA-2051E, DA-2051W DA-2022N, DA-2022S
8	FA 8 has been incorporated into FA 9.		
9	T2C T2D	Offgas Tunnel Turbine Bldg., 250' East	-- DA-2031
10	C1	Cable Spreading Room	DX-3011A, DX-3011B
11	C2 C3	Auxiliary Control Room Main Control Room	D-3031PL, DX-3031A, DX-3031B D-3054

APPENDIX A (Cont'd.)

Fire Area	Fire Zone	Location	Fire Detection Zone(s)
12	AB1A, AB1B, AB1C, AB1D, AB1E, AB2A, AB2B, AB2C, AB2D, AB3A, AB3B, AB3C, AB3D, AB3E, AB3F, AB4A, AB4B, AB4C, AB4D, AB5	Admin. Bldg., Ships/Stores Admin. Bldg., Addition	-- --
13	S1	Screenhouse	D-5013
14	S2	Diesel Fire Pump Room	D-5023
15	WD1	Waste Disposal Building and Radwaste Solidification and Storage Building	--
16A	B1A	Battery Board Room 12	DA-2161E
16B	B1B	Battery Board Room 11	DA-2161E
17A	B2A	Battery Room 11	D-2224
17B	B2B	Battery Room 12	D-2224
18	D3	DG 102 Missile Shield	D-2151
19	D1A D2A	DG 103 Foundation DG 103 Room	DA-2041S DX-2151A, DX-2151B, DA-2151
20	D1C	DG 103 Cableway	DA-2041N
21	D1D	Area Under PB 102/PB 103	DA-2041N
22	D1B D2B	DG 102 Foundation DG 102 Room	DA-2041N DX-2141A, DX-2141, DA-2141
23	D2C	PB 102 Room	DX-2123A, DX-2123B
24	D2D	PB 103 Room	DX-2113A, DX-2113B

The hotwell contains a baffle system in the form of a rectangular labyrinth that enables the condensate to gradually work its way toward the outside of the hotwell. This assures a retention time of approximately 5 min, allowing time for radioactive decay of short-lived isotopes from the time condensate enters the hotwell until it is removed by the condensate pumps.

The condenser shell and turbine exhaust hoods are protected by relief diaphragms in the event of a failure of the turbine bypass valves to close or on loss of condenser vacuum. The diaphragms are designed to relieve at a backpressure of 5 psig.

Deaeration is provided in the condenser for removal of any normal in-leakage of air, plus the hydrogen and oxygen gases contained in the turbine steam due to disassociation of water in the reactor. It is recommended that the oxygen content in the condensate feedwater system be maintained between 30-200 ppb at Station operating design rating per the fuels contract and approved plant procedures. However, the upper ceiling for oxygen for long-term plant operation must also consider the impact of electrochemical potential on corrosion, as described in the EPRI BWR Water Chemistry Guidelines.

3.0 Condenser Air Removal and Offgas System

Noncondensable radioactive process offgas is continuously removed from the main condenser by the condenser air removal and offgas (OFG) system (Figure XI-3). The condenser offgas normally contains activation gases (N-16, O-19 and N-13) and the radioactive noble gas parents of the biologically significant Sr-89, Sr-90, Ba-140 and Cs-137.

The condenser air removal and OFG system was designed to handle the following volume flow rate:

Dry Air	22 scfm
Hydrogen	79 scfm
Oxygen	39 scfm
Water Vapor	Saturated
Noble Gases	Negligible
Total	140 scfm

The condenser air removal and OFG system (Figure XI-3) consists of the following major equipment:

Condenser
Precooler
SJAEs 1st Stage
Intercondenser

Vent Cooler
SJAEs 2nd Stage
After Condenser
Mixing Jet
Offgas Preheater
Recombiners
Recombiner Condensers
Vent Coolers
Hydrogen Analyzers
30-Minute Holdup Pipe
Chillers
Refrigeration Equipment, associated with Chillers
Preadsorbers
Charcoal Columns
Offgas Vacuum Pumps
Offgas Moisture Separator
Offgas Vacuum Pump Coolers
Stack
Sump Tank
Mechanical Vacuum Pumps
1.75-Minute Holdup Pipe (for Steam Packing Exhaust Discharge)
Deicing Water Buffer Tank
Drain Tank (Recombiner)
Associated Valves, Piping and Instrumentation
Hydrogen Water Chemistry Oxygen Injection
Hydrogen Water Chemistry Offgas Sample

The gases to be evacuated by the OFG system are mainly concentrated in the condenser, but steam, air, and other gases evacuated by the steam packing exhauster are also discharged to the OFG system. The first-stage SJAEs extract the gases from the condenser. The gases are diluted with steam in the second-stage air ejector and in the mixing jet. This mixture enters the preheater. The preheater is used during startup to heat the steam/gas mixture to approximately 350°F. Once the system is in operation, the steam heating is secured to the preheater.

Condensate formed in the preheater is returned to the condenser via the drain tank. Leaving the preheater, the gases enter the recombiner. The mixture enters through the inlet nozzle and hits a baffle plate and is guided upwards. Then it flows downwards to the recombiner catalyst and outlet nozzle positioned at the bottom of the vessel. At the maximum concentration of hydrogen (4 percent by volume), the temperature inside the vessel can rise to approximately 750°F. The purpose of the recombiner is to catalytically combust the hydrogen and oxygen in a controlled manner to form water. Leaving the recombiners, the remaining gas mixture enters the recombiner condenser. The condenser cools the superheated gas steam mixture and condenses the steam. The condensate is returned to the main condenser via a drain tank.

A high-point vent is provided at the inlet piping to each recombiner to allow venting of accumulated hydrogen from the inactive recombiner train to the active recombiner train.

The noncondensable offgas then enters the vent cooler. The vent cooler lowers the moisture content of the concentrated inert gases which contain air, fission gases and traces of moisture by cooling from approximately 200°F to approximately 90°F.

After leaving the vent cooler, the gas mixture is directed to the 30-min holdup pipe. Prior to entering the pipe, a sample of the gas mixture is continuously drawn and checked for hydrogen concentration. The hydrogen content should normally be zero.

A sample is drawn from the 30-min holdup pipe where the activity of the gas is measured. If a high reading is detected, the system will be isolated.

Leaving the 30-min holdup pipe, the gases enter the chiller. There are three chillers in the OFG system. One will normally be placed in service while another will be on standby. The remaining unit will be in deice or precool modes. Each of the three chillers has precool, cool and deice cycles. Thus, it can be seen that a number of operations can take place at any one time. The chillers are provided to remove moisture from the gas, through cooling, prior to the gas entering the charcoal columns. After 2 hr of cool cycle, if a chiller outlet temperature exceeds 20°F for longer than a preset time, another chiller will start on a precool cycle. If after the precool cycle the running chiller still exceeds 20°F, the second chiller will begin its cool cycle and first chiller will deice automatically. The deiced water is drained to a buffer tank. From the buffer tank the water is sent to the radwaste system or to barrels, depending on the freon concentration in the water. Each chiller has its own complete refrigeration unit.

A bypass is provided around the three chillers in the event of an emergency when none of the chillers would be operative but the gas flow would have to be maintained to avoid tripping the generating unit.

After the gas leaves the chillers, it enters the preadsorbers. Between the chiller outlet and the preadsorber inlet, the offgas is sampled for freon contamination. The preadsorber is a small charcoal column. Its function is to trap particles and prevent any moisture from entering the main charcoal columns. Only one of the two preadsorbers is normally in service while the second is maintained as a standby unit.

After leaving the preadsorber, the offgas enters the charcoal columns. All six columns will normally be operated in series. However, they can be valved such that the first three or last three can be bypassed.

The charcoal columns delay the noble gases; Xenon for a minimum of 20 days and Krypton for a minimum of 33 hr by adsorption. This is accomplished by means of selected adsorption.

The offgas enters each charcoal column from the bottom and flows upward through the charcoal which rests on diagonal trays. Each set of three columns has a differential pressure indicator across it. In addition, each column has three temperature indicators located at different heights. It should be noted that the efficiency of the charcoal columns decreases (adsorption/delay) with an increase in charcoal temperature.

After leaving the charcoal columns, the offgas enters one of two offgas vacuum pumps. In order to prevent leakage of radioactive gases from the offgas system into the Station and to evacuate the gas to the stack, the system is operated under slight vacuum conditions between the mixing jet and the offgas vacuum pumps.

The two vacuum pumps establish vacuum for operation of the OFG system during startup and hold the vacuum during operation. Normally, one pump is in operation while the other pump serves as a standby unit. If necessary, both pumps can operate in parallel. The vacuum pumps are liquid ring pumps (horizontal type) and are made of noncorrosive material with top suction and discharge. The shaft is sealed through twin stuffing boxes with a liquid seal. The vacuum pumps are designed for a greater gas capacity than expected from the OFG system.

To supply the necessary gas quantities, a bypass from the discharge side of the pump is fed back into the suction line. A vacuum of approximately 12.0 psia is maintained by the vacuum pump between the discharge of the chillers and the inlet of the preabsorbers. A vacuum of approximately 11.4 psia is maintained at the inlet of the vacuum pump(s).

The gases then pass into the offgas moisture separator where the water is separated from the offgas. The water flows through the offgas vacuum pump cooler and returns to the ring water pump. The cooling water for the offgas vacuum pump cooler is reactor building closed loop cooling water (RBCLCW). Unlike the mechanical vacuum pump, there is no pump involved in transferring the water from the moisture separator back to the vacuum pump.

At the outlet of the offgas moisture separator, the offgas is passed first through a wire mesh matting, where droplets of water are separated before the offgas finally enters the stack.

The main offgas blocking valve is located after the moisture separator. This valve will isolate the offgas system if activity in the system reaches the high activity setpoint.

A mechanical vacuum pump system is provided for hogging air from the condenser prior to starting the turbine when steam is not available to operate the SJAEs. Once the SJAEs are placed in

service, the suction of the mechanical vacuum pump may be diverted to the condenser water boxes. The condenser water boxes are normally primed using the circulating water priming pumps.

The system consists of two mechanical vacuum pumps, two moisture separators, two seal pumps and two mechanical vacuum pump coolers. This system is capable of evacuating the condenser and associated system from atmospheric pressure to 5-in mercury absolute in approximately 1 hr, with both pumps operating. Operation of one pump extends time to 2 hr.

The mechanical vacuum pump line is capable of automatic isolation initiated from high radioactivity (five times normal) in the main steam line (MSL).

The offgas equipment, piping, valves and filter housings are designed to withstand the high pressure generated by a possible hydrogen-oxygen explosion.

To detect the source of air in-leakage in the OFG system, use of tracer gas monitoring and analyzing equipment temporarily connected to the offgas sampling station has been evaluated. The same technique has been evaluated for condenser tube leaks.

The HWC includes an oxygen injection system to offgas, upstream of the offgas recombiner to maintain stoichiometric mixture of hydrogen and oxygen in the recombiner. The system is provided due to an excess ratio of hydrogen to oxygen at the entrance to the OFG system because of hydrogen injection through the feedwater system.

The HWC includes an additional OFG sample system for monitoring of the offgas percent oxygen concentration from the recombiners to assure that the oxygen addition flows are properly balanced. The HWC OFG sample system draws gas from downstream of the offgas vent coolers.

4.0 Circulating Water System

Two 125,000-gpm vertical, mixed flow, circulating water pumps located in the screenhouse deliver water from Lake Ontario to the condenser water box as shown on Figure XI-4. Each pump discharges in a separate line to one side of the condenser divided water box. Fish screens are installed in each circulating water inlet pipe at the entrance to the water box. These fish screens are in the open position during operation. They are closed just before the circulating water pumps are removed from service to prevent debris from backwashing from the condenser water boxes into the inlet tunnel. This debris collects on the closed fish screen and will be sluiced into the circulating water discharge tunnel.

Each pump suction pit is sectionalized to permit draining of one pit for maintenance while the other pump is in operation. After

leaving the condenser, the circulating water is discharged back into the lake. The screenhouse, intake and discharge tunnels are further described in Section III-F.

5.0 Condensate Pumps

Three one-half capacity, centrifugal, motor-driven vertical condensate pumps, each rated at 4,000,000 lb/hr, take suction from the condenser hotwell and discharge it through the full-flow condensate demineralizer (CND) system, the SJAE intercondenser, and the recombiner condensers into the three feedwater booster pumps. Operation of two pumps is sufficient to handle the full operating load (100-percent power) requirements.

Alarms for low condensate discharge header pressure, low and high hotwell level, high condensate temperature leaving the hotwell, and low condenser vacuum are provided to alert the Operator of abnormal conditions.

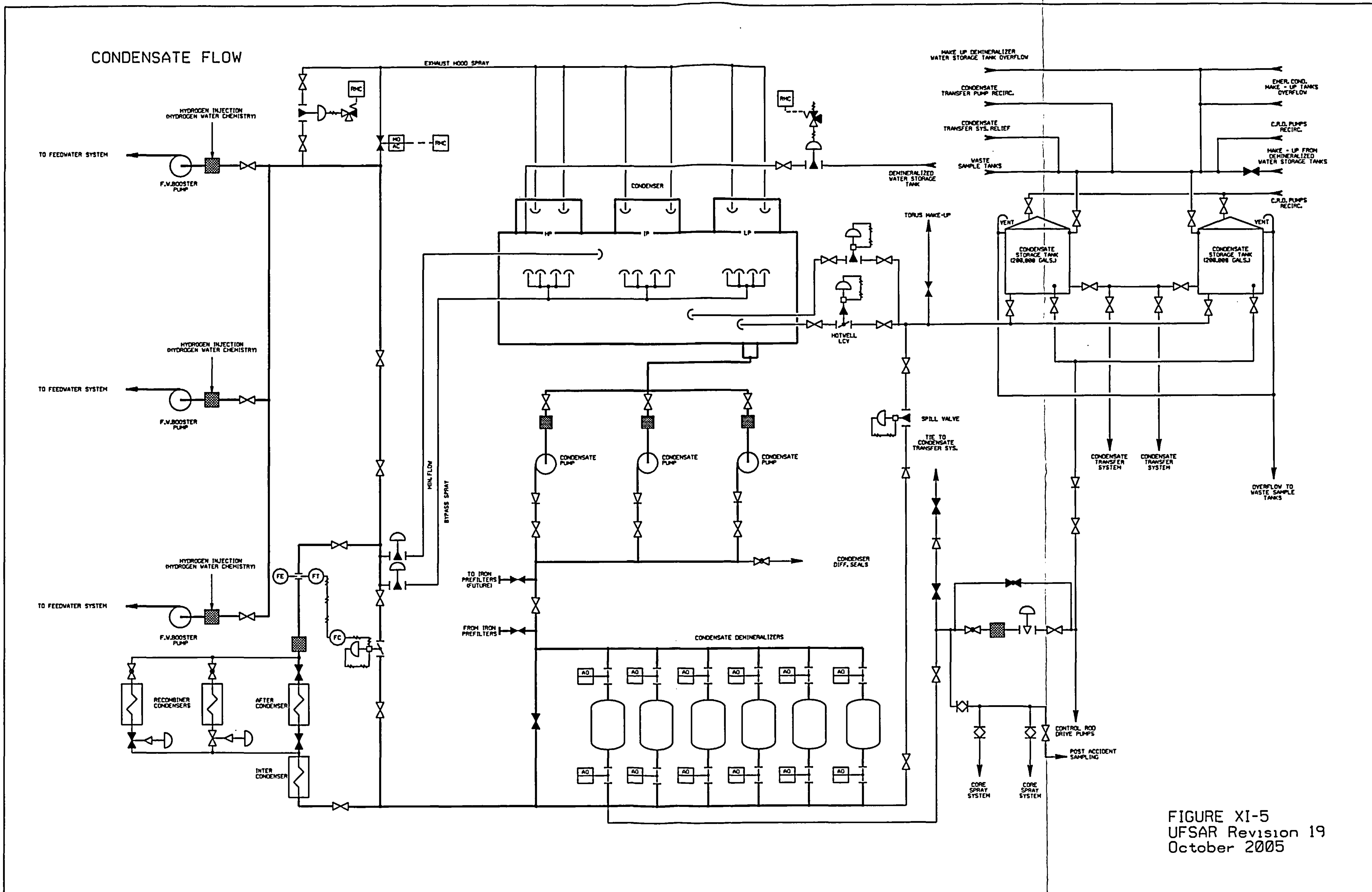


FIGURE XI-5
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October 2005

Radiation Area. Personnel exposures in radiation areas are kept to a minimum by use of administrative procedures based on accumulated doses and by keeping time spent in radiation areas as short as possible. Radiation areas may be isolated with yellow and magenta rope and are posted with signs:

CAUTION

RADIATION AREA

2. <u>High Radiation Area</u>

Any area in which the radiation level is greater than 100 mrem/hr is designated as a high radiation area. Entrances to high radiation areas (100 to 1000 mrem/hr) to which personnel require frequent access are barricaded and normally kept locked and may be equipped with an alarm system which will warn the person entering. Entrances to high radiation areas above 1000 mrem/hr shall be provided with locked doors to prevent unauthorized entry, and the hard keys or access provided by magnetic keycard shall be maintained under the administrative control of the Shift Manager (SM) or designate on duty and/or the Manager Radiation Protection or designate, and issued to personnel with the appropriate radiation work permit (RWP). Access to high radiation areas that may be reached only by ladders or climbing structures, such as loft spaces above false ceilings or the upper volumes of high rooms, is not controlled by automatic alarms or special barricades.

All high radiation areas will be posted with signs:

CAUTION OR DANGER

HIGH RADIATION AREA

Radiation protection personnel make routine surveys of all the accessible areas in the Station to keep abreast of any changes in the radiation levels in these areas.

3.3 Contamination Control

Contamination control is achieved in general by physical separation of the contaminated area.

3.3.1 Facility Contamination Control

Contamination of the general Station areas is prevented by using the "step-off-pad" technique when leaving areas that are contaminated. Monitoring devices are placed near the step-off-pad so that personnel can check to assure they are not

inadvertently carrying some contamination with them. Unless specifically exempted by radiation protection supervision, personnel will monitor themselves prior to each exit from the RCA to assure that no contamination is being carried from the RCA. For maintenance jobs involving high levels of contamination, the installation of plastic or paper on the floor around the equipment to be maintained will permit quick and easy cleanup after the work is completed. Thus, spread of contamination to other equipment or other floor areas is prevented.

