Superseded pp per Rev 15 to uFSAR dtd 4/10/98 9804220241 50-250

The Reactor Protection System is capable of protecting against any single anticipated malfunction of the reactivity control system and is designed to limit reactivity transients to DNBR equal to or greater than the safety analysis value due to any single malfunction in the deboration controls.

Limits, which include considerable margin, are placed on the maximum reactivity worth of control rods and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large change of reactivity cannot: (a) rupture the reactor coolant pressure boundary; or (b) disrupt the core, its support structures, or other vessel internals so as to lose capability to cool the core.

The control rod cluster drive mechanisms are wired into preselected groups, and are therefore prevented from being withdrawn in other than their respective groups. The rod drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable speed rod travel. The maximum insertion rate is analyzed in the detailed plant analysis assuming two of the highest worth groups to be accidentally withdrawn at maximum speed, yielding reactivity insertion rates of the order of 12 x 10^{-4} Δk/sec which is well within the capability of the overpower-overtemperature protection circuits to prevent core damage.

Reference sections:

Section Title	Section
Reactor Design Bases	3.1
Protection Systems	7.2
Regulating Systems	7.3
Chemical and Volume Control System	9.2

1.3.6 REACTOR COOLANT PRESSURE BOUNDARY (GDC 33-GDC 36)

The reactor coolant boundary is shown to be capable of accommodating without rupture the static and dynamic loads imposed as a result of a sudden reactivity insertion such as a rod ejection.

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The following general criteria are followed to assure conservatism in computing the required containment structural load capacity:

a) In calculating the containment pressure, rupture sizes up to and including a double-ended break of reactor coolant pipe are considered.

b) In considering post-accident pressure effects, various malfunctions of the emergency systems are evaluated including failures of a diesel-generator, an emergency containment cooler and a containment spray pump.

c) The pressure and temperature loadings obtained by analyzing various loss-of-coolant accidents, when combined with operating loads and design wind or seismic forces, do not exceed the load-carrying capacity of the structure, its access openings or penetrations.

The reinforced concrete containment is not susceptible to a low temperature brittle fracture. The containment liner is enclosed within the containment and thus is not exposed to the temperature extremes of the environs. Typically, the containment bulk ambient temperature during operation is between 50°F and 120°F. Operation with elevated normal bulk containment temperatures up to 125°F for short periods of time during the summer months has been evaluated (See Section 14.0). The material for the containment penetrations, which are designed to Subsection B of Section III ASME B&PV Code has a NDT of 0°F.

The reactor coolant pressure boundary does not extend outside of the containment. Isolation valves for all fluid system lines penetrating the containment provide at least two barriers against leakage of radioactive fluids to the environment in the event of a loss-of-coolant accident. These barriers, in the form of isolation valves or closed systems, are defined on an individual line basis. In addition to satisfying containment isolation criteria, the valving is designed to facilitate normal operation, and maintenance of the systems and to ensure reliable operation of other engineered safety features.

After completion of the containment structure an initial integrated leak rate test is conducted at the calculated peak accident pressure, to verify that the leakage rate is not greater than 0.25 per cent by weight of the containment volume per day.

Leak rate tests, using the same method as the initial leak rat.e test, will be performed during unit shutdowns periodically in accordance with the Technical Specifications.

Auxiliary Coolant System

Two component cooling headers provide a means to isolate certain passive failures (defined as a 50 gpm leak). A partition has been added to the component cooling surge tank. Each compartment is connected to one component cooling header. Following isolation of the headers, leakage in one header will not communicate through the tank to the intact header.

Waste Disposal System

The boric acid reprocessing train is now part of the Chemical Volume and Control System. The waste disposal system has been designed as purely a waste process system, which includes waste evaporators, demineralizers, waste hold-up tanks, monitor tanks, condensate tank and associated pumps. The system also includes equipment to prepare the waste for disposal. (See Section 11.1.)

1.6.5 BLOWDOWN CAPABILITY OF REACTOR INTERNALS

The forces exerted on reactor internals and the core, following a loss-of-coolant accident, are computed by employing the BLODWN-2 digital computer program developed for the space-time-dependent analysis of multiloop PWR plants. This program, the models used and the results are discussed in Section 14.3.3.

REFERENCES, Section 1.6

1) Wood, P.M., Baller, E.A., et al, "Use of Burnable Poison Rods in Westinghouse Pressurized Water Reactors," WCAP 7113 (October 1967), NON-PROPRIETARY.

2) Redfield, V.A., "CHIC-KIN...A Fortran Program for Intermediate and Fast Transients in a Water Moderated Reactor," WAPD-TM-479, (January 1, 1965).

3) Poncelet, C.G. and Christie, A.M., "Xenon Induced Spatial Instabilities in Large Pressurized Water Reactors," WCAP-3680-20, (March 1968), NON-PROPRIETARY.

4) McGaugh, J.D., "The Effect of Xenon Spatial Variations and the Moderator Coefficient on Core Stability," WCAP-2983, (August 1966), PROPRIETARY.

5) Westinghouse Report, "Power Distribution Control in Westinghouse PWR's," WCAP-7208, (October 1968), PROPRIETARY. The NON-PROPRIETARY version of this document is WCAP-7811.

6) Westinghouse Report, "Power Maldistribution Investigations", WCAP-7407-L, (January 1970), PROPRIETARY.

8. Containment Polar Crane and Rail Support (Unloaded)

9. Refueling Water Storage Tanks

10. Emergency Containment Cooling and Filtering Units

11. Intake Cooling Water Systems

    Intake structure and crane supports

    Intake cooling water pumps and motors

    Intake cooling water piping, from pumps to component cooling water heat exchanger inlets

12. Component Cooling System

    Component cooling heat exchangers

    Component cooling pumps and motors

    Residual heat removal pumps and motors (low-head safety injection pumps)

    Residual heat removal heat exchangers

    Component cooling surge tanks

13. Spent Fuel Storage Facilities

    Spent fuel pit and racks

    Spent fuel pit pump and motor

    Spent fuel pit heat exchanger

    Spent fuel pit demineralizer

14. Safety Injection System

    Containment spray pumps and motors

    Low-head safety injection pumps and motors (residual heat removal pumps)

    High-head safety injection pumps and motors

    Containment spray headers

    Boron injection tank

    Boron injection tank accumulator

    Accumulator system

    Containment recirculation sumps

15. Chemical and Volume Control System

Charging pumps

Volume control tank

Boric acid blender

Boric acid tanks

Boric acid transfer pumps

Boric acid filters

Heat exchangers

Primary water storage tank

16. Fuel Transfer Tube

17. Motor-Driven Fire Pumps

18. Instrument Air System

Dryers

Receivers

19. Auxiliary Building Exhaust System

20. Control Building Ventilating System

21. Fuel Handling System

22. Vessel and Internals Lifting Devices

23. Electrical System

1.9.3 ORGANIZATION

Charts of the Turkey Point Quality Assurance organization are attached hereto as Figures 1.9-1, 1.9-2 and 1.9-3. Responsibility for quality assurance rests with Florida Power & Light Company's Vice President of Power Plant Engineering and Construction. Reporting to him is the Manager of Power Plant Engineering who is responsible for administration of all Florida Power & Light Company power plant engineering functions. A Project Manager has been assigned to the Turkey Point Units Nos. 3 and 4 project. The

LIST OF TABLES (Continued)

LIST OF FIGURES

2.12 ENVIRONMENTAL MONITORING

2.12.1 GENERAL

The environmental monitoring program is designed to accomplish two objectives.

The first objective was to determine the existing level of background radioactivity resulting from natural occurrence and global fallout in the Turkey Point Plant environs before radioactive materials are delivered to the site. This preoperational phase began approximately one year before nuclear fuel was received at the site and continued until the first nuclear reactor went critical.

The type, frequency, and location of samples included in the preoperational environmental monitoring program were selected on the basis of population density and distribution, agricultural practices, sources of public water and food sources, industrial activities, recreational and fishing activities in the area. In addition, the natural features of the environment including meteorology, topography, geology, hydrology, hydrography, pedology, and natural vegetative cover of the area were also considered. Accessibility within the area and the necessity for protecting the sampling equipment from vandalism limited the choice of available sampling sites.

In the design of the preoperational monitoring program, various factors were studied in the preliminary evaluation of available or possible exposure pathways including: (1) method or mode of radionuclide release, (2) estimated isotopes, (3) activity, (4) chemical and physical form of radionuclides which may be expected from the operation of the facility.

During the preoperational phase, procedures were established, methods and techniques were developed and a continuing review of the program made to verify the suitability and adequacy of the environmental monitoring program.

The second objective of the environmental monitoring program is to determine the effect of the operation of the nuclear units on the environment. This operational phase began with initial criticality, startup and subsequent operation of units 3 and 4, and is essentially a continuation of the preoperational program.

Significant quantities of radioactive materials should not be released to the environment during the operation of the nuclear units and the monitoring program is designed to demonstrate this. The sampling and analysis program is described in the plant Technical Specifications Section 4.12.

2.12.2 AIR ENVIRONMENT

The air environmental monitoring program was designed to determine existing natural background radioactivity and to detect changes in radiation levels in the air environment which may be attributed to the operation of the nuclear units.

Air borne radioactivity is detected by collection of air particulates, iodines, precipitation, and measurements of external gamma radiation.

Air particulates are collected on filters and iodines are collected on activated charcoal. The air samplers operate continuously and the filters are changed and analyzed weekly. Air samplers are located relative to the prevailing winds at on-site locations and several locations within a 10-mile radius of the plant. A control location more than 20 miles away from the plant site is used for comparison with U. S. Public Health Air Surveillance Network samples taken in the Miami area.

Precipitation samples are collected and analyzed monthly at an on-site location, two off-site locations and a control location more than 20 miles away from the site.

External or direct gamma radiation exposure in the air environment is determined by use of high sensitivity, integrating type dosimeters. Thermoluminescent dosimeters (TLD's) have been selected for this purpose. Due to the low levels of radiation anticipated, the TLD's will be changed monthly under normal conditions. In addition to the TLD's, direct reading ion chamber type dosimeters are utilized in selected locations. The ion chamber dosimeters are read bi-weekly and the readings used for comparison with the TLD's.

2.12.3 WATER ENVIRONMENT

The water environmental monitoring program was designed to determine existing natural background radioactivity and to detect changes in radiation levels which may be attributed to the operations of the nuclear units.

In the preliminary assessment of exposure pathways in the Water Environmental Program, it was apparent that drinking water was not the critical exposure pathway because Biscayne Bay water is essentially sea water. Investigation was directed to other pathways that may be steps in the food chain to man since it is known that certain species of aquatic biota, inherently or by means of aquatic food sources, may concentrate specific radionuclides several times above the equilibrium concentration of radionuclides in the water environment. Accordingly, samples of water, bottom sediment, edible fish, crustacea, algae, sponges, and bottom grasses are collected and analyzed for radioactivity and radionuclide content in order to determine the existing background radioactivity in the water environment.

All water, bottom sediment, and aquatic biota samples are analyzed by gamma spectroscopy for radionuclides which may be expected as background radioactivity as shown in Technical Specification Table 4.12-1. Specific radionuclide analysis for Sr-89 and Sr-90 are performed on edible fish and crustacea samples. Additionally, water samples from Biscayne Bay, canals, ground and potable water are specifically analyzed for H-3 (tritium), by liquid scintillation spectroscopy as shown in Technical Specification Table 4.12-1.

Evaluation of the results of sample radioactivity analysis and radionuclide analysis will provide data on the concentration of specific radionuclides in water environmental media which may be present as background radioactivity.

The operational water environmental monitoring program, which is essentially a continuation of the preoperational program, will monior any increase in radioactivity or determine reconcentration of these specific radionuclides in the various water environmental media sampled.

The type, frequency, and location of water, bottom sediment, and aquatic biota samples are listed in Technical Specification Table 4.12-1. The location, distance, and direction of the sample station relative to the facility are shown graphically on the map included as Figure 2.12-1 (See Technical Specification Table 4.12-1).

2.12.4 LAND ENVIRONMENT

In the land environmental monitoring program, as in the water monitoring program, the program was designed to determine existing natural background radioactivity and to detect changes in radiation levels in the land environment which may be attributed to the operation of the nuclear units.

In the preliminary assessment of exposure pathways in the land environmental program, milk was not the critical pathway because there are no dairy herds within 25 miles of the facility. Other exposure pathways which may be steps in the food chain to man were investigated, including fruit and vegetable crops which may be grown in the vicinity of the facility. Radionuclides are present in soil as background radioactivity and may be incorporated into plant life. Accordingly, samples of soil are collected and analyzed by gamma spectroscopy as shown in Technical Specification Table 4.12-1. A one kilogram sample of soil is collected which represents 0.1 square meter area.

Samples of mangrove leaves are collected and analyzed by gamma spectroscopy as shown in Technical Specification Table 4.12-1. These samples are indicative of foliar deposition of radionuclides and/or uptake from soil.

Food crops are collected at various stages of development and at harvest time. The edible parts of fruit and vegetables are analyzed. When practicable identical crops are followed in identical locations in succeeding years. Analysis is performed by gamma spectroscopy in accordance with Technical Specification Table 4.12-1 with chemical separation and analysis for Sr-89 and Sr-90.

Evaluation of the results of sample radioactivity analysis and radionuclide content will provide data on the concentration of specific radionuclides which may be present as background radioactivity in the land environment. Changes in radioactivity or concentration of specific radionuclides in land environmental samples will be detected by the continuation of the preoperational monitoring program into the operational phase of the land environmental monitoring program.

Although not a critical exposure pathway, a small land animal will be collected and analyzed for radioactivity and specific radionuclides.

The type, frequency, and location of leafy vegetation, fruit, vegetables, grass, and soil samples are listed in Technical Specification Table 4.12-1, and the location, distance, and direction of the sampling stations relative to the plant are shown on the maps included as Figure 2.12-1 (see Plant Technical Specifications Figure 4.12-1).

2.13 EXCLUSION ZONE - LOW POPULATION ZONE

2.13.1 EXCLUSION ZONE

On the basis of meteorological data presented in Section 2.6, Appendices 2A and 2D, and the analysis of the consequences of a postulated release of fission products set forth in Section 14.3.5 and Appendix 14F, the exclusion zone is included within the property boundary line. As shown on the property plan, the minimum exclusion distance is 4164 feet to the north property line. The minimum distance to the south property line is 5582 feet. The exclusion radius as identified in Appendix 14F is 4164 feet which is bounded by the exclusion zone. The exclusion zone is identified as the area within the property boundary line.

Within the exclusion zone there are: (1) two fossil fuel electric generating units staffed by approximately 65 FP&L employees, (2) a Scout camp used intermittently by about 20 people, (3) a picnic area used intermittently, that has been used by as many as about 1500 persons (during a local organization's picnic), (4) an Air Force Sea Survival School with class visits of perhaps two dozen Air Force personnel.

2.13.2 LOW POPULATION ZONE

The low population area is enclosed by a circle of 5-mile radius. The area includes Homestead Bayfront Park and farmland to the north, a portion of Homestead Air Force Reserve Base to the northwest, the Turkey Point elementary school, farmland to the west and undeveloped swampland to the southwest and south (refer to Figure 2.2-2). There are no permanent residents in the area at the present time (refer to Tables 2.4-1 and 2.4-2). Additionally, population projections through the year 2013, as presented in Tables 2.4-13 through 2.4-16, indicate that this area will remain uninhabited by permanent residents for the remaining plant operating period authorized in the Turkey Point Units 3 and 4 Operating Licenses.

It should be noted that the land within this area is low and is periodically subject to hurricane flooding. Development has traditionally taken place in the more elevated areas to the west. While it can be said that there is some pressure to develop areas having Biscayne Bay frontage, two factors are present as a deterrent to such development. The western boundary of Biscayne National Monument coincides with the western shore of Biscayne Bay for almost 4 miles south of the plant. There is strong local sentiment against bayshore development which might impair the values of the monument or which would deny the bayfront to general public use. Secondly, land adjoining the bayfront is overlain with a five or six-foot deep layer of organic peat or "muck" as it is known locally. This material is unsuitable for the foundation of structures, consequently the cost of any development is extremely high.

Transient population in the low population zone is principally confined to visitors to the Homestead Bayfront Park. The maximum number of persons expected to visit the Park is 10,000 which would be for the 4th of July. Since the only available estimates are for total daily visitors, the number present in the Park at any one time would be less than this amount. Likewise the figure can be compared to the normal weekend day of 5000 visitors and the normal weekday of 1000 visitors.

Monroe County and Dade County Disaster Preparedness Coordinators, the State Department of Health and Rehabilitative Services, and State Bureau of Disaster Preparedness are responsible for determining and implementing protective measures in offsite areas. (Emergency Plan Section 5.2.1).

The Park is served by two roads, one on each side of North Canal. It is reasonable to assume that cars can be evacuated at the rate of about 1650 cars per hour. Thus 5000 cars could be evacuated over one road in about three hours.

The low population zone is served by several hard surfaced roads. Tallahassee Road and South Allapattah-East Allapattah Road provide access to the area from the north around the west and east sides of the Homestead Air Force Base respectively. Tallahassee Road also provides access to the south via Card

Sound Road and Key Largo. Palm Drive, North Canal Drive and Mowry Drive all provide access to the area from the west. On the basis of the paucity of population, the existence of several hard surfaced roads, and the analysis set forth in Section 14.3.5, it is concluded that the proposed low population zone meets the criteria set forth in 10CFR100.

Limits, which include margin, are placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that the potential effects of a sudden or large reactivity change cannot (a) rupture the reactor coolant pressure boundary, or (b) disrupt the core, its support structures, or other vessel internals so as to lose capability to cool the core.

The reactor control system employs RCCA's approximately half of which are fully withdrawn during power operation, serving as shutdown rods. The remaining rods comprise the control groups which are used to control load and reactor coolant temperature. The full length rod cluster drive mechanisms are wired into preselected groups, and are therefore prevented from being withdrawn in other than their respective groups. The rod drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable speed rod travel.

The maximum reactivity insertion rate assumed in the RCCA Withdrawal safety analysis bounds the rate corresponding to the maximum differential rod worth for two overlapping groups moving together in the highest worth region of the core. The assumed maximum reactivity insertion rate is well within the capability of the overpower-overtemperature protection circuits to prevent core damage.

No single mechanical or electrical control system malfunction can cause a rod cluster to be withdrawn at a speed greater than 77 steps per minute (48 inches per minute). This represents the maximum theoretical limit. However, the nominal maximum design limit of 72 steps per minute is used in the design calculation.

3.1.3 DESIGN OBJECTIVES

The reactor is capable of meeting the performance objectives throughout core life under both steady state and transient conditions without violating the integrity of the fuel cladding. Thus the release of unacceptable amounts of fission products to the coolant is prevented.

The limiting conditions discussed below are the highest functional capacity or performance levels for the nuclear, control, thermal and hydraulic, and mechanical aspects of design permitted to assure safe operation of the facility.

<u>Nuclear</u>

At a full power level (license application power) the nuclear heat flux hot channel factor, F^N_q, specified in Table 3.2.1-1, Line 18, is not exceeded.

The nuclear axial peaking factor F^N_z, and the nuclear enthalpy rise hot channel factor $F^N_{\Delta H}$ are limited in their combined relationship so as not to exceed the F_q or DNBR limits.

The limiting nuclear hot channel factors are higher than those calculated at full power for the range from all control rods fully withdrawn to maximum allowable control rod insertion. Control rod insertion limits as a function of power are delineated in the Technical Specifications to ensure that hot channel factors do not exceed those specified in Table 3.2.1-1 at lower power levels due to control rod insertion and that the DNB ratio is always greater at part power than at full power.

The protection system ensures that the nuclear core limits are not exceeded.

The structural internals are designed to maintain their functional integrity in the event of a major loss-of-coolant accident or a maximum hypothetical earthquake. The dynamic loading resulting from the pressure oscillations because of a loss-of-coolant accident does not prevent rod cluster control assembly insertion.

The following components of the reactor internals were checked for buckling under the combined effect of design earthquake and a double ended pipe break: upper barrel during hot leg break, upper and lower support columns, and fuel assemblies thimbles, for both cold and hot leg break.

The internals were analyzed by applying to each component the exciting forces due to the transient postulated condition. Maximum stresses and deflections were obtained from the structural response and compared with allowable values. The stress analysis was performed obtaining the maximum dynamic response for each component and computing the corresponding stress intensity using standard strength of materials formulas.

Resulting stresses were then combined in the most unfavorable manner with the seismic stresses and the maximum stress intensities were obtained for each component. The dynamic analysis has been performed using the following conservative assumptions:

1. The mechanical and hydraulic analyses were performed separately without including the effect of the water-solid interaction. Peak pressures obtained from the hydraulic analysis will be attenuated by the deformation of the structures.

2. When applying the hydraulic forces no credit was taken for the stiffening effect of the fluid environment which will reduce the deflections and stresses in the structure.

3. The multi-mass model was considered to have enough degrees-of-freedom to represent the most important modes of vibration in the vertical direction. This model is conservative in the sense that further mass-spring resolution of the system would lead to further attenuation of the shock effects obtained with the present model.

To assure that the components will not fail, an allowable stress criterion was established as explained in Section 14.3.3. This criterion limits the maximum strain to percentages of the material uniform strain which is an indication of the adopted margin.

Uncertainties in the dynamic loads have increased the margin contained in the maximum stresses. The major factor of conservatism is the assumption that the double ended break will occur in 0.001 sec.; larger breaking times will reduce all the stresses. The hydraulic analysis, with which the loads were computed, is performed by the BLODWN-2 Code which solves hydraulic equations by the method of characteristics. Results of this Code have been checked against results obtained from the LOFT program. ("Loss of Coolant Analysis: Comparison between BLODWN-2 Code Results and Test Data", WCAP-7401, November, 1969 by S. Fabic Non-Proprietary).

Uncertainties in the geometric modeling technique, when applied to a full scale reactor, have been also determined analytically by studying the same reactor using models of different complexity. Results indicate that the loads obtained with the present model are conservative.

Fuel Assemblies

The fuel assemblies are designed to perform satisfactorily throughout their lifetime. The loads, stresses, and strains resulting from the combined effects of flow induced vibrations, earthquakes, reactor pressure, fission gas pressure, fuel growth, thermal strain, and differential expansion during both steady state and transient reactor operating conditions have been considered in the design of the fuel rods and fuel assembly. The assembly is also structurally designed to withstand handling and shipping loads prior to irradiation, and to maintain sufficient integrity at the completion of design burnup to permit safe removal from the core and subsequent handling during cooldown, shipment and fuel reprocessing.

In order to reduce the dissolved poison requirement for control of excess reactivity, burnable poison rods can be incorporated in the core design. The result is that changes in the coolant density will have less effect on the density of poison and the moderator temperature coefficient will become less positive.

In Cycle 1 there were 816 of the borosilicate glass rods in the form of clusters distributed throughout the core in vacant rod cluster control guide tubes as illustrated in Figures 3.2.1-7 and 3.2.1-8. Information regarding research, development and nuclear evaluation of the burnable poison rods can be found in Reference 3 and 4. These rods initially controlled the installed excess reactivity shown on lines 40 and 41 of Table 3.2.1-1, and their addition resulted in a reduction of the initial hot zero power boron concentration in the coolant to the value shown on line 34. The moderator temperature coefficient is negative at the operating coolant temperature with this boron concentration and with burnable rods installed.