Radiation protection personnel make routine surveys of the contamination levels in all the accessible areas of the Station to keep abreast of any changes in contamination status. Any areas found contaminated to undesirable levels will be roped off and posted. These areas are decontaminated as soon as is reasonable.

3.3.2 Personnel Contamination Control

Contamination of personnel is controlled in two ways. First, contamination is prevented from getting into areas where personnel can unknowingly come in contact with it by using the methods described in Section 3.3.1.

Second, personnel who enter contaminated areas are protected with special protective clothing. The following types of protective clothing are used:

1. Coveralls - Worn for most work in contaminated areas.
2. Plastic suits - Worn in areas where potential exists for liquid contamination of personnel.
3. Gloves - Cotton gloves are worn for protection against dry contamination and rubber gloves for protection against dry or wet forms of contamination.
4. Shoecovers - Cloth covers are worn for protection against dry contamination; plastic shoecovers for dry or moist contamination; rubber overshoes for dry, moist or wet contamination.
5. Head protection - Caps are worn for protection against low-level contamination; cloth hoods for protection against high-level contamination; plastic hoods for protection against very high or moist contamination.

If contamination levels are moderate to high, the various pieces of clothing worn are taped together to prevent contamination from entering the joints. In some cases, double layers of clothing are worn to give additional protection.

Normally, most of the Station is accessible to personnel in street clothes or nonradioactive work clothes. To minimize the

area in which special protective clothing is worn, such clothing is donned at the job site where it is required. Thus, temporary change areas are set up for special maintenance jobs, or a more permanent change area is established for special areas routinely requiring protective clothing.

3.3.3 Airborne Contamination Control

Airborne contamination is minimized by keeping floor contamination levels low, and by reducing leaks as much as possible. However, when airborne contamination levels exceed, or if there is potential for exceeding, the values given in 10CFR20, an evaluation of internal dose commitments may be compared to projected whole body exposures and application of respirators based on this evaluation.

Allowances are made for the use of respiratory protective equipment in determining whether individuals are exposed to concentrations in excess of the values specified in 10CFR20. The protection factors used do not exceed those authorized by 10CFR20.

To assure that these protection factors are provided, the following administrative controls are incorporated in the respiratory protection program.

1. Each respirator user is advised that he may leave the high airborne area for either physical or psychological relief from respirator use, and that he must leave the area in the case of respirator malfunction or any other condition that might cause reduction in the protection afforded the user.

2. Sufficient air samples and other surveys are made to identify the hazards, evaluate individual exposure, and to permit proper selection of respiratory protective equipment.

3. Procedures are established to:

    a. Assure proper training for the correct use of the various types of respiratory equipment.

    b. Assure proper maintenance so that the full effectiveness of the respiratory equipment is maintained. (Includes: cleaning, survey, inspection, repair, sanitizing and storage.)

4. Bioassays and/or whole body counts are made on individuals to evaluate individual exposures, and to assess the adequacy of the respiratory protection program.

3.4 Personnel Dose Determinations

3.4.1 Radiation Dose

Monitoring of personnel is accomplished by the use of thermoluminescence dosimeters (TLD), direct-reading dosimeters, electronic dosimeters, and neutron TLD badges. Personnel entering the RCA are issued TLDs and self-reading dosimeters in accordance with 10CFR20 and Station procedures.

The TLD readings are normally used as the official record. The TLDs are National Voluntary Laboratory Accreditation Program (NVLAP) certified for gamma and beta radiation and able to differentiate between penetrating and nonpenetrating radiations. TLDs are processed quarterly or in accordance with Station procedures. If a TLD should be lost or damaged, an individual's exposure is estimated using appropriate methods and documented.

Direct-reading dosimeters or electronic dosimeters are worn by plant personnel for a day-to-day or job-to-job estimate of personnel exposure. Direct-reading dosimeters are calibrated at a frequency specified in Station procedures, or when damage is suspected.

Station personnel are kept advised of the accumulated dose by Radiation Exposure Reports issued at least weekly. Appropriate records of employee doses are maintained at the Station.

The internal deposition of radioactive material in personnel working in any of the RCAs of the Station is evaluated at intervals dependent upon their occupational group. This evaluation is made by whole body gamma counting. If a significant deposit is detected, the associated dose will be added to the individual's radiation dose records. Whole body counts will be supplemented by bioassay data when appropriate.

3.5 Radiation Protection Instrumentation

3.5.1 Counting Room Instrumentation

The counting room instrumentation includes:

1. Germanium (Ge) detectors.

2. Alpha and beta detectors.

3. G-M type counters with thin window detectors.

3.5.2 Portable Radiation Instrumentation

The portable radiation instruments which are normally stored in the portable radiation instrument storage area of the calibration facility include:

1. Low and intermediate range ion chamber instruments.

2. Portable G-M type instruments.

3. An alpha scintillation instrument.

4. High-range dose rate instruments.

5. A neutron dose rate instrument.

6. An R-meter and a set of standardized ionization thimbles, or equivalent instrument.

7. Small article monitors with plastic scintillation detectors.

3.5.3 Air Sampling Instrumentation

The portable air sampling instruments include:

1. Low-volume air samplers equipped to use filter paper, charcoal cartridges, or silver zeolite cartridges.

2. High-volume air samplers equipped to use filter paper, charcoal cartridges, or silver zeolite cartridges.

3.5.4 Personnel Monitoring Instruments

The personnel monitoring instruments include:

1. Self-reading dosimeters with a range of 0-200 mrem.

2. Self-reading dosimeters with a range of 0-500 mrem.

3. Count rate meters with G-M detectors.

4. Automatic whole body beta and gamma sensitive contamination monitors.

5. Electronic dosimeters.

3.5.5 Emergency Instrumentation

Instruments are kept in special locations for use as designated by the emergency procedures in event of an emergency where Station instruments are unobtainable. These instruments receive

periodic surveillance so that they are known to be functioning correctly.

These instruments include:

1. Low-range dose rate meters.

2. High-range dose rate meters.

3. Portable G-M type instruments.

4. Battery-operated high volume air samplers.

5. Self-reading dosimeters with a range of zero to 5×10^3 mrem and zero to 5×10^4 mrem.

Procedures and associated training for the accurate determination of airborne iodine concentration in areas within the plant where plant personnel may be present during an accident have been established and implemented, and are maintained to meet or exceed the requirements and recommendations of Section 2.1.8.c of NUREG-0578 (Item III.D.3.3 of NUREG-0737).

4.0 Tests and Inspections

4.1 Shielding

Visual inspections of Station shielding were conducted during the construction phase. Their value, however, is limited to locating major defects because of the massive nature of the shielding. During reactor operation, radiation surveys are performed at various power levels. The purpose of these surveys is to assure that:

1. There are no defects or inadequacies in the shielding that might affect personnel exposures during operation of the Station at the same power level as the test.

2. There are no serious defects which might create untenable radiation levels at higher power levels.

3. Areas in the Station are correctly posted and barricaded as Radiation and High Radiation Areas.

These surveys consisted of both gamma and neutron monitoring with appropriate portable instrumentation. Gamma surveys were performed on all Station shielding, while neutron surveys were conducted around the biological shield and associated penetrations.

After the survey, key locations were selected for routine radiation surveys throughout the life of the plant. These surveys, while primarily designed to detect changes in radiation

levels due to process conditions, also monitor aging effects on shielding integrity.

4.2 Area Radiation Monitors

Each area radiation monitor is tested to:

1. Determine that the monitor is correctly wired into the control room.

2. Calibrate the monitor so that the control room readout instrumentation indicates true radiation levels. (For the GE monitors, radiation sources are placed at reproducible geometries on each monitor detector to set the calibration of at least two points on the four-decade scale).

3. Set upscale and downscale alarm trip points.

4. Determine that both the control room and the local alarm (when so equipped) function correctly.

Steps 2, 3 and 4 are repeated semiannually to assure that calibration and alarm setpoints are correct.

4.3 Area Air Contamination Monitors

Each area air contamination monitor is tested to:

1. Determine that the monitor is correctly wired into the control room.

2. Calibrate the monitor so that meter readings can be interpreted in terms of μc/cc. (Filter papers impregnated with known quantities of appropriate radionuclides are placed on the detector section of each monitor to set the calibration at no less than two points over the range of the monitor.)

3. Set upscale/downscale (GE) and high/alert (Eberline) alarm trip points.

4. Determine that both control room and the monitor alarms function correctly.

Steps 2, 3 and 4 are repeated annually to assure that calibration and alarm setpoints are correct.

4.4 Radiation Protection Facilities

4.4.1 Ventilation Air Flows

Ventilation air flows in the radiation protection facilities are checked as part of the turbine building ventilation tests.

4.4.2 Instrument Calibration Well Shielding

The instrument calibration well shielding was tested when the sources were installed.

Station surveys of nearby areas ensure continued shielding integrity.

4.5 Radiation Protection Instrumentation

The following instrumentation is tested and calibrated at a frequency specified in Station procedures, with deviations, not exceeding annually, allowed based on documented instrument reliability:

1. Counting room instrumentation.
2. Portable radiation instruments.
3. Personnel monitoring instruments (except self-reading dosimeters).
4. Emergency instruments.
5. Air samplers.
6. Self-reading dosimeters.

Tests and calibration include (where applicable):

1. Calibration with appropriate calibrated radioactive sources.
2. Calibration of air flow rates with a flow rate measuring system.

SECTION XIII

CONDUCT OF OPERATIONS

A. ORGANIZATION AND RESPONSIBILITY

The following sections describe the organizational structure of NMPNS and delineate the lines of responsibility for the operation of Unit 1 in accordance with established administrative and quality standards. The organizational structure associated with the Quality Assurance (QA) Program for plant operation is described in Appendix B.

1.0 Management and Technical Support Organization

1.1 Station Organization

The senior level Station management organization is depicted on Figure XIII-1. The Vice President Nine Mile Point reports to the Senior Vice President and Chief Nuclear Officer of Constellation Generation Group and has overall responsibility for the administration and operation of the Nine Mile Point Nuclear Station, including: Engineering Services; Quality & Performance Assessment; Nuclear Security; Emergency Preparedness; Human Resources; Business Planning, Budgeting & Cost Control; Nuclear Generation; and Training Nuclear.

1.1.1 Vice President Nine Mile Point

The Vice President Nine Mile Point reports to the Senior Vice President and Chief Nuclear Officer of Constellation Generation Group and has overall responsibility for the administration and operation of the Nine Mile Point Nuclear Station. The Manager Engineering Services, Director Quality & Performance Assessment, Director Nuclear Security, Director Emergency Preparedness, Director Human Resources, Director Business Planning, Budgeting & Cost Control, and the General Supervisor Licensing report directly to Constellation Generation Group (CGG) senior management and have matrixed reporting to the Vice President Nine Mile Point for functional and priority setting direction. The Plant General Manager and Manager Training Nuclear report directly to the Vice President Nine Mile Point.

1.1.2 Matrixed Reporting

1. The Manager Engineering Services reports to the CGG Vice President Nuclear Technical Services for program and policy direction, and has a matrixed reporting to the Vice President Nine Mile Point for functional and priority setting direction. This position has full authority to provide nuclear engineering services that comply with applicable safety, regulatory, and quality requirements within defined cost and scheduling parameters. In addition, this position has single-point accountability for technical concerns and responses.

   The Engineering Services organization chart is provided on Figure XIII-2. The following positions report to this manager:

   a. The General Supervisor Design Engineering supervises design engineering services to assure safe, reliable, and economic operation of Nine Mile Point Nuclear Station. Specific responsibilities are to ensure:

      - Engineering is performed in accordance with applicable regulatory and code requirements (e.g., the UFSAR, Technical Specifications, etc.).

      - Detailed design/engineering is completed based upon conceptual design information including specifications and drawings necessary to implement these designs.

      - As-installed conditions are reflected on drawings.

      - Implementation of the NMP Configuration Management Program.

      - Implementation of conceptual engineering.

      - Plant evaluations are performed to monitor and detect internal and external factors that would indicate an actual or potential degradation of design bases or margin in design bases for initial plant systems and components.

- Development, verification and maintenance of special programs for:

  - Seismic Qualification
  - Metallurgy
  - Environmental Qualification
  - Reactor Vessel and Internals (VIP)

b. The General Supervisor Plant Design Support supervises plant engineering services, work management services, and provides engineering technical oversight (ETO) services to assess engineering product quality with the objective of improving technical skills and overall performance of engineering services.

c. The Principal Engineer Reliability Engineering oversees and directs engineering activities associated with Analysis Services and Probabilistic Risk Assessment.

d. The General Supervisor Engineering Programs is responsible for ASME Programs, AOV/MOV/Check Valve Program, Fire Protection, and Maintenance Rule/EPIX.

e. The General Supervisor System Engineering reports to the Manager Engineering Services, but is not part of the matrixed relationship to CGG Technical Services. This group is considered to be plant staff. The Manager Engineering Services has final design authority for technical issues.

2. The Director Quality & Performance Assessment (NMP) reports directly to the CGG Manager Quality & Performance Assessment for program and policy direction, with matrixed reporting to the Vice President Nine Mile Point for functional and priority setting direction. The Director Quality & Performance Assessment, in performing duties as the manager quality assurance, has the authority and responsibility to report directly to the Vice President Nine Mile Point regarding implementation of the Nine Mile Point QA Program.

   The Quality Assurance organization is depicted on Figure XIII-3.

3. The Director Nuclear Security reports to the CGG Manager Security & Emergency Preparedness Programs for program and policy direction, with matrixed reporting to the Vice President Nine Mile Point for functional and priority setting direction.

4. The Director Emergency Preparedness reports to the CGG Manager Security & Emergency Preparedness Programs for program and policy direction, with matrixed reporting to the Vice President Nine Mile Point for functional and priority setting direction.

5. The Director Human Resources reports to CGG Human Resources for program and policy direction, with matrixed reporting to the Vice President Nine Mile Point for functional and priority setting direction. This director is responsible for Employee/Labor Relations and Leadership/Career Development.

6. The Director Business Planning, Budgeting and Cost Control reports to the Vice President Finance and Business Planning Constellation Nuclear. The Director Business Planning, Budgeting and Cost Control also reports to the Vice President Nine Mile Point for business planning functions with matrixed reporting for all other functions. This director is responsible for the functions of Business Planning, Site Accounting, Budgets, Cost Control, and PSC interface for the nuclear station.

7. The General Supervisor Licensing reports to the CGG Manager Fleet Licensing and is matrixed to the Vice President Nine Mile Point. Supervises Licensing functions, including: regulatory interface (NRC, EPA and DEC); nuclear industry interface (INPO); regulatory reporting; licensee controlled change processes; licensing action requests; generic regulatory communications; commitment management development and implementation; and environmental monitoring.

1.1.3 Qualifications of Support Personnel

General responsibilities and activities of management and technical support personnel are described in appropriate documents including administrative procedures and engineering

procedures. Contract support for Unit 1 is utilized in the same general manner as contract support at Unit 2.

2.0 Nuclear Generation Organization

This section describes the structure, function, and responsibilities of the onsite organizations established to operate and maintain the plant. The onsite and offsite independent review committees are described in Section XIII-G. Unit 1 and Unit 2 operations are independent of each other, including backshift operation. Only licensed individuals may direct licensed activities.

An organization chart showing the title of each position is shown on Figures XIII-4 through XIII-4c. The lines of authority are described in administrative procedures.

2.1 Plant General Manager

The Plant General Manager reports to the Vice President Nine Mile Point, is responsible for overall unit operation, shall have control over those resources necessary for safe operation of the plant, and assumes the duties and responsibilities of the Vice President Nine Mile Point, in his absence, for matters affecting the Station. The Plant General Manager has overall responsibility for safe and efficient Station operation, in accordance with applicable licensing, regulatory and Quality Assurance Program requirements, and controlling the preparation, review, and approval of Station procedures.

The Plant General Manager maintains an organization comprised of the following direct reports with associated responsibilities:

1. The Manager Operations performs the following functions:

    a. Ensures safe operation of the Station in accordance with approved procedures and regulatory requirements.

    b. Advises Shift Manager (SM) (formerly the Station Shift Supervisor) during emergency conditions.

    c. Performs the duties associated with SORC membership.

    d. Assists in the development of training programs.

e. Administers implementation of the Fire Protection Program for the Nine Mile Point site.

f. Maintains an organization comprised of the following functional sections:

- Station Operations
- Operations Planning
- Reactor Engineering
- Operations Programs & Procedures
- Fire Protection
- Radwaste Management

2. The Manager Radiation Protection manages radiation protection monitoring and control programs in support of Station operation. This manager meets the radiation protection manager qualifications in Technical Specifications Section 6.3.1. The Manager Radiation Protection has:

- Direct access to appropriate levels of corporate management, including the Chief Nuclear Officer, to resolve radiation protection concerns.

- Authority to require plant shutdown if unsafe radiological conditions exist.

The Manager Radiation Protection manages Radiation Protection and ALARA personnel and ensures procedures/qualifications comply with Federal and Technical Specification requirements related to monitoring, control and minimization of radiation exposure to plant personnel. This manager:

a. Performs the duties associated with SORC membership.

b. Controls preparation, review, and approval of Radiation Protection and Waste Handling procedures, and assists in the development of training programs.

c. Maintains an organization comprised of the following functional sections:

- ALARA
- Radiological Support

- Radiation Protection Operations

3. The General Supervisor Chemistry monitors and controls programs, including personnel, procedures and qualifications, to ensure compliance with Federal and Technical Specification requirements related to primary and secondary system chemistry and radiochemistry, radioactive effluent, chemistry control, post-accident assessment, and solid radioactive waste measurements. This manager:

   a. Manages operation of, and waste disposal aspects of, the Sewage Treatment Facility.

   b. Performs the duties associated with SORC membership.

   c. Assists in development of training programs.

   d. Maintains an organization comprised of the following functional sections:

      - Chemistry Operations
      - Chemistry Support

4. The Manager Assessment and Corrective Action establishes and maintains the program documents and procedures for implementing the Corrective Action Program (CAP).

5. The Supervisor Fuels reports to the CGG Director Nuclear Fuels Services and is matrixed to the Plant General Manager. This position:

   a. Provides reliable, safe and economic fuel supply for NMPNS by performing the activities necessary to specify the procurement, receipt, use and disposal of nuclear fuel.

   b. Administers, maintains, and controls the Core Operating Limits Report (COLR).

6. The Manager Maintenance ensures modifications, surveillance, maintenance, preventative maintenance, radiation instrument calibration, and housekeeping and decontamination are properly performed in accordance

with applicable rules, regulations, approved procedures, codes and standards. This position:

a. Manages relay and control testing activities, measuring and test equipment calibration, and maintenance planning functions.

b. Performs the duties associated with SORC membership.

c. Assists in the development of training programs.

d. Ensures necessary maintenance personnel are available to maintain the Station in a safe and efficient manner.

e. Ensures radiologically-controlled area (RCA) housekeeping and decontamination are maintained.

f. Maintains an organization comprised of the following functional sections:

- Mechanical Maintenance
- Electrical Maintenance
- I&C Maintenance
- FIN
- Construction/Outage Services

7. The Manager Work Control/Outage Management ensures the safe and efficient planning and implementation of forced, planned and refuel outages at NMPNS, as well as planning and implementation of weekly work schedules. This position:

a. Manages the scheduling function.

b. Ensures integrity of the Work Control Center and scheduling databases.

c. Maintains interfaces among Nuclear Generation departments for maintenance, modification and testing activities.

d. Maintains an organization comprised of the following functional sections:

- Outage Management

- On-line Work Management
- Work Management Programs
- Planning

e. Is the onsite interface and contact for Project Management. The General Supervisor Project Management has a matrixed reporting relationship to the Manager Work Control/Outage Management and reports directly to the CGG Director Project Management.

f. Is the onsite interface and contact for materials and services. The Director Materials and Services has a matrixed reporting relationship to the Manager Work Control/Outage Management and reports directly to the CGG Manager Procurement and Warehouse Services.

8. The Director Personnel Safety interprets Occupational Safety and Health Administration (OSHA) requirements and advises, assists, and coordinates efforts in the implementation of those requirements.

9. The Technical Advisor/SORC Chairman reports to the Plant General Manager and performs the following functions:

   a. Serves as Chairman of the NMP Station Operations Review Committee.

   b. Advises the Plant General Manager on technical and nuclear safety matters.

   c. Serves as rotating Chairman of the Corrective Action Review Board and Self-Assessment Review Board.

2.2 Other Functions Reporting to the Vice President Nine Mile Point

1. The Manager Training Nuclear reports directly to the Vice President Nine Mile Point and manages the activities of the Training organization, including the development, administration, and coordination of training and retraining programs for NMPNS personnel. This manager ensures activities within the Training

organization are properly conducted per applicable regulations, codes, standards, and procedures.

2. The Director Employee Concerns Program reports to the Vice President Nine Mile Point for implementation of the Employee Concerns Program, and administratively to the Director Human Resources.

2.3 Supervisor Reactor Engineering

The Supervisor Reactor Engineering reports to the Manager Operations and is responsible for proper implementation of the Reactivity Management Program. This position:

a. Provides direction and engineering expertise to Operations and other groups for the control of reactivity.

b. Evaluates site and industry reactivity related events for applicability and lessons learned.

c. Supports review of plant procedures, maintenance activities, and modifications for potential reactivity effects.

d. Monitors the effectiveness of the Reactivity Management Program.

e. Ensures that training is provided to Operations personnel prior to implementation of new core design or new core operating strategies.

f. Controls and verifies proper implementation of the Fuel Handling Procedures.

g. Performs duties associated with SORC membership.

Acts as the Special Nuclear Material Custodian and is responsible to ensure:

a. Applicable procedures are developed and implemented to control receipt, storage, movement, and shipment of special nuclear material (SNM).

b. The possession and use of SNM is confined to the locations and purposes authorized by the Station's Operating License.

3.0 Quality Assurance

The operations phase QA Program is described in the Quality Assurance Program Topical Report (QATR) for Nine Mile Point Nuclear Station Units 1 and 2 - Operations Phase (see UFSAR Appendix B). The QATR identifies the Station organizations responsible for activities affecting the operation, maintenance or modification of safety-related and fire protection structures, systems, or components, and describes the assigned authorities and duties for quality-attaining functions and for quality verification functions.

4.0 Operating Shift Crews

Table XIII-2 shows the position titles, applicable Operator licensing requirements, and minimum numbers of personnel planned for each shift for the various reactor operating conditions. Unique requirements for additional personnel for the refueling condition are also noted in Table XIII-2. The following additional requirements apply:

a. At least one licensed Operator shall be in the control room when fuel is in the reactor. During reactor operation, this licensed Operator shall be present at the controls of the facility.

b. A licensed Senior Reactor Operator or licensed Senior Reactor Operator Limited to Fuel Handling shall be responsible for all movement of new and irradiated fuel within the site boundary.

c. All fuel moves within the core shall be directly monitored by a member of the reactor analyst group.

5.0 Qualifications of Staff Personnel

Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971. Position qualification requirements are shown in Table XIII-1.

A retraining and replacement training program for the facility staff shall be maintained under the direction of the Manager Training Nuclear, and shall meet or exceed the recommendations and requirements of Section 5.5 of ANSI N18.1-1971 and of 10CFR55, and shall include familiarization with relevant industry operational experience.

B. QUALIFICATIONS AND TRAINING OF PERSONNEL

1.0 (This section deleted)

2.0 (This section deleted)

3.0 (This section deleted)

4.0 Training of Personnel

4.1 General Responsibility

The Manager Training Nuclear is responsible for all training at the Nine Mile Point Nuclear Station.

4.2 Implementation

1. The Manager Training Nuclear reports directly to the Vice President Nine Mile Point and manages the activities of the Training organization, including the development, administration, and coordination of training and retraining programs for site personnel.

2. The Manager Training Nuclear develops and ensures implementation of the Training organization portion of the business plan.

3. The Manager Training Nuclear ensures activities within the Training organization are properly conducted per applicable regulations, codes, standards, and procedures.

4. The Manager Training Nuclear maintains appropriate safety and budget control programs, and ensures adequate resources are assigned within the Training organization.

4.3 Quality

Responsibility for the general quality of training in each area shall be distributed as follows:

4.3.1 For Operator Training

The Plant General Manager with the assistance of the Manager Operations.

4.3.2 For Maintenance

The Manager Maintenance.

4.3.3 For Technicians

The Manager Maintenance, General Supervisor Chemistry, Manager Radiation Protection, Manager Operations.

4.3.4 For Radwaste Operators

The Supervisor Radwaste Management.

4.3.5 For General Employee Training/Radiation Protection and Emergency Plan

The General Supervisor Chemistry, Manager Radiation Protection, Director Nuclear Security, Director Quality and Performance Assessment, Lead Operations Engineer, and Director Emergency Preparedness.

4.3.6 For Industrial Safety

The Director Personnel Safety.

4.3.7 For Nuclear Quality Assurance

The Director Quality and Performance Assessment.

4.3.8 For Fire Brigade

The Manager Operations.

4.3.9 For Manager Operations and General Supervisor Operations

As a minimum, either the Manager Operations or the General Supervisor Operations shall hold a SRO license. The Manager Operations, who in lieu of meeting the SRO license requirements of ANSI N18.1-1971, shall: 1) hold a SRO license at the time of appointment, or 2) have held a SRO license at Unit 1 or at a similar unit, or 3) have been certified for equivalent SRO knowledge.

4.4 Training of Licensed Operator Candidates/Licensed NRC Operator Retraining

Detailed training programs for Unit 1 Operations are designed to provide initial training, requalification training, and continuing training at all levels of the Operations organization. These programs fulfill the requirements included in the following documents:

10CFR50, Licensing of Production and Utilization Facilities

10CFR55, Operators Licenses

NUREG-0737, Clarification of TMI Action Plan Requirements

NUREG-1021, Operator Licensing Examiner Standards

ANSI N18.1-1971, Selection and Training of Nuclear Power Plant Personnel

ANSI/ANS 3.4-1983, Medical Certification and Monitoring of Personnel Requiring Operator Licenses for Nuclear Power Plants

The training program is designed in accordance with accreditation programs described in the latest approved ACAD recommendations, and uses a simulation facility acceptable to the NRC under 10CFR55.

Nuclear Division procedures contain the requirements, policies, and practices necessary to implement Operator training programs. Each program is described in dedicated nuclear training procedures (NTPs). These procedures contain the scope and purpose of the training program, an outline of the course curriculum, instructions for scheduling the program, and reporting requirements. Copies of procedures NTP-10 and NTP-11 detailing the training program were initially submitted to the NRC in a letter dated October 28, 1986, in accordance with Generic Letter 84-014. The current training procedures are:

1. NIP-TQS-01, Qualification and Certification (formerly AP-1.3.1 and AP-9.1)

2. NTP-TQS-101, Training of Licensed Operator Candidates (formerly NTP-10)

3. NTP-TQS-102, Licensed Operator Requalification Training (formerly NTP-11)

4. NTP-TQS-103, Training of Nuclear Auxiliary Operators (formerly NTP-12)

Entry into these training programs is controlled by the Operations organization. Eligibility criteria for license candidates is contained in instructions and procedures maintained by the Operations organization.

5.0 Cooperative Training With Local, State and Federal Officials

A detailed Site Emergency Plan and Procedures for Nine Mile Point Nuclear Station has been submitted to the NRC. Included in this document are the training procedures involving local, state and federal officials.

C. OPERATING PROCEDURES

The Station operating staff has prepared written operating procedures to be used for all normal operating conditions.

Changes may be initiated by the Station operating staff subject to approval by the Operations supervisory staff, and by the branch manager for the functional area of the procedure, or higher levels of management as governed by administrative procedures.

Procedures cover operation of major systems such as starting the entire Station from "cold" conditions. Other procedures cover less extensive systems in detail.

Still another type of procedure instructs the Operator in the methods of operating individual pieces of equipment, such as regeneration of resin in a demineralizer.

The format for all operating procedures is essentially the same. Each procedure is prefaced with the technical limitations of the system or equipment, as set forth in the Technical Specifications, OL, or 10CFR20. Other data helpful to operation, such as a system description and plant operating requirements, are included in a separate section of the procedure. Details of operation are then set down in a stepwise procedure. Prior to startup, prepared lists are checked off by the Operators. These vary in degree with the extent of the period preceding the startup.

The emergency operating procedures (EOP) and the severe accident procedures (SAP) have been developed, validated and implemented in accordance with the requirements of NUREG-0737 Supplement 1. The EOPs/SAPs are prepared using the guidance provided by the BWR Owners' Group Emergency Procedure Guidelines and Severe Accident Guidelines (BWROG EPG/SAG Revision 1), and the format recommended by NUREG-0899. The EOPs/SAPs are symptom oriented rather than event based. They address conditions beyond the design basis. They provide guidance for the entire range of available systems. This "defense-in-depth" approach provides for safe shutdown of the plant in all postulated events, including anticipated transients without scram (ATWS), thus preventing or mitigating the consequences of any accident or malfunction.

In the event of an unlikely, yet credible, accident situation which might involve radioactivity release to the public domain, the SM, in accordance with written procedures, is responsible

for notifying Station supervision and outside authorities. It is recognized that a program of this type must be rehearsed; therefore, planned nuclear incident drills are held periodically to review established procedures, personnel assignments and relations with outside authorities.

D. EMERGENCY PLAN AND PROCEDURES

The Nine Mile Point Nuclear Station Site Emergency Plan describes the total preparedness program established, implemented and coordinated by the Station to assure the capability and readiness for coping with and mitigating both onsite and offsite consequences of radiological emergencies. The Site Emergency Plan covers the spectrum of emergencies from minor localized incidents to major emergencies involving protective measures by offsite response organizations. Included are guidelines for immediate response, assessment of emergency situations, defined action criteria and delineation of support functions. Site Emergency Plan Implementing Procedures provide detailed information for individuals who may be involved with specific emergency response functions. The Site Emergency Plan provides for a graded scale of response for distinct classifications of emergency conditions, action within those classifications, and criteria for escalation to a more severe classification. This classification system is the same as that used by the State of New York and the Oswego County Emergency Management Office. The plans have four emergency categories: unusual event, alert, site area emergency, and general emergency. In addition to notifying the offsite agencies of the existing emergency classification, provisions are made in the emergency procedures for the Station to advise the State and County of appropriate protective actions.

The organization for control of emergencies begins with the shift organization, and contains provisions for augmentation and extension to include other Station personnel and outside emergency response organizations (EROs).

The following emergency response facilities (ERFs) are provided to ensure the capabilities for the prompt, efficient assessment and control of situations over the entire spectrum of probable and postulated emergency conditions.

1. Technical Support Center (TSC)

2. Operations Support Center (OSC)

3. Emergency Operations Facility (EOF)

4. Joint News Center (JNC)

5. Oswego County Emergency Operations Center

6. State Emergency Operations Center

Formal training along with drills and exercises are essential in maintaining an in-depth emergency preparedness program.

The Site Emergency Plan and Implementing Procedures have been submitted to the NRC under separate cover.

The current version of the Site Emergency Plan is Revision 49.

E. SECURITY

A detailed Nine Mile Point Nuclear Station Physical Security, Safeguards Contingency, and Security Training and Qualification Plan, identified as safeguards information and withheld from public disclosure in accordance with 10CFR73.21, has been submitted to the NRC.

The security plan described above details the measures taken to provide adequate Site and Station security and conforms to 10CFR73.55.

The current version of the plan is the Physical Security, Safeguards Contingency, and Security Training and Qualification Plan - Issue 6, Revision 0.

F. RECORDS

1.0 Operations

The following logs will be maintained by the operating staff as a part of the Station records. When electronic logs are used, the control room log and the SM log may be combined.

1.1 Control Room Log

Shall contain all information pertaining to changing core reactivity during all modes of reactor operation, including rod manipulation, orifice modifications, control rod testing, etc. Also, entries affecting Station outputs, changes in auxiliary equipment, unusual condition, line trips, annunciator signals not recorded on data logger, etc., will be entered in this log. The log shall contain the date and time of all entries and the name of the Chief Shift Operator (CSO) or other authorized personnel only. The control room log is to be treated as a legal document subject to being entered in a court record. All entries in this log shall be by the Operator on duty or his Supervisor. No other entries are authorized. Included with the control room log is a fuel log in which specific detailed fuel moves, channel changes, and in-core instrumentation changes are recorded.

1.2 Shift Manager's Log

Shall contain an overall summary of Station operation including the name of the SM on duty, the Operators and Auxiliary Operators on duty, major equipment not in service or inoperable, and the date and time of all entries. Also note any Operator surveillance tests run and deviations from acceptance criteria. The log may be written by the Control Room Supervisor (CRS) or a CRS/SM in training, or other designee, but must be signed and acknowledged by the SM.

1.3 Radwaste Log

The log shall contain pertinent information associated with the radwaste facility operation.

1.4 Waste Quantity Level Shipped

Solid waste and resins removed from site.

2.0 Maintenance

The Manager Maintenance will be responsible for maintaining a record of maintenance performed on all pertinent equipment in a maintenance log.

3.0 Radiation Protection

The Manager Radiation Protection will be responsible for the following records.

3.1 Personnel Exposure

1. Dosimeter readings, daily

2. Thermoluminescence dosimeter (TLD) record, quarterly

3. Continuous exposure record conforming to 10CFR20

4. Appropriate records and forms required in 10CFR20

3.2 By-Product Material as Required by 10CFR30

3.3 Meter Calibrations of all survey meters, environmental monitors and monitors affecting radioactive discharge.

3.4 Station Radiological Conditions in Accessible Areas

1. Radiation levels

2. Contamination levels

3. Airborne activity

3.5 Administration of the Radiation Protection Program and Procedures

4.0 Chemistry and Radiochemistry

The General Supervisor Chemistry is responsible for primary and secondary system Chemistry and Radiochemistry including monitoring and control of liquid and gaseous radiological effluents.

5.0 Special Nuclear Materials

The special nuclear materials records will be maintained and reported in conformity with 10CFR70.

6.0 Calibration of Instruments

The calibration of instruments and controls, both nuclear and conventional, will be recorded, as well as maintenance performed on them.

7.0 Administrative Records and Reports

1. Investigations of abnormal operation will be prepared in report form and distributed to interested parties.

2. Records will be kept of all changes to equipment or procedures.

3. Reports of production and pertinent operating data with a summary of items of interest will be produced at regular intervals and distributed to interested parties and to those who audit Station operations.

4. Reports of exposure to individuals, loss or theft of licensed material, etc., as outlined in 10CFR20 will be reported in the time and manner specified.

G. REVIEW AND AUDIT OF OPERATIONS

A means is provided for processing changes and assuring safe operation and compliance by periodic audit through the establishment of two review bodies.

1.0 Station Operations Review Committee

This is composed of Managers and General Supervisors/Supervisors attached to the Station and directly responsible for daily operation and environmental protection. Responsibilities and procedures for committee operation are given in the Quality Assurance Topical Report (QATR) (Appendix B). Organization of this committee is shown on Figure XIII-5.

1.1 Function

The SORC functions to advise the Plant General Manager on all matters related to nuclear safety and plant operations. SORC meetings include a review of in-house and industry operating experience at the discretion of the Plant General Manager.

2.0 Nuclear Safety Review Board

No more than a minority of the quorum shall have line responsibility for operation of the facility. Organization of this board is also shown on Figure XIII-5.

2.1 Function

The Nuclear Safety Review Board (NSRB) shall function to provide independent review and audit of designated activities in the areas of:

1. nuclear power plant operations
2. nuclear engineering
3. chemistry and radiochemistry
4. metallurgy
5. instrumentation and control
6. radiological safety
7. mechanical and electrical engineering

8. quality assurance practices

9. other appropriate fields associated with the unique characteristics of the nuclear power plant

3.0 Review of Operating Experience

Internal and external operating experience is reviewed and assessed via corrective action procedures to ensure that information pertinent to plant safety is supplied to Operators and other appropriate personnel, and is used for effecting design and procedural changes to correct generic or specific deficiencies and to enhance plant safety when warranted.