The effect of burnup on the moderator temperature coefficient is calculated and the coefficient becomes more negative with increasing burnup. This is due to the buildup of fission products with burnup and dilution of the boron concentration with burnup. The latter effect is considerably more important. However, the buildup of equilibrium xenon contributes a positive increment to the coefficient for a constant boron concentration. The calculated net effect and the predicted unrodded moderator temperature coefficient with equilibrium xenon at BOL for Cycle 1 is shown in table 3.2.1-1, Line 42. With core burnup, the coefficient will become more negative as boron is removed because of a shift in the neutron energy spectrum due to the buildup of plutonium and fission products. At end of life with no boron or rods in the core, the moderator coefficient is specified in Table 3.2.1-1, Line 42.

The current Technical Specifications allows a +5 pcm/°F ($+5 \times 10^{-5}$ $\Delta K/K/°F$) MTC below 70 percent of rated power, ramping to a 0 pcm/°F MTC at 100 percent power and above. A power-level dependent MTC was chosen to minimize the effect of the specification on postulated accidents at high power levels.

Moreover, as the power level is raised, the average core water temperature becomes higher as allowed by programmed average temperature for the plant, tending to bring the moderator coefficient more negative. Also, the boron concentration can be reduced as xenon builds into the core. Thus, there is less need to allow a positive coefficient as full power is approached. As fuel burnup is achieved, boron is further reduced and the moderator coefficient will become negative over the entire operating power range.

The control rods provide a negative contribution to the moderator coefficient as can be seen in Figure 3.2.1-9. Moderator temperature coefficients for current cycles are given in the Reload Safety Evaluations.

Moderator Pressure Coefficient

The moderator pressure coefficient has an opposite sign to the moderator temperature coefficient. The effect on the total coefficient is small because the pressure coefficient is 100 times smaller. The calculated beginning and end of life pressure coefficients are specified in Table 3.2.1-1, Line 43.

Moderator Density Coefficient

A uniform moderator density coefficient is defined as a change in the neutron multiplication per unit change in moderator density. The range of the moderator density coefficient from BOL to EOL is specified in Table 3.2.1-1, Line 44.

Doppler and Power Coefficients

The Doppler coefficient is defined as the change in neutron multiplication per degree change in fuel temperature. The coefficient is obtained by calculating neutron multiplication as a function of effective fuel temperature. The results are shown in Figure 3.2.1-10 for BOL conditions for the first cycle. The coefficient becomes slightly more negative with increasing fuel burnup. Doppler coefficients for current cycles are given in the Reload Safety Evaluations.

In order to know the change in reactivity with power, it is necessary to know the change in the effective fuel temperature with power as well as the Doppler coefficient. It is very difficult to predict the effective temperature of the

TABLE 3.2.1-1

NUCLEAR DESIGN DATA

(FIRST CYCLE)

STRUCTURAL CHARACTERISTICS

1.	Fuel Weight (UO_2), lbs.	176,000
2.	Zircaloy Weight, lbs.	34,900
3.	Core Diameter, inches	119.7
4.	Core Height, inches	144
	Reflector Thickness and Composition	
5.	Top - Water Plus Steel	~10 in.
6.	Bottom - Water Plus Steel	~10 in.
7.	Side - Water Plus Steel	~15 in.
8.	H_2O/U Volume Ratio (cold)	4.18
9.	Number of Fuel Assemblies	157
10.	UO_2 Rods per Assembly	204

PERFORMANCE CHARACTERISTICS

11.	Core Heat Output, MWt (initial rating)	2200
12.	Heat Output, MWt (maximum calculated turbine rating)	2300
13.	Fuel Burnup, MWD/MTU	
	First Cycle (Average)	13,000
	Enrichments, w/o*	
14.	Region 1	1.85
15.	Region 2	2.55
16.	Region 3	3.10
17.	Equilibrium	3.10
18.	Nuclear Heat Flux Hot Channel Factor, F_q^N**	3.13
19.	Nuclear Enthalpy Rise Hot Channel Factor, $F_{\Delta H}^N$ *	1.75

*Corresponding values for current cycles are given in the Reload Safety Evaluations.

**The current F_q^N limit is 2.32 and $F_{\Delta H}^N$ limit is 1.62.

CONTROL CHARACTERISTICS FOR FIRST CYCLE

Effective Multiplication (Beginning of Life) With Burnable Poison Rods In (First Cycle)	
20. Cold, No Power, Clean	1.180
21. Hot, No Power, Clean	1.138
22. Hot, Full Power, Clean	1.119
23. Hot, Full Power, Xe and Sm Equilibrium	1.077
Rod Cluster Control Assemblies	
24. Material	5% Cd; 15% In; 80% Ag
Number of RCC Assemblies	
25. Full Length	45
26. Partial Length*	8
27. Number of Absorber Rods per RCC Assembly	20
28. Total Rod Worth, BOL, % (See Table 3.2.1-3)	
Boron Concentrations (ppm) for 1st Core Cycle Loading with Burnable Poison Rods	
29. Refueling Shutdown; Rods in (k = .90)	1950
30. Shutdown (k = .99) with Rods Inserted, Clean, Cold	780
31. Shutdown (k = .99) with Rods Inserted, Clean, Hot	510
32. Shutdown (k = .99) with No Rods Inserted, Clean, Cold	1250
33. Shutdown (k = .99) with No Rods Inserted, Clean, Hot	1210
To Control at Hot Full Power, No Rods Inserted k = 1.0	
34. Clean	1000
35. Xenon	720
36. Xenon and Samarium	670
37. Shutdown, All but One Rod Inserted, Cold (k = .99)	850
38. Shutdown, All but One Rod Inserted, Hot (k = .99)	610

*Partial length control rods are not used in the present reloads.

TABLE 3.2.1-1

BURNABLE POISON RODS

39.	Number and Material*	816 Borated Pyrex Glass
40.	Worth Hot Δk/k %	6.9
41.	Worth Cold Δk/k, %	5.3

RANGE OF KINETIC CHARACTERISTICS FOR FIRST CYCLE*

42.	Moderator Temperature Coefficient, (Δk/k)/°F	$+0.3 \times 10^{-4}$ to 3.5×10^{-4}
43.	Moderator Pressure Coefficient (Δk/k)/psi	-0.3×10^{-6} to $+3.5 \times$ 1-$^{-6}$
44.	Moderator Density Coefficient, (Δk/k)/gm/cm^3	-0.1 to 0.3
45.	Doppler Coefficient, (Δk/k)/°F	-1.0×10^{-5} to -1.6×10^{-5}
46.	Delayed Neutron Fraction, %	0.52 to 0.72
47.	Prompt Neutron Lifetime, sec.	1.4×10^{-5} to 1.8×10^{-5}
48.	Moderator Void Coefficient, (Δk/k)/% void	$+0.5 \times 10^{-3}$ to -2.5×10^{-3}

*Corresponding values for current cycles are given in the Reload Safety Evaluations.

TABLE 3.2.1-2

REACTIVITY REQUIREMENTS FOR CONTROL RODS*

Requirements	Per Cent Δρ Beginning of Life	End of Life
Control		
Power Defect (Doppler effect, Temperature Change)	1.80	2.30
Operational Maneuvering Band and Control Rod Bite	0.70	0.30
Maximum Void and Redistribution	0.25	0.70
Total Control	2.75	3.30

* Corresponding values for current cycles are given in Reload Safety Evaluations.

TABLE 3.2.1-3

CALCULATED ROD WORTHS, $\Delta\rho$
FOR FIRST CYCLE WITH BURNABLE POISON RODS*

Core Condition	Rod Configuration	Worth	Worth Less 10%**	Design Reactivity Requirements	Shutdown Margin
BOL, HFP	45 rod in	8.14%			
	44 rods in; Highest Worth Rod Stuck Out	7.03%	6.33%	2.65%	3.68%
EOL, HFP (1st Cycle)	45 rods in	8.68%			
	44 rods in; Highest Worth Rod Stuck Out	7.42%	6.68%	3.58%	3.1%

BOL = Beginning of Life
EOL = End of Life
HFP = Hot Full Power

* Corresponding values for current cycles are given in the Reload Safety Evaluations

** Calculated rod worth is reduced by 10% to allow for uncertainties. Current Cycles (Appendices 14A and 14B) allow 7% uncertainty.

TABLE 3.2.1-4

RESULTS OF CALCULATIONS AS A FUNCTION OF LABORATORY PROVIDING EXPERIMENTAL DATA

Laboratory	Type of Experiment	No. of Experiments	Calculated $k \pm \sigma$
Westinghouse Atomic Power Division (WAPD)	Critical	16	0.9968 ± 0.0036
Bettis Atomic Power Laboratory	Critical	14	0.9940 ± 0.0022
Brookhaven National Laboratory	Exponential	35	0.9964 ± 0.0051
Hanford Atomic Products Operation	Exponential	20	0.9953 ± 0.0105
Babcock and Wilcox	Critical	26	0.9885 ± 0.0094
		111	

3.2.3 MECHANICAL DESIGN AND EVALUATION

The reactor core and reactor vessel internals are shown in cross-section in Figure 3.2.3-1 and in elevation in Figure 3.2.3-2. The core, consisting of the fuel assemblies, control rods, source rods and burnable poison rods provides and controls the heat source for the reactor operation. The internals, consisting of the upper and lower core support structure, are designed to support, align, and guide the core components, direct the coolant flow to and from the core components, and to support and guide the in-core instrumentation. A listing of the core mechanical design parameters is given in Table 3.2.3-1.

The fuel assemblies are arranged in a roughly circular cross-sectional pattern. The LOPAR and OFA (including DRFA) assemblies are nearly identical in their geometric configuration (number of fuel rods and thimble tubes, fuel rod dimensions, assembly pitch, etc.) with the following exceptions: 1) the diameter of the upper portion of the OFA guide thimble tubes has been reduced, relative to the LOPAR assembly, to accommodate the increased Zircaloy-4 grid strap thickness and results in reduced diameter thimble plugs, and; 2) the five intermediate support grids are of different materials. The enrichment of each region of fuel will vary slightly depending on the energy requirements for a given cycle of operation.

The fuel is in the form of slightly enriched uranium dioxide ceramic pellets. The pellets are stacked to an active height of 144 inches within Zircaloy-4 tubular cladding, which is plugged and seal welded at the ends to encapsulate the fuel. The enrichments of the fuel for the various regions in the first core are given in Table 3.2.3-1. Enrichment for subsequent cycles are given in the cycle specific RSE. All fuel rods are internally pressurized with helium during fabrication. Heat generated by the fuel is removed by demineralized borated light water which flows upward through the fuel assemblies and acts as both moderator and coolant.

The stress criteria of Article 4 Section III of the ASME code is employed in the design of the fuel assembly with the exception of the fuel clad which is specifically excluded by the code. The criteria for the design of fuel rods are listed in Section 3.1.3. Zircaloy-4 which is used for fabricating the guide thimbles of the fuel assembly and Inconel 718 which is used for fabricating grids and assembly hold down springs are not yet considered as code materials. In LOPAR fuel, all grids are made of Inconel-718. In OFA fuel, intermediate grids are made of Zircaloy-4 and the top and bottom grids of Inconel-718. The method for establishing design stress intensity values for the materials is consistent with that outlined in the code.

The core is divided into regions of three different enrichments. The loading arrangement for the initial cycle is indicated on Figure 3.2.3-3. Refueling generally follows an inward loading schedule. However to increase neutron economy and as part of a vessel flux reduction program to resolve pressurized thermal shock concerns, the Turkey Point Units now employ a low leakage loading pattern aimed at reducing the neutron flux at the periphery of the core. This consists of using once-burned and twice-burned assemblies in peripheral core locations and loading a maximum number of fresh assemblies in-board while meeting energy requirements and ensuring the safe operation of the core. The loading patterns for current cycles are given in the Reload Safety Evaluation.

The control rods, designated as Rod Cluster Control Assemblies (RCCA's), consist of groups of individual absorber rods which are held together with a spider at the top end and actuated as a group. The absorber rods fit within hollow guide thimbles in the fuel assemblies. The guide thimbles are an integral part of the fuel assemblies and occupy locations within the regular fuel rod pattern. In the withdrawn position, the absorber rods are guided and supported laterally by guide tubes which form an integral part of the upper core support structure. Figure 3.2.3-4 shows a typical RCCA.

As shown in Figure 3.2.3-2, the fuel assemblies are positioned and supported vertically in the core between the upper and lower core plates. The core plates are provided with pins which index into closely fitting mating holes in the fuel assembly top and bottom nozzles. The pins maintain the fuel assembly alignment which permits free movement of the control rods from the fuel assembly into the guide tubes in the upper support structure without binding or restriction between the rods and their guide surfaces.

Operational or seismic loads imposed on the fuel assemblies are transmitted through the core plates to the upper and low support structures and ultimately to the internals support ledge at the pressure vessel flange in the case of vertical loads or to the lower radial support and internals support

In-Core Instrumentation Support Structures

The in-core instrumentation support structures consist of an upper system to convey and support thermocouples penetrating the vessel through the head and a lower system to convey and support flux thimbles penetrating the vessel through the bottom.

The upper system utilizes the reactor vessel head penetrations. Instrumentation port columns are slip-connected to in-line columns that are in turn fastened to the upper support plate. These port columns protrude through the head penetrations. The thermocouples are routed through these port columns and across the upper support plate to positions above their readout locations. The thermocouple conduits are supported from the columns of the upper core support system. The thermocouple conduits are sealed stainless steel tubes.

In addition to the upper in-core instrumentation, there are reactor vessel bottom port columns which carry the retractable, cold worked stainless steel flux thimbles that are pushed upward into the reactor core. Conduits extend from the bottom of the reactor vessel down through the concrete shield area and up to a thimble seal line. The minimum bend radii are about 90 inches and the trailing ends of the thimbles (at the seal line) are extracted approximately 13 feet during refueling of the reactor in order to avoid interference within the core. The thimbles are closed at the leading ends and serve as the pressure barrier between the reactor pressurized water and the containment atmosphere.

Mechanical seals between the retractable thimbles and the surrounding conduits are provided at the seal table. During normal operation, the retractable thimbles are stationary in the core and move only during refueling or for maintenance, at which time a space of approximately 13 feet above the seal table is cleared for the retraction operation. Section 7.4 contains more information on the layout of the in-core instrumentation system.

The incore instrumentation support structure is designed for adequate support of instrumentation during reactor operation and is rugged enough to resist damage or distortion under the conditions imposed by handling during the refueling sequence.

Evaluation of Core Barrel and Thermal Shield

The internals design is based on analysis, test and operational information. Experience in previous Westinghouse PWR's has been evaluated and information derived has been considered in this design. For example, Westinghouse uses a one-piece thermal shield which is attached rigidly to the core barrel at one end and flexured at the other.

The Connecticut Yankee reactor and the Zorita reactor core barrels are of the same construction as the Turkey Point reactor core barrel. Deflection measuring devices employed in the Connecticut Yankee reactor during the hot-functional test, and deflection and strain gages employed in the Zorita reactor during the hot-functional test have provided important information that has been used in the design of the present day internals, including that for Turkey Point. When the Connecticut Yankee thermal shield was modified to the same design as for Southern California Edison, it, too, operated satisfactorily as was evidenced by the examination unsupported span between the fuel assembly adaptor plate and the end of the guide tube in the upper internals package. The spiders which support the source rods and burnable poison rods are all contained within the fuel top nozzle. Beginning with the Turkey Point Unit 3 Cycle 14 reload (Region 16), a keyless/cuspless top nozzle and holddown spring change was implemented. The keyless/cuspless top nozzle is functionally interchangeable with the old design.

Guide Thimbles

The control rod guide thimbles in the fuel assembly provide guided channels for the absorber rods during insertion and withdrawal of the control rods. They are fabricated from a single piece of Zircaloy 4 tubing, which is drawn to two different diameters. The larger inside diameter at the top provides a relatively large annular area for rapid insertion during a reactor trip and to accommodate a small amount of upward cooling flow during normal operations. The bottom portion of the guide thimble is of reduced diameter to produce a dashpot action when the absorber rods near the end of travel in the guide thimbles during a reactor trip. The transition zone at the dashpot section is conical in shape so that there are no rapid changes in diameter in the tube.

Flow holes are provided just above the transition of the two diameters to permit the entrance of cooling water during normal operation, and to accommodate the outflow of water from the dashpot during reactor trip.

The dashpot is closed at the bottom by means of a welded end plug. The end plug is fastened to the bottom nozzle during fuel assembly fabrication.

Grids

The grid assemblies consist of individual slotted straps which are assembled and interlocked in an "egg-crate" type arrangement and then furnace brazed to permanently join the straps at their points of intersection. Details such as spring fingers, support dimples, mixing vanes, and tabs are punched and formed in the individual straps prior to assembly.

Two types of grid assemblies are used in the fuel assembly. One type of these grids having mixing vanes which project from the edges of the straps into the coolant stream is used in the high heat region of the fuel assemblies to promote mixing of the coolant. A grid of this type is shown in Figure 3.2.3-10. The other type of grids, located at the bottom and top ends of the assembly, are of the nonmixing type. They are similar to the mixing type with the exception that they contain no mixing vanes on the internal straps.

There are two materials used to construct support grids for the LOPAR and OFA assemblies. Inconel-718 is used for all seven LOPAR grids, and the top and bottom non-mixing, support grids in the OFA assembly. Zircaloy is used for the five intermediate mixing-vane grids in the OFA assembly. A more detailed description can be found in the Reload Transition Safety Report (RTSR) for Turkey Point Units (Reference 2).

The outside straps on all grids contain mixing vanes which, in addition to their mixing function, aid in guiding the grids and fuel assemblies past projecting surfaces during handling or loading and unloading the core. Additional small tabs on the outside straps and the irregular contour of the straps are also for this purpose.

Inconel-718 and Zircaloy are for the grid material because of their corrosion resistance and high strength properties. The Inconel grids are furnace brazed to permanently join the straps at their intersections. After the combined brazing and solution annealing temperature cycle, the grid material is age hardened to obtain the material strength necessary to develop the required grid spring forces. The Zircaloy-4 grid interlocking strap joints and grid-to-sleeve joints are fabricated by laser welding.

Impact tests have been performed at 600°F to obtain the dynamic strength data and verify that the Zircaloy grid strength data at reactor operating conditions is structurally acceptable. Both the OFA Zircaloy and Inconel grid designs maintain their integrity during the most severe load conditions of a combined seismic/LOCA event.

Fuel Rods

The fuel rods consist of uranium dioxide ceramic pellets contained in a slightly cold worked and stress relieved Zircaloy-4 tubing which is plugged and seal welded at the ends to encapsulate the fuel. Sufficient void volume and clearances are provided within the rod to accommodate fission gases released from the fuel, differential thermal expansion between the cladding and the fuel, and fuel swelling due to accumulated fission products without over-stressing of the cladding or seal welds. Shifting of the fuel within the cladding is prevented during handling or shipping prior to core loading by a stainless steel helical compression spring which bears on the top of the fuel.

The fuel rods employed on LOPAR and OFA assemblies are geometrically identical with only slight variations in some design parameters. The Debris Resistant Fuel Assembly (DRFA), a modified OFA with debris resistant features, utilizes a lower end plug which is approximately 1.4 inches longer than in the standard OFA design. On a cycle-to-cycle and region-to-region basis, fuel enrichment, plenum void volume and initial helium backfill pressure will vary somewhat to accommodate specific cycle design requirements. This fact was also applicable prior to the introduction of OFA assemblies. For Unit 3 beginning with cycle-12, the DRFA incorporates axial blankets which consist of low enriched or natural uranium oxide pellets extending 6 inches at the top and bottom of the fuel stack within the fuel rod. Unit 4 has axial blankets starting with Cycle 14 and DRFA starting with Cycle 13.

During fuel rod assembly, the pellets are stacked in the cladding to the required fuel height. The compression spring is then inserted into the top end of the fuel and the end plugs pressed into the ends of the tube and welded. All fuel rods are internally pressurized with helium during the welding process. A hold-down force in excess of the weight of the fuel is obtained by compression of the spring between the top end plug and the top of the fuel pellet stack.

The fuel pellets are right circular cylinders consisting of slightly enriched uranium-dioxide powder which is compacted by cold pressing and sintering to the required density. The ends of each pellet are dished slightly to allow the greater axial expansion at the center of the pellets to be taken up within the pellets themselves and not in the overall fuel length. The ends of each OFA fuel pellet have a small chamfer at the outer cylinder surface.

The pellet densities are adjusted as shown in Table 3.2.3-1 to compensate for the effects of the higher burnup of fuel in regions remaining longest in the core. A different fuel enrichment as listed in Table 3.2.3-1 is used for each of the three regions in the first core loading. Reload region, as-built fuel enrichments and pellet densities are provided in each applicable Reload Safety Evaluation (RSE) Report.

To prevent the possibility of mixing enrichments during fuel manufacture and assembly, meticulous process control is exercised.

Process Control

Powder withdrawal from storage can be made by one authorized group only who direct the powder to correct pellet production line. All pellet production lines are physically separated from each other and pellets of only a single enrichment and density are produced in a given production line.

Finished pellets are placed on trays having the same color code as the powder containers and transferred to segregated storage racks within the confines of the pelleting area. Physical barriers prevent mixing of pellets of different densities and enrichments in this storage area. Unused powder and substandard pellets are returned to storage in the original color coded containers.

Each fuel assembly will be identified by means of a serial number engraved on the upper nozzle. The fuel pellets will be fabricated by a batch process so that only one enrichment region is processed at any given time. The serial numbers of the assemblies and corresponding enrichment will be documented by the manufacturer and verified prior to shipment.

Each assembly will be assigned a core loading position. A record will then be made of the core loading position, serial number and enrichment. Prior to core loading, independent checks will be made to ensure that this assignment is correct.

During initial core loading and subsequent refueling operations, detailed handling and checkoff procedures will be utilized throughout the sequence. The initial core will be loaded in accordance with the core loading diagram similar to Figure 3.2.3-3 which shows the location for each of the three enrichment types of fuel assemblies in the region. Reload cycle core loading diagrams are provided in the cycle specific RSE Report.

Rod Cluster Control Assemblies

The rod cluster control assemblies (RCCA) each consist of a group of individual absorber rods fastened at the top end to a common hub or spider assembly. These assemblies one of which is shown in Figure 3.2.3-4 are provided to control the reactivity of the core under operating conditions. These assemblies consist of rods containing full length absorber material. The number of RCC assemblies is specified in Table 3.2.3-1.

The absorber material used in the control rods is silver-indium-cadmium alloy which is essentially "black" to thermal neutrons and has sufficient additional resonance absorption to significantly increase its worth. The alloy is in the form of extruded single length rods which are sealed in stainless steel tubes to prevent the rods from coming in direct contact with the coolant.

The overall control rod length is such that when the assembly has been withdrawn through its full travel, the tip of the absorber rods remain engaged in the guide thimbles so that alignment between rods and thimbles is always maintained. Since the rods are long and slender, they are relatively free to conform to any small misalignments with the guide thimble. Prototype tests have shown that the RCC assemblies are very easily inserted and not subject to binding even under conditions of severe misalignment.