An initial applicability review of externally-generated operating experience shall be performed primarily by individuals in the Assessment and Corrective Action group. These reviews include, but are not limited to, NRC issuances such as Generic Letters, Information Notices, Bulletins, and Administrative Letters; INPO issuances such as Significant Operating Experience Reports, Significant Event Reports, Significant Event Notifications, Significant by Others, and Operations and Maintenance Reminders; Vendor issuances such as GE Service Information Letters, Rapid Information Communication Service Information Letters, Technical Information Letters, Service Advisory Letters, and potential 10CFR21 notifications.

External operating experiences that require further evaluation are assigned to responsible Station organizations, via the Deviation/Event Report (DER) process, as appropriate, for evaluation and corrective and preventive action. The evaluations and dispositions are reviewed by the applicable Branch Manager and the Plant General Manager when SORC review is required. Hardware and software modifications, procedure revisions, design changes, etc., resulting from the reviews are then implemented by the responsible groups. The evaluations and dispositions are reviewed by SORC as required by the Plant General Manager.

In-house operating experience, such as significant equipment malfunction, adverse trends developed from testing and operations surveillance, reactor core operating trends, operability problems, and/or organizational and programmatic problems that may impact plant safety and reliability, will be treated as an event/deviation and processed accordingly. Processing shall be accomplished by the appropriate Branch

Manager allowing the Plant General Manager to designate SORC review as appropriate.

TABLE XIII-1

ANSI STANDARD CROSS-REFERENCE UNIT 1

ANSI N18.1-1971 TITLE	SECTION	NMPNS TITLE (UNIT 1)
Plant Manager	4.2.1	•Plant General Manager
Operations Manager	4.2.2	•Manager Operations*
Maintenance Manager	4.2.3	•Manager Maintenance
Technical Manager See NOTE Below	4.2.4 N/A	•General Supervisor System Engineering •General Supervisor Chemistry •Manager Work Control/Outage Management •Manager Radiation Protection
Supervisors Requiring NRC License	4.3.1	•Shift Manager •Control Room Supervisor
Supervisor Not Requiring NRC License	4.3.2	•Supervisor Radwaste Operations •General Supervisor Operations •General Supervisor Maintenance Support •Supervisor Operations Fire Protection •General Supvs (Mech & Elect) Maintenance •Supervisors (Mech & Elect) Maintenance •Supervisor Maintenance Programs •Supervisor Radiological Instrument Calibration •Supervisor Operations Programs & Procedures •General Supervisor Planning/FIN •Supervisor Condition Monitoring •Supervisor Component Specialist (Elect & I&C) •Supervisor Component Specialist (Mech)
Reactor Engineering	4.4.1	•Supervisor Reactor Engineering
Instrumentation and Control	4.4.2	•General Supervisor I&C Maintenance •Supervisor I&C Maintenance
Radiochemistry	4.4.3	•Supervisor Chemistry Operations
Radiation Protection	4.4.4	•Supervisor RP Operations •Supervisor ALARA
Operators	4.5.1	•Nuclear Auxiliary Operator •Chief Shift Operator •Radwaste Operator •Chief Radwaste Operator
Technicians	4.5.2	•Chief Technician •Technician
Repairmen	4.5.3	•Chief Electrician A Nuclear •Electrician Nuclear •Chief Mechanic A Nuclear •Mechanic Nuclear
Engineer in Charge	4.6.1	•General Supervisor System Engineering

NOTE: Manager Radiation Protection meets or exceeds the qualifications of Regulatory Guide 1.8, September 1975, per Technical Specifications Section 6.3.

* For Unit 1, as a minimum either the Manager Operations or the General Supervisor Operations shall hold a Senior Reactor Operator License.

SOURCE: NIP-TQS-01 Form 1

TABLE XIII-2

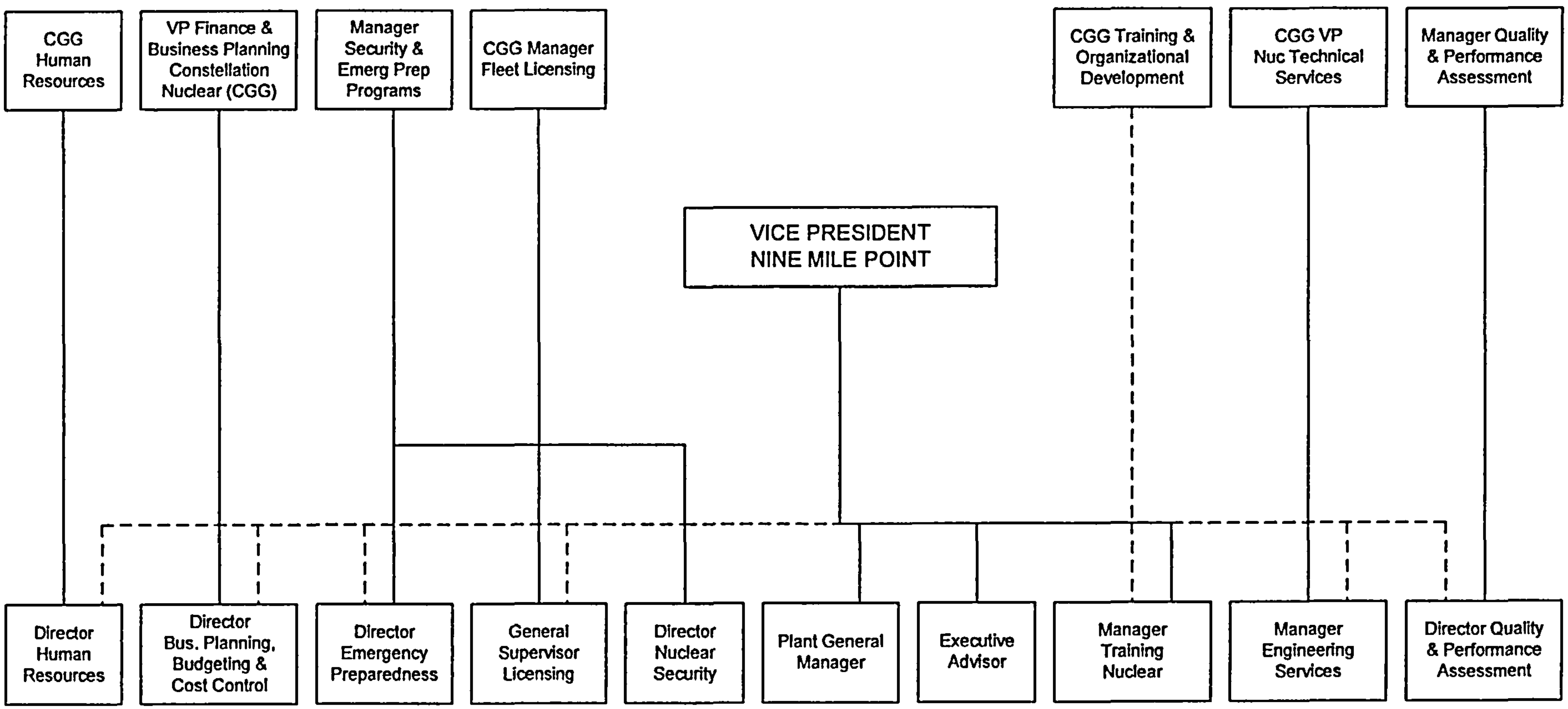
MINIMUM SHIFT CREW COMPOSITION

Position	Operating Mode				
	License Requirements	Normal Operation	Reactor Startups	Shutdown Condition	Operation Without Process Computer(1)
SM	Senior Operator	1	1	1(3)	1
CRS/STA(4)	Senior Operator	1	1	1(2)	1
Licensed Operator	Operator	2	3	2(2)	2
Non-Licensed Operator	--	2	2	1	3

NOTES:

1. For operation longer than 8 hr without the process computer.
2. Hot shutdown condition only. For cold shutdown and refueling conditions, only one Senior Operator and one Operator are required to be on shift.
3. An additional Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling who has no other concurrent responsibilities shall directly supervise all core alterations.
4. Normally the Control Room Supervisor is a combined CRS/STA; however, there may be instances when a shift may be staffed by two Senior Reactor Operators plus a dedicated STA.

SENIOR LEVEL STATION MANAGEMENT ORGANIZATION CHART



Note: The Manager Engineering Services has a direct reporting relationship to the Vice President Nine Mile Point for accountability for the System Engineering function which is part of the Nuclear Generation Organization.

Figure XIII-1
UFSAR Rev. 19 (October 2005)

ENGINEERING SERVICES ORGANIZATION CHART

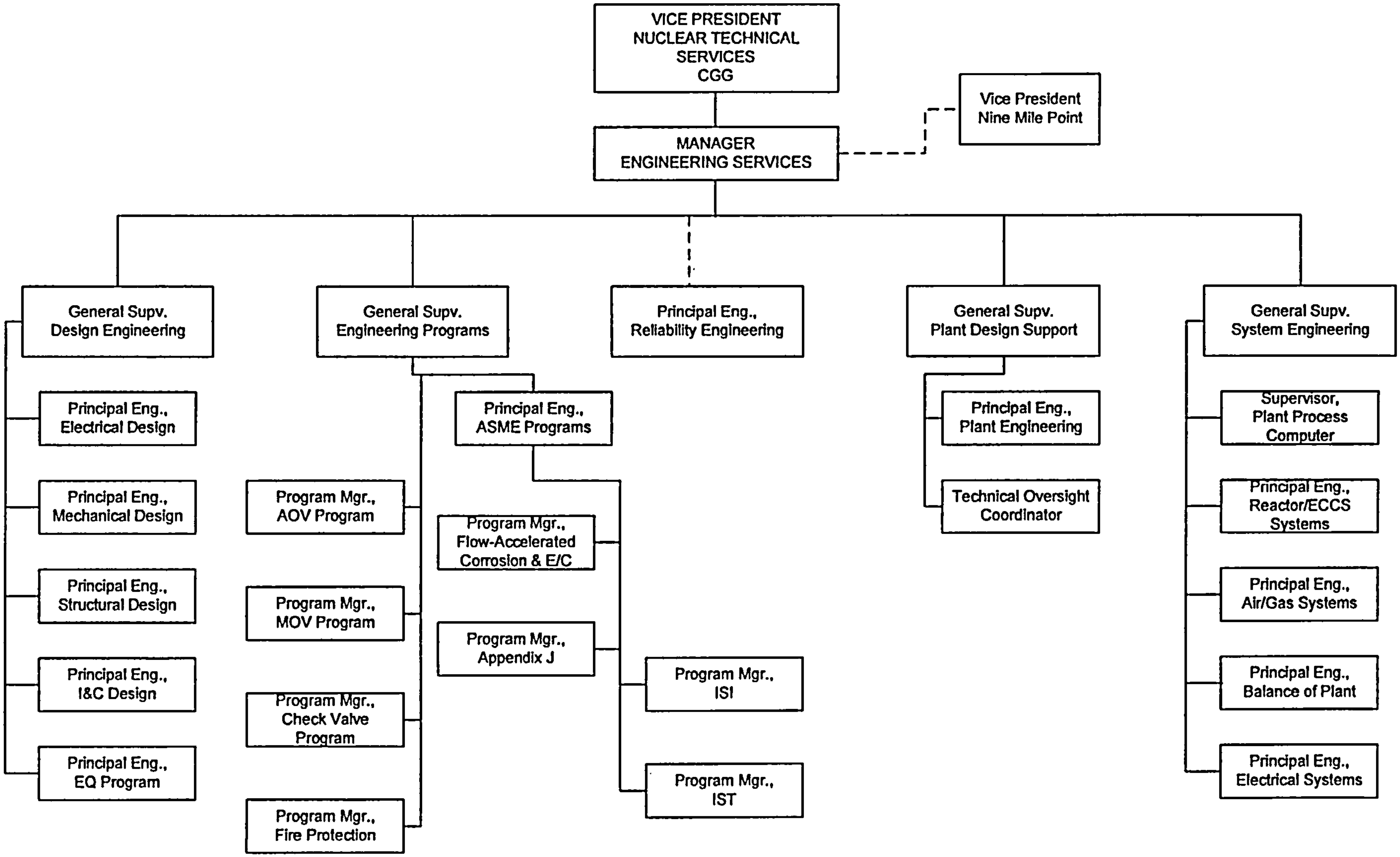


Figure XIII-2
UFSAR Rev. 19 (October 2005)

QUALITY ASSURANCE ORGANIZATION

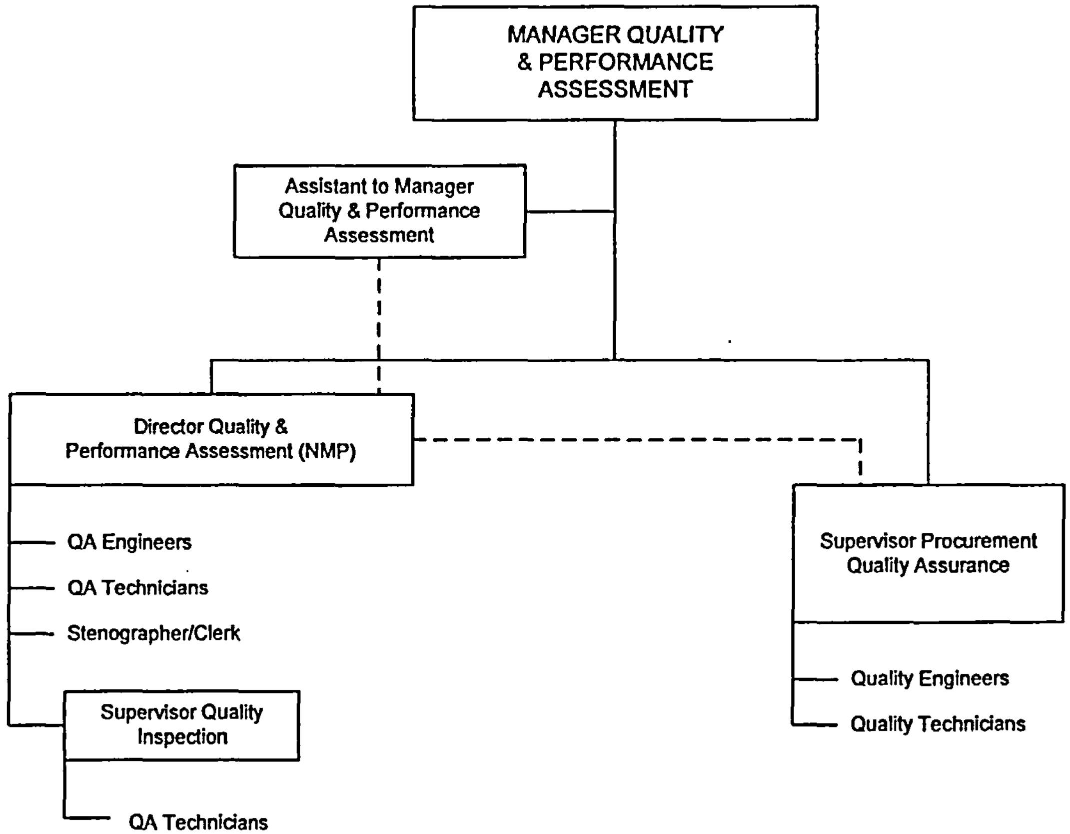


Figure XIII-3
UFSAR Rev. 19 (October 2005)

NUCLEAR GENERATION ORGANIZATION CHART

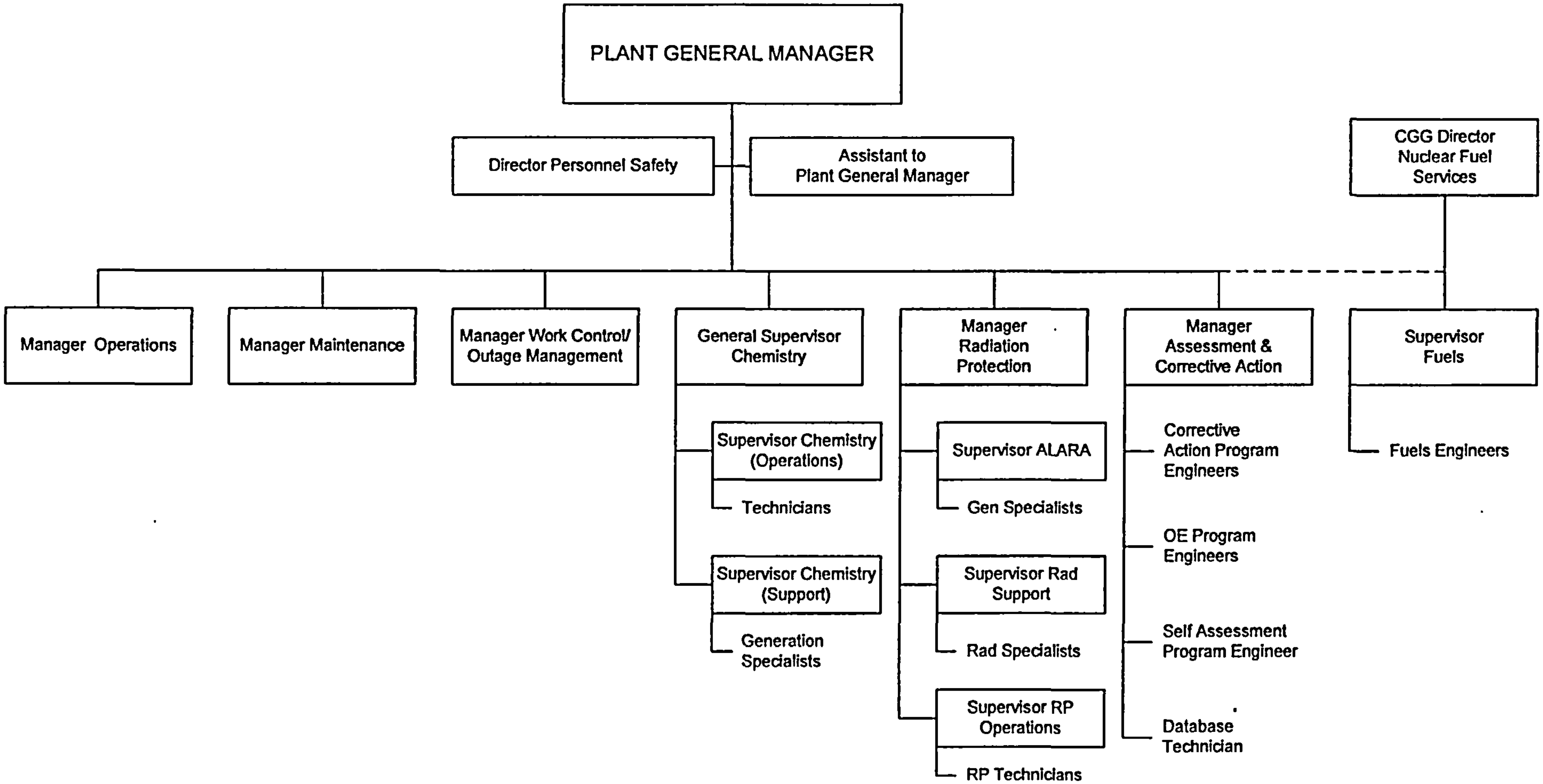


Figure XIII-4
UFSAR Rev. 19 (October 2005)

NUCLEAR GENERATION ORGANIZATION CHART

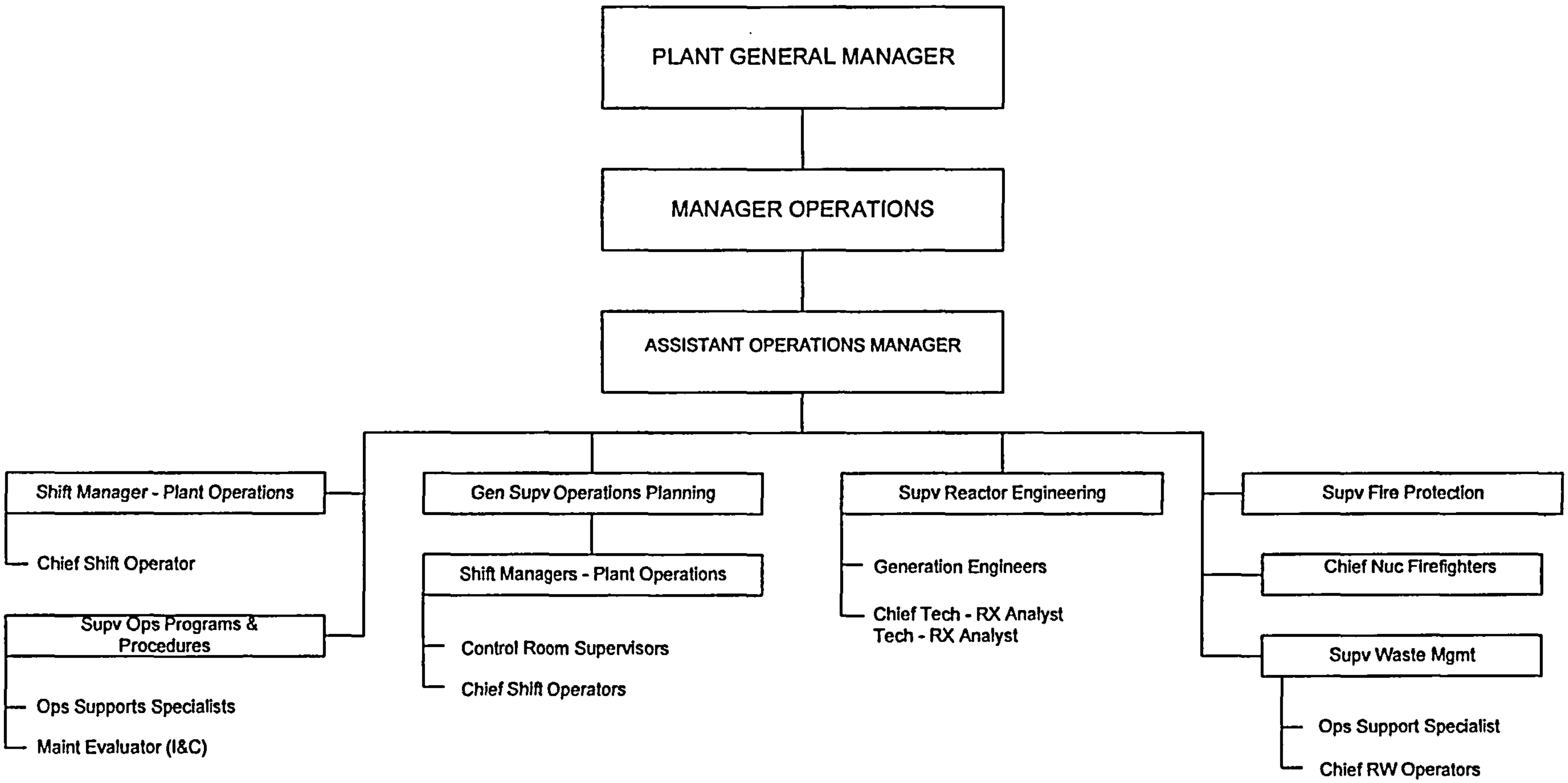


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Figure XIII-4a
UFSAR Rev. 19 (October 2005)

NUCLEAR GENERATION ORGANIZATION CHART

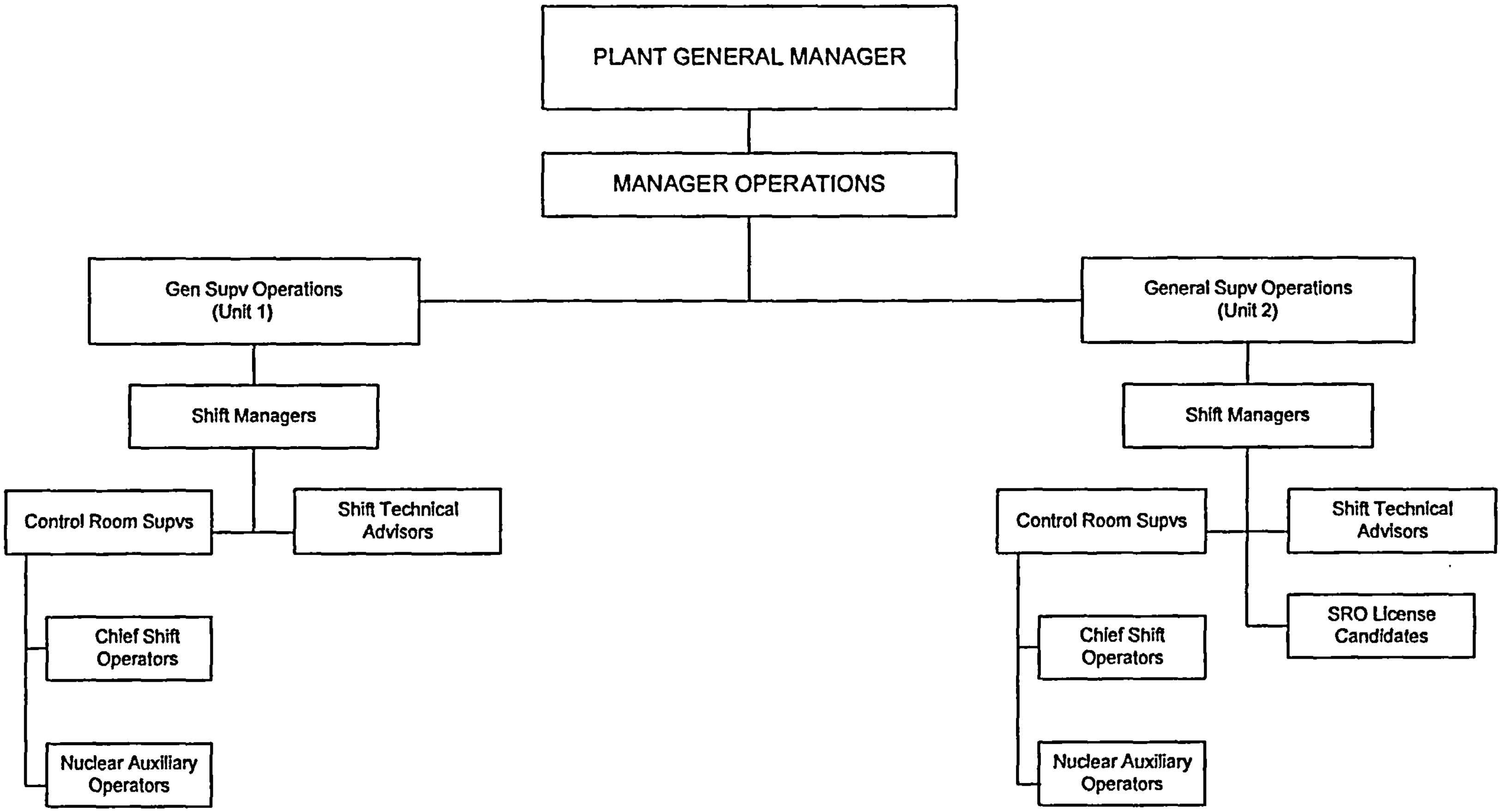

Figure XIII-4a
UFSAR Rev. 19 (October 2005)

NUCLEAR GENERATION ORGANIZATION CHART

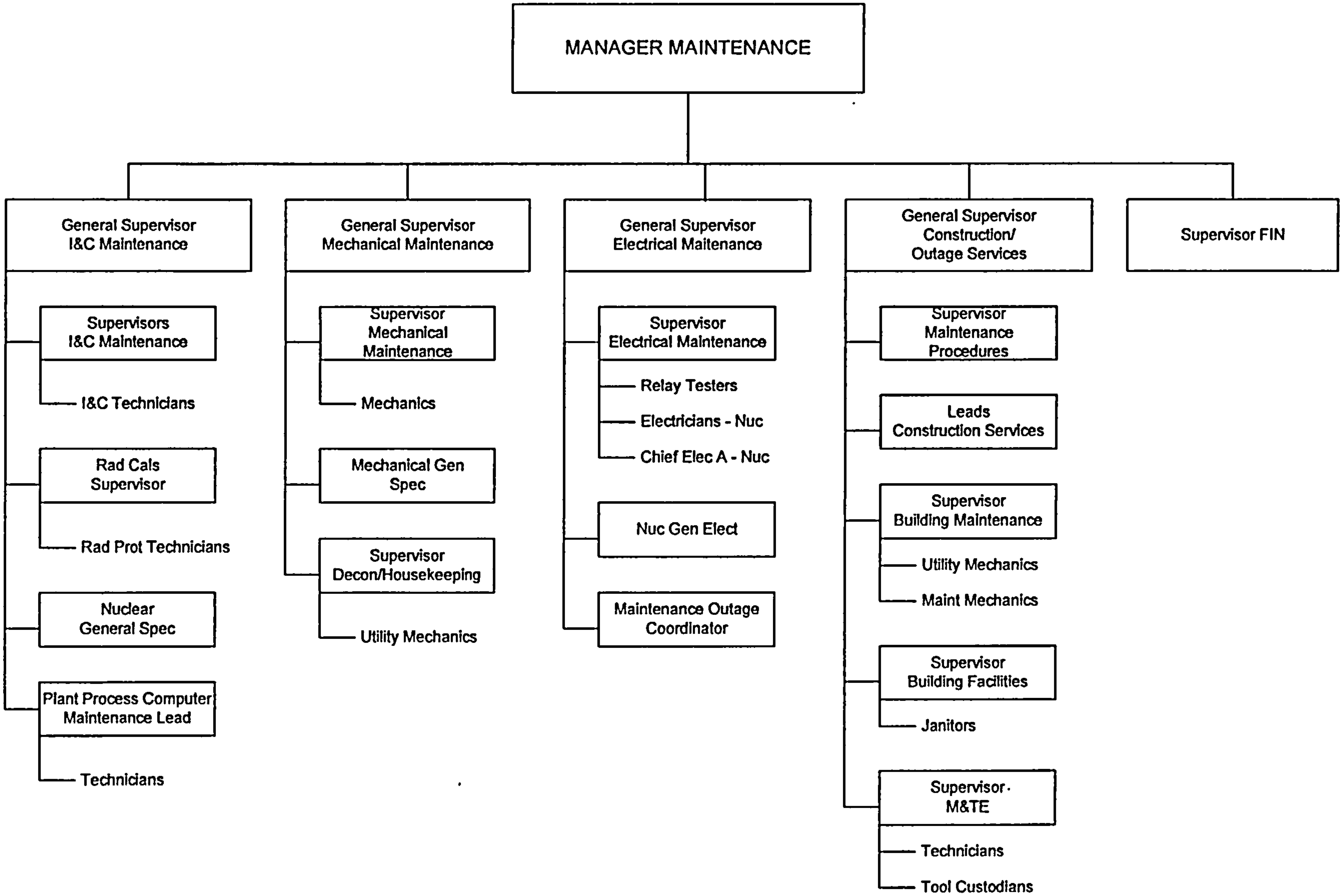

Figure XIII-4b
UFSAR Rev. 19 (October 2005)

NUCLEAR GENERATION ORGANIZATION CHART

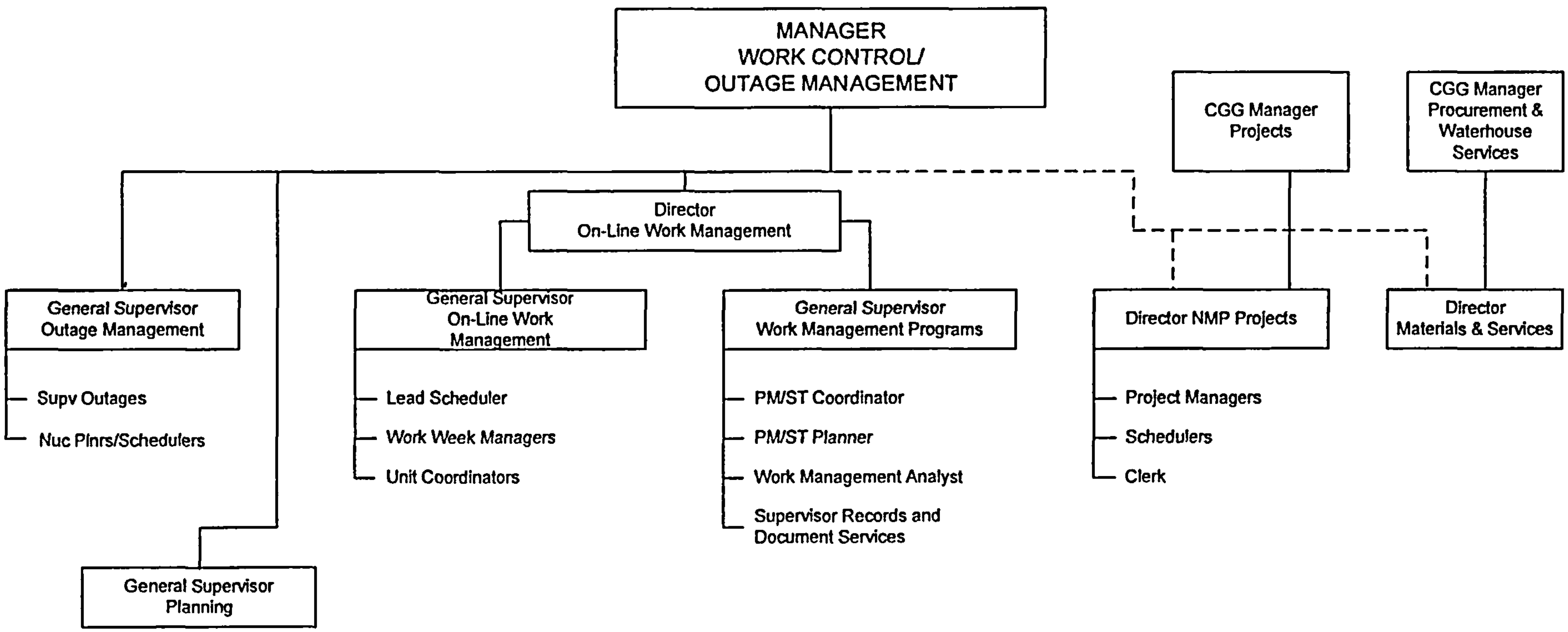

Figure XIII-4c
UFSAR Rev. 19 (October 2005)