The spider assembly is in the form of a center hub with radial vanes containing cylindrical fingers from which the absorber rods are suspended. Handling detents, and detents for connection to the drive shaft, are machined into the upper end of the hub. A spring pack is assembled into a skirt integral to the bottom of the hub to stop the RCC assembly and absorb the impact energy at the end of a trip insertion. The radial vanes are joined to the hub, and the fingers are joined to the vanes by furnace brazing. A centerpost which holds the spring pack and its retainer is threaded into the hub within the skirt and welded to prevent loosening in the service. All components of the spider assembly are made from Type 304 stainless steel except for the springs which are Inconel X-750 alloy and the retainer which is of 17-4 Ph material.

The absorber rods are secured to the spider so as to assure trouble free service. The rods are first threaded into the spider fingers and then pinned to prevent rotation, after which the pins are welded in place. The end plug below the pin position is designed with a reduced section to permit flexing of the rods to correct for small operating of assembly misalignments.

In construction, the silver-indium-cadmium rods are inserted into cold-worked stainless steel tubing which is then sealed at the bottom and the top by welded end plugs. Sufficient diametral and end clearance is provided to accommodate relative thermal expansions and to limit the internal pressure to acceptable levels.

The bottom plugs are made bullet-nosed to reduce the hydraulic drag during a reactor trip and to guide smoothly into the dashpot section of the fuel assembly guide thimbles. The upper plug is threaded for assembly to the spider and has a reduced end section to make the joint more flexible.

Stainless steel clad silver-indium-cadmium alloy absorber rods are resistant to radiation and thermal damage ensuring their effectiveness under all operating conditions.

Neutron Source Assemblies

Four neutron source assemblies were utilized in the initial core. They consisted of two secondary source assemblies each, and two primary source assemblies each. The rods in the source assembly are fastened to a spider at the top end similar to the RCC spiders.

In the core, the neutron source assemblies are inserted into the RCC guide thimbles in fuel assemblies at unrodded locations. The location of these assemblies in the core is shown in Figure 3.2.3-3. The number and location of secondary source assemblies is given in each cycle specific RSE report.

The primary and secondary source rods both utilized the same type of cladding material as the absorber rods (cold-worked type 304 stainless steel tubing, 0.432 in O.D. with 0.019 inch thick walls). The secondary source rods contain Sb-Be pellets stacked to a height of 121.75 inches. Design criteria similar to those for the fuel rods are used for the design of the source rods; ie, the cladding is free standing, internal pressures are always less than reactor operating pressure, and internal gaps and clearances are provided to allow for differential expansions between the source material and cladding.

Thimble Plug Assemblies

Evaluations have been performed to support the complete or partial removal of thimble plugs from Turkey Point Units 3 & 4. These evaluations have addressed the effect of thimble plug removal on Core Design, Core Thermal Hydraulics, Reactor Pressure Vessel System thermal hydraulics and the non-LOCA and LOCA safety analyses. Based on these evaluations, it has been determined that it is acceptable to remove all or any combination of thimble plugs from Turkey Point Units 3 & 4.

The thimble plug assemblies as shown in Figure 3.2.3-10A consist of a flat base plate with short rods suspended from the bottom surface and a spring pack assembly. The twenty short rods, called thimble plugs, project into the upper ends of the guide thimbles to reduce the bypass flow area. Similar short rods are also used on the source assemblies and burnable poison assemblies to plug the ends of all vacant fuel assembly guide thimbles. At installation in the core, the thimble plug assemblies interface with both the upper core plate and with the fuel assembly top nozzles by resting on the adaptor plate. The spring pack is compressed by the upper core plate when the upper internals assembly is lowered into place. Each thimble plug is permanently attached to the base plate by a nut which is locked to the threaded end of the plug by a small lock-pin welded to the nut.

The OFA thimble plug has a smaller diameter (0.485 inch) than the LOPAR thimble plug diameter (0.498 inch) in order to maintain the same thimble plug to thimble tube diametral clearance, and to limit bypass flow through the OFA guide thimbles while providing sufficient coolant flow to cool the core components.

All components in the thimble plug assembly, except for the springs, are constructed from type 304 stainless steel. The springs are wound from an age hardened nickel base alloy for corrosion resistance and high strength.

Burnable Poison Rod

The burnable poison rods are statically suspended and positioned in vacant RCC thimble tubes within the fuel assemblies at nonrodded core locations. The poison rods in each fuel assembly are grouped and attached together at the top end of the rods by a flat base plate which fits within the fuel assembly top nozzle and rests on the top adaptor plate.

References Section 3.2.3

1. Letter from Uhrig, R. E., FP&L to Varga, S. A., NRC, Subject: Pressurized Thermal Shock, Letter No L-83-180, March 25, 1983

2. Petrarca, D., et al, "Reload Transition Safety Report For Turkey Point Units 3 & 4", June, 1983

3. Letter from Thomas, C. O., NRC, to Rahe, E. P., Westinghouse, Subject: Acceptance for Referencing of Licensing Topical Report WCAP-10021 (P), Revision 1, and WCAP-10377 (NP), "Westinghouse Wet Annular Burnable Absorber Evaluation Report", August 9, 1983

4. WCAP-9000 (1968), "Nuclear Design of Westinghouse Pressurized Water Reactor with Burnable Poison Rods", PROPRIETARY. A NON-PROPRIETARY version of this report is WCAP-7806, Rev. 1.

5. WCAP-8720, Addendum-2, "Westinghouse Revised Pad Code Thermal Safety Model", October 27, 1982 (Proprietary)

6. Daniel, R. C., et al. "Effects of High Burnup on Zircaloy-Clad Bulk DO_2, Plate Fuel Element Samples," WAPD-263, (September, 1965)

7. George, R. A., Lee, Y. C., Eng, G. H. "Revised Clad Flattening Model," WCAP-8377 (Westinghouse Proprietary) and WCAP-8381 (Non-Proprietary), July 1974.

8. XN-NF-85-12(P) Ford, K. L., et al "Mechanical Design Report For Turkey Point Units 3 & 4 Hafnium Vessel Flux Depression (HVFD) Cluster Assemblies", Proprietary.

TABLE 3.2.3-1

CORE MECHANICAL DESIGN PARAMETERS[1]

Active Portion of the Core	
Equivalent Diameter, in.	119.7
Active Fuel Height, in - Unit 3	144.00, 144.00, 143.474
Unit 4	144.00, 143.40, 142.80
Length-to-Diameter Ration	1.2
Total Cross Section Area, $Ft.^2$	78.1
Fuel Assemblies	
Number 157	
Rod Array 15 x 15	
Rods per Assembly	204 (2)
Rods Pitch, in.	0.563
Overall Dimensions, in.	8.426 x 8.426
Fuel Weight (as UO_2), pounds	176,000
Total Weight, pounds	225,000
Number of Grids per Assembly	7
Guide Thimble I.D. (Above Dashpot), in.	0.499
(at Dashpot), in.	0.455
Fuel Rods	
Number	32,028
Outside Diameter, in.	0.422
Diametral Gap, mils	7.5, 7.5, 8.5
Clad Thickness, in.	0.0243
Clad Material	Zircaloy-4
Overall Length, in. Unit 3	152.235
Unit 4	152.235
Fuel Pellets	
Material	UO_2 sintered
Density (% of Theoretical) - First Cycle (3)	
Region 1	94 (10.3 g/cc)
Region 2	93 (10.19 g/cc)
Region 3	92 (10.08 g/cc)(Unit 4-93)
Fuel Enrichments w/o - First Cycle (3)	
Region 1	1.85
Region 2	2.55
Region 3	3.10
Diameter, in. - Unit 3 (Regions 1, 2, 3)	0.3659, 0.3659, 0.3649
Unit 4 (All Regions)	0.3659
Length, in.	0.439

NOTES :

(1) All Dimensions are for cold conditions.

(2) Twenty-one rods are omitted: twenty to provide passage for control rods and one to contain in-core instrumentation.

(3) Values for current cycles are given in Appendixes 14A and 14B.

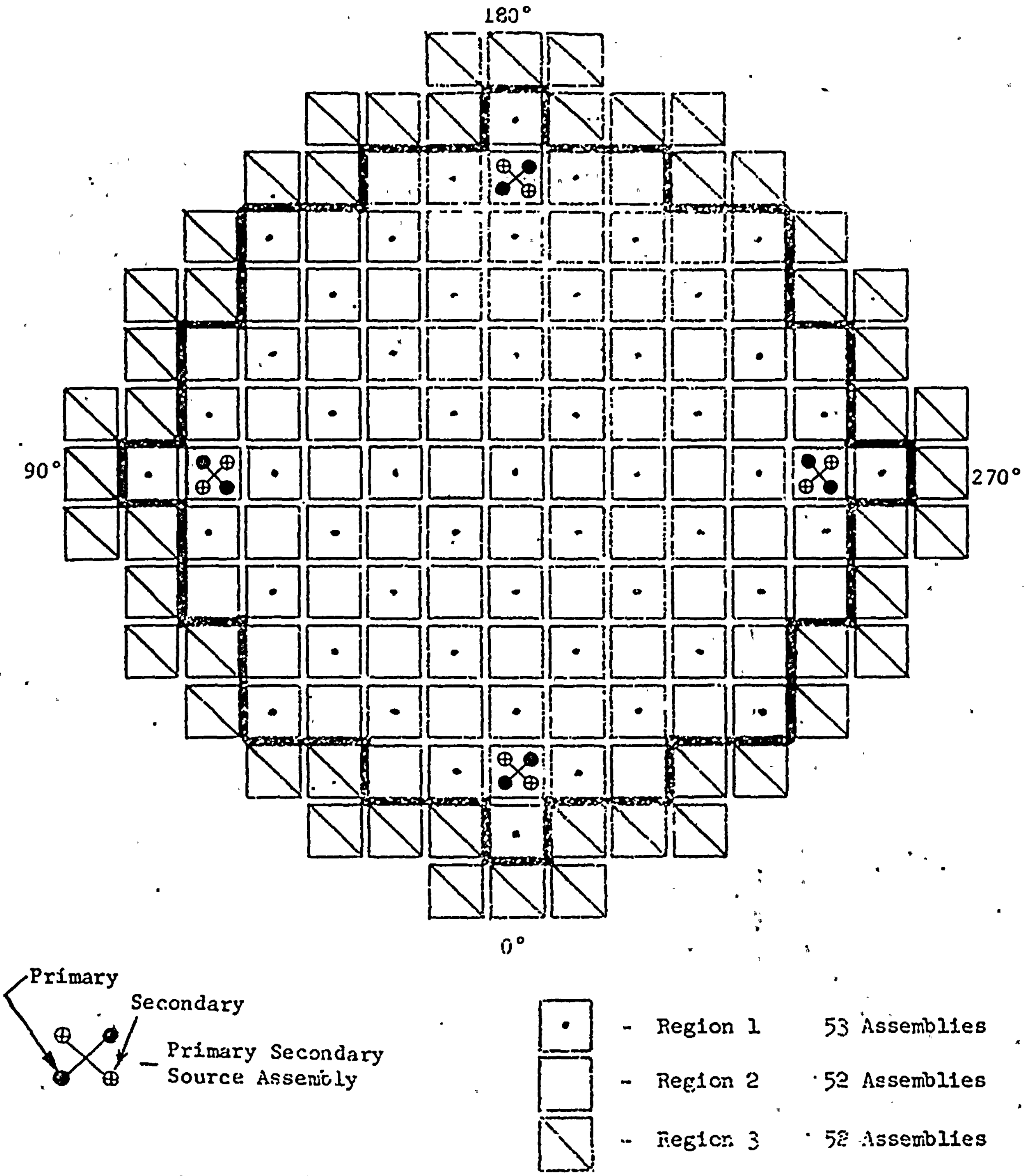
TABLE 3.2.3-1

<u>Rod Cluster Control Assemblies</u>	
Neutron Absorber	5% Cd, 15% In, 80% Ag
Cladding Material	Type 304 SS - Cold Worked
Clad Thickness, in.	0.019
Number of Clusters	45
Full Length	45
Number of Control Rods per Cluster	20
Weight in 60°F Water	
Full Length, pounds	147
Length of Rod Control, in.	158.454 (overall) 150.574 (insertion length)
Length of Absorber Section, in.	142.00
<u>Core Structure</u>	
Core Barrel, in.	
I.D.	133.875
O.D.	137.875
Thermal Shield, in.	
I.D.	142.625
O.D.	148.0
<u>Burnable Poision Rods</u> (4)	
Number	816
Material	Borosilicate Glass
Outside Diameter, in.	0.4395
Inner Tube, O.D. in.	0.2365
Clad Material	S.S.
Inner Tube Material	S.S.
Boron Loading (natural) gm/cm of glass rod	0.0429
<u>Neutron Source Assemblies</u> (5)	
Primary Source (typical)	Pu-Be
Secondary Source (typical)	Sb-Be

NOTES :

(4) Values for current cycles are given in Appendices 14A and 14B.

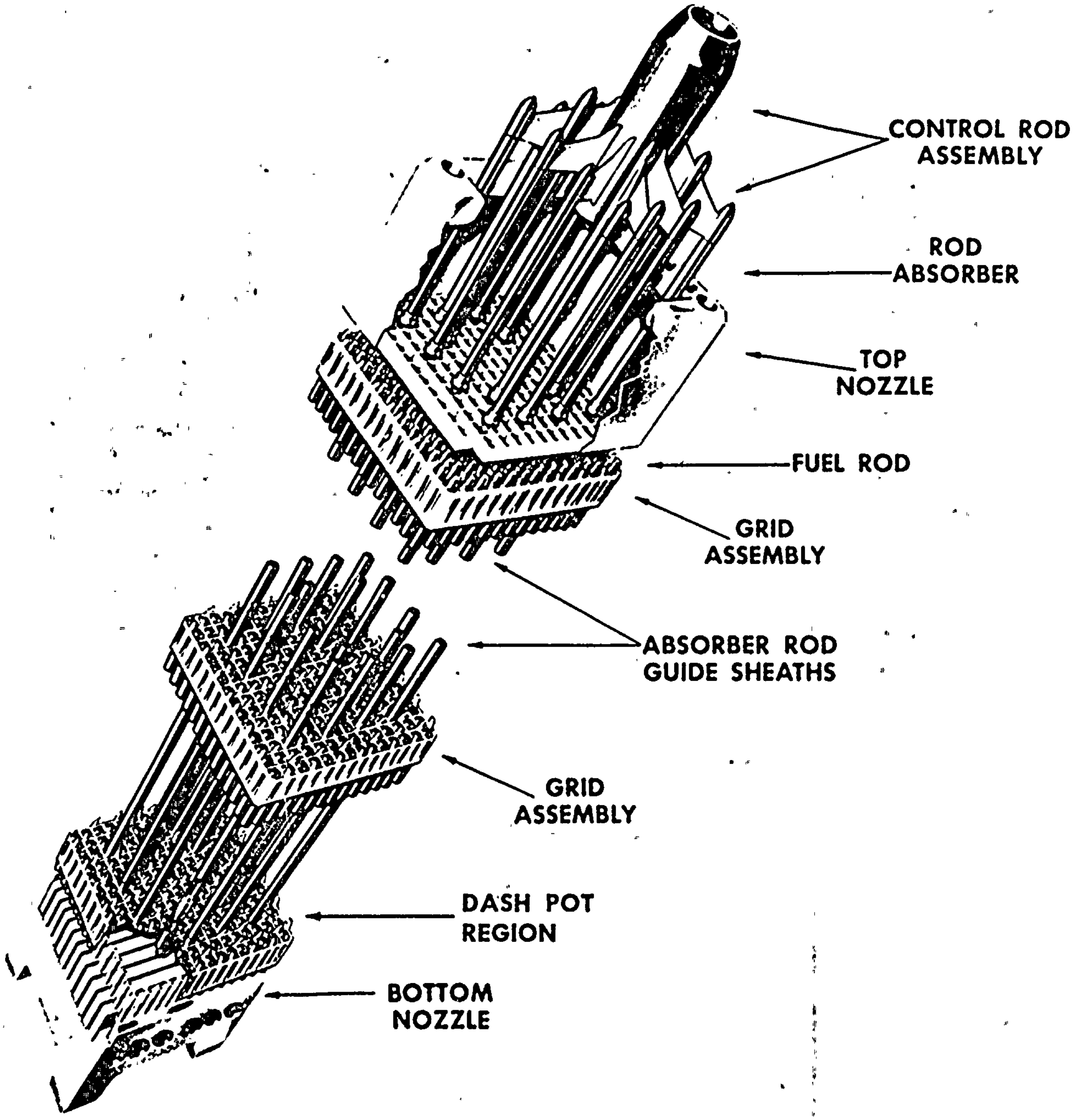
(5) The actual neutron source installed are described in the Reload Safety Evaluation for each specific cycle.



*Corresponding locations for current cycles are given in the Reload Safety Evaluations, Appendices 14A and 14B.

THREE-REGION CORE LOADING*

FIGURE 3.2.3-3



TYPICAL ROD CLUSTER CONTROL ASSEMBLY
FIG. 3.2.3-4

Over the range from 15% full power up to but not exceeding 100% of full power, the Reactor Coolant System and its components are designed to accomodate 10% of full power step changes in unit load and 5% of full power per minute ramp changes without reactor trip. The turbine bypass and steam dump system make it possible to accept a step load decrease of 50% of full power without reactor trip.

4.1.6 SERVICE LIFE

The service life of Reactor Coolant System pressure components depends upon the material irradiation, unit operational thermal cycles, quality manufacturing standards, environmental protection, and adherence to established operating procedures.

The reactor vessel is the only component of the Reactor Coolant System which is exposed to a significant level of neutron irradiation and it is therefore the only component which is subject to any appreciable material irradiation effects.

The NDTT shift of the vessel material and welds, due to radiation damage effects, is monitored by a radiation damage surveillance program which conforms with ASTM - E 185 standards.

Reactor vessel design is based on the transition temperature method of evaluating the possibility of brittle fracture of the vessel material, as result of operations such as leak testing and heatup and cooldown.

To establish the service life of the Reactor Coolant System components as required by the ASME (part III), Boiler and Pressure Vessel Code, for Class "A" Vessels, the unit operating conditions have been established for the 40 year design life. These operating conditions include the cyclic application of pressure loadings and thermal transients.

The number of thermal and loading cycles used for design purposes are listed in Table 4.1-8.

4.1.7 CODES AND CLASSIFICATIONS

All pressure-containing components of the Reactor Coolant System are designed, fabricated, inspected and tested in conformance with the applicable codes listed in Table 4.1-9.

The Reactor Coolant System is classified as Class I for seismic design, requiring that there will be no loss of function of such equipment in the event of the assumed maximum hypothetical ground accelerations acting in the horizontal and vertical directions simultaneously, when combined with the primary steady state stresses.

Reactor coolant system valves, fittings and piping were designed, fabricated, inspected and tested in conformance with the Code requirements listed in Table 4.1-9. Hydrostatic testing of piping and fittings is done after installation at the pressure given in Table 4.1-6, which is the reactor coolant system test pressure also. This is 1 1/4 times design pressure and is a necessary deviation from Code Case N-10.

ASME Code Case N-416, "Alternate Rules for Hydrostatic Testing of Repair or Replacement of Class 2 Piping, Section XI, Division I", is an acceptable Code Case for use at Turkey Point Units 3 and 4.

Reactor Coolant System inservice inspection of ASME Code Class 1, 2, and 3 components shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a(g)(6)(i).

Inservice inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83; Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

TABLE 4.1-9

REACTOR COOLANT SYSTEM - CODE REQUIREMENTS

Component	Codes
Reactor Vessel	ASME III* Class A
Control Rod Drive Mechanism Housings	ASME III* Class A
Steam Generator	
Tube Side	ASME III* Class A
Shell Side ***	ASME III* Class C
Reactor Coolant Pump Casing	No Code (Design per ASME III-Article 4)
Pressurizer	ASME III* Class A
Pressurizer Relief Tank	ASME III* Class C
Pressurizer Safety Valves	ASME III*
Reactor Coolant Piping	ASA B31.1**
System valves, fittings and piping	ASA B31.1**
Core Exit Thermocouple Seal Assemblies (Head Port Adapters & Drive Sleeves)	ASME III* Subsection NB, Class 1, 1986 Edition

* ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

** ASA B31.1-1955 Code for Pressure Piping, plus Code Cases N-7 and N-10 where applicable.

*** The shell side of the steam generator conforms to the requirements for Class A vessels and is so stamped as permitted under the rules of Section III.

Thermal sleeves are installed at the following locations where high thermal stresses could otherwise develop due to rapid changes in fluid temperature during normal operational transients:

a) Return line from the residual heat removal loop.
b) Both ends of the pressurizer surge line.
c) Pressurizer spray line connection to the pressurizer.
d) Charging lines and auxiliary charging line connections.

Valves

All valve surfaces in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant materials. Connections to stainless steel piping are welded. Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection.

4.2.3 PRESSURE-RELIEVING DEVICES

The Reactor Coolant System is protected against overpressure by control and protective circuits such as the high pressure trip and by code relief valves connected to the top head of the pressurizer. The relief valves discharge into the pressurizer relief tank which condenses and collects the valve effluent. The schematic arrangement of the relief devices is shown in Figure 4.2-1, and the valve design parameters are given in Table 4.1-3. Valve sizes are determined as indicated in Section 4.3.4. Power-operated relief valves and code safety valves are provided to protect against pressure surges which are beyond the pressure limiting capacity of the pressurizer spray. Each pressurizer safety valve has an acoustic accelerometer mounted on the discharge of the valve to provide the control room operator with positive indication of the pressurizer safety valve position.

The pressurizer relief tank is protected against a steam discharge exceeding the design pressure value by a rupture disc which discharges into the reactor containment. The rupture disc relief conditions are given in Table 4.1-3.

4.2.4 PROTECTION AGAINST PROLIFERATION OF DYNAMIC EFFECTS

Engineered Safety Features and associated systems are protected from loss of function due to dynamic effects and missiles which might result from a loss-of-coolant accident. Protection is provided by missile shielding and/or segregation of redundant components. This is discussed in Section 6.2.

The Reactor Coolant System is surrounded by concrete shield walls. These walls provide shielding to permit access into the containment during full power operation for inspection and maintenance of miscellaneous equipment. These shielding walls also provide missile protection for the containment liner plate.

The concrete deck over the Reactor Coolant System also provides for shielding and missile damage protection.

Steam generator lateral bracing is provided near the upper tube support elevation to resist lateral loads, including those resulting from seismic forces and pipe rupture forces. Additional bracing is provided at a lower elevation to resist pipe rupture loads.

The NRC documents in their letter of November 28, 1988 (Reference 3) that the leakage detection systems at Turkey Point Units 3 and 4 satisfy the requirements of Generic Letter 84-04, and that the primary loop piping complies with the criteria of GDC 4 from 10 CFR 50, Appendix A. GDC 4 allows the use of plant-specific Leak-Before-Break analysis to eliminate the dymanic effects of postulated pipe ruptures in high energy piping from the design basis of a plant. Plants with an NRC-approved Leak-Before-Break analysis may remove pipe whip restraints and jet impingment barriers. Turkey Point Units 3 and 4 received NRC approval (Reference 4) for elimination of the dynamic effects of postulated pipe ruptures in reactor coolant piping from the design basis of the plant. The Turkey Point analysis for the Leak-Before-Break Methodolgy is documented in the Westinghouse report WCAP-14237 (Reference 5). Therefore, the dynamic loads associated with a rupture of the reactor coolant piping need not be considered in the design of the reactor support structures.