SAFETY ORGANIZATION

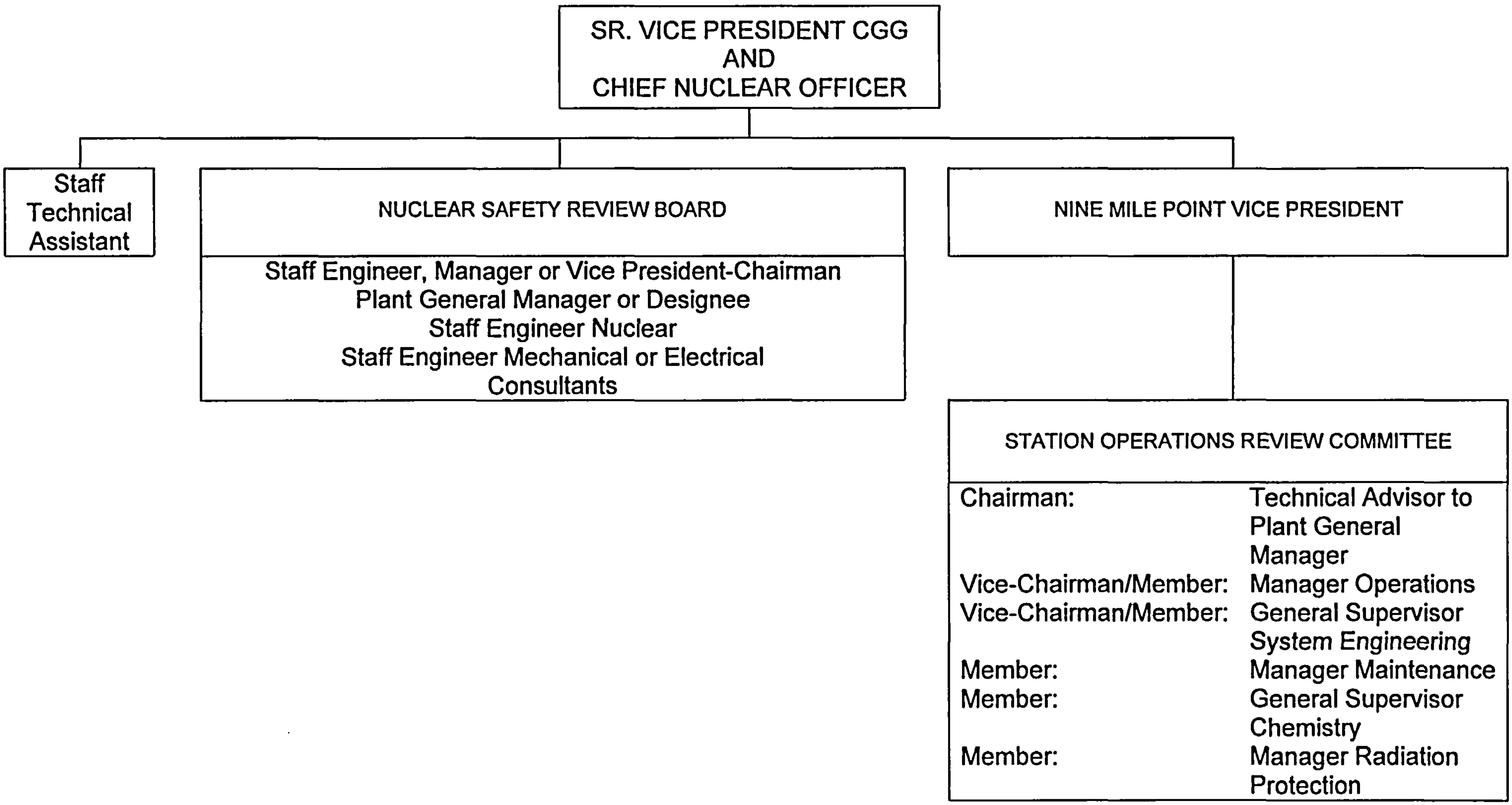

Figure XIII-5
UFSAR Rev. 19 (October 2005)

U.S. NUCLEAR REGULATORY COMMISSION
DOCKET 50-220
LICENSE DPR-63

NINE MILE POINT NUCLEAR STATION UNIT 1

FINAL SAFETY ANALYSIS REPORT (UPDATED)

VOLUME 4

OCTOBER 2005

REVISION 19

The first impact dissipates 0.80 x 17,000 or 13,600 ft-lb of energy. It is assumed that 50 percent of this energy is absorbed by the dropped fuel assembly and that the remaining 50 percent is absorbed by the struck fuel assemblies in the core. Because the fuel rods of the dropped fuel assembly are susceptible to the bending mode of failure and because 1 ft-lb of energy is sufficient to cause cladding failure as a result of bending, all 63 rods of the dropped 8x8 fuel assembly and all 62 rods of the 8x8R and P8x8R assemblies are assumed to fail. Since the tie-rods of the struck fuel assemblies are more susceptible to bending failure than the other 55 or 54 fuel rods, it is assumed that they fail on the first impact. Thus, 4 x 8 = 32 tie-rods (total in four assemblies) are assumed to fail.

Because the remaining fuel rods of the struck assemblies are held rigidly in place in the core, they are susceptible only to the compression mode of failure. To cause cladding failure of one fuel rod as a result of compression, 250 ft-lb of energy is required. To cause failure of all the remaining rods of the four struck assemblies, 250 x 56 x 4 or 56,000 ft-lb of energy would have to be absorbed in cladding alone. Thus, it is clear that not all the remaining fuel rods of the struck assemblies can fail on the first impact. The number of fuel rod failures caused by compression is computed as follows:

$$\frac{0.5 \times 13{,}600 \times \frac{11}{11 + 17}}{250} = 11 \text{ (8x8, 8x8R, P8x8R)}$$

Thus, during the first impact, fuel rod failures are as follows:

	8x8	8x8R/P8x8R
Dropped assembly	63 rods (bending)	62 rods (bending)
Struck assemblies	32 tie-rods (bending)	32 tie-rods (bending)
Struck assemblies	11 rods (compression)	11 rods (compression)
	106 failed rods	105 failed rods

Because of the less severe nature of the second impact and the distorted shape of the dropped fuel assembly, it is assumed that in only 2 of the 24 struck assemblies are the tie-rods subjected to bending failure. Thus 2 x 8 = 16 tie-rods are assumed to fail. The number of fuel rod failures caused by compression on the second impact is computed as follows:

$$\frac{\frac{0.19}{2} \times 17{,}000 \times \frac{11}{11 + 17}}{250} = 3 \text{ (8x8, 8x8R, P8x8R)}$$

Thus, during the second impact the fuel rod failures are as follows:

Struck assemblies	16 tie-rods (bending)
Struck assemblies	3 rods (compression)

The total number of failed rods resulting from the accident is as follows:

	8x8	8x8R/P8x8R	GE11[8]
First impact	106 rods	105 rods	125 rods
Second impact	19 rods	19 rods	15 rods
Third impact	0 rods	0 rods	0 rods
	125 failed rods	124 failed rods	140 failed rods

3.3 Radiological Effects

3.3.1 Fission Product Releases

Fission Product Release from Fuel

Fission product release estimates for the maximum expected 125 fuel rod failures are based on the following assumptions:

1. The reactor fuel has an average irradiation time of 1,000 days at 1850 MWt up to 24 hr prior to the fuel assembly drop. This irradiation time yields conservative inventory results for noble gases and halogens.

2. As in the CRDA, a maximum of 1.0 percent of the noble gas activity is in the fuel rod plenums and a maximum of 0.5 percent of the halogen activity is in the fuel plenums. Negligible solid or particulate activity is released from the fuel and any that is released is absorbed in the reactor pool water.

   The quantities of fission products to be released from the failed fuel to the water are:

Fission Product	Amount Released (curies)
Noble Gases (Xe, Kr)	3.41×10^3
Halogens (Br, I)	2.12×10^3

Fission Product Inventory in the Reactor Building

All of the noble gas fission products are assumed to be released from the reactor water to the reactor building. The halogens

released are absorbed in the pool and evolve from the pool into the air to establish an equilibrium partition factor between water and air concentrations of 10^2.

All the noble gases are assumed to be directly released to the reactor building. As fission products are released to the reactor building, high radiation signals initiate alarms and start the emergency ventilation system. This system maintains the reactor building below atmospheric pressure and discharges a volume equivalent to 100 percent of the building volume per 24 hr through high-efficiency and charcoal filters to the stack. The airborne fission product inventory in the reactor building is shown in Table XV-22.

Discharge of Fission Products to Atmosphere

The noble gases and halogens are exhausted from the reactor building through a dryer, a high-efficiency filter, a charcoal filter and another high-efficiency filter. Because of the relatively small heat and vapor input the building remains at relatively low temperature and humidity. The building exhaust is treated so that humidity is reduced and filter efficiency is maintained. As previously discussed, a filter efficiency of 99 percent is used for removal of halogens. The stack discharge rates are shown in Table XV-23.

3.3.2 Meteorology and Dose Rates

The doses resulting from 125 failed fuel rods, even using conservative meteorological assumptions, are well below 10CFR100 limits. The thyroid dose (2 hr) at the site boundary is 9.88 x 10^{-5} rem, and the whole body dose is 1.85 x 10^{-5} rem. The dose for the complete period of the accident is 2.11 x 10^{-3} rem to the thyroid and 1.81 x 10^{-4} rem to the whole body. Even if the upper bound of 445 failed fuel rods is considered, the doses are still well below 10CFR100 limits.

3.3.3 Comparison to Regulatory Guide 1.25

Table XV-24 compares the doses obtained using the assumptions of the regulatory guide with those used in the above analysis. In either case, the results are within the limits of 10CFR100.

Table XV-25 gives comparisons of fission product release assumptions used in the regulatory guide with those used in this analysis. Transport meteorological and dose conversion factors are given in Table XV-26. The effects that these factors have in the calculations are illustrated in Table XV-27.

4.0 Control Rod Drop Accident

4.1 Identification of Causes

The accidental removal of a control rod from the core at a more rapid rate than that which can be achieved by the CRD system results in a power excursion. A fully-inserted control rod is assumed to become disconnected from its drive. The drive is then fully withdrawn and, subsequently, the control rod falls out of the core.

The severity of the resulting excursion is reduced by strict procedural controls, supplemented by use of a rod worth minimizer (RWM). Control rod withdrawal and insertion sequences are established to assure that the maximum in-sequence individual control rod or control rod segments which are withdrawn could not be worth enough to cause the core to be more than 0.013 Δk supercritical if a rod drop accident were to occur. The severity is further reduced by limiting the maximum "dropout velocity" of any control rod with the rod velocity limiter.

4.2 Accident Analysis

CRDA results from banked position withdrawal sequence (BPWS) plants have been statistically analyzed and documented in Reference 9. The results show that, in all cases, the peak fuel enthalpy in a rod drop accident would be much less than the 280 cal/gm design limit even with a maximum incremental rod worth corresponding to 95-percent probability at the 95-percent confidence level. Based on these results, it was proposed to the NRC, and subsequently found acceptable, to delete the CRDA from the standard GE boiling water reactor (BWR) reload package for the BPWS plants.

Because of the large margin available to CRDA design limits for BPWS plants, implementation of the advanced physics methods[10] does not result in challenging the 280 cal/gm limit. Therefore, the impact of using the advanced physics methods of Reference 10, as compared to the physics methods described in Reference 11, on the generic BPWS analysis is considered negligible.

4.3 Designed Safeguards

The control rod system is designed to minimize the probability of blades sticking in the core. The blades of the control rods travel in gaps between the fuel channels with approximately 1/2-in clearance and are equipped with rollers which make contact with the channel walls. Since a control blade weighs approximately 220 lb, even if it separates from its drive, gravity forces would tend to make the blade follow its drive movement as if it were connected.

The control rod coupling to the drive index tube significantly reduces the probability of an accidental separation of a control

rod from its drive. Couplings of this design have undergone extensive tests under simulated reactor conditions and also at conditions more extreme than those expected to be encountered in reactor service. They have been operated through thousands of cycles of scram operation and a separation has never occurred. Tests have shown that the coupling will not separate when subjected to pull forces up to 20 times greater than can be applied with a CRD.

Movements of the control rods, when the reactor is critical or near critical, cause changes in the neutron flux. Control rod coupling can be verified by observing the neutron flux changes during rod movement.

A velocity limiter which adds substantial hydraulic drag against downward control rod movement is incorporated in the design. Testing and analysis of the velocity limiter has demonstrated a maximum rod drop velocity of 3.11 fps[53].

4.4 Procedural Safeguards

Operating procedures require that control rod movements follow preplanned patterns to flatten the power distribution. A rod withdrawal procedure, incorporating the BPWS and a reduced notch worth procedure[12] (which minimizes the chance of short period scrams to an even greater extent than required for fulfilling CRDA safety requirements), forces adherence to certain constraints applied to all control rod withdrawals (and insertions) between 100-percent control rod density (all control rods inserted) and 10 percent of design rated power, in order to limit incremental control rod worths. A description of the BPWS and reduced notch worth procedure is given in References 13 and 12, respectively.

Operating procedures require rod following verification checks during startup and during major rod movements, and frequent verification checks on all rods not fully inserted, to assure that any rod-from-drive separation is detected. Procedures require the full insertion of rods when following is not verified.

After full withdrawal from the core, a control rod sits on a seal. Procedurally, the Operator attempts to withdraw each rod to a further overtravel position. If the drive is coupled to the control rod blade, the overtravel position cannot be attained. If the drive is uncoupled, the overtravel position is reached and an indicator light warns the Operator. The drive would then be immediately reinserted to prevent possible fallout of the stuck control rod blade. This method is used on fully withdrawn control rods during reactor startup when control rod following is not verified by observing the response of the neutron flux instrumentation.

4.5 Radiological Effects

The following radiological consequences are based on a release pathway through the mechanical vacuum pumps. Dose calculations for the CRDA do not indicate a need for mechanical vacuum pump line isolation. However, the capability was provided to automatically isolate the mechanical vacuum pump line on high radioactivity in the MSLs. As a result, dose calculations were not reevaluated based on mechanical vacuum pump line isolation; releases would be considerably less since the major pathway for radioactivity has been removed.

4.5.1 Fission Product Releases

Fission Product Release from Fuel

A maximum of 1 percent of the noble gas activity and 0.5 percent of the halogen activity in a fuel rod are released from the rods experiencing cladding perforation. Release of solids is negligible. These estimates of maximum plenum activity are based on measured activity releases from fuel with failed cladding in operating reactors[14,15]. The fission products generated by the excursion are negligible compared to those already in the fuel due to the long-term (1,000 days) reactor operation. This irradiation time yields conservative inventory results for noble gases and halogens. Based on 1,000 days' operation at 1850 MWt, the fission products released from the fuel are as follows:

Noble Gases	6.66×10^4 curies
Halogens	5.62×10^4 curies

Fission Product Transport

At hot standby, the pressure regulator maintains reactor pressure constant by bypassing steam to the condenser. A little over two full-power seconds of energy are produced in the excursion, of which less than 3 percent are released promptly and the rest released according to the relatively slow conduction heat transfer time constant of 8 to 9 sec, characteristic of UO_2 fuel rods. Therefore, the increase in steam flow to the main condenser is handled by the turbine bypass system without a significant pressure transient in the reactor or in the condenser.

A fraction of the fission products released from the perforated fuel rods are carried through the MSLs to the condenser. The activity is monitored in the MSLs, and alarmed in the control room upon a high activity signal. Position switches on the steam line isolation valves also actuate reactor scram when the valves are partly closed.

Normally, the air ejector offgas system maintains condenser vacuum and the airborne and noncondensible fission products are carried into the offgas piping. High radiation signals isolate

this piping from the stack. If the radiation is not intensive enough to cause isolation of the offgas piping and the Operator fails to isolate manually, the fission products are released to the stack, after a 30-min delay, at rates below those permitted by 10CFR20. During hot standby, the mechanical vacuum pumps are used instead of air ejectors. With the reactor isolated, the mechanical vacuum pump is not automatically isolated and continues to operate. The mechanical vacuum pump flow rate (2000

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therefore, the maximum accident loadings produce negligible stresses on the structure.

Deformations are not listed in the table but are negligible (well within elastic limits), except on the core support plate and fuel channel. Total deflection at the center of the core support plate is about 1 3/4 in, with a permanent deformation of about 1 1/2 in. The deformation does not in any way affect the design scram capability of the CRD.

Stress is not tabulated for the core support plate because the surface stress is above yield. Note that this does not mean that uncontrolled deformation occurs. Only the top and bottom surface stresses are above the yield; the stresses in the interior of the beam are still within the elastic limit.

During a recirculation line break (immediate reactor scram), the fuel channels will possibly buckle inward at the bottoms of the assemblies.

The pressure reported in Table XVI-8 occurs at the bottom of a given channel, whereas no differential pressure is applied at the channel top. The inward motion of the channels is limited to about 0.140 in by the fuel bundle assembly, which is, in turn, substantially supported along its length by the inlet casting and the fuel spacers. Because of the inward movement, the clearance between the control rod and the fuel channel will be increased; hence, the deformation will not hamper insertion of the control rod.

2.7.2.2 Steam Line Break

The applied differential pressure and the resultant stresses on the various internal components due to a steam line break are listed in Table XVI-9.

The differential pressures listed in Table XVI-9 were derived assuming the main steam line break (MSLB) occurs at initial conditions of 100 percent power and 100 percent core flow. If the break occurs at certain low power, high flow initial conditions, then the upper shroud differential pressure will be higher than the value listed in Table XVI-9. This low power, high flow MSLB is typically referred to as the faulted interlock point and is defined on the power flow maps as the reactor internals protection (RIP) region. Avoidance of this low power, high flow region is an initial assumption for the MSLB accident analysis with respect to the evaluation of structural integrity of the vessel internals. The RIP region is defined by the following boundaries on the power flow maps; at 65 percent rated core flow a line from 0 percent power up to 20 percent rate power, a line connecting 65 percent core flow at 20 percent power, and 100 percent core flow at 50 percent power. Administrative controls to restrict operation in the RIP region provide assurance that

the upper shroud differential pressure listed in Table XVI-9 will not be exceeded in the event of a MSLB.

Deformation of the structural components listed in Table XVI-9 are negligible except for the fuel channel. Total outward deformation due to a 30-psi internal pressure is about 0.070 in, as measured from experimental tests recently conducted on unirradiated channels. A permanent set of about 0.015 in results. Such a deformation would not hinder the functional capability of the CRD system.

It also should be noted that the highest pressure difference occurs when the break is assumed to occur inside the velocity limiter. The pressure difference caused by a break outside the velocity limiters is 67 percent of the value from a break inside the limiters.

2.7.2.3 Earthquake Loadings

The effects of earthquake loadings on the Nine Mile Point core structure were analyzed utilizing the dynamic analyses of the

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reactor vessel. The resultant loadings were then directly applied to the internals. The results indicated that the response of the core structure was about 20 percent to 40 percent lower than the reactor vessel, indicating a conservatism in the assumptions.

Stresses induced by the design earthquake on the fuel channel and rod guide tubes were 3200 psi and 480 psi, respectively. Deflections were about 0.32 in and less than 0.016 in, respectively, for the above components. The lateral earthquake acceleration force on the core support is directly applied to shear pins that connect the core support to the shroud. Shear stress due to a design earthquake is 6500 psi, which is substantially below the ASME Code allowable for a direct shear application. (Note that the steam line break accident produces negligible loads on these pins.) There are also 4 core plate wedges (spacers) located between the core plate and the shroud inner diameter (ID) that were added with the core shroud repair tie-rod assemblies. The wedges provide a direct load path from the core plate to the shroud ID during an earthquake.

The lateral thrust applied to the top guide is sustained by the same pin arrangement as the thrust on the core support. However, backing these pins are eight spacer plates, equally spaced around the outer rim of the top guide. These spacer plates transfer the horizontal loads from the top guide directly to the ID of the shroud. Resultant stresses in the top guide are below ASME Code allowable for the design earthquake.

Design earthquake loadings produce stresses less than 1600 psi on the core support and shroud. These stresses and any shroud displacement will not produce any significant effects on the response of the core structure to the differential pressure induced by an accident.

2.7.3 Stresses and Deformations at Which the Component is Unable to Function and Margin of Safety

This question is not readily answered, with the possible exception of those members sustaining a buckling load. Consequently, each loading on each component must be individually discussed. Where it was evident that the stress margin of a given component was very large, the margin was calculated using Code allowable stress in the numerator, rather than using loss-of-function stress. Where less margin was evident, the loss-of-function stress was used to calculate the margin. This has the effect of understating the margin whenever the Code allowable stresses are utilized.

drain nozzle is carbon steel, partially clad, attached to the vessel by full penetration welds.

The reactor vessel was fabricated by the Combustion Engineering Company in its Chattanooga, Tennessee, shops during the period of February 1964 to September 1966.

All welding was performed by Code-qualified welders and to procedures in conformance with ASME Code, Section IX, which were developed by Combustion Engineering and approved by GE. Each specific weld on the drawing was marked so that the applicable welding procedure used could be identified. The welding procedure specifications for attaching the vessel flange to the vessel shell, as well as many other welds on vessel base material, are shown in Section XVI-E, Exhibits 4 (manual welding) and 5 (machine welding). The welding procedure specifications for applying the stainless steel cladding are shown in Exhibits 6 (manual welding) and 7 (machine welding).

Heat treatment and stress relief of the reactor vessel were in conformance with Section I of the ASME Boiler and Pressure Vessel Code and all applicable Code cases. Preheat and postheat treatment, as required by the welding procedure specifications, were also performed.

All weld clad was ultrasonically inspected for bonding to the base material, and all clad material was dye penetrant inspected after final heat treatment. All forgings were inspected by magnetic particle and ultrasonic means to ensure freedom from defects.

Imperfections detected in the inspection of the plates, forgings, cladding, and weld were removed and material replaced by the vendor employing welding repair procedures which were approved by GE.

During vessel fabrication, multiple cracking transverse to the weld axis was discovered by the welding operator in the weld joining a recirculation outlet nozzle to the lower shell course of the reactor vessel. The weld was approximately three quarters completed when the cracks were found in the weld surface. At this time all shop submerged-arc welding with the materials in question was held up pending establishment of the cause and corrective action.

The cause of the cracking was determined to be the particular welding wire, welding flux combination being used. A portion of the final alloy content of the weld deposit was derived from the alloying constituents of the welding flux. It was found that in this instance the wire used and the flux both exceeded the normal range of manganese content.

All seams of the vessel, where the use of this combination was possible, were rechecked chemically and ultrasonically. No other

cases were found, and later radiographic examination verified the fact. Stricter controls were put into force for qualifying all lots of flux and wire combinations to be used in fabrication, thereby preventing undesirable lots from reaching the floor of the shop.

Based upon the results of all inspections, the vessel has received an ASME Code stamp and has been accepted by GE as meeting its specification.

All inspections which were required to meet the ASME Boiler Code were witnessed by an inspector licensed by the National Board of Boiler and Pressure Vessel Inspectors. Continuous inspections were also performed by Combustion Engineering personnel during fabrication. These inspections were audited by GE's vendor quality assurance representatives. Certain inspections, such as dye penetrant inspection of vessel cladding, were witnessed by a GE representative.

The certificate of Boiler Shop Inspection along with Combustion Engineering Certifications are given in the vendor inspection report (see Section XVI-3.1 above). The following specifications are included in Section XVI-E.

Liquid Penetrant Testing	-	Exhibit 8
Ultrasonic Testing of Heavy Forgings	-	Exhibit 9
Ultrasonic Testing of Plate Material	-	Exhibit 10
Ultrasonic Testing of Weld Overlay Cladding	-	Exhibit 11
Magnetic Particle Testing	-	Exhibit 12
Hydrostatic Testing of the Vessel	-	Exhibit 13

All radiographic testing met or exceeded 2-percent sensitivity. The majority of the radiographs provided 1-percent sensitivity. The limits of acceptance for other testing specifications are shown in Exhibits 8 through 13.

4.0 Surveillance Provisions

4.1 Coupon Surveillance Program

The initial nil ductility reference temperature (RT_{NDT}) of the limiting vessel material opposite the core is 40°F. The adjusted reference temperature (ART) increases with increasing fast neutron exposure. Regulatory Guide (RG) 1.99, Revision 2, is used to calculate the ART as a function of neutron exposure.

Vessel material surveillance samples are located within the reactor vessel core region to permit periodic monitoring of exposure and changes in material properties. The original, plant-specific material sample program conformed with ASTM

E185-66 except for the material withdrawal schedule, which was originally specified in the Technical Specifications.

Three surveillance capsules were installed in the Unit 1 reactor in 1969 prior to initial operation. Since plant life extension is being considered, two capsules (A' and C') were reinserted. The prime indicator is used to designate the new capsule in the same azimuthal location as the original capsules. The radial location of the new capsules is slightly closer to the core than the original capsules to increase the neutron flux.

In Reference 40, the NRC approved Unit 1 participation in the BWR Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP), as described in BWRVIP-78 (Reference 37) and BWRVIP-86-A (Reference 38). The NRC approved the ISP for the industry in their safety evaluation dated February 1, 2002 (Reference 39). The ISP meets the requirements of 10CFR50, Appendix H. Participation in the ISP replaces the Unit 1 plant-specific vessel material surveillance program.

The current surveillance capsule withdrawal schedule for Unit 1 representative materials is based on the latest NRC-approved version of BWRVIP-86 (Reference 38). No capsules from the Unit 1 vessel are included in the ISP. Capsules from other plants will be removed and specimens will be tested in accordance with the ISP implementation plan. The results from these tests will provide the necessary data to monitor embrittlement of the Unit 1 vessel.

4.2 Periodic Inspection

Periodic inspections of the reactor vessel and its components are performed in accordance with the Inservice Inspection (ISI) Program (Technical Specification 4.2.6).

5.0 Core Shroud Repair Design Description

5.1 Horizontal Weld Repair

The reactor core shroud stabilizers are designed to structurally replace horizontal shroud welds H1 through H7. Figure XVI-12a depicts the Unit 1 horizontal shroud welds. The Unit 1 shroud stabilizers consist of two separate design features as shown on Figure XVI-12b. Tie-rod assemblies combined with core plate wedges replace welds H1 through H7 and the upward vertical load-carrying capability of weld H8. The shroud stabilizers are designed to maintain the shroud functions described in Section IV-B.7.0, in the event welds H1 through H7 become cracked 360 deg circumferentially throughwall. The design of the shroud stabilizers is in accordance with the Boiling Water Reactor Owners' Group Vessel Internals Project (BWROG VIP) criteria[8]. The shroud repair design was approved by the NRC as documented in NRC Safety Evaluation for NMP1, Evaluation of Core Shroud Stabilizer Design, dated March 31, 1995. Details of the

stabilizer design are located in the reference documents listed in Table XVI-9a.

Modifications to the tie-rod assemblies were made during refueling outage 14 (RFO14) and RFO15 to correct original design deficiencies. Details of the design analyses are included in the shroud repair hardware analysis listed in Table XVI-9a. The original design of the tie-rod assemblies was performed as an alternative to ASME Section XI as permitted by 10CFR50.55a(a)(3), which required NRC approval of the original design. Consequently, the modifications made during RFO14 and RFO15 also require approval by the NRC. The NRC safety evaluations that approved the various tie-rod modifications are listed in Table XVI-9a. The NRC safety evaluations describe the design basis of the tie-rod modifications.

5.2 Vertical Weld Repair

The reactor core shroud vertical weld repair clamps are designed to structurally replace vertical shroud welds V9 and V10. Figure XVI-12c provides a roll-out drawing of the shroud and depicts the vertical shroud welds. Figure XVI-12d provides a schematic of the vertical weld repair clamps. The vertical weld repair design was reviewed and approved by the NRC as an alternative code repair pursuant to 10CFR50.55a(a)(3)(i) as documented in References 35 and 36. Core shroud vertical weld repair design documentation is listed in Table XVI-9a.

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39. Letter from USNRC to C. Terry (BWRVIP), "Safety Evaluation Regarding EPRI Proprietary Reports 'BWR Vessel and Internals Project, BWR Integrated Surveillance Program Plan (BWRVIP-78)' and 'BWRVIP-86: BWR Vessel and Internals Project, BWR Integrated Surveillance Program Implementation Plan'," dated February 1, 2002.

40. NRC Letter to NMPNS dated November 8, 2004, "Nine Mile Point Nuclear Station Unit Nos. 1 and 2 - Issuance of Amendments Re: Implementation of the Reactor Pressure Vessel Integrated Surveillance Program (TAC Nos. MC1758 and MC1759)."

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TABLE XVI-9

CORE STRUCTURE ANALYSIS STEAM LINE BREAK

Structural Component	Actual Applied Differential Pressure - psi		Resultant Stress Due to Break Inside Flow Limiter - psi	Collapse Loading or ASME Code Allowable Loading - psi (See Notes Below)	Safety Margin
	Break Outside Flow Limiter	Break Inside Flow Limiter			
Lower Shroud and Core Support	40 (Outward)	63 (Outward)	3800	15,800***	4.2**
Upper Shroud	13 (Outward)	22 (Outward)****	1400	15,800***	11.3**
Core Support Plate	27 (Upward)	41 (Upward)	7000	15,800***	2.3**
Guide Tube	27 (Inward)	41 (Inward)	1400	106*	2.6*
Fuel Channel	14 (Outward)	23 (Outward)	-	>30*	>1.3*

* Loading, or margin, based on collapse stress.
** Loading, or margin, based on ASME Code allowable stress.
*** ASME Code allowable stress.
**** A pressure drop margin for the upper shroud differential pressure of 22 psi exists for operation outside of the RIP region specified on the power flow operating maps. However, normal operation within the RIP region may exceed 22 psi in the event of a MSLB. Plant operating procedures restrict operation in the RIP region.

B.2.2.6 Nuclear quality assurance supervisors are required to have demonstrated their management competence through prior assignments of increasing responsibility in addition to meeting the qualifications described in Section 4.4.5 of ANSI/ANS-3.1-1978.

B.2.2.7 The operations phase QA Program applies to activities affecting the operation and the quality of structures, systems, components, and services during plant operation, maintenance, testing and modifications. Safety-related structures, systems, and components are identified in Q-Lists, which are developed and maintained for each Unit, and are consistent with the FSAR commitments.

Appropriate elements of the QATR are applied to the Fire Protection Program, emergency plans, radiation protection procedures and radioactive waste shipment programs for the Station.

The application of the 10CFR50 Appendix B QA Program, as applied to activities under 10CFR71 for Unit 1 and Unit 2, is limited to procurement and use of packaging for shipment of radioactive materials. Design and fabrication of shipping casks will not be conducted under this QA Program.

B.2.2.8 Those elements of the QATR which apply to radioactive waste handling activities include:

- Quality Assurance will provide oversight of the radioactive waste handling activities through audits and inspections.
- Quality Inspectors will be trained in Department of Transportation (DOT) and NRC radioactive waste handling requirements.

B.2.2.9 NMPNS and departmental procedures specify the methods and controls for implementing operational phase activities.

B.2.2.10 The programmatic Regulatory Guides and ANSI Standards, and their applicable revisions, to which NMPNS commits with regard to QA matters, and appropriate explanations of interpretations and exceptions, are tabulated in Table B-2.

B.2.2.11 The scope of the program and the extent to which its controls are applied are established as follows:

1. NMPNS uses the criteria specified in Nuclear Implementing Procedures for identifying structures, systems and components to which the QA Program applies.

2. This identification process results in a Q-List and Safety Classification Determinations, which identify safety-related items for each Unit. The Q-List is a controlled document. Safety-related items are determined by an engineering analysis of the function(s) of plant structures, systems and components in relation to safe operation and shutdown.

3. The controls specified in the QA Program described in this QATR are applied to safety-related items, and others as specified by NMPNS.

B.2.2.12 Safety-related activities are accomplished under controlled conditions. Preparations for such activities include confirmation that prerequisites have been met, such as:

1. Assigned personnel are qualified.

2. Work is planned in accordance with the proper revisions of applicable engineering and/or Technical Specifications.

3. Specified equipment and/or tools, if any, are on hand to be used.

4. Equipment and materials are in an acceptable status.

5. Systems or structures on which work is to be performed are in the proper conditions or operational mode for the task.

6. Current and approved instructions, procedures, and drawings for the work are available for use.

7. Items and facilities that could be damaged by the work have been protected as required.

8. Provisions have been made for special equipment, environmental conditions, skills, controls, processes, tests and verification methods.

B.2.2.13 Development, control and use of computer programs affecting nuclear power plant safety-related design and operation are subject to appropriate controls.

B.2.2.14 Responsibility and authority for planning and implementing indoctrination and training programs are delegated to each department. The training and indoctrination program provides for the following as appropriate:

1. Personnel responsible for performing and verifying activities that affect quality are familiar with the activities and the requirements identified in applicable quality-related manuals, instructions, procedures, and drawings.

2. Proficiency tests are utilized where appropriate to determine that individuals can perform their assigned tasks.

3. Personnel who perform inspections, examination, tests, audit and special process activities are trained and qualified in accordance with applicable requirements. Certificates of qualification (where required) designate specific areas of qualification and the bases for the qualification.

4. Provisions are included for retraining, reexamination and recertification (where certification is required) to ensure that proficiency is maintained.

5. Training content and attendance records, and required qualification and certification records are maintained.

B.2.2.15 The management of Constellation Nuclear at the CEO level assesses the scope, status, adequacy, and compliance of the QA Program for NMPNS at a predetermined regularity. Management at this level employs the following means to assess the program.

1. The senior executive of NMPNS is responsible for reporting on the status, adequacy and effectiveness of the NMPNS QA Program.

2. The senior executive of NMPNS regularly attends Constellation Nuclear senior management meetings and makes verbal presentations regarding quality-related matters. When necessary, the manager quality assurance assists with these

presentations. Minutes of these meetings are generally documented.

Certain actions of the Nuclear Safety Review Board (NSRB) and of the Station Operations Review Committee (SORC) result in audits and/or reports by which members of these offsite and onsite review committees are made aware, on a regular basis, of the effectiveness of the QA Program.

B.2.2.16 Nuclear Safety Review Board

1. Function

The NSRB shall function to provide independent review and audit of designated activities in the areas of:

a. Nuclear power plant operations

b. Nuclear engineering

c. Chemistry and radiochemistry

d. Metallurgy

e. Instrumentation and control

f. Radiological safety

g. Mechanical and electrical engineering

h. Quality assurance practices

i. Other appropriate fields associated with the unique characteristics of the nuclear power plant

The NSRB shall report to and advise the senior executive of NMPNS on those areas of responsibility specified under Items 7 and 8 of this section.

2. Composition

The NSRB shall be composed of the following:

Chairman:	vice president, manager or staff engineer
Member:	plant manager or designee
Member:	staff engineer - nuclear
Member:	staff engineer - mechanical or electrical
Member:	consultant (item 4 of this section)

3. Alternates

All alternate members shall be appointed in writing by the NSRB Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in NSRB activities at any one time.

4. Consultants

Consultants shall be utilized as determined by the NSRB Chairman to provide expert advice to the NSRB.

5. Meeting Frequency

The NSRB shall meet at least once per 6 months.

6. Quorum

The quorum of the NSRB necessary for the performance of the NSRB review and audit functions described in this section shall consist of not less than a majority of the members including alternates. The quorum requires the presence of the Chairman or the Chairman's designated alternate and no more than a minority of the quorum shall have line responsibility for operations of the facility.

7. Review

The NSRB shall be responsible for the review of:

a. The safety evaluations for: 1) changes to procedures, equipment, or systems, and 2) tests or experiments completed under the provision of 10CFR50.59 to verify that such actions did not constitute an unreviewed safety question;

b. Proposed changes to procedures, equipment, or systems which involve an unreviewed safety question as defined in 10CFR50.59;

c. Proposed tests or experiments which involve an unreviewed safety question as defined in 10CFR50.59;

d. Proposed changes to Technical Specifications or the Operating License;

e. Violations of codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance;

f. Significant operating abnormalities or deviations from normal and expected performance of unit equipment that affect nuclear safety;

g. All Reportable Events;

h. All recognized indications of an unanticipated deficiency in some aspect of design or operation of structures, systems, or components that could affect nuclear safety; and

i. Reports and meeting minutes of the SORC.

8. Audits

Audits of unit activities shall be performed under the cognizance of the NSRB. These audits shall encompass:

a. The conformance of unit operation to provisions contained within the Technical Specifications and applicable license conditions at least once every 24 months;

b. The performance, training, and qualifications of the entire unit staff at least once every 24 months;

c. The results of actions taken to correct deficiencies occurring in unit equipment, structures, systems, or method of operation that affect nuclear safety, at least once every 24 months;

d. The performance of activities required by the Operational Quality Assurance Program to meet the criteria of Appendix B, 10CFR50, at least once every 24 months;

e. The facility Emergency Plan and implementing procedures at least once every 24 months or as necessary based on an assessment by the licensee against performance indicators, and as soon as reasonably practicable after a change occurs in personnel, procedures, equipment, or facilities that potentially

could adversely affect emergency preparedness, but no longer than 12 months after the change;

f. The facility Security Plan and implementing procedures at least once every 24 months or as necessary based on an assessment by the licensee against performance indicators, and as soon as reasonably practicable after a change occurs in personnel, procedures, equipment, or facilities that potentially could adversely affect security, but no longer than 12 months after the change;

g. The Radiological Environmental Monitoring Program and the results thereof at least once every 24 months;

h. The Offsite Dose Calculation Manual (ODCM) and implementing procedures at least once every 24 months;

i. The Process Control Program and implementing procedures for processing and packaging of radioactive wastes at least once every 24 months;

j. Any other area of unit operation considered appropriate by the NSRB or the site vice president;

k. The Fire Protection Program and implementing procedures at least once per 24 months;

l. An independent fire protection and loss prevention program inspection and audit shall be performed at least once per 12 months utilizing either qualified offsite licensee personnel or an outside fire protection firm;

m. An inspection and audit of the fire protection and loss prevention program shall be performed by an outside qualified fire consultant at intervals no greater than 36 months;

n. The facility Fitness for Duty program and implementing procedures at least once every 12 months.