Missile protection afforded by the arrangement of the Reactor Coolant System is illustrated in the containment structure drawings which are given in Section 5.

low coolant flow in Westinghouse PWR plants. The expected absolute accuracy of the channel is within ±10% and field results have shown the repeatability of the trip point to be within ±1%. The analysis of the loss of flow transient presented in Section 14.1.9 assumes instrumentation error of ± 3.7%.

4.2.10 REACTOR COOLANT SUBCOOLED MARGIN MONITOR

The reactor coolant system subcooled margin monitor system is an on-line microcomputer based system which uses reactor coolant process signals to provide a continuous indication of the margin from saturation conditions. The subcooled margin monitor system also provides an alarm signal into the main control room annunciator.

The reactor coolant system parameters monitored are the three coolant loops hot leg temperature, and loops A and B hot leg pressure. The operator has the choice of continuous main control board indication of either the pressure or temperature margin from saturation.

The temperature sensors are dual RTD's installed in thermowells. These RTD's are connected to provide the subcooling margin monitor system computing module with a 4-20 ma dc signal.

The reactor coolant pressure transmitters also provide a 4-20 ma dc signal to the computing module.

The computing module selects the highest temperature from those provided and the lowest pressure and calculates the margin to saturation from those two readings. The readings then appear on the display module in the control room.

4.2.11 REACTOR COOLANT VENT SYSTEM

The RCS vent system provides the operator with a means to vent non-condensible gases from the Reactor Coolant System. As shown on Figure 4.2-1 and 4.2-5, the RCS can be vented separately through the reactor vessel head vent or from the pressurizer steam space via the pressurizer relief line.

To vent system discharges to the containment sump and/or the pressurizer relief tank.

The RCS vent system can vent one-half of the RCS volume (gas) in one hour at operating pressure, but is sized such that the RCS mass inventory will be maintained by the charging pumps should the vent line suffer a guillotine break.

The power for the vent valves is taken from vital DC power outside the containment. Valve control and position indication is located in the control room. Pressure indication is provided in the control room to assist the operator in determining leakage in the vent line. Each vent is powered from an emergency bus.

The vent system has been seismically analyzed.

4.2.12 REACTOR VESSEL DRAIN LEVEL INDICATION SYSTEM

The reactor vessel drain down level indication system (see Figure 4.2-1) provides the continuous measurement of reactor coolant level during drain down operations and while in a drain down condition. This system also provides audible and visual alarm annunciation on increasing reactor vessel level above a preset volume. The system consists of two independent and redundant level (differential pressure) transmitters with control room indication. Audio and visual alarms are located in the control room and an audio alarm (horn) and light is located at each steam generator manway.

and the summation is carried out over the total number of monthly intervals comprising the total irradiation period.

In the above equation, the ratio P_j/P_{ref} accounts for month by month variation of power level within a given fuel cycle. The ratio C_j is calculated for each fuel cycle and accounts for the change in sensor reaction rates caused by variations in flux level due to changes in core power spatial distributions from fuel cycle to fuel cycle. For a single cycle irradiation $C_j = 1.0$. However, for multiple cycle irradiations, particularly those employing low leakage fuel management the additional C_j correction must be utilized.

Corrections to Reaction Rate Data

Prior to using the measured reaction rates in the least squares adjustment procedure discussed above, additional corrections are made to the U-238 measurements to account for the presence of U-235 impurities in the sensors as well as to adjust for the build-in of plutonium isotopes over the course of the irradiation.

In addition to the corrections made for the presence of U-235 in the U-238 fission sensors, corrections are also made to both the U-238 and Np-237 sensor reaction rates to account for gamma ray induced fission reactions occuring over the course of the irradiation.

Least Squares Adjustment Procedure

Values of key fast neutron exposure parameters are derived from the measured reaction rates using the FERRET least squares adjustment code[11]. The FERRET approach uses the measured reaction rate data, sensor reaction cross-sections, and a calculated trial spectrum as input and proceeds to adjust the group fluxes from the trial spectrum to produce a best fit (in a least squares sense) to the measured reaction rate data. The "measured" exposure parameters along with the associated uncertainties are then obtained from the adjusted spectrum.

In the FERRET evaluations, a log-normal least squares algorithm weights both the trial values and the measured data in accordance with the assigned uncertainties and correlations. In general, the measured values f are linearly related to the flux ϕ by some response matrix A:

$$f_i^{(s,\alpha)} = \sum_g A_{ig}^{(s)} \phi_g^{(\alpha)}$$

where i indexes the measured values belonging to a single data set s, g designates the energy group, and α delineates spectra that may be simultaneously adjusted. For example,

$$R_i = \sum_g \sigma_{ig} \phi_g$$

relates a set of measured reaction rates R_i to a single spectrum ϕ_g by the multigroup reaction cross-section σ_{ig}. The log-normal approach automatically accounts for the physical constraint of positive fluxes, even with large assigned uncertainties.

In the least squares adjustment, the continuous quantities (i.e., neutron spectra and cross-sections) are approximated in a multi-group format consisting of 53 energy groups. The trial input spectrum is converted to the FERRET 53 group structure using the SAND-II code[2]. This procedure is carried out by first expanding the 47 group calculated spectrum into the SAND-II 620 group structure using a SPLINE interpolation procedure in regions where group boundaries do not coincide. The 620 point spectrum is then re-collapsed into the group structure used in FERRET.

Reference Forward Calculation

The forward transport calculation for the reactor is carried out in r,θ geometry using the DORT two-dimensional discrete ordinates code[4] and the BUGLE-93 cross-section library[5]. The BUGLE-93 library is a 47 neutron group, ENDFB-VI based, data set produced specifically for light water reactor applications. In these analyses, anisotropic scattering is treated with a P_3 expansion of the scattering cross-sections and the angular discretization is modeled with an S_8 order of angular quadrature. The reference forward calculation is normalized to a core midplane power density characteristic of operation at the stretch rating for the reactor.

The spatial core power distribution utilized in the reference forward calculation is derived from statistical studies of long-term operation of Westinghouse 3-loop plants. Inherent in the development of this reference core power distribution is the use of an out-in fuel management strategy; i.e., fresh fuel on the core periphery. Furthermore, for the peripheral fuel assemblies, a 2σ uncertainty derived from the statistical evaluation of plant to plant and cycle to cycle variations in peripheral power is used.

Due to the use of this bounding spatial power distribution, the results from the reference forward calculation establish conservative exposure projections for reactors of this design operating at the stretch rating. Since it is unlikely that actual reactor operation would result in the implementation of a power distribution at the nominal $+2\sigma$ level for a large number of fuel cycles and, further, because of the widespread implementation of low leakage fuel management strategies, the fuel cycle specific calculations for this reactor will result in exposure rates well below these conservative predictions.

Cycle Specific Adjoint Calculations

All adjoint analyses are also carried out using an S_8 order of angular quadrature and the P_3 cross-section approximation from the BUGLE-93 library. Adjoint source locations are chosen at several key azimuths on the pressure vessel inner radius. In addition, adjoint calculations were carried out for sources positioned at the geometric center of all surveillance capsules.

Again, these calculations are run in r,θ geometry to provide neutron source distribution importance functions for the exposure parameter of interest; in this case, $\phi(E > 1.0\ \text{MeV})$.

The importance functions generated from these individual adjoint analyses provide the basis for all absolute exposure projections and comparison with measurement. These importance functions, when combined with cycle specific neutron source distributions, yield absolute predictions of neutron exposure at the locations of interest for each of the operating fuel cycles; and, establish the means to perform similar predictions and dosimetry evaluations for all subsequent fuel cycles.

Having the importance functions and appropriate core source distributions, the response of interest can be calculated as:

$$\phi(R_0,\theta_0) = \int_r \int_\theta \int_E I(r,\theta,E)\ S(r,\theta,E)\ r\ dr\ d\theta\ dE$$

where: $\phi(R_0,\theta_0)$ = Neutron flux ($E > 1.0$ MeV) at radius R_0 and azimuthal angle θ_0.

$I(r,\theta,E)$ = Adjoint importance function at radius r, azimuthal angle θ, and neutron source energy E.

$S(r,\theta,E)$ = Neutron source strength at core location r,θ and energy E.

It is important to note that the cycle specific neutron source distributions, $S(r,\theta,E)$, utilized with the adjoint importance functions, $I(r,\theta,E)$, permit the use not only of fuel cycle specific spatial variations of fission rates within the reactor core; but, also allow for the inclusion of the effects of the differing neutron yield per fission and the variation in fission spectrum introduced by the build-in of plutonium isotopes as the burnup of individual fuel assemblies increases.

3. MEASUREMENT OF THE INITIAL NIL-DUCTILITY TRANSITION (NDT) TEMPERATURE OF THE REACTOR PRESSURE VESSEL BASE PLATE AND FORGINGS MATERIAL

The unirradiated or initial nil-ductility transition temperature of the pressure vessel base plate and forgings material was measured by two methods. These methods are the drop weight test per ASTM E208 and the Charpy V-notch impact test (Type A) per ASTM E23. The nil-ductility transition (NDT) temperature is defined in ASTM E208 as "the maximum temperature where a standard drop-weight specimen breaks when tested according to the provisions of this method". Using the Charpy V-notch test, the NDT temperature was defined as the temperature at which the energy required to break the specimen is a certain "fixed" value. For SA 302B and A508 Class 2 steel the ASME III Table N-421 specified an energy value of 30 ft-lb. This value was based on a correlation with the drop weight test and referred to as the "30 ft-lb-fix". A curve of the temperature versus energy absorbed in breaking the specimen was plotted. To obtain this curve, 15 tests were performed which included three tests at five different temperatures. The intersection of the energy versus temperature curve with the 30 ft-lb ordinate was designated as the NDT temperature.

The available data indicate differences as great as 40°F between curves plotted through the minimum and average values respectively. The determination of the NDT temperature from the average curve was considered representative of the material and was consistent with procedures as specified in ASTM E23. In assessing the NDT temperature shift due to irradiation, the translation of the average curve was used.

As part of the Westinghouse surveillance program referred to above, Charpy V-impact tests, tensile tests, and fracture mechanics specimens were taken from the core region plates and forgings, and core region weldments including heat-affected zone material. The test locations are similar to those used in the tests by the fabricator at the plate mill.

The uncertainties of measurement of the NDT temperature of the base plate were:

1. Differences in Charpy V-notch foot pound values at a given temperature between specimens.

2. Variation of impact properties through plate thickness.

The fracture toughness technology for pressure vessels and correlation with service failures based on Charpy V-notch impact data were based on the averaging of data. The Charpy V-notch 30 ft-lb "fix" temperature was based on multiple tests by the material supplier, the fabricator, and by Westinghouse as part of the surveillance program. The average of sets of three specimens at each test temperature was used in determining each of five data points (total of 15 specimens). In the review of available data, differences of 0°F to approximately 40°F were observed in comparing curves plotted through the minimum and average values, respectively. The value of the NDT temperature derived from the average curve was judged to be representative of the material because of the averaging of at least 15 data points, consistent with the specified procedures of ASTM E23.

In the case of the assessment of RT_{NDT} shift due to fast neutron flux, the displacement of transition curves is measured. The selection of maximum, minimum or average curves for this assessment is not significant since like curves would be used.

There are quantitative differences between the RT_{NDT} at the surface, 1/4 thickness or the center of a plate.

The 1/4T location is considered conservative, since the enhanced metallurgical properties of the surface are not used for the determination of RT_{NDT}. In addition, the limiting RT_{NDT} for the reactor vessel after operation will be based on the RT_{NDT} shift due to irradiation. Since the fast neutron dose is highest at the inner surface, usage of the 1/4T RT_{NDT} criterion is conservative.

To assess any possible uncertainties in the consideration of the RT_{NDT} shift for welds heat affected zone, and base metal, test specimens of these three "material types" have been included in the reactor vessel surveillance program.

REFERENCES

1. Schmittroth, E. A., "FERRET Data Analysis Code", HEDL-TME-79-40, Hanford Engineering Development Laboratory, Richland, Washington, September 1979.

2. McElroy, W. N., et. al., "A Computer-Automated Iterative Method of Neutron Flux Spectra Determined by Foil Activation," AFWL-TR-67-41, Volumes I-IV, Air Force Weapons Laboratory, Kirkland AFB, NM, July 1967.

3. RSIC Data Library Collection DLC-178, "SNLRML Recommended Dosimetry Cross-Section Compendium", July 1994.

4. RSIC Computer Code Collection CCC-543, "TORT-DORT Two- and Three-Dimensional Discrete Ordinates Transport, Version 2.8.14", January 1994.

5. RSIC Data Library Collection DLC-175, "BUGLE-93, Production and Testing of the VITAMIN-B6 Fine Group and the BUGLE-93 Broad Group Neutron/Photon Cross-Section Libraries Derived from ENDF/B-VI Nuclear Data", April 1994.

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APPENDICES

LIST OF TABLES

TABLE 5.4.3-1

PIPE RUPTURE
PROTECTION CRITERIA

LINES	A	B	C	D	E	F
High Head Safety Injection Lines	X	X	X	X	X	X
Low Head Safety Injection Lines	X	X	X	X		X
Boron Injection Tank Lines	X	X	X	X		X
Charging Line	X	X		X	X	
Emergency Cooler Lines	X	X	X	X	X	X
Reactor Coolant Letdown Lines	X	X	X	X	X	
Decay Heat Removal Line	X	X		X	X	
Blowdown Line	X		X	X	X	X
Main Steam and Feedwater Lines	X		X	X	X	X
Reactor Coolant System Lines	X	X	X	X	X	X
Spray Headers	X	X	X	X	X	X

7. Emergency Diesel Generators

- Engine, generator, fuel skid
- Fuel day tanks
- Fuel storage tanks
- Fuel transfer pumps
- Air start receivers
- Associated piping

NOTE: Load combinations for Class I structures, as supplemented by more recent criteria for Seismic Category I structures listed in Section 5.3.4.2, were used in the design of the Unit 4 EDG Seismic Category I structures. See Section 5.3.4.3 for specific design criteria.

8. Containment Polar Crane and Rail Support (Unloaded)

The containment polar crane and associated rails are seismically qualified Class I structures in the unloaded configuration. These structures are also seismically qualified in all plant operating modes for a maximum load lift of 1 ton (2,000 lbs.) by either hoist of the polar crane.

9. Refueling Water Storage Tanks

10. Emergency Containment Cooling and Filtering Units

11. Intake Cooling Water Systems

- Intake structure and crane supports
- Intake cooling water pumps and motors
- Intake cooling water piping, from pumps to component cooling water heat exchanger inlets
- Basket strainers

12. Component Cooling System

- Component cooling heat exchangers
- Component cooling pumps and motors
- Component cooling surge tanks

13. Spent Fuel Storage Facilities

- Spent fuel pit and racks
- Spent fuel pit cooling water pump and motor
- Spent fuel pit heat exchanger
- Spent fuel pit demineralizer

14. Safety Injection System

- Containment spray pumps and motors
- Residual heat removal pumps and motors (low-head safety injections pumps)
- Residual heat removal heat exchangers
- High-head safety injection pumps and motors
- Containment spray headers
- Accumulator tanks

15. Chemical and Volume Control System

- Charging pumps
- Volume control tank
- Boric acid blender
- Boric acid tanks
- Boric acid transfer pumps
- Boric acid filters
- Regenerative Heat Exchanger

16. Fuel Transfer Tube

17. Post Accident Containment Venting System

- Piping within containment and to at least the second valve outside containment

18. Waste Handling Facilities Building

19. Load Center HVAC

5A-1.3 Class I Structures, Systems and Equipment Design Requirements

5A-1.3.1 Class I Structure Design Requirements

5A-1.3.1.1 Normal Operation

For loads to be encountered during normal operation, Class I structures are designed in accordance with design methods of accepted standards and codes insofar as they are applicable.

5A-1.3.1.2 Hypothetical Accident, Wind and Earthquake Conditions

The Class I structures are proportioned to maintain elastic behavior when subjected to various combinations of dead loads, accident loads, thermal loads and wind or seismic loads. The upper limit of elastic behavior is considered to be the yield strength of the effective load-carrying structural materials. The yield strength for steel (including reinforcing steel) is considered to be the minimum as given in the appropriate ASTM Specification. Concrete structures are designed for ductile behavior whenever possible; that is, with steel stress controlling the design. The values for concrete, as given in the ultimate strength design portion of the ACI 318-63 Code, are used in determining "Y", the required yield strength of the material. Limited yielding is allowable provided the deflection is checked to ensure that the affected Class I systems and equipment (except reactor vessel internals under MHA loadings) are not stressed beyond the values given below.

The structure design loads are increased by load factors based on the probability and conservatism of the predicted normal design loads.

The Class I structures <u>outside</u> the containment structure satisfy the most severe of the following:

$$Y = 1/\phi\ (1.25D + 1.25E)$$

$$Y = 1/\phi\ (1.25D + 1.0R)$$

$$Y = 1/\phi\ (1.25D + 1.25H + 1.25E)$$

$$Y = 1/\phi\ (1.0D + 1.0E')$$

where:

Y = required yield strength of the material.

D = dead load of structure and equipment plus any other permanent loads contributing stress, such as soil or hydrostatic loads. In addition, a portion of "live load" is added when such load is expected to be present when the unit is operating. An allowance is also made for future permanent loads.

R = force or pressure on structure due to rupture of any one pipe.

H = force on structure due to restrained thermal expansion of pipes under operating conditions.

E = design earthquake load.

E' = maximum earthquake load.

W = wind load (to replace E in the above load equations whenever it produces higher stresses then E does).

Ø = 0.90 for reinforced concrete in flexure.

Ø = 0.85 for tension, shear, bond, and anchorage in reinforced concrete.

Ø = 0.75 for spirally reinforced concrete compression members.

Ø = 0.70 for tied compression members.

Ø = 0.90 for fabricated structural steel.

5A-1.3.2 Class I Systems and Equipment Design Requirements

All Class I systems and equipment are designed to the standards of the applicable Code. The loading combinations which are employed in the design of Class I systems and equipment are given in Table 5A-1.

Table 5A-1 also indicate the stress limits which are used in the design of the listed equipment for the various loading combinations.

To perform their function, i.e., allow core shutdown and cooling, the reactor vessel internals must satisfy deformation limits which are more restrictive than the stress limits shown on Table 5A-1. For this reason the reactor vessel internals are treated separately.

5A-1.3.2.1 Piping and Vessels

The reasoning for selection of the load combinations and stress limits given in Table 5A-1 is as follows: For the design earthquake, the nuclear steam supply system is designed to be capable of continued safe operation, i.e., for the combination of normal loads and design earthquake loading. Critical equipment needed for this purpose is required to operate within normal design limits.

In the case of the maximum hypothetical earthquake, it is only necessary to ensure that critical components do not lose their capability to perform their safety function, i.e., shut the unit down and maintain it in a safe condition. This capability is ensured by maintaining the stress limits as shown in Table 5A-1. No rupture of a Class I pipe is caused by the occurrence of the maximum hypothetical earthquake.

Careful design and thorough quality control during manufacture and construction and inspection during unit life, ensures that the independent occurrence of a reactor coolant pipe rupture is extremely remote. Leak-Before-Break (LBB) criteria has been applied to the reactor coolant system piping based on fracture mechanics technology and material toughness. That evaluation, together with the leak detection system, demonstrates that the dynamic effects of postulated primary loop pipe ruptures may be eliminated from the design basis (Reference 5A-2). This Leak-Before-Break evaluation was approved by the NRC for use at Turkey Point (Reference 5A-5).

5A-1.3.2.2 Reactor Vessel Internals

5A-1.3.2.2.1 Reactor Vessel Internals Design Criteria

The internals and core are designed for normal operating conditions and subjected to load of mechanical, hydraulic, and thermal origin. The response of the structure under the design earthquake is included in this category.

The stress criteria established in the ASME Boiler and Pressure Vessel Code, Section III, Article 4, have been adopted as a guide for the design of the internals and core with the exception of those fabrication techniques and materials which are not covered by the Code. Earthquake stresses are combined in the most conservative way and are considered primary stresses.

The members are designed under the basic principles of: (1) maintaining distortions within acceptable limits; (2) keeping the stress levels within acceptable limits; and (3) prevention of fatigue failures.

5A-1.3.2.2.2 Reactor Vessel Internals Design Analysis

A mathematical model of the reactor pressure vessel using three-dimensional nonlinear finite elements was used to evaluate the reactor internals as part of the thermal uprate project. The model consists of three submodels interconnected by nonlinear impact elements. The first submodel consists of the reactor vessel, shell, and associated components. The second submodel consists of the reactor core barrel, thermal shield, lower support plate, tie plates, and secondary core support components. The third submodel represents the upper support plate, guide tubes, support columns, upper and lower core plates, and the fuel.

Loading applied to the analytical model includes: (a) deadweight of the components and contents; (b) pressure differentials due to coolant flow; (c) seismic excitation; (d) loss of coolant accident loads; (e) vibrational loading; (f) thermal expansion; and (g) preloads on certain components.

Global element matrices and arrays are assembled into the global structural matrices and arrays and used for dynamic solution of the differential equation of motion for the structure:

$$[M]\{\ddot{U}\} + [D]\{U\} + [K]\{U\} = F$$

All resulting stresses and deflections are less than the respective criteria. Fatigue usage factors are in accordance with ASME acceptance limits (Reference 5A-1).

5A-1.3.3 Class I Structures, Systems and Equipment Seismic Loading (Seismic Loads E and E')

AEC Publication TID 7024, "Nuclear Reactors and Earthquakes", as amplified in this Appendix is used as the basic design guide for seismic analysis.

Seismic loading on structures, systems and equipment is determined by realistic evaluation of dynamic properties and the accelerations from the attached acceleration spectrum curves. These spectrum curves are corrected for the design ground accelerations. Damping factors are listed in the table below.

Seismic forces are combined by absolute summation of the vertical and highest horizontal direction. The vertical component of acceleration at any level is taken as two-thirds of the horizontal ground acceleration.

DAMPING FACTORS FOR VARIOUS TYPES OF CONSTRUCTION

STRUCTURAL COMPONENT	% CRITICAL DAMPING	
	Design Earthquake (E) (0.05g Ground Surface Acceleration)	Maximum Earthquake (E') (0.15g Ground Surface Acceleration)
Welded Steel Plate Assemblies	1	1
Welded Steel Framed Structures	2	2
Bolted Steel Framed Structures	2	2
Concrete Equipment Supports on Another Structure	2	2
Prestressed Concrete Containment Structure	2	5
Soil	5	10
Prestressed Containment Including Interior Concrete and Soil Composite	3.5	7.5
Reinforced Concrete Frames and Buildings	3	5
Composite with Soil	5	7.5
Steel Piping	0.5	0.5

5A-1.3.4 Class I Structures, Systems and Equipment Wind Loading (Wind Load W)

The wind loads are determined from the fastest mile of wind for a 100-year occurrence as shown in Figure 1(b) of Reference 5A-4. This is 122 mph at the Turkey Point site. The Class I structures are designed, however, to withstand a wind velocity at 145 mph.

The forces due to the wind are calculated in accordance with methods described in Reference 5A-4. Applicable pressure and shape coefficients are used. There is no variation with height or gust factor.

5A-1.3.5 Class I Structures, Systems and Equipment Tornado Wind Loading

Class I structures are designed to resist the effects of a tornado. Design loadings due to tornado winds used in the design of tornado resistant structures are as follows, the loads to be applied simultaneously:

1. Differential pressure between inside and outside of enclosed areas - 1.5 psi (bursting).

2. External forces resulting from a tornado wind velocity of 225 mph.

3. Missiles as defined in Appendix 5E.

The forces resulting from a tornado are combined with dead loads only. Dead loads include piping and all other permanently attached or located items. There will be sufficient time after sighting a tornado to remove significant live loads such as loads on cranes.

When considering tornado wind loading, allowable stresses are limited to yield strength for structural steel and reinforced concrete. Local crushing of concrete is permitted at the missile impact zone. In addition, all Class I structures are reviewed to assure no loss of function for tornado wind 337 MPH combined with a pressure differential of 2.25 psi.

5A-1.4 Class III Structures, Systems and Equipment

5A-1.4.1 Design Requirements

Class III Systems and equipment including pipe are not designed to withstand any earthquake loads. The wind loads are as per South Florida Building Code which has a basic design pressure of 37 psf. Shape Factors are applied in accordance with Reference 5A-4. No tornado loads are considered.

5A-1.4.2 Turkey Point Fossil Units 1 and 2 Chimney Design Requirements

The Fossil Unit 1 & 2 chimneys, located directly north of Unit 3, do not perform any safety related functions, or directly protect safety related equipment. However, failure of these structures has the potential of adversely affecting safety related systems. Accordingly, these structures have been designed to not fail and cause an adverse interaction with any safety related systems, when subjected to the Class I seismic loads (0.15 g) and wind loads (145 mph hurricane and 225 mph tornado) described in Sections 5A-1.3.4 and 5A-1.3.5 of this appendix.

5A-1.5 Miscellaneous Loads for Structures, Systems and Equipment

The units are designed for an outdoor temperature range of +30°F to +95°F. No ice or snow loads are considered in the design of the various structures and equipment.

External flood protection is described in Appendix 5G.

5A-2.0 METHOD OF SEISMIC ANALYSIS

5A-2.1 Structures

The methods for seismic analysis of the containment and control building structures are described in Section 5.1.3.2.

5A-2.2 Response Spectra

Response spectra curves for floors at grade and for the containment basemat were developed based on the El Centro, California, earthquake. These curves are shown in Figures 5A-1 for the design basis earthquake event (E), and Figure 5A-2 for the maximum earthquake event (E′). The analysis methodology is similar to the technique described in Section 5.1.3.2(b). (Reference 5A-3)

5A-2.3 Seismic Class I Piping Analysis

Seismic Class I piping systems are typically analyzed as mathematical models consisting of lumped masses connected by elastic members. The distance from the pipe axis to the center of gravity of the valve and operator is considered, with the mass of the valve and operator, for all motor, air, or gear operated valves. When necessary for the integrity of the piping, valve, or operation, the valve structure is externally supported. The stiffness matrix for the pipe is developed to include the effects of torsional, bending, shear and axial deformations as well as change in flexibility due to curved members and internal pressure. Flexibility factors are calculated in accordance with USAS B31.1. System natural frequencies and mode shapes for all significant modes of vibration are then determined using equations of motion, and spectral accelerations as determined from the response spectra applied.

The following equations are successively used to determine the response for each mode, maximum displacement for each mode, and the total displacement for each mass point:

(1) $$Y_n(\max) = \frac{R_n Sa_n D}{M_n \omega_n^2}$$

(2) $$V_{in} = \Phi_{in} Y_n(\max)$$

(3) $$V_i = \sqrt{\sum V_{in}^2}$$

where;

$Y_n(\max)$ = response of the n^{th} mode

R_n = participation factor for the n^{th} mode = $\Sigma M_i \Phi_{in}$

M_i = mass i

Φ_{in} = mode shape i for n^{th} mode

Sa_n = spectral acceleration for the n^{th} mode

D = earthquake direction matrix

M_n = generalized mass matrix for the n^{th} mode = $\Sigma M_i \Phi^2_{in}$

ω_n = angular frequency of the n^{th} mode

V_{in} = maximum displacement of mass i for mode n

V_i = maximum displacement of mass i due to all modes calculated

The inertial forces for each direction of earthquake for each mode are then determined from:

$$Q_n = KV$$

where;

Q_n = inertia force matrix for mode n

V = displacement matrix corresponding to Q_n

K = stiffness matrix

Each mode's contribution to the total displacements, internal forces, moments and reactions in the pipe can be determined from standard structural analysis methods using the inertia forces for each mode as an external loading condition. The total combined results are obtained by taking the square root of the sum of the squares of each parameter under consideration, in a manner similar to that done for displacements.

A representative number of critical piping runs have been analyzed by this method. Balance of the pipe runs have been evaluated by:

(i) Closeness of similarity to the runs fully analyzed,

(ii) Simplicity of layout lending to a visual examination for location of seismic restraints to remove the fundamental frequency away from the resonance range, and

(iii) Static analysis based on a uniform static load equal to the peak of the pertinent response spectrum curve.

5A-3.0 METHOD OF SEISMIC ANALYSIS AND RESULTS FOR REACTOR COOLANT LOOP

The reactor coolant loop (RCL) which consists of the reactor vessel (RV), steam generator (SG), reactor coolant pump (RCP), the pipe connecting these components, and the large component supports has been analyzed for seismic loads. The components and piping are modeled as a system of lumped masses connected by springs whose values are computed from elastic properties that are input. A simplified support model was arrived at by representing the structural support system as equivalent springs rather than as member beams and columns.

The analysis was performed by using a proprietary computer code called WESTDYN. The code uses as input, system geometry, inertia values, member sectional properties, elastic characteristics, support and restraint characteristics, and the appropriate seismic floor response spectrum for 0.5% critical damping. The floor response spectrum curves were generated at the appropriate support locations of the equipment by a time history technique described in Section 5.1.3(b). Both horizontal and vertical components of the seismic response spectrum are applied simultaneously. Two directions, namely X and Z axes, were chosen for application of the horizontal component of the seismic response spectrum. The results of the two cases were combined to determine the most severe loading condition.

With this input data, the overall stiffness matrix [K] of the three dimensional piping system is generated (including translational and rotational stiffnesses). Zero rows and columns representing restraints are deleted, and the stiffness matrix is inverted to give the flexibility matrix [F] of the system.

$$[F] = [K]^{-1}$$

A product matrix is formed by the multiplication of the flexibility and mass matrices. This product matrix forms the dynamic matrix, [D], from which the modal matrix is computed.

$$[D] = [F]\,[M]$$

The eigenvalues and eigenvectors representing the frequency and associated mode shape for each mode are generated using a modified Jacobi method.

$$(\omega^2[M] - [K])\,\{X\} = 0$$

From this information, the modal participation factor is combined with the mode shapes and the appropriate seismic response spectrum values to give the structural response for each mode. Then the forces, moments, deflections, rotations, constraint reactions, and stresses are calculated for each significant mode. The maximum response of the system is obtained by combining the modal contributions using the root mean square method.

b. Using the design practice of ASME Section VIII for flange design.
c. And by controlling the load during the bonnet body connection stud tightening process.

The pressure containing parts except the flange and studs are designed per criteria established by the USAS B16.5. Materials of construction for these parts are procured per ASTM A182, F316, or A351, GR CF8M.

Stud and nut material is ASTM A193-B7 and A194-2H. The proper stud torquing procedures and the use of torque wrench, with indication of the applied torque, limit the stress of the studs to the allowable limits established in the ASME Code, i.e., 20,000 psi. This stress level is far below the material yield, i.e., about 105,000 psi. The complete valves are hydrotested per USAS B16.5. (1500# USAS valves are hydro to 5400 psi). The cast stainless steel bodies and bonnets are radiographed and dye penetrant tested to verify soundness.

Valves with nominal diameters of 2" or smaller are forged and have screwed bonnets with canopy seals. The canopy seal is the pressure boundary while the bonnet threads are designed to withstand the hydrostatic end force. The pressure containing parts are designed per criteria established by the USAS B16.5 Specification.

Valve Replacements:

Use of the ASME Section III Code for procurement of replacement valves is acceptable in lieu of the above design requirements. The ASME Section III Code is a well recognized nuclear design code meeting the design and quality requirements of the Nuclear industry. Additionally, substitution of the original construction code for ASME Section III is permitted via the NRC adopted Code Case N-406.

Reactor Coolant Pump Flywheel

The reactor coolant pump flywheel is not considered to be a credible source of missiles because of conservative design and care in manufacture and inspection. The flywheel material is ASTM A-533 having an NDTT less than $10^{\circ}F$. The design results in a primary stress less than 50% of the material yield strength at operating speed. The flywheel is subjected to 100% volumetric ultrasonic inspection which will be repeated at intervals during unit life. The finished machined bore is subjected to either magnetic particle or liquid penetrant examination. The design overspeed of the pump is 125% of rated speed. The maximum pump speed on loss of external load is 112% of rated speed.

Recirculation Phase

After the injection operation, coolant spilled from the break and water collected from the containment spray is cooled and returned to the Reactor Coolant System by the recirculation system.

Those portions of the Safety Injection System located outside of the containment which are designed to circulate, under post-accident conditions, radioactively contaminated water collected in the containment, meet the following requirements:

a) Shielding to maintain radiation levels within the guidelines set forth in 10CFR100. (Section 11.2)

b) Collection of discharges from pressure relieving devices into closed systems.

c) Means to limit radioactivity leakage to the environs, within guidelines set forth in 10CFR100.

When the break is large, depressurization occurs due to the large rate of mass and energy loss through the break to containment. The system is arranged so that the residual heat removal pumps take suction from the sump in the containment floor and deliver spilled reactor coolant and borated refueling water back to the core through the residual heat exchangers. The system is arranged to allow either of the residual heat removal pumps to take over the recirculation function. Only one pump is required to handle the total recirculation flow after the MHA.

There are two sump return lines which lead from the containment to the residual heat removal pumps. The arrangement of recirculation equipment is shown on Figures 6.2-1 and 6.2-5.

Filtration of the water entering the residual heat removal pump section piping is accomplished by screens located over the sumps which remove all debris 1/4" or larger.

Two sumps, each with individually 14" diameter outlet, are provided at the 14' -0" elevation. In the unlikely event that one sump is 100% clogged and the other sump is 50% clogged, required recirculation flow can still be maintained.

Recirculation may start with a water depth of 2.93 feet on the containment floor at elevation 14' -0". This is equivalent to 249,000 gallons of water at 283°F. The maximum velocity of approach to the Screens is less than 1/2 ft/sec.

Recirculation loop leakage is discussed in Section 6.2.3.

Recirculation Phase - Hot Leg

The hot leg recirculation flow path via the high head safety injection pumps is provided for continuation of the recirculation phase. A residual heat removal train supplies flow to the SI pumps suctions. The SI pumps discharge to the hot leg injection header. Hot leg recirculation is required to prevent boric acid plate-out on the fuel cladding from reducing core cooling following a cold leg break.

Recirculation Phase - Cold Leg

For the recirculation phase of the accident the reactor coolant water which eventually drains to the containment recirculation sump is recirculated through the sump line from the containment to the suction of the residual heat removal pump through two independent and redundant recirculation lines. Each line has two motor operated valves. The first valve is located as close as possible to the containment such that the line outside the containment can be isolated in the event of a passive failure. During recirculation one recirculation train will be in service which includes either of the two residual heat removal pumps and either one or two residual heat exchangers. The flow will go from the discharge of the residual heat removal pump through the residual heat exchanger and then into the reactor via either the low head injection path or the high head injection path via the safety injection pumps.

Components

All associated components, piping, structures, and power supplies, of the Safety Injection System are designed to Class I seismic criteria.

All components inside the containment are capable of withstanding or are protected from differential pressure which may occur during the rapid pressure rise.

Motors which operate only during or after the postulated accident are designed as if used in continuous service. Periodic operation of the motors and the tests of the insulation will ensure that the motors remain in a reliable operating condition.

All motors, instruments, transmitters, and their associated cables located inside the containment which are required to operate following the accident are designed to function under the post-accident temperature, pressure and humidity conditions.

The quality standards of all safety injection system components is tabulated in summary form in Table 6.2-3.

Accumulators

The accumulators are pressure vessels filled with borated water and pressurized with nitrogen gas. During normal operation each accumulator is isolated from the Reactor Coolant System by two check valves in series.

Should the Reactor Coolant System pressure fall below the accumulator pressure, the check valves open and borated water is forced into the Reactor Coolant System. Mechanical operation of the swing-disc check valves is the only action required to open the injection path from the accumulators to the core via the cold leg.

The accumulators are passive engineered safety features because the gas forces injection; no external source of power or signal transmission is needed to obtain a fast-acting, high-flow capability when the need arises. One accumulator is attached to each of the cold legs of the Reactor Coolant System.

The design capacity of the accumulators is based on the assumption that flow from one accumulator spills onto the containment floor through the ruptured loop, and the flow from the remaining accumulators provides sufficient water to fill the volume outside of the core barrel below the nozzles, the bottom plenum, and penetrate the core. Connections for remotely draining or filling the fluid space, during normal operation, are provided.

The level of borated water in each accumulator tank is adjusted remotely as required during normal operation. Refueling water is added using a safety injection pump. Water level is reduced by draining to the reactor coolant drain tank. Samples of the solution in the tanks are taken at the sampling station to confirm boron concentration.

Redundant level and pressure indicators are provided with read outs on the control board. Each indicator is equipped with high and low level alarms.

The accumulator design parameters are given in Table 6.2-4.

Boron Injection Tank

The boron injection tank is located in the flow path between the high head safety injection pumps discharge and the cold legs. The tank contains refueling concentration boric acid solution. The tank was previously maintained at 12% boric acid solution, with heating to maintain tank temperature above the solubility limits of this solution. Reanalysis of the steam pipe rupture accident showed adequate results for all accident conditions for ranges of boron concentration in the tank from 0-2350 ppm boron.

The tank no longer serves any accident mitigating functions other than as part of the Safety Injection System boundary.

The tank is vertical with the outlet nozzle on top.

Design parameters are given in Table 6.2-5. The Unit 4 BIT has been bypassed and removed from the system flowpath.

Refueling Water Storage Tank

In addition to its usual duty to supply borated water to the refueling canal for refueling operations, this tank provides borated water to the safety injection pumps, the residual heat removal pumps and the containment spray pumps for the loss-of-coolant accident. During operation it is aligned to the suction of the pumps. It is constructed of epoxy coated carbon steel.

The capacity of the refueling water storage tank is based on the requirement for filling the refueling canal, given in Table 9.5-1. This capacity provides an amount of borated water to assure:

a) A volume sufficient to refill the reactor vessel above the nozzles.

b) The volume of borated refueling water needed to increase the concentration of initially spilled water to a point that assures no return to criticality with the reactor at cold shutdown.

c) A sufficient volume of water on the floor to permit the initiation of recirculation.

The water in the tank is borated to a concentration which assures reactor shutdown by at least 5% $\Delta k/k$ when all RCC assemblies are inserted and when the reactor is cooled down for refueling. The maximum boric acid concentration is approximately 1.4 weight percent boric acid. At 32°F the solubility limit of boric acid is 2.2%. Therefore the concentration of boric acid in the refueling water storage tank is well below the solubility limit at 32°F.

A technical specification minimum level alarm and a high level alarm are provided. Nominal RWST level indication with high and low level alarms are also provided. The low level alarm setpoint has been determined to provide sufficient NPSH for the containment spray pumps.

A dynamic response analysis similar to that performed for the Containment Structure has been performed to determine the horizontal loads applied to this tank for a 5% ground acceleration based on yield stresses and a 15% ground acceleration based on maximum deflection. Waves generated in the tank have been taken into account as per "Nuclear Reactors and Earthquake", TID 7024. A membrane stress analysis of the vertical cylindrical tank was performed considering the discontinuities at the base and top.

The design parameters are given in Table 6.2-6.

<u>Safety Injection Pumps</u>

The four high-head safety injection pumps for supplying borated water to the Reactor Coolant System are horizontal centrifugal pumps driven by electrical motors. Parts of the pump in contact with borated water are stainless steel or equivalent corrosion resistant material. A minimum flow bypass line is provided on each pump discharge to recirculate flow to the refueling water storage tank in the event the pumps are started with the normal flow paths blocked. The design parameters are presented in Table 6.2-7 and Figure 6.2-3 gives the performance characteristic of these pumps.

The two residual heat removal (low head) pumps of the Auxiliary Coolant System are used to inject borated water at low pressure to the Reactor

The designs of the heat exchangers also conform to the requirements of TEMA (Tubular Exchanger Manufacturers Association) for Class R heat exchangers. Class R is the most rugged class of TEMA heat exchangers and is intended for units where safety and durability are required under severe service conditions. Items such as: tube spacing, flange design, nozzle location, baffle thickness and spacing, and impingement plate requirements are set forth by TEMA Standards.

In addition to the above, additional design and inspection requirements were imposed to ensure rugged, high quality heat exchangers such as: confined-type gaskets, main flange studs with two nuts on each end to ensure permanent leak tightness, general construction and mounting brackets suitable for the plant seismic design requirements, tubes and tube sheet capable of withstanding full shell side pressure and temperature with atmospheric pressure on the tube side, ultrasonic inspection in accordance with Paragraph N-324.3 of Section III of the ASME Code of all tubes before bending, penetrant inspection in accordance with Paragraph N-627 of Section III of the ASME Code of all welds and all hot or cold formed parts, a hydrostatic test duration of not less than thirty minutes, the witnessing of hydro and penetrant tests by a qualified inspector, a thorough final inspection of the unit for good workmanship and the absence of any gouge marks or other scars that could act as stress concentration points, a review of the radiographs and of the certified chemical and physical test reports for all materials used in the unit.

The Residual Heat Exchangers are conventional vertical shell and U-tube type units. The tubes are seal welded to the tube sheet. The shell connections are flanged to facilitate shell removal for inspection and cleaning of the tube handle. Each unit has a SA-285 Grade C carbon steel shell, a SA-234 carbon steel shell end cap, SA-213 TP-304 stainless steel tubes, SA-240 Type 304 stainless steel channel, SA-240 Type 304 stainless steel channel cover and SA-240 Type 304 stainless steel tube sheet.

Valves

All parts of valves used in the Safety Injection System in contact with borated water are austenitic stainless steel or equivalent corrosion resistant material. The motor operators on the injection line isolation valves are capable of rapid operation. All valves required for initiation of safety injection or isolation of the system have remote position indication in the control room.

Valving is specified for exceptional tightness and, where possible, such as instrument valves, packless diaphragm valves are used. All valves, except those which perform a control function, are provided with backseats which are capable of limiting leakage to less than 1.0 cc per hour per inch of stem diameter, assuming no credit taken for valve packing. Manual and motor operated gate and globe valves that are normally operated and in containment are not backseated. Other normally opened valves are backseated. Normally closed globe valves are installed with recirculation flow under the seat to prevent leakage of recirculated water through the valve stem packing. Relief valves are totally enclosed. Control and motor-operated valves, 2 1/2" and above, which are exposed to recirculation flow, are provided with double-packed stuffing boxes and stem leakoff connections which are piped to the Waste Disposal System.

The check valves which isolate the Safety Injection System from the Reactor Coolant System are installed immediately adjacent to the reactor coolant piping to reduce the probability of an injection line rupture causing a loss-of-coolant accident.

Four relief valves are associated with the post loss of coolant recirculation. One is located outside the containment upstream of MOV-*843A&B to prevent overpressure in the header and in the and relieves to the refueling water storage tank. The high head safety injection piping leading to the hot legs is protected by the second, that is the relief valve which is inside the containment in the piping associated with containment Penetration No. 18. This valve relieves to the pressurizer relief tank. The third valve is located on the residual heat removal loop common header leading to the accumulator pipes. This valve is inside containment and relieves to the pressurizer relief tank. The fourth valve is also located inside containment in the test line and provides overpressure protection for the piping associated with Penetration No. 17. This valve also relieves to the pressurizer relief tank. The relieving capacity of these valves is based on a flow several times greater than the expected leakage rate through the check and isolation valves. They will also prevent overpressurization due to thermal expansion. The relief valves on the accumulator protect them from pressures in excess of the design values.

Motor Operated Valves

The pressure containing parts (body, bonnet and discs) of the valves employed in the Safety Injection System are designed per criteria established by the USAS B16.5 or MSS SP66 specifications. The materials of construction for these parts are procured per ASTM A182, F316 or A351, GR F8M, or F8. All material in contact with the primary fluid, except the packing, is austenitic stainless steel or equivalent corrosion resisting material. The pressure containing cast components are radiographically inspected as outlined in ASTM E-71 Class 1 or Class 2. The body, bonnet and discs are liquid penetrant inspected in accordance with ASME Boiler and Pressure Vessel Code Section VIII, Appendix VIII. The liquid penetrant acceptable standard is as outlined in USAS B31.1 Case N-10. When a gasket is employed the body-to-bonnet joint is designed per ASME Boiler and Pressure Vessel Code Section VIII or USAS B16.5 with a fully trapped, controlled compression, spiral wound asbestos gasket with provisions for seal welding, or of the pressure seal design with provisions for seal welding. The body-to-bonnet bolting and nut materials are procured per ASTM A193 and A194, respectively.

The entire assembled unit is hydrotested as outlined in MSS SP-61 with the exception that the test is maintained for a minimum period of 30 minutes per inch of wall thickness. Any leakage is cause for rejection. The seating design is of the Darling parallel disc design, the Crane flexible wedge design, or the equivalent. These designs have the feature of releasing the mechanical holding force during the first increment of travel. Thus, the motor operator has to work only against the frictional component of the hydraulic unbalance on the disc and the packing box friction. The discs are guided throughout the full disc travel to prevent chattering and provide ease of gate movement. The seating surfaces are hard faced (Stellite No. 6 or equivalent) to prevent galling and reduce wear.

The stem material is ASTM A276 Type 316 condition B or precipitation hardened 17-4 PH stainless procured and heat treated to Westinghouse Specifications. These materials are selected because of their corrosion resistance, high tensile properties, and their resistance to surface scoring by the packing. The valve stuffing box is designed with a lantern ring leak-off connection with a minimum of a full set of packing below the lantern ring and a maximum of one-half of a set of packing above the lantern ring; a full set of packing is defined as a depth of packing equal to 1-1/2 times the stem diameter. The experience with this stuffing box design and the selection of packing and stem materials has been very favorable in both conventional and nuclear power plants. The RHR suction isolation valves (MOV-*-750, MOV-*-751) stuffing boxes are designed with one full set of packing. Additionally, MOV-*-751 valves have no leakoff connections. The experience with this design has also been very favorable in both conventional and nuclear power plants.

The motor operator is extremely rugged and is noted throughout the power industry for its reliability. The unit incorporates a "hammer blow" feature that allows the motor to impact the discs away from the fore or backseat upon opening or closing. This "hammer blow" feature not only impacts the disc but allows the motor to attain its operational speed.

The valve is assembled, hydrostatically tested, seat-leakage tested (fore and back), operationally tested, cleaned and packaged per specifications. All manufacturing procedures employed by the valve supplier such as hard facing, welding, repair welding and testing are submitted to Westinghouse for approval.

For those valves which must function on the safety injection signal, 10 second operators are provided. For all other valves in the system, the valve operator completes its cycle from one position to the other within 180 seconds. Valve stroke times may be increased as a result of evaluations performed in accordance with NRC Generic Letter 89-10.

Valves are required to function under the maximum differential pressures determined in accordance with the requirements of NRC Generic Letter 89-10.

Safety related power operated gate valves were evaluated for their susceptibility to pressure locking and thermal binding as required by NRC Generic Letters 89-10 and 95-07. The following motor operated valves each have a design feature (either a hole drilled in one of the discs or a bonnet vent to provide relief from the inter-disc space) which preclude the potential for pressure locking as described in the two generic letters:

MOV-*-350, MOV-*-750/751, MOV-*-843A/B, MOV-*-860A/B, MOV-*-861A/B, MOV-*-869, and MOV-*-872.

<u>Manual Valves</u>

The stainless steel manual globe, gate and check valves are designed and built in accordance with the requirements outlined in the motor operated valve description above.

The carbon steel valves are built to conform with USAS B16.5. The materials of construction of the body, bonnet and disc conform to the requirements of ASTM A105 Grade II, A181 Grade II or A216 Grade WCB or WCC. The carbon steel valves pass only non-radioactive fluids and are subjected to hydrostatic test as outlined in MSS SP-61, except that the test pressure is maintained for at least 30 minutes per inch of wall thickness. Since the fluid controlled by the carbon steel valves is not radioactive, the double packing and seal weld provisions are not provided.

Accumulator Check Valves

The pressure containing parts of this valve assembly are designed in accordance with MSS SP-66. All parts in contact with the operating fluid are of austenitic stainless steel or of equivalent corrosion resistant materials procured to applicable ASTM or WAPD specifications. The cast pressure-containing parts are radiographed in accordance with ASTM E-94 and the acceptance standard as outlined in ASTM E-71. The cast pressure-containing parts, machined surfaces, finished hard facings, and gasket bearing surfaces are liquid penetrant inspected per ASME B&PV Code, Section VIII and the acceptance standard is as outlined in USAS B31.1 Code Case N-10. The final valve is hydrotested per MSS SP-66, except that the test pressure is maintained for at least 30 minutes. The seat leakage is conducted in accordance with the manner prescribed in MSS SP-61, except that the acceptable leakage is 2cc/hr/in, nominal pipe diameter.

The valve is designed with a low pressure drop configuration with all operating parts contained within the body, which eliminates those problems associated with packing glands exposed to boric acid. The clapper arm shaft is manufactured from 17-4 PH stainless steel heat treated to Westinghouse Specifications, The clapper arm shaft bushings are manufactured from Stellite No. 6 material, The various working parts are selected for their corrosion resistant, tensile, and bearing properties.

The disc and seat rings are manufactured from a forging. The mating surfaces are hard faced with Stellite No. 6 to improve the valve seating life. The disc is permitted to rotate, providing a new seating surface after each valve opening.

The valves are intended to be operated in the closed position with a normal differential pressure across the disc of approximately 1550 psi. The valves shall remain in this position except for testing and safety injection and are not subjected to impact loads caused by sudden flow reversal.

except the RHR suction isolation valves (MOV-*-750, MOV-*-751) which have one set of packing. Additionally, MOV-*-751 valves have no stem leak-off connections.

The specified leakage across the valve disc required to meet the equipment specification and hydrotest requirements is as follows:

a) Conventional globe - 3 cc/hr/in. of nominal pipe size.
b) Gate valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in for 300 and 150 pound USA Standard.
c) Motor-operated gate valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in for 300 and 150 pound USA Standard.
d) Check valves - 3 cc/hr/in. of nominal pipe size; 10 cc/hr/in for 300 and 150 pound USA Standard
e) Accumulator check valves -2 cc/hr/in. of nominal pipe size

Relief valves are totally enclosed. Leakage from components of the recirculation loop including valves is tabulated in Table 6.2-12.

Piping

All Safety Injection System piping in contact with borated water is austenitic stainless steel. Piping joints are welded except for the flanged connections at the safety injection and containment spray pumps.

The piping beyond the accumulator stop valves is designed for Reactor Coolant System conditions (2485 psig, 650°F). All other piping connected to the accumulator tanks is designed for 700 psig and 400°F.

The safety injection pump suction piping (210 psig at 300°F) from the refueling water storage is designed for low pressure losses to meet NPSH (net positive suction head) requirements of the pumps.

The safety injection high pressure branch lines (1500 psig at 300°F) to the hot legs are designed for high pressure losses to limit the flow rate out of a potential rupture of a branch line at the connection to the reactor coolant loop.

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The rising water level in the pressurizer provides indication of systems delivery. Flow into the reactor coolant system is terminated at a prescribed pressurizer level by manually stopping safety injection pumps.

Tests are performed to provide information to confirm valve operating times, pump motor starting times, the proper automatic sequencing of, load addition to the emergency diesels, and delivery rates of injection water to the reactor coolant system.

Tests are performed for the various modes of operation needed to demonstrate performance at partial effectiveness, i.e., to demonstrate the proper loading sequence with loss of one of the diesel generator power sources. These latter cases are performed without delivery of water to the reactor coolant system, but include starting of all pumping equipment involved in each test.

The systems are accepted only after demonstration of proper actuation and after demonstration of flow delivery and shutoff head within design requirements.

Flow is introduced into the Reactor Coolant loops through the accumulator discharge line to demonstrate operability of the check valves and remotely actuated stop valve and confirm L/D ratios of accumulator discharge lines used in the calculation.

Post-Operational Testing

Component Testing

Routine periodic testing of the safety injection system components and all necessary support systems at power is planned. No inflow to the Reactor Coolant System will occur whenever the reactor coolant pressure is above 1500 psi. If such testing indicates a need for corrective maintenance, the redundancy of equipment in these systems permits such maintenance to be performed without shutting down or reducing load under conditions defined in the Technical Specifications. These conditions include such matters as the period within which the component should be restored to service and the capability of the remaining equipment to meet safety limits within such a period.

The operation of the remote stop valves in the accumulator discharge line may be tested by opening the remote test valves just downstream of the stop valves. Flow through the test line can be observed on instruments and the opening and closing of the discharge line stop valves can be sensed on this instrumentation. Test capabilities are provided to periodically examine the leakage back through the check valves and to ascertain that these valves seat whenever the reactor system pressure is raised.

It is expected that this test will be routinely performed when the reactor is being returned to power after an outage and the reactor pressure is raised above the accumulator pressure.

The residual heat removal and high head safety injection pumps will be run periodically. Idle intake cooling water and component cooling water pumps will be put in service periodically as part of the normal rotation of machinery use. The content of the accumulators, the boron injection tank and the refueling water storage tank are sampled periodically to determine that the required boron concentration is present.

TABLE 6.2-1

SAFETY INJECTION SYSTEM - CODE REQUIREMENTS

Component	Code
Refueling Water Storage Tank	AWWA D100-65
Residual Heat Exchanger	
Tube Side	ASME Section III*Class C
Shell Side	ASME Section VIII
Accumulators	ASME Section III Class C
Boron Injection Tank	ASME Section III Class C
Valves	USAS B16.5**
Piping	USAS B31.1***

*ASME Section III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code Section III, Nuclear Vessels - 1965

**Aloyco valve weld ends in accordance with Westinghouse Spec. No. G-676241, Dwg. No. 498B932, hydrostatically retested at system test pressure after installation

***USAS B31.1 - Code for Pressure Piping - 1955

TABLE 6.2-2

INSTRUMENTATION READOUTS ON THE CONTROL BOARD FOR OPERATOR MONITORING DURING RECIRCULATION

Valves

System	Valve Number
SIS	MOV 3-860 A, B
SIS	MOV 3-861 A, B
SIS	MOV 3-862 A, B
SIS	MOV 3-863 A, B
SIS	MOV 3-864 A, B
SIS	MOV 3-866 A, B
SIS	MOV 3-843 A, B
SIS	MOV 3-869
SIS	MOV 3-880 A, B
SIS	MOV 3-856 A, B
ACS	AOV 3-758
ACS	AOV 3-605
ACS	MOV 3-744 A, B
ACS	MOV 3-749 A, B

Instrumentation

System	Channel Number
SIS	FI 3-940
SIS	FI 3-943
SIS	FI 3-932
SIS	FI 3-933
SIS	LS3-1570
SIS	LS3-1571
SIS	LI3-1545

Note: Prefix 3 indicates that the component also is supplied for unit 4.

TABLE 6.2-4

ACCUMULATOR DESIGN PARAMETERS

Number	3
Type	Stainless steel clad/ carbon steel
Design pressure, psig	700
Design temperature, °F	300
Operating temperature, °F	70 - 120
Normal pressure, psig	660
Minimum pressure, psig	600
Total volume, $ft.^3$	1200
Minimum water volume at operating conditions, $ft.^3$	875 (2)
Boron concentration, ppm	1950 +400, -0 ppm
Relief valve set point (1), psig	700

NOTES :

1. The relief valves have soft seats and are designed and tested to ensure zero leakage at normal operating pressure

2. A minimum Technical Specification volume of 872 $ft.^3$ for the tank above has been approved by the NRC as Operating Licensee Amendment Nos. 143/138, dated May 29, 1991. This approved minimum tank volume takes credit for the accumulator water stored in the piping run between the accumulator tank and the first check valve which, when added to the tank volume, equals 875 $ft.^3$

TABLE 6.2-5

BORON INJECTION TANK

Number	1
Type	Vertical
Total Volume (1)	900 gal
Design Pressure	1750 psig
Design Temperature	300°F
Operating Pressure	0 - 1750 psig
Operating Temperature	Ambient
Fluid	1950 +400, -0 ppm Boric Acid Solution
Material	Austenitic Stainless Steel
Code	Class C, Section III ASME

NOTES :

1. Tank always maintained full of boric acid solution.

TABLE 6.2-10

COMPONENT FUNCTIONS EVALUATIONS

Component	Normal Operating Function	Normal Operating Arrangement	Accident Function	Accident Arrangement
Boron Injection Tank (Unit 3 only)	None	Lined up to discharge of safety injection pump	Supply borated water to core	Line up to discharge of safety injection pumps
Refueling Water Storage Tanks (1 per unit, can be shared)	Storage tank for refueling operations	Line up to suction of safety injection residual heat removal and spray pumps, one to each unit	Source of borated water for core and spray nozzles	Lined up to suction of safety injection residual heat removal, and spray one to each unit
Accumulators per unit)	None	Line up to cold legs of reactor coolant piping	Supply borated water to core	Line up to cold (3 legs of reactor coolant piping
Safety Injection Pumps (4 shared)	None	Line up to hot and cold legs of reactor coolant piping, two to each unit	Supply borated water to core	Line up to hot and cold legs of reactor coolant piping, two to each unit
Residual Heat Removal Pumps per unit)	Supply water to core to remove residual heat during shutdowns	Lined up to take suction from refueling water storage tank	Supply borated water to core	Lined up to take suction from (2 refueling water storage tank
Intake Cooling Water Pumps (3 per unit)	Supply cooling canal water to component cooling heat exchangers	Two pumps in service	Supply cooling canal water to component cooling heat exchangers	One pump in service (See Section 6.2-3)

Component	Normal Operating Function	Normal Operating Arrangement	Accident Function	Accident Arrangement
Component Cooling Pumps (3 per unit)	Supply cooling water to station nuclear components	One pump in service	Supply cooling water to residual heat exchangers and S.I. pump bearings	One pump in service
Residual Heat Exchangers (2 per unit)	Remove residual heat from core during shutdown	Line up for recirculation	Cool water from containment sump for core cooling and containment spray	Lined up for recirculation
Component Cooling Heat Exchangers (3 per unit)	Remove heat from component cooling water	Three heat exchangers in service	Cool water for residual heat exchangers	Two heat exchangers in service

TABLE 6.2-13

RESIDUAL HEAT REMOVAL SYSTEM
DESIGN, OPERATION AND TEST CONDITIONS

	Pumps	Heat Exchangers	Valves	Pipes and Fittings
Design Conditions				
Pressure, psig	600	600	665	700
Temperature, °F	400	400	400	400
Operating Conditions (Max) (NOTE 1)				
Pressure, psig	160	160	160	160
Temperature, °F (NOTE 2)	180	180	180	180
Test Pressure, psig	1200	900	1100	900
Allowable Pressure at Operating Temp. psig	>600	>600	>690	>850

NOTES :

1. During post loss-of-coolant recirculation.

2. Maximum calculated RHR heat exchanger outlet temperature was calculated to be 187.1 °F for Thermal Power Uprate based on Normal Cooldown with cut-in at 4 hours. Refer to Westinghouse Uprating Engineering Report WCAP-14291, Volume 2, December 1995.

6.3 EMERGENCY CONTAINMENT COOLING AND FILTERING SYSTEM

6.3.1 DESIGN BASIS

Containment Heat Removal Systems

Criterion: Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure, this system shall perform its required function, assuming failure of any single active component. (GDC 52)

Adequate heat removal capability for the Containment is provided by two separate, engineered safety features systems. These are the Containment Spray System, whose components are described in Section 6.4 and the Emergency Containment Cooling System whose components operate as described in Section 6.3.2. These systems are of different engineering principles and serve as independent backups for each other.

Performance Objectives

The Emergency Containment Cooling and Filtering systems are designed to provide the following engineered safeguard functions:

(a) Cooling System: Remove sufficient heat from the reactor containment following a MHA to keep the containment pressure from exceeding design pressure. The emergency fan cooling units continue to remove heat after the MHA and reduce the pressure to atmospheric. (See Fig. 6.3-1). Refer to Sect. 14.3.4 for heat removal capacity.

(b) Filtering System: Reduce the iodine concentration in the containment atmosphere following a MHA to levels ensuring that the off-site dose will not exceed the guidelines of 10 CFR 100 at the site boundary. Details of the site boundary dose calculations are given in Section 14.3.5. The air filtering capacity used to satisfy the design basis is determined for the following conditions. (See Fig. 6.3-2)

(1) Postulated iodine release to the containment were calculated with the ORIGEN2 code using TID 14844 release fractions at a power level of 2346 MW (t), based on a 24,000 MWD/MTU 2 region equilibrium cycle, equilibrium fission products inventory.

(2) Twenty-five percent of the total core iodine inventory is available for leakage from the containment. This assumes 50% of the total core iodine is released to containment and 50% of this activity immediately plates out on the containment walls.

(3) 0.25% per day containment leak rate for the first 24 hours and 0.125% per day thereafter.

(4) 4% of the total iodine in the containment atmosphere is methyl iodide, 91% is elemental iodine and 5% is particulate iodide.

(5) Two (2) filter units of the three (3) installed in operation for 2 hours.

(6) 90% filter efficiency for elemental iodine, 95% filter efficiency for particulate iodine, and 30% filter efficiency for methyl iodine.

The equipment design will permit subsequent operation in an air-steam atmosphere at 5 psig, 152 °F for an indefinite period.

All components are capable of withstanding MHA pressures.

6.4 CONTAINMENT SPRAY SYSTEM

6.4.1 DESIGN BASES

Containment Heat Removal Systems

Criterion: Where an active heat removal system is needed under accident conditions to prevent exceeding containment design pressure, this system shall perform its required function, assuming failure of any single active component. (GDC 52)

Adequate containment heat removal capability for the Containment is provided by two separate, full capacity, engineered safety feature systems. The Containment Spray System, whose components operate in the sequential modes described in 6.4.2, and the Emergency Containment Cooling and Filtering System which is discussed in Section 6.3.

The primary purpose of the Containment Spray System is to spray cool water into the containment atmosphere when appropriate in the event of a loss-of-coolant accident and thereby ensure that containment pressure does not exceed its design value which is 59 psig at 283 °F (100% R.H.). This protection is afforded for all pipe break sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant pipe. Pressure and temperature transients for loss of coolant accident are presented in Section 14. Although the water in the core after a loss-of-coolant accident is quickly subcooled by the Safety Injection System, the Containment Spray System design is based on the conservative assumption that the core residual heat is released to the containment as steam.

The original design basis for containment heat removal considered simultaneous operation of one spray pump and 2 of 3 emergency containment coolers. The design basis relative to the emergency containment coolers was changed to provide significant component cooling water system operating margin at uprated conditions. For short-term accident mitigation, only 1 of 3 emergency containment coolers is required and long-term mitigation would require 2 of 3 emergency containment coolers. This is the basis for the containment pressure transient calculations in Section 14.

Inspection of Containment Pressure Reducing Systems

Criterion: Design provisions shall be made to the extent practical to facilitate the periodic physical inspection of all important components of the containment pressure reducing systems, such as pumps, valves, spray nozzles and sumps. (GDC 58)

Where practicable, all active components and passive components of the Containment Spray Systems are inspected periodically to assure system readiness. The pressure containing systems are inspected for leaks from pump seals, valve packing, flanged joints and safety valves. During operational testing of the containment spray pumps, the portions of the systems subjected to pump pressure are inspected for leaks. Design provisions for inspection of the Safety Injection System, which also function as part of the Containment Spray System, are described in Section 6.2.5.

Testing of Containment Pressure - Reducing Systems Components

Criterion: The containment pressure reducing systems shall be designed, to the extent practical so that active components, such as pumps and valves, can be tested periodically for operability and required functional performance (GDC 59).

All active components in the Containment Spray Systems are adequately tested both in pre-operational performance tests in the manufacturer's shop and in-place testing after installation. Thereafter, periodic tests are also performed after any component maintenance. Testing of the components of the Safety Injection System used for containment spray purposes are described in Section 6.2.5.

The component cooling water pumps and the intake cooling water pumps which supply the cooling water to the residual heat exchangers are in operation on a relatively continuous schedule during plant operation. Those pumps not running during normal operation may be tested by changing the operating pump(s).

from the refueling water storage tank) this system provides the design heat removal capacity for the containment. After the injection phase, each train of the recirculation system provides sufficient cooled recirculated water to keep the core flooded as well as providing, if required, sufficient flow to the suction of the containment spray pumps to maintain the containment pressure below the design value. This applies for all reactor coolant pipe sizes up to and including the hypothetical instantaneous circumferential rupture of a reactor coolant pipe. Only one pumping train and one heat exchanger are required to operate for this capability at the earliest time recirculation is initiated.

For the MHA concurrent with limiting cooling system heat removal capability, continued operation of recirculation spray may be required during long-term recirculation to restore post-accident containment temperatures to pre-event conditions.

During the injection and recirculation phases the spray water is raised to the temperature of the containment in falling through the steam-air mixture. The minimum fall path of the droplets is approximately 70 ft. from the spray headers to the operating deck. The actual fall path is longer due to the trajectory of the droplets sprayed out from the header. Heat transfer calculations, based upon 700 micron droplets, show that thermal equilibrium is reached in a distance of approximately five feet. Thus, the spray water reaches essentially the saturation temperature. The model for spray droplet heat removal is discussed in Section 14.3.

In addition to heat removal, the spray system is effective in scrubbing fission products from the containment atmosphere. However, no credit is taken for absorption of iodine in the analysis of the hypothetical accident (Section 14.3).

System Response

The starting sequence of the containment spray pumps and their related emergency power equipment is designed so that delivery of the minimum required flow is reached within 60 seconds which is the delay assumed for the starting of emergency containment cooling (Section 14.3).

Single Failure Analysis

A failure analysis has been made on all active components of the system to show that the failure of any single active component will not prevent fulfilling the design function. This analysis is summarized in Table 6.4-3.

The analysis of the loss-of-coolant accident presented in Section 14 reflects the single failure analysis.

Reliance on Interconnected Systems

The Containment Spray System initially operates independently of other engineered safety features following a loss-of-coolant accident. It provides backup cooling to the Emergency Containment Cooling System. For extended operation in the recirculation mode, water is supplied through the residual heat removal pumps. Spray pump cooling is supplied from the component cooling loop.

During the recirculation phase, the flow leaving the residual heat exchangers may be directed to the suction of the containment spray pumps and the high head safety injection pumps. Minimum flow requirements are set for the flow being sent to the core. Sufficient flow instrumentation is provided so that the operator can perform appropriate flow adjustments with the remote throttle valves in the flow path as shown in Figures 6.4-2 and 6.4-3.

vii) A sample flow rate indicator is calibrated linearly (from 0 to 14 cubic feet per minute).

Alarm lights are actuated by the following:

1. Flow alarm assembly (low and high flow)
2. The pressure sensor assembly (high pressure)
3. The filter paper sensor (paper drive malfunction)
4. Failure of any microprocessor controlled self test

Component Cooling Liquid Monitors

These channels continuously monitor the component cooling loops of the Auxiliary Coolant System for activity indicative of a leak of reactor coolant from either the Reactor Coolant System, the recirculation loop, or the residual heat removal loop of the Auxiliary Coolant System. A scintillation counter is located in an in-line well in each component cooling pump suction header. Each detector assembly output is amplified by a preamplifier and transmitted to the Radiation Monitoring System cabinets in the control room. The activity is indicated on a meter and recorded by a multipoint recorder. High-activity alarm indications are displayed on the control board annunciator in addition to the Radiation Monitoring System cabinets.

The measuring range of each monitor is 10^{-5} to 10^{-2} uc/cc.

Reactor Vessel Head Leakage Detection System

A sampling skid located in containment samples and analyzes each CRDM Cooler Ventilation discharge and the containment atmosphere. The output from the analyzer is transmitted to the monitoring cabinet (3C367) located in the computer room. The monitoring cabinet is common to both units. An increasing trend in CRDM discharge radioactivity levels over containment background radioactivity levels indicates a Reactor Vessel Head Leak. The monitoring cabinet also contains sample pump controls, sample valve status, and air filter unit control.

Condenser Air Ejector Gas Monitor

This channel monitors the discharge from the air ejector exhaust header of the condensers for gaseous radiation which is indicative of a primary to secondary system leak. The gas discharge is routed to the atmosphere.

The detector output is transmitted to the Radiation Monitoring System cabinets in the control room. The activity is indicated by a meter and recorded by a multipoint recorder. High-activity alarm indications are displayed on the control board annunciator in addition to the Radiation Monitoring cabinets.

A gamma sensitive Geiger-Mueller tube is used to monitor the gaseous radiation

level. The detector is inserted into an in-line fixed volume container which includes adequate shielding to reduce the background radiation to where it does not interfere with the detectors maximum sensitivity. This monitor has a maximum sensitivity of 10^{-6} microcuries per cubic centimeter.

Steam Generator Liquid Sample Monitor

This channel monitors the liquid phase of the secondary side of the steam generator for radiation, which would indicate a primary-to-secondary system leak, providing backup information to that of the condenser air ejector gas monitor. Samples from the bottom of each of the three steam generators are mixed to a common header and the common sample is continuously monitored by a scintillation counter and holdup tank assembly. Upon indication of a high-radiation level (R-19), blowdown is automatically isolated. Each steam generator is then manually sampled in order to determine the source of the activity. This sampling sequence is achieved by manually obtaining steam generator liquid samples at the primary sample sink for laboratory analysis after allowing sufficient time for sample equilibrium to be established.

A remote indicator panel, mounted at the detector location, indicates the radiation level and high-radiation alarm.

The measuring range of this monitor is 10^{-5} to 10^{-2} microcuries per cubic centimeter.

A photomultiplier tube - scintillation crystal (NaI) combination, mounted in a hermetically sealed unit, is used to monitor liquid effluent activity. Lead shielding is provided to reduce the background level so it does not interfere with the detector's maximum sensitivity. The in-line, fixed-volume container is an integral part of the detector unit.

During cold shutdown personnel can enter the containment and make a visual inspection for leaks. The location of any leak in the Reactor Coolant System would be determined by the presence of boric acid crystals near the leak. The leaking fluid transfers the boric acid crystals outside the Reactor Coolant System and the process of evaporation leaves them behind.

If an accident involving gross leakage from the Reactor Coolant System occurred it could be detected by the following methods.

Pump Activity

During normal operation only one charging pump is operating. If a gross loss of reactor coolant to another closed system occurred which was not detected by the methods previously described, the speed of the charging pump would indicate the leakage.

The leakage from the reactor coolant will cause a decrease in the pressurizer liquid level that is within the sensitivity range of the pressurizer level indicator. The speed of the charging pump will automatically increase to try to maintain the equivalence between the letdown flow and the combined charging line flow and flow across the reactor coolant pump seals. If the pump reaches a high speed limit, an alarm is actuated.

A break in the primary system would result in reactor coolant flowing into the containment sump. Gross leakage to this sump would be indicated by the frequency of operation of the containment sump pumps and by indication on the containment sump level recorder.

Liquid Inventory

Gross leaks might be detected by unscheduled increases in the amount of reactor coolant makeup water which is required to maintain the normal level in the pressurizer. This is inherently a low precision measurement, since makeup water is necessary as well for leaks from systems outside the containment.

A large tube side to shell side leak in the non-regenerative (letdown) heat exchanger would result in reactor coolant flowing into the component cooling water and a rise in the liquid level in the component cooling water surge tank. The operator would be alerted by a high water alarm for the surge tank and high radiation and temperature alarms actuated by monitors at the component cooling water pump suction header.

A high level alarm for the component cooling water surge tank and high radiation and temperature alarms actuated by monitors at the component cooling pump suction header could also indicate a thermal barrier cooling coil rupture in a reactor coolant pump. However, in addition to these alarms, high temperature and high flow on the component cooling outlet line from the pump would activate alarms.

Gross leakage might also be indicated by a rise in the normal containment sump level. High level in this sump will actuate an alarm.

Residual Heat Removal Loop

The residual heat removal loop removes residual and sensible heat from the core and reduces the temperature of the Reactor Coolant System during the second phase of shutdown.

Leakage from the residual heat removal loop during normal operation would be detected by the component cooling loop radiation monitor (see analysis of detection of leakage from the Reactor Coolant System in this section).

The physical layout of the two residual heat removal pumps will be within separate shielded and isolated rooms outside of the containment. This will permit the detection of a leaking residual heat removal pump by means of the radiation monitor located in the plant vent. Supplemental radiation monitoring will be provided by the plant vent gas monitoring system. Alarms in the control room will alert the operator when the activity exceeds a preset level. Small leaks to the environment could be detected with these systems within a short time after they occurred.

Should a large tube side to shell side leak develop in a residual heat exchanger or the seal of a residual heat removal pump break, the water level in the component cooling surge tank would rise, and the operator would be alerted by a high water alarm. Radiation and temperature monitors at the component cooling water pump suction header will also signal an alarm.

Leakage from the residual heat removal pumps is drained to separate sumps equipped with a sump pump. The operation of either sump pump will be indicated in the control room as a means of detection of gross leakage (i.e., a seal failure) from a residual heat removal pump.

Component Cooling Loop

Leakage from the component cooling loop inside the reactor containment, will be detected by level change in the containment sump.

Visual inspection inside the containment is possible during cold shutdown.

Gross leakage from the component cooling loop would be indicated inside the containment by a rise in the liquid level of the containment sump. This sump has a high level recorder and a high level alarm.

If the leakage is from a part of the component cooling loop outside the containment, it would be directed by floor drains to the auxiliary building sump. The auxiliary building sump pumps then transfer the leakage to the waste holdup tank. Operation of the sump pumps is indicated in the control room and would thus serve as a means of leak detection for this part of the system.

The Reactor Vessel Head Area Leakage Detection System (Unit 3) supplements the monitoring performed via primary side monitoring systems and containment area radiation monitoring to provide detection of any leaks in the area of the reactor head.

The system monitors samples drawn from the CRDM cooler discharge as well as from the containment atmosphere for a reference. The system is designed to detect small RCS leaks by monitoring particulate radiation levels in the reactor vessel head area by means of these samples.

It includes a sampling skid located within the containment and a remote control and display rack in the computer room. The sample pump delivers a continuous sample through a slow moving filter set-up. Particulates emitted are trapped on the filter paper and are monitored by a beta scintillation detector. The beta detector provides a digital signal to the Universal Digital Ratemeter located inside in the remote control and display rack in the computer room.

6.5.2 LEAKAGE PROVISIONS

Provisions are made for the isolation and containment of any leakage.

If either the containment air particulate gamma activity or the radioactive gas activity exceed pre-set levels on the containment air particulate and radioactive gas monitors, respectively, the containment purge supply and exhaust duct valves and instrument air bleed valves are closed.

A high radiation alarm actuated by the steam generator liquid sample monitor initiates closure of the isolation valves in the blowdown lines and sample lines.

If the component cooling loop radiation monitor signals a high radiation alarm, the valve in the component cooling surge tank vent line automatically closes to prevent gaseous activity release.

If a leak from the Reactor Coolant System to the component cooling loop was a gross leak or if the leak could not be isolated from the component cooling loop before the inflow completely filled the surge tank, the relief valve on the surge tank would lift. The discharge from this valve is routed to the waste holdup tank in the Auxiliary Building.

A large leak in the Reactor Coolant System pressure boundary, which does not flow into another closed loop, would result in reactor coolant flowing into the containment sump.

Residual Heat Removal Loop

High containment air particulate gamma activity or high radioactive gas activity will result in an alarm being activated by either the containment air particulate or radioactive gas monitors, respectively. The containment purge supply and exhaust duct valves and pressure relief line valves are closed. This prevents the release of radioactivity to the atmosphere outside the containment.

If leakage from the residual heat removal loop into the component cooling loop occurs, the component cooling radiation monitor will actuate an alarm and the valve in the component cooling surge tank vent line is automatically closed to prevent gaseous radioactivity release. If the leaking component (i.e. , a residual heat exchanger) could not be isolated from the component cooling loop before the inflow completely filled the surge tank, the relief valve on the surge tank would lift and the effluent would be discharged to the auxiliary building waste holdup tank.

Gross leakage from the section of the residual heat removal loop inside the containment, which does not flow into another closed loop, would result in reactor coolant flowing into the containment sump.

Other leakage provisions for the residual heat removal loop are discussed is Section 9.3.

Component Cooling Loop

Gross leakage from the section of the component cooling loop inside the containment which does not flow into another closed loop will flow into the containment sump. Outside the containment major leakage would be drained to the auxiliary building sump. From here it is pumped to the waste holdup tank.

Other provisions made for leakage from the component cooling loop are discussed in Section 9.3.

6.5.3 References

1. FPL Letter L-88-481, "Application of Leak Before Break Technology to Primary Coolant System Piping", dated November 1, 1988.

2. NRC Letter dated November 28, 1988, "Turkey Point Units 3 and 4 Generic Letter 84-04, Asymmetric LOCA Loads".

requirements of Regulatory Guide 1.97, Revision 3. This guide recommended that valve position indication be provided to permit the operators to ascertain the status of containment integrity and main steam safety valve positions. The valves which have been provided with position indication to comply with the Regulatory Guide 1.97 commitments are included in Table 6.6.1.

6.6.2.3 ISOLATION ACTUATION

Phase A Isolation is initiated by a safety injection (SI) signal. Phase B Isolation is initiated by a high containment pressure coincident with high-high containment pressure. Containment Ventilation Isolation is initiated by a safety injection signal or high containment radioactivity (R-11 or R-12) signals. Additional information is provided in Table 7.2-1.

Table 6.6-1 provides a listing of isolation valves and their actuating signals. Automatic closure of the valves listed in Table 6.6-1 will achieve containment isolation in accordance with the requirements of the 1967 Proposed GDC 53 and the plant Technical Specifications. The listed valves are considered to be part of the isolation barrier capability even if they open in response to accident conditions. That is, selected valves in essential penetration flow paths may receive a signal to open (e.g., SI signal or Auxiliary Feedwater Actuation signal). Barriers that provide a containment integrity function, but which do not receive an isolation signal (e.g., manual valves), have also been included in Table 6.6-1.

6.6.3 TESTING AND INSPECTION

The Turkey Point Units 3 and 4 containment structure was designed such that the maximum allowable containment vessel leakage rate shall not exceed 0.25% per day of containment free volume at the conditions of a Maximum Hypothetical Accident (MHA), that is, 49.9 psig and 276 °F. 10 CFR 50, Appendix J requires pre-operational and periodic operational verification by testing of the leak-tight integrity of the containment structure and lines penetrating containment. The testing consists of Type A, Type B, and Type C tests. Testing performed to meet 10 CFR 50, Appendix J provides assurance that leakage through the primary reactor containment and systems penetrating containment does not exceed this maximum allowable leakage rate. The combined leakage from all penetrations subject to Type B and C tests must be less than 0.6 times the maximum allowable leakage rate (La).

Type A tests are the Integrated Leak Rate Tests (ILRT), which measure the containment structure overall integrated leak rate. FSAR Section 5.1.7 describes the pre-operational ILRTs. Integrated leak rate tests are performed periodically over the operating life of the plant.

Type B Local Leak Rate Tests (LLRT) detect local leaks across pressure-containing or leakage limiting boundaries other than valves. Containment penetrations that are required to be Type B tested include:

(a) Personnel and Emergency Air locks

(b) Equipment access hatch

(c) Fuel transfer tube flange

(d) Electrical penetrations

(e) Other containment penetrations whose design incorporates degradable mechanical parts such as resilient seals, gaskets or sealant compounds.

Type C Local Leak Rate tests measure containment isolation valve leakage rates. Containment isolation valves in the following categories (from 10 CFR 50, Appendix J) shall be leak rate tested in accordance with the Type C test requirements:

(a) Valves located in lines that provide a direct connection between the inside and outside atmospheres of the primary reactor containment under normal operation, such as purge, ventilation, vacuum relief, and instrumentation valves;

(b) Valves required to close automatically upon receipt of a containment isolation signal in response to controls intended to effect containment isolation; and

(c) Valves required to operate intermittently under post accident conditions.

In general, Type C tests are performed by pressurizing the valves from the side facing the inside of containment. However, there are configurations in which such testing is not practical. Alternative test configurations have been reviewed to ensure that the reverse testing is equivalent to the preferred test direction. In particular, the review must consider any potential leak paths (such as valve packing or vents, drains, or test connections) which would not be detected by the reverse flow test.

Periodic local leak rate testing and pre-operational leak rate testing discussed above describe a reasonable approach to assuring that the containment leakage is maintained below design limits during the life of the plant. Periodic local leak testing provides an accurate method of monitoring changes in the leakage characteristics of the containment. An integrated leak rate test (ILRT) is performed less frequently. An ILRT is also performed if major maintenance or modification to the containment was made.

Automatic and power-operated containment isolation valve closure times shall be verified periodically by testing in accordance with the inservice test requirements of ASME Section XI.

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TABLE 6.6-1

CONTAINMENT PIPING PENETRATIONS
AND ISOLATION BARRIERS

TABLE LEGEND

SYSTEMS

AFWS	Auxiliary Feedwater System
BA	Breathing Air System
CSS	Containment Spray System
CVCS	Chemical and Volume Control System
CCWS	Component Cooling Water System
IAS	Instrument Air System
FW	Feedwater System
MS	Main Steam
PACVS	Post Accident Containment Ventilation System
PAHMS	Post Accident Hydrogen Monitoring System
RCS	Reactor Coolant System
RHRS	Residual Heat Removal System
SGBD	Steam Generator Blowdown System
SIS	Safety Injection System
SS	Sample System
Vent	Containment Ventilation System
WDS	Waste Disposal System

ABBREVIATIONS

Cntmt	Containment
Constr	Construction
CSIC	Closed System Inside Containment
CSOC	Closed System Outside Containment
Exch	Exchanger
ILRT	Integrated Leak Rate Test
LC	Locked Closed
LLRT	Local Leak Rate Test
NA	Not Applicable
PCV	Pressure Control Valve
PRT	Pressurizer Relief Tank
RCDT	Reactor Coolant Drain Tank
RCP	Reactor Coolant Pump
RM	Remote Manual
SG	Steam Generator
SI	Safety Injection

FLOW DIRECTIONS

In	Indicates that the predominate low direction is into containment during normal operation.
Out	Indicates that the predominate flow direction is out of containment during normal operation.

TABLE 6.6-1

CONTAINMENT PIPING PENETRATIONS
AND ISOLATION BARRIERS

TABLE LEGEND
(Continued)

METHODS OF ACTUATION

Auto	Self actuating valve (Check, PCV, Relief)
PWR	Power operated valve (Air, MOV, Solenoid)
Manual	Handwheel (or reach rod) operated valve

SIGNALS (Refer to Table 7.2-1 for additional information)

Phase A	Containment Isolation Signal initiated by a Safety Injection Signal (Also known as a T-signal) - closes non-essential automatic containment valves.
Phase B	Containment Isolation Signal initiated by containment pressure (Also known as a P-signal) - closes selected automatic isolation valves which are beneficial to remain open following a Phase A signal. See Table 7.2-1 for cause of actuation.
AFAS	Auxiliary Feedwater Actuation Signal - opens essential steam flow to the AFW pump turbine and actuates auxiliary feedwater. See Table 7.2-1 for cause of actuation.
CVS	Containment Ventilation System Isolation initiated by Safety Injection Signal or Containment High Radiation Signal - isolates non-essential containment ventilation lines.
FWIS	Main Feedwater Isolation Signal - closes the main feedwater control and bypass valves. See Table 7.2-1 for cause of actuation.
MSIS	Main Steam Isolation Signal - isolates non-essential portions of the main steam lines. See Table 7.2-1 for cause of actuation.
RM	Remote Manual (Power operated)
SIS	Safety Injection Signal - initiates Phase A isolation and actuates safety injection.

TABLE 6.6-1
CONTAINMENT PIPING PENTRATIONS AND ISOLATION BARRIERS

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
1	Shutdown Cooling Suction/ Alternate Hot Leg Injection (Essential/RHRS)	Out/In	Water	2	14"	In	Gate	MOV-*-751	PWR	RM	L.C.	As Is	Closed	Yes	NA	Note 10, 18
				1	14"	In	Gate	MOV-*-750	PWR	RM	L.C.	As Is	Closed	Yes	NA	Note 1, 10, 18
2	Shutdown Cooling Return/Low Head Cold Leg Injection (Essential/RHRS)	In	Water	2	12"	In	Gate	MOV-*-744A	PWR	SIS	Closed	As Is	Open	Yes	NA	Note 2, 22
				2	12"	In	Gate	MOV-*-744B	PWR	SIS	Closed	As Is	Open	Yes	NA	Note 2, 22
				2	6"	In	Gate	*-734	Manual	NA	L.C.	NA	Closed	No	NA	Note 22
				2	2"	In	Relief	RV-*-706	Auto	NA	Closed	NA	Closed	No	NA	Note 22
				1	8"	In	Check	*-876A	Auto	NA	Closed	NA	Open	No	NA	Note 22
				1	8"	In	Check	*-876B	Auto	NA	Closed	NA	Open	No	NA	Note 22
				1	8"	In	Check	*-876C	Auto	NA	Closed	NA	Open	No	NA	Note 22
3	Reactor Coolant Pump Cooling Water Supply (Essential/CCWS)	In	Water	1	6"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	6"	Out	Gate	MOV-*-716B	PWR	Ph B	Open	As Is	Closed	Yes	NA	Note 18
4	RCP Oil Cooler Water Return (Essential/CCWS)	Out	Water	1	6"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	6"	Out	Gate	MOV-*-730	PWR	Ph B	Open	As Is	Closed	Yes	NA	Note 18
5	PRT Gas Analyzer Sample (Non-Essential/WDS)	Out	Gas	1	3/8"	Out	Globe	SV-*-6385	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 3, 18
				2	3/8"	Out	Globe	CV-*-516	PWR	Ph A	Closed	Closed	Closed	Yes	C	Note 3, 18
6	PRT Nitrogen Supply (Non-Essential/WDS)	In	Gas	1	3/4"	In	Check	*-518	Auto	NA	Closed	NA	Closed	No	C	Note 18
				2	3/4"	In	Stop Check (check)	3-519 4-519	Auto	NA	Closed	NA	Closed	No	C	Note 9, 18

TABLE 6.6-1
CONTAINMENT PIPING PENTRATIONS AND ISOLATION BARRIERS

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
7	Primary Water to PRT and RCP Stand Pipes (Non Essential/Primary)	In	Water	1	3"	In	Dphrm	CV-*-519B	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				1	3/4"	In	Dphrm	CV-*-522A	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				1	3/4"	In	Dphrm	CV-*-522B	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				1	3/4"	In	Dphrm	CV-*-522C	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				2	3"	Out	Dphrm	CV-*-519A	PWR	Ph A	Closed	Closed	Closed	Yes	C	Note 18
8	Pressurizer Steam Space Sample (Non Essential/SS)	Out	Water	1	3/8"	In	Globe	CV-*-951	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				2	3/8"	Out	Globe	CV-*-956A	PWR	Ph A	Closed	Closed	Closed	Yes	C	Note 18
9	Pressurizer Liquid Space Sample (Non Essential/SS)	Out	Water	1	3/8"	In	Globe	CV-*-953	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				2	3/8"	Out	Globe	CV-*-956B	PWR	Ph A	Closed	Closed	Closed	Yes	C	Note 18
10	RCDT Vent and Nitrogen Supply (Non Essential/WDS)	Out/In	Gas	1	1"	Out	Dphrm	CV-*-4658A	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
				2	1"	Out	Dphrm	CV-*-4658B	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
				1	1"	Out	Dphrm	*-4658	Manual	None	L.C.	NA	Closed	No	C	Note18
				2	3/4"	Out	Dphrm	*-4639	Manual	None	L.C.	NA	Closed	No	C	Note 18
				2	3/8"	Out	Globe	*-3449	Manual	None	L.C.	NA	Closed	No	C	Note 18
11	Alternate Low Head Cold Leg Injection (Essential/RHRS)	In	Water	1	8"	In	Check	*-876D	Auto	NA	Closed	NA	Closed	No	NA	Note 22
				1	8"	In	Check	*-876E	Auto	NA	Closed	NA	Closed	No	NA	Note 22
				2	8"	Out	Gate	MOV-*-872	PWR	RM	Closed	As Is	Closed	Yes	NA	Note 22
12	Excess Letdown Heat Exch.Cooling Water Supply (Non Essential/CCWS)	In	Water	1	3"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	3"	In	Check	*-738	Auto	NA	Open	NA	Closed	No	NA	Note 18

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
13	Excess Letdown Heat Exch.Cooling Water Return (Non-Essential/CCWS)	Out	Water	1	3"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	3"	Out	Globe	CV-*-739	PWR	Ph A	Open	Closed	Closed	Yes	NA	Note 18
14	CVCS Normal Letdown (Non-Essential/CVCS)	Out	Water	1	2"	In	Globe	CV-*-200A	PWR	Ph A	Closed	Closed	Closed	Yes	C	Note 18
				1	2"	In	Globe	CV-*-200B	PWR	Ph A	Closed	Closed	Closed	Yes	C	Note 18
				1	2"	In	Globe	CV-*-200C	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
				1	2"	In	Relief	RV-*-203	Auto	NA	Closed	NA	Closed	No	C	
				2	2"	Out	Globe	CV-*-204	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
15	CVCS Charging (Non-Essential/CVCS)	In	Water	1	3"	In	Check	*-312C	Auto	NA	Open	NA	Closed	No	C	Note 4, 18
				2	3"	Out	CSOC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
16	Post-Accident Containment Air Sampling and H2 Control (Non-Essential/PACVS)	Out	Gas	1	2"	Out	Dphrm	HV-*-1	Manual	NA	L.C.	NA	Closed	No	C	Note 9, 18
				2	2"	Out	Dphrm	HV-*-2	Manual	NA	L.C.	NA	Closed	No	C	Note 9, 18
				2	3/4"	Out	Globe	PAHM-*-002A	Manual	NA	L.C.	NA	Closed	No	C	Note 9, 18
17	Safety Injection Test and Purge (Non-Essential/SIS)	Out	Water	1	3/4"	In	Globe	CV-*-850A-F	PWR	RM	Closed	Closed	Closed	Yes	NA	Note 18
				1	3/4"	In	Relief	RV-*-859	Auto	NA	Closed	NA	Closed	No	NA	
				2	3/4"	Out	Globe	*-895V	Manual	NA	L.C.	NA	Closed	No	NA	Note 18
18	Hot Leg Injection (Essential/SIS)	In	Water	1	2"	In	Gate	MOV-*-866A/B	PWR	SIS	Closed	As Is	Closed	Yes	NA	Note 8, 10, 22
				1	3"	In	Globe	CV-*-851ABC	PWR	RM	Closed	Closed	Closed	Yes	NA	Note 9, 22
				1	3/4"	In	Relief	RV-*-6511	Auto	NA	Closed	NA	Closed	No	NA	Note 22
				2	3"	Out	Gate	MOV-*-869	PWR	RM	Closed	As Is	Closed	Yes	NA	Note 8, 22

TABLE 6.6-1
CONTAINMENT PIPING PENTRATIONS AND ISOLATION BARRIERS

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
19A	Containment Spray (Essential/CSS)	In	Water	2	6"	Out	Gate	MOV-*-880A	PWR	Ph B	Closed	As Is	Open	Yes	C	Note 22
				2	1"	Out	Globe	*-883M	Manual	NA	L.C.	NA	Closed	No	C	Note 9, 22
				1	6"	Out	Check	*-890A	Auto	NA	Closed	NA	Open	No	C	Note 22
19B	Containment Spray (Essential/CSS)	In	Water	2	6"	Out	Gate	MOV-*-880B	PWR	Ph B	Closed	As Is	Open	Yes	C	Note 22
				2	1"	Out	Globe	*-883N	Manual	NA	L.C.	NA	Closed	No	C	Note 9, 22
				1	6"	Out	Check	*-890B	Auto	NA	Closed	NA	Open	No	C	Note 22
20	Reactor Coolant System Hot Leg Sample (Non-Essential/SS)	Out	Water	1	3/8"	In	Globe	SV-*-6427A	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				1	3/8"	In	Globe	SV-*-6427B	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				2	3/8"	Out	Globe	SV-*-6428	PWR	Ph A	Closed	Closed	Closed	Yes	C	Note 18
21	Normal Containment Cooling Water Supply (Non-Essential/CCWS)	In	Water	1	10"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	10"	Out	Gate	MOV-*-1417	PWR	Ph A	Open	As Is	Closed	Yes	NA	Note 18
22	Normal Containment Cooling Water Return (Non-Essential/CCWS)	Out	Water	1	10"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	10"	Out	Gate	MOV-*-1418	PWR	Ph A	Open	As Is	Closed	Yes	NA	Note 18
23	Containment Sump Discharge (Non-Essential/WDS)	Out	Water	1	3"	Out	Globe	CV-*-2822	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
				2	3"	Out	Globe	CV-*-2821	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
24A	Seal Water Injection (Non-Essential/CVCS)	In	Water	1	2"	In	Check	*-298A	Auto	NA	Open	NA	Closed	No	C	Note 18

TABLE 6.6-1
CONTAINMENT PIPING PENTRATIONS AND ISOLATION BARRIERS

Pen No.	Service (Classification/System)	Flow Dir.	Fluid.	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
				2	2"	Out	CSOC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
24B	Seal Water Injection (Non-Essential/CVCS)	In	Water	1	2"	In	Check	*-298B	Auto	NA	Open	NA	Closed	No	C	Note 18
				2	2"	Out	CSOC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
24C	Seal Water Injection (Non-Essential/CVCS)	In	Water	1	2"	In	Check	*-298C	Auto	NA	Open	NA	Closed	No	C	Note 18
				2	2"	Out	CSOC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
25	RCP Seal Water Leakoff/ Excess Letdown (Non-Essential/CVCS)	Out	Water	1	3"	In	Gate	MOV-*-6386	PWR	Ph A	Open	As Is	Closed	Yes	C	Note 18
				2	3"	Out	Gate	MOV-*-381	PWR	Ph A	Open	As Is	Closed	Yes	C	Note 18
26A	Main Steam/AFWS Steam Supply (Essential/Secondary)	Out	Steam	1	26"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	3/4"	Out	Globe	SGWL-*-022	Manual	NA	L.C.	NA	Closed	No	NA	Note 23
				2	6"	Out	Globe	CV-*-1606	PWR	RM	Closed	Closed	Closed	Yes	NA	Note 23
				2	12"	Out	Relief	RV1400/1/2/3	Auto	NA	Closed	NA	Closed	No	NA	Note 23
				2	4"	Out	Globe	MOV-*-1403	PWR	AFAS	Closed	As Is	Open	Yes	NA	Note 22, 23
				2	26"	Out	Stop Check	POV-*-2604	PWR	MSIS	Open	Closed	Closed	Yes	NA	Note 5, 9, 23
				2	2"	Out	Globe	MOV-*-1400	PWR	MSIS	Closed	As Is	Closed	Yes	NA	Note 23
				2	3/4"	Out	Globe	3-10-107 (4-10-105)	Manual	NA	Open	NA	Open	No	NA	Note 17
26B	Main Steam/AFWS Steam Supply (Essential/Secondary)	Out	Steam	1	26"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	3/4"	Out	Globe	SGWL-*-028	Manual	NA	L. C.	NA	Closed	No	NA	Note 23
				2	6"	Out	Globe	CV-*-1607	PWR	RM	Closed	Closed	Closed	Yes	NA	Note 23
				2	12"	Out	Relief	RV1405/6/7/8	Auto	NA	Closed	NA	Closed	No	NA	Note 23

TABLE 6.6-1
CONTAINMENT PIPING PENTRATIONS AND ISOLATION BARRIERS

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
				2	4"	Out	Globe	MOV-*-1404	PWR	AFAS	Closed	As Is	Open	Yes	NA	Note 22, 23
				2	26"	Out	Stop Check	POV-*-2605	PWR	MSIS	Open	Closed	Closed	Yes	NA	Note 5, 9, 23
				2	2"	Out	Globe	MOV-*-1401	PWR	MSIS	Closed	As Is	Closed	Yes	NA	Note 23
				2	3/4"	Out	Globe	*-10-207	Manual	NA	Open	NA	Open	No	NA	Note 17
26C	Main Steam/AFWS Steam Supply (Essential/Secondary)	Out	Steam	1	26"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	3/4"	Out	Globe	SGWL-*-046	Manual	NA	L.C.	NA	Closed	No	NA	Note 23
				2	6"	Out	Globe	CV-*-1608	PWR	RM	Closed	Closed	Closed	Yes	NA	Note 23
				2	12"	Out	Relief	RV1410/1/2/3	Auto	NA	Closed	NA	Closed	No	NA	Note 23
				2	4"	Out	Globe	MOV-*-1405	PWR	AFAS	Closed	As Is	Open	Yes	NA	Note 22, 23
				2	26"	Out	Stop Check	POV-*-2606	PWR	MSIS	Open	Closed	Closed	Yes	NA	Note 5, 9, 23
				2	2"	Out	Globe	MOV-*-1402	PWR	MSIS	Closed	As Is	Closed	Yes	NA	Note 23
				2	3/4"	Out	Globe	*-10-307	Manual	NA	Open	NA	Open	No	NA	Note 17
27A	Main Feedwater/Aux. Feedwater (Essential/Secondary)	In	Water	1	14"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	14"	Out	Globe	FCV-*-478	PWR	FWIS	Open	Closed	Closed	Yes	NA	Note 6, 23
				2	4"	Out	Globe	FCV-*-479	PWR	FWIS	Closed	Closed	Closed	Yes	NA	Note 23
				2	2"	Out	Gate	SGWL-*-007	Manual	NA	Closed	NA	Closed	No	NA	Note 23
				2	1/2"	Out	Check	*-20-137	Auto	NA	Closed	NA	Closed	No	NA	Note 23
				2	4"	Out	Check	*-20-140	Auto	NA	Closed	NA	Open	No	NA	Note 22, 23
				2	4"	Out	Globe	CV-*-2831	PWR	AFAS	Closed	Closed	Open	Yes	NA	Note 6, 15
27B	Main Feedwater/Aux. Feedwater (Essential/Secondary)	In	Water	1	14"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	14"	Out	Globe	FCV-*-488	PWR	FWIS	Open	Closed	Closed	Yes	NA	Note 6, 23
				2	4"	Out	Globe	FCV-*-489	PWR	FWIS	Closed	Closed	Closed	Yes	NA	Note 23

TABLE 6.6-1
CONTAINMENT PIPING PENTRATIONS AND ISOLATION BARRIERS

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
				2	2"	Out	Gate	SGWL-*-025	Manual	NA	Closed	NA	Closed	No	NA	Note 23
				2	1/2"	Out	Check	*-20-237	Auto	NA	Closed	NA	Closed	No	NA	Note 23
				2	4"	Out	Check	*-20-240	Auto	NA	Closed	NA	Open	No	NA	Note 22, 23
				2	4"	Out	Globe	CV-*-2832	PWR	AFAS	Closed	Closed	Open	Yes	NA	Note 6, 15
27C	Main Feedwater/Aux. Feedwater (Essential/Secondary)	In	Water	1	14"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	14"	Out	Globe	FCV-*-498	PWR	FWIS	Open	Closed	Closed	Yes	NA	Note 6, 23
				2	4"	Out	Globe	FCV-*-499	PWR	FWIS	Closed	Closed	Closed	Yes	NA	Note 23
				2	2"	Out	Gate	SGWL-*-042	Manual	NA	Closed	NA	Closed	No	NA	Note 23
				2	1/2"	Out	Check	*-20-337	Auto	NA	Closed	NA	Closed	No	NA	Note 23
				2	4"	Out	Check	*-20-340	Auto	NA	Closed	NA	Open	No	NA	Note 22, 23
				2	4"	Out	Globe	CV-*-2833	PWR	AFAS	Closed	Closed	Open	Yes	NA	Note 6, 15
28A	Steam Generator Blowdown & Wet Layup (Non-Essential/Secondary)	Out/In	Water	1	4"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	6"	Out	Globe	CV-*-6275A	PWR	Ph A	Open	AS-IS	Closed	Yes	NA	Note 18
				2	3/4"	Out	Globe	SV-*-6275A-1	PWR	Ph A	Open	Closed	Closed	Yes	NA	Note 18
				2	2"	Out	Gate	SGWL-*-011	Manual	NA	L.C.	NA	Closed	No	NA	Note 18
28B	Steam Generator Blowdown & Wet Layup (Non-Essential/Secondary)	Out/In	Water	1	4"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	6"	Out	Globe	CV-*-6275B	PWR	Ph A	Open	AS-IS	Closed	Yes	NA	Note 18
				2	3/4"	Out	Globe	SV-*-6275B-1	PWR	Ph A	Open	Closed	Closed	Yes	NA	Note 18
				2	2"	Out	Globe	SGWL-*-031	Manual	NA	L.C.	NA	Closed	No	NA	Note 18
28C	Steam Generator Blowdown & Wet Layup (Non-Essential/Secondary)	Out/In	Water	1	4"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	6"	Out	Globe	CV-*-6275C	PWR	Ph A	Open	AS-IS	Closed	Yes	NA	Note 18

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
				2	3/4"	Out	Globe	SV-*-6275C-1	PWR	Ph A	Open	Closed	Closed	Yes	NA	Note 18
				2	2"	Out	Globe	SGWL-*-049	Manual	NA	L.C.	NA	Closed	NA	NA	Note 18
29	Instrument Air Supply (Non-Essential/IAS)	In	Gas	1	2"	In	Stop Check (Check)	3-40-340A (4-40-340A)	Auto	NA	Open	NA	Closed	No	C	Note 9, 18
				2	2"	In	Check	*-40-336	Auto	NA	Open	NA	Closed	No	C	Note 18
30	Breathing Air Supply (Non-Essential/BA)	In	Gas	1	2.5"	In	Check	*-BA-201	Auto	NA	Closed	NA	Closed	No	C	Note 18
				2	2.5"	Out	Globe	CV-*-6165	PWR	Ph A	L.C.	As Is	Closed	Yes	C	Note 16, 18
31	RCDT Gas Analyzer Sample (Non-Essential/WDS)	Out	Gas	1	3/4"	Out	Dphrm	CV-*-4659A	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 3, 18
				2	3/4"	Out	Dphrm	CV-*-4659B	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 3, 18
32	Containment Air Sample Return (Non-Essential/Vent)	In	Gas	1	1"	In	Check	*-11-003	Auto	NA	Closed	NA	Closed	No	C	Note 9, 18
				2	1"	Out	Globe	SV-*-2912	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
				2	1"	Out	Globe	PAHM-*-001A	Manual	NA	L.C.	NA	Closed	No	C	Note 7, 9, 18
				2	1"	Out	Globe	PAHM-*-001B	Manual	NA	L.C.	NA	Closed	No	C	Note 7, 9, 18
33	Containment Air Sample (Non-Essential/Vent)	Out	Gas	1	1"	Out	Globe	SV-*-2913	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
				2	1"	Out	Globe	SV-*-2911	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
34	Service Air Supply (Non-Essential/Service Air)	In	Gas	1	2"	In	Check	*-40-205	Auto	NA	Closed	NA	Closed	No	C	Note 18
				2	2"	Out	Gate	*-40-204	Manual	NA	L.C.	NA	Closed	No	C	Note 18

TABLE 6.6-1
CONTAINMENT PIPING PENTRATIONS AND ISOLATION BARRIERS

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
45B	Emergency Containment Cooling Water Return (Essential/CCWS)	Out	Water	1	10"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	10"	Out	Butterfly	CV-3-2906 (CV-4-2906)	PWR	SIS	Closed (Open)	Open	Open	Yes	NA	Note 14, 22, 25
				2	6"	Out	Globe	CV-3-2810 (CV-4-2810)	PWR	RM	Open (Closed)	Closed	Open	Yes	NA	Note 22, 25
45C	Emergency Containment Cooling Water Return (Essential/CCWS)	Out	Water	1	10"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	10"	Out	Butterfly	CV-3-2907 (CV-4-2908)	PWR	SIS	Closed (Open)	Open	Open	Yes	NA	Note 14, 22, 25
				2	6"	Out	Globe	CV-3-2812 (CV-4-2814)	PWR	RM	Open (Closed)	Closed	Open	Yes	NA	Note 22, 25
46A,B, C	Sealed Closed/Spare (U-3) Containment Pressure Sensors(U4)	NA	NA	1	1"	In	Integral	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
		NA	NA	1	1"	Out	Integral	NA	NA	NA	NA	NA	NA	NA	B	Note 12, 19
47	Primary Water Supply to Wash Header (Non-Essential/Primary)	In	Water	1	2"	In	Gate	*-10-582	Manual	NA	L.C.	NA	Closed	No	C	Note 18
				2	2"	Out	Check	*-10-567	Auto	NA	Closed	NA	Closed	No	C	Note 18
48	Electrical Penetrations (High Voltage)	NA	NA	1	NA	In	Electrical Penetrtn	NA	NA	NA	NA	NA	NA	NA	B	Note 19, 24
	Spare			1	NA	NA	Integral	NA	NA	NA	NA	NA	NA	NA	NA	Note 19, 24
49	Emergency Escape Airlock	NA	NA	1	66"	In	Door	NA	NA	NA	Closed	NA	Closed	NA	B	Note 20
							Valve	*-S9B	Manual	NA	Closed	NA	Closed	NA	B	Note 20
				2	66"	Out	Door	NA	NA	NA	Closed	NA	Closed	NA	B	Note 20
							Valve	*-S9A	Manual	NA	Closed	NA	Closed	NA	B	Note 20

TABLE 6.6-1
CONTAINMENT PIPING PENTRATIONS AND ISOLATION BARRIERS

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
51 (U-4)	Post-Accident Containment Air Sampling & H2 Control (Non-Essential/PACVS)	Out	Gas	1	2"	Out	Dphrm	HV-4-3	Manual	NA	L.C.	NA	Closed	No	C	Note 7, 9, 18
				2	2"	Out	Dphrm	HV-4-4	Manual	NA	L.C.	NA	Closed	No	C	Note 7, 9, 18
				2	3/4"	Out	Globe	PAHM-4-002B	Manual	NA	L.C.	NA	Closed	No	C	Note 7, 9, 18
52	RCDT Pump Discharge (Non-Essential/WDS)	Out	Water	1	3"	Out	Dphrm	CV-*-4668A	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
				2	3"	Out	Dphrm	CV-*-4668B	PWR	Ph A	Open	Closed	Closed	Yes	C	Note 18
53 (U-3)	Post-Accident Containment Air Sampling & H2 Control (Non-Essential/PACVS)	Out	Gas	1	2"	Out	Dphrm	HV-3-3	Manual	NA	L.C.	NA	Closed	No	C	Note 7, 9, 18
				2	2"	Out	Dphrm	HV-3-4	Manual	NA	L.C.	NA	Closed	No	C	Note 7, 9, 18,
				2	3/4"	Out	Globe	PAHM-3-002B	Manual	NA	L.C.	NA	Closed	No	C	Note 7, 9, 18
54A	Containment Sump Recirculation (Essential/RHR)	Out/In	Water	1	14"	Out	Gate	MOV-*-860A	PWR	RM	Closed	As Is	Closed	Yes	NA	Note 9, 13, 22
				1	1"	Out	Check	*-2052	Auto	NA	Closed	NA	Closed	No	NA	Note 22
				2	14"	Out	Gate	MOV-*-861A	PWR	RM	Closed	As-Is	Closed	Yes	NA	Note 9, 13, 22
				2	3/4"	Out	Relief	RV-*-871	Auto	NA	Closed	Closed	Closed	No	NA	Note 22
54B	Containment Sump Recirculation (Essential/RHR)	Out/In	Water	1	14"	Out	Gate	MOV-*-860B	PWR	RM	Closed	As Is	Closed	Yes	NA	Note 9, 13, 22
				2	14"	Out	Gate	MOV-*-861B	PWR	RM	Closed	As-Is	Closed	Yes	NA	Note 9, 13, 22
55	Accumulator Sample (Non-Essential/SS)	Out	Water	1	3/8"	In	Globe	CV-*-955C	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				1	3/8"	In	Globe	CV-*-955D	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				1	3/8"	In	Globe	CV-*-955E	PWR	RM	Closed	Closed	Closed	Yes	C	Note 9, 18
				2	3/8"	Out	Globe	CV-*-956D	PWR	Ph A	Closed	Closed	Closed	Yes	C	Note 18

TABLE 6.6-1
CONTAINMENT PIPING PENTRATIONS AND ISOLATION BARRIERS

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
56	Sealed Closed/Spare	NA	NA	1	1/2" (3/8)	In (Out)	Integral	NA	NA	NA	NA	NA	NA	NA	NA (B)	Unit 3, Note 19 (Unit 4), Note 19
57	Sealed Closed/Spare	NA	NA	1	4"	In	Integral	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
58	High Head Cold Leg Injection (Essential/SIS)	In	Water	1	2"	In	Check	*-873A	Auto	NA	Closed	NA	Open	No	NA	Note 22
				2	3/4"	Out	Globe	*-895T	Manual	NA	L.C.	NA	Closed	No	NA	Note 22
				2	6"	Out	Gate	MOV-*-843A,B	PWR	SIS	Closed	As Is	Open	Yes	NA	Note 22
59	High Head Cold Leg Injection (Essential/SIS)	In	Water	1	2"	In	Check	*-873B	Auto	NA	Closed	NA	Open	No	NA	Note 22
				2	3/4"	Out	Globe	*-895T	Manual	NA	L.C.	NA	Closed	No	NA	Note 22
				2	6"	Out	Gate	MOV-*-843A,B	PWR	SIS	Closed	As-Is	Open	Yes	NA	Note 22
60	High Head Cold Leg Injection (Essential/SIS)	In	Water	1	2"	In	Check	*-873C	Auto	NA	Closed	NA	Open	NA	NA	Note 22
				2	3/4"	Out	Globe	*-895T	Manual	NA	L.C.	NA	Closed	No	NA	Note 22
				2	6"	Out	Gate	MOV-*-843A,B	PWR	SIS	Closed	As-Is	Open	Yes	NA	Note 22
61A	Sealed Closed/Spare (U-3) Sealed Closed Unusable (U-4)	NA	NA	1	1"	In	Integral	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
		NA	NA	1	3/8"	Out	Globe	4-2030	Manual	NA	Closed	NA	Closed	NA	B	Note 19
				2	3/8"	Out	Cap	NA	NA	NA	NA	NA	NA	NA	NA	
61B	Sealed Closed/Spare	NA	NA	1	3/8"	In	Integral	NA	NA	NA	NA	NA	NA	NA	NA	Note 19

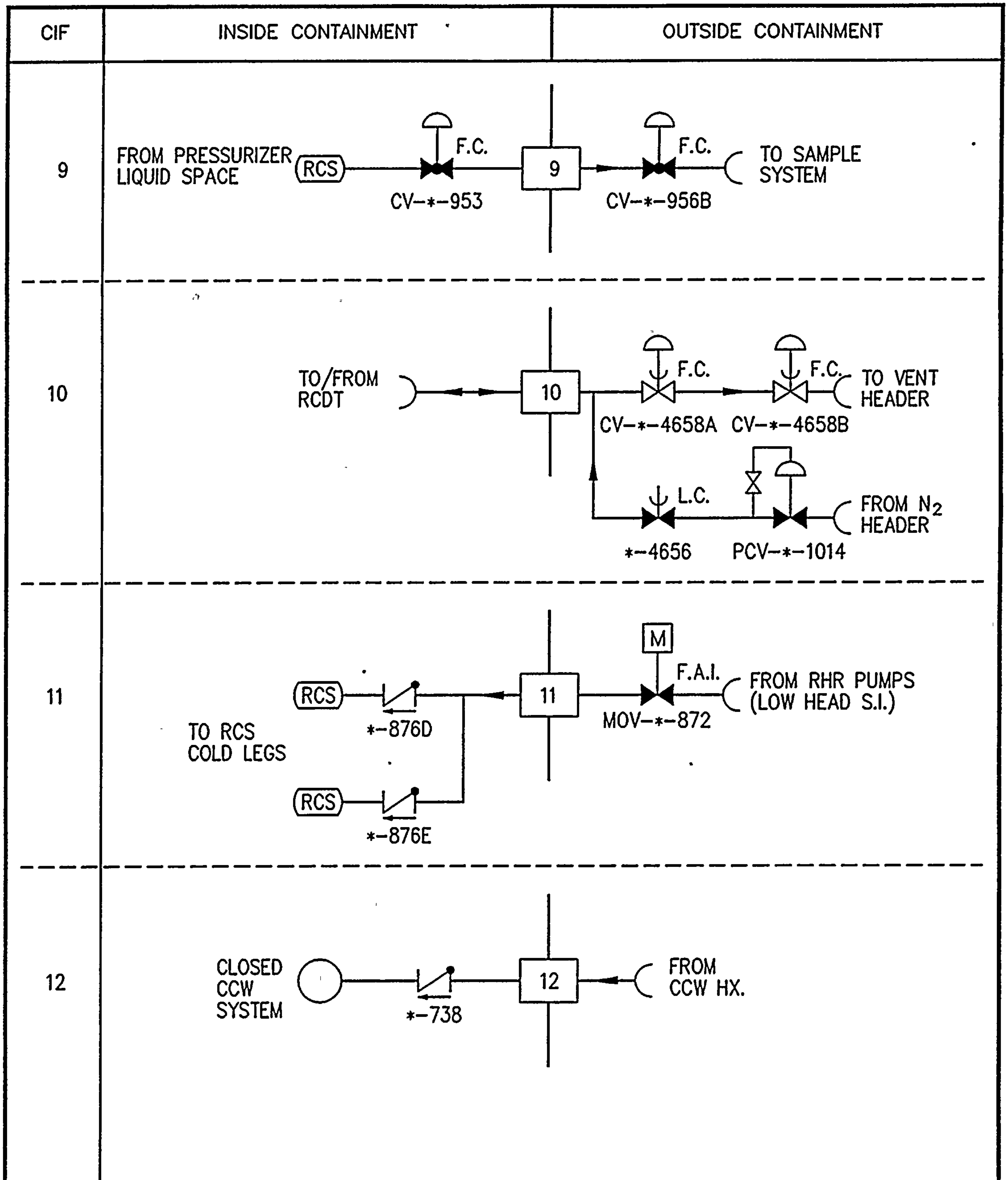
TABLE 6.6-1
CONTAINMENT PIPING PENTRATIONS AND ISOLATION BARRIERS

Pen No.	Service (Classification/System)	Flow Dir.	Fluid	Barrier Number	Line Size	Loc.	Barrier Type	Valve No.	Method of Act'n	Signal	Normal Pos.	Pwr Flr Pos.	Post Accident Position	Rem Pos Ind	App J Test Type (B or C)	Notes
62A,B, C Unit 3	Containment Pressure Sensors	NA	NA	1	1"	Out	Integral	NA	NA	NA	NA	NA	NA	NA	B	Note 12, 19
63	Instrument Air Bleed (Non-Essential/Vent)	Out	Gas	1	2"	In	Globe	CV-*-2819	PWR	CVS	Open	Closed	Closed	Yes	C	Note 18
				2	2"	Out	Globe	CV-*-2826	PWR	CVS	Open	Closed	Closed	Yes	C	Note 18
64A	S/G Blowdown Sample (Non-Essential/Secondary)	NA	Water	1	1"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	1"	Out	Gate	MOV-*-1427	PWR	Ph A	Open	As Is	Closed	Yes	NA	Note 18
64B	S/G Blowdown Sample (Non-Essential/Secondary)	NA	Water	1	1"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	1"	Out	Gate	MOV-*-1426	PWR	Ph A	Open	As Is	Closed	Yes	NA	Note 18
64C	S/G Blowdown Sample (Non-Essential/Secondary)	NA	Water	1	1"	In	CSIC	NA	NA	NA	NA	NA	NA	NA	NA	Note