9. Authority

The NSRB shall report to and advise the senior executive of NMPNS on those areas of responsibility specified in Items 7 and 8 of this section.

10. Records

Records of NSRB activities shall be prepared, approved, and distributed as indicated below:

a. Minutes of each NSRB meeting shall be prepared, approved, and forwarded to the senior executive of NMPNS within 14 days following each meeting.

b. Reports of reviews encompassed by Items 7.b, e, f, g and h of this section shall be prepared, approved, and forwarded to the senior executive of NMPNS within 14 days following completion of the review.

c. Audit reports encompassed by Item 8 of this section shall be forwarded to the senior executive of NMPNS and to the management positions responsible for the areas audited within 30 days after completion of the audit by the auditing organization.

B.2.2.17 Station Operations Review Committee

Details of SORC responsibilities are discussed in Section XIII-G.1 of the Unit 1 UFSAR and Section 13.4 of the Unit 2 USAR.

1. Function

The SORC shall function to advise the plant manager on all matters related to nuclear safety.

2. Composition

The SORC shall be composed of the following:

Chairman:	technical advisor*
Vice-Chairman/Member:	manager operations
Vice-Chairman/Member:	general supervisor system engineering
Member:	manager maintenance
Member:	general supervisor chemistry
Member:	manager radiation protection

* The individual filling the technical advisor position reports to the plant manager. The responsibilities for this position are described in Unit 1 UFSAR Chapter XIII and Unit 2 USAR Chapter 13.

3. Alternates

All alternate members shall be appointed in writing by the SORC Chairman or Vice-Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in SORC activities at any one time.

4. Meeting Frequency

The SORC shall meet at least once every calendar month and as convened by the SORC Chairman, Vice-Chairman, or a designated alternate.

5. Quorum

The quorum of the SORC necessary for the performance of the SORC responsibility and authority provisions described in this section

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shall consist of the Chairman or a Vice-Chairman, and four members including alternates.

6. Responsibilities

The SORC shall be responsible for:

a. Investigation of all violations of the Technical Specifications, including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence, to the site vice president and to the NSRB.

b. Review of all Reportable Events, and submitting the results of this review to the NSRB and site vice president.

c. Review of unit operations to detect potential hazards to nuclear safety.

d. Performance of special reviews, investigations, or analyses and reports thereon as requested by the plant manager or the NSRB.

e. Safety evaluations and analyses resulting from technical review and control activities identified in Items 1, 2, 3 and 5 of Section B.5.2.9 (Unit 2).

f. Review of Licensee-initiated changes to the ODCM prior to implementation. Changes become effective upon acceptance by SORC.

7. Duties

The SORC shall:

a. Render determinations in writing with regard to whether or not each item considered under Items 6.a through 6.e, above, constitutes an unreviewed safety question.

b. Provide written notification within 24 hr to the site vice president and the NSRB of disagreement between the SORC and the plant manager; however, the plant manager shall have responsibility for resolution of such disagreements pursuant to Technical Specifications 6.1.1 (CTS)/5.1.1 (ITS).

c. Review Safety Limit Violation Reports, submit Safety Limit Violation Report to NSRB and site vice president within 14 days of the violation, and notify the SRAB and site vice president within 24 hr in the event a Safety Limit is violated.

8. Records

The SORC shall maintain written minutes of each SORC meeting that, at a minimum, document the result of all SORC activities performed under the responsibilities and authority provisions of the Technical Specifications and this section. Copies shall be provided to the site vice president and the NSRB.

B.2.2.18 ISEG Functions, Training/Qualification Requirements, Reporting Requirements/Records, and Oversight

1. Functions

The review of plant operating characteristics, NRC issuances, industry advisories, Licensee Event Reports, and other appropriate sources of plant design and operating experience is performed by knowledgeable personnel in accordance with established procedures. Independent reviews of plant activities, including maintenance, modifications, operational concerns, and analysis, will be performed by personnel independent of the operating organization. Detailed recommendations for revised procedures, equipment modifications, maintenance activities, operations activities, or other means of improving plant safety are documented as corrective/preventative actions in Deviation/Event Reports.

2. Training/Qualification Requirements

ISEG functions shall be performed by qualified personnel. Personnel are trained and qualified in accordance with the training and qualification described in the Technical Specifications and UFSAR/USAR. This includes degreed individuals, as appropriate, for specific engineering technical reviews. Independent technical reviews are performed by qualified personnel functioning independent of the operating organization.

2. The change is approved by two members of the unit management staff, at least one of whom holds a Senior Operator license on the unit affected; and

3. The change is documented, reviewed in accordance with Section B.5.2.9, and approved within 14 days of implementation by the branch manager for the functional area of the procedure or higher levels of management, as governed by administrative procedures.

B.5.2.9 Technical Review and Control Activities

1. Each procedure and program required by Technical Specifications 6.8 (CTS)/5.4 (ITS) and other procedures that affect nuclear safety, and changes thereto, shall be prepared by a qualified individual/organization. Each such procedure, and changes thereto, shall be reviewed by an individual/group other than the individual/group that prepared the procedure, or changes thereto, but who may be from the same organization as the individual/group that prepared the procedure, or changes thereto. Approval of procedures and programs, and changes thereto, and their safety evaluations shall be controlled by administrative procedures.

2. Proposed changes to the Technical Specifications shall be prepared by a qualified individual/organization. The preparation of each proposed Technical Specifications change shall be reviewed by an individual/group other than the individual/group that prepared the proposed change, but who may be from the same organization as the individual/group that prepared the proposed change. Proposed changes to the Technical Specifications shall be approved by the plant manager.

3. Proposed modifications to unit structures, systems, and components that affect nuclear safety shall be designed by a qualified individual/organization. Each such modification shall be reviewed by an individual/group other than the individual/group that designed the modification, but who may be from the same organization as the individual/group that designed the modification. Proposed modifications to structures, systems, and components and the safety evaluations shall be approved before implementation by the plant

manager or the manager technical support, as previously designated by the plant manager.

4. Individuals responsible for reviews performed in accordance with Items 1, 2, 3 and 5 of this section shall be members of the Station supervisory staff, previously designated by the Plant Manager to perform such reviews. Each such review shall include a determination of whether or not additional, cross-disciplinary review is necessary. If deemed necessary, such review shall be performed by the appropriate designated Station review personnel.

5. Proposed tests and experiments that affect Station nuclear safety and are not addressed in the UFSAR or Technical Specifications and their safety evaluations shall be reviewed by the plant manager or the manager technical support, as previously designated by the plant manager.

6. The plant manager shall assure the performance of special reviews and investigations, and the preparation and submittal of reports thereon, as requested by the site vice president.

7. The facility security program and implementing procedures shall be reviewed at least every 12 months. Recommended changes shall be approved by the plant manager and transmitted to the site vice president and to the Chairman of the NSRB.

8. The facility emergency plan and implementing procedures shall be reviewed at least every 12 months. Recommended changes shall be approved by the plant manager and transmitted to the site vice president and to the Chairman of the NSRB.

9. The plant manager shall assure the performance of a review by a qualified individual/organization of changes to the radiological waste treatment systems.

10. Review of any accidental, unplanned, or uncontrolled radioactive release, including the preparation of reports covering evaluation, recommendations, and disposition of the corrective action to prevent recurrence and the forwarding of these reports to the site vice president and to the NSRB.

11. Review of changes to the Process Control Program and the ODCM. Approval of any changes shall be

made by the plant manager or a designee before implementation of such changes.

12. Reports documenting each of the activities performed under Items 1 through 9 of this section shall be maintained. Copies shall be provided to the site vice president and the NSRB.

13. The plant manager shall assure the performance of a review, by a qualified individual/organization, of the Fire Protection Program and implementing procedures at least every 12 months, and submittal of recommended changes to the NSRB.

B.17 QUALITY ASSURANCE RECORDS

B.17.1 POLICY

QA records are records that furnish documentary evidence of the quality of items and services. Such documents are prepared by the originator and maintained by designated organizations. They are accurate, complete and legible and are protected against damage, deterioration or loss. They are identifiable and retrievable.

B.17.2 IMPLEMENTATION

B.17.2.1 General organizational responsibilities are described in Section B.1, ORGANIZATION.

B.17.2.2 Documents that furnish evidence of quality of items and services are generated and controlled in accordance with the procedures that govern those activities. Such documents are considered Quality Assurance records upon completion.

Record Retention

In addition to the applicable record retention requirements of Title 10 of the Code of Federal Regulations (10CFR), the following records shall be retained for at least the minimum period indicated.

1. The following records shall be retained for at least 5 yr:

   a. Records and logs of unit operation covering time interval at each power level.

   b. Records and logs of principal maintenance activities, inspections, repair, and replacement of principal items of equipment related to nuclear safety.

   c. All Reportable Events submitted to the Commission.

   d. Records of surveillance activities, inspections, and calibrations required by the Technical Specifications.

   e. Records of changes made to the procedures required by Technical Specifications 6.8.1 (CTS)/5.4.1 (ITS).

   f. Records of radioactive shipments.

g. Records of sealed source and fission detector leak tests and results.

h. Records of annual physical inventory of all sealed source material of record.

2. The following records shall be retained for the duration of the unit Operating License:

   a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the UFSAR.

   b. Records of new and irradiated fuel inventory, fuel transfers, and assembly burnup histories.

   c. Records of radiation exposure for all individuals entering radiation control areas.

   d. Records of gaseous and liquid radioactive material released to the environs.

   e. Records of transient or operational cycles for those unit components designed for a limited number of transients or cycles. For Unit 2, these components are specified in the USAR.

   f. Records of reactor tests and experiments.

   g. Records of training and qualification for current members of the unit staff.

   h. Records of in-service inspections performed pursuant to the Technical Specifications.

   i. Records of quality assurance activities required by the QATR and not listed under Item 1 of this section.

   j. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments pursuant to 10CFR50.59.

   k. Records of meetings of the SORC and the NSRB.

   l. Records of the service lives of all snubbers, including the date at which the service life commences and associated

installation and maintenance records (Unit 2).

m. Records of analyses required by the Radiological Environmental Monitoring Program that would permit evaluation of the accuracy of the analysis at a later date. This should include procedures effective at specified times and QA records showing that these procedures were followed.

n. Records of unit radiation and contamination surveys.

B.17.2.3 A document becomes a record when completed. At that time it is designated as a lifetime or nonpermanent record and is transmitted to file. Nonpermanent records have specified retention times. Lifetime records are maintained for the life of the item and/or plant as appropriate.

B.17.2.4 In-process documents are controlled by the originator until completed and transmitted to file.

B.17.2.5 Records may be original documents, legible copies, or in various microform formats. Records may also be stored as electronic images on optical disks, using optical disk technology that does not allow deletion or modification of record images.

B.17.2.6 Authorized personnel may issue corrections or supplements to records. Procedures address acceptable methods of making corrections to records.

B.17.2.7 Traceability between the record and the item or activity to which it applies is provided.

B.17.2.8 Records are stored in appropriate fire rated facilities, or in remote dual facilities to prevent damage, deterioration, or loss due to natural or unnatural causes.

B.18 AUDITS

B.18.1 POLICY

Audits are carried out to provide an independent evaluation of compliance and effectiveness of the QA Program, including those elements of the program implemented by suppliers. Audits are performed in accordance with written procedures or checklists by qualified personnel not having direct responsibility in the areas audited. Audit results are documented and are reviewed by management. Follow-up action is taken where indicated.

B.18.2 IMPLEMENTATION

B.18.2.1 General organizational responsibilities are described in Section B.1, ORGANIZATION.

B.18.2.2 NQA audits are performed:

1. To provide a comprehensive independent verification and evaluation of quality-related procedures and activities; and

2. To verify and evaluate the QA programs, procedures, and activities of suppliers.

B.18.2.3 Audits are performed in accordance with established schedules. Applicable QA Program elements are audited at least once every 2 years.

B.18.2.4 NSRB audits are performed as specified in Section B.2.2.16. Except for audits specified in paragraphs 8e, 8f, and 8n, audit frequency may be extended by up to 90 days based on reasonable administrative considerations such as resource availability and plant conditions. The next performance due date for the audit will be based on its originally scheduled date, i.e., the periodicity for these audits will not be allowed to exceed the original schedule plus 90 days.

B.18.2.5 Regularly scheduled audits are supplemented by special audits when appropriate. Conditions which may warrant special audits include:

1. Significant changes are made in the QA Program.

2. When it is suspected that quality has been adversely affected.

3. When an independent assessment of program effectiveness is considered appropriate.

B.18.2.6 Audits include an objective evaluation of quality-related practices, procedures, instructions, activities, items, documents and records to confirm that the QA Program is effective and properly implemented. The following activities are included:

1. Indoctrination and training program.
2. Interface control between NMPNS organizational units and between NMPNS and its principal contractors.
3. Corrective action.
4. M&TE calibration.
5. Nonconformance control.
6. FSAR commitments.
7. Activities associated with computer codes.
8. Activities associated with design verification performed by designers' immediate supervisor.

B.18.2.7 Audit procedures and the scope, plans, checklists and results of individual audits are documented.

B.18.2.8 Personnel selected for auditing assignments have experience or are given training commensurate with the needs of the audit and have no direct responsibilities in the areas audited.

B.18.2.9 Lead auditors are qualified and certified in accordance with approved procedures.

B.18.2.10 Audit data are analyzed to identify any quality deficiencies and assess the effectiveness of the QA Program. Audit reports are distributed to the responsible management of both the audited and auditing organizations.

B.18.2.11 Management of the audited organization takes appropriate action to correct observed deficiencies and to identify the cause and prevent recurrence of any significant conditions adverse to quality. Audit-identified deficiencies requiring cause determination are considered adverse audit findings. Follow-up shall be performed to evaluate the adequacy of the response and to verify that corrective actions are completed as written and as scheduled.

B.18.2.12 QA audits are conducted and documented to verify compliance with the Fire Protection Program.

Fire Protection Program audits are performed per the requirements of the applicable sections of this QATR.

Fire protection audits may be combined during a specific audit period provided the scope of the audit clearly indicates the required audit attributes, team composition and results based on the type of audit. (Reference NRC Generic Letter 82-21, "General Scope of Fire Protection Audits and Composition and Qualification of Auditors," for guidance regarding audit team participation and audit scope).

Audit results are documented and reviewed with management having responsibility in the area audited and the NSRB.

TABLE B-2 (Cont'd.)

DOCUMENT	REVISION/DATE	TITLE, INTERPRETATION & EXCEPTIONS
p. Para. 5.3		Requirement: This paragraph establishes administrative controls for written procedures.* Implementation: In lieu of these controls, NMPNS will comply with those controls described in the applicable sections of the Nine Mile Point Units 1 and 2 FSARs, the related Technical Specifications, and Section B.5 of the QATR. (See related items 2.e, 2.g, 2.j, 2.n, and 2.q of this table.)
q. Para. 5.3.9.3		Requirement: This paragraph suggests ANSI/ANS-3.7.1-1979, ANSI/ANS-3.7.2, and ANSI/ANS-3.7.3-1979 for additional guidance in preparation of Emergency Plan Implementing Procedures.* Exception: In lieu of the above references described in ANSI/ANS-3.2, NMPNS will comply with the emergency preparedness controls described in the applicable sections of the Nine Mile Point Units 1 and 2 FSARs. (See related items 2.e, 2.g, 2.j, 2.n, and 2.p of this table.)
3. ANSI/ASME NQA-1	1983 1983 Addenda	Quality Assurance Program Requirements for Nuclear Facilities
a. Supplement 2S-1		Requirement: This supplement provides requirements for the qualification of personnel performing inspection and test. Interpretation: Consistent with guidance found in Regulatory Guide 1.28, personnel qualified in accordance with the requirements of ANS-3.1 need not be qualified in accordance with NQA-1. (See related items 3.c and 8.d of this table.)
b. Supplement 2S-2		Requirement: The American Society of Nondestructive Testing (ASNT) Recommended Practice No. SNT-TC-1A, June 1975 Edition, and its applicable supplements, shall apply as requirements to NDE personnel covered by this supplement. Exception: In lieu of the referenced standard, NMPNS is committed to ASNT Recommended Practice No. SNT-TC-1A, June 1980, and its applicable supplements.
c. Supplement 2S-3		Requirement: Personnel who participate in QA Program audits shall be qualified in accordance with ANSI/ASME NQA-1 Supplement 2S-3. Exception: Personnel who perform NSRB audits that are outside the scope of 10CFR50 Appendix B are not required to be so qualified. (See related items 3.a and 8.d of this table.) Exception: For Lead Auditor Recertification, an assessment of each lead auditor's qualifications will be performed and the lead auditor's records will be updated annually, with a 90-day grace period for completion of this activity. The next performance due date for the activity will be based on its originally scheduled date, i.e., the periodicity for this activity will not be allowed to exceed the original schedule plus 90 days.

TABLE B-2 (Cont'd.)

DOCUMENT	REVISION/DATE	TITLE, INTERPRETATION & EXCEPTIONS
c. Supplement 2S-3 (cont'd.)		Exception: Prospective lead auditors shall demonstrate their ability to effectively implement the audit process and effectively lead an audit team. NMPNS will describe this demonstration process in written procedures and shall evaluate and document the results of the demonstration. Regardless of the methods used for the demonstration, the prospective lead auditor shall have participated in at least one nuclear quality assurance audit within the year preceding the individual's effective date of qualification. Upon successful demonstration of the ability to effectively implement the audit process and effectively lead audits, and having met the other provisions of Supplement 2S-3 of NQA-1, the individual may be certified as being qualified to lead audits.
d. Supplement 7S-1 Para. 8.1		Requirement: Where required by code, regulation or contract requirements, documentary evidence that items conform to procurement document requirements shall be available at the nuclear facility site prior to installation or use. Interpretation: NMPNS requires that the required documentary evidence be available at the site prior to use, but not necessarily prior to installation. This allows installation to proceed under specified conditions while any missing documents are being obtained, but precludes dependence on the item for safety purposes. (See related item 2.1 of this table.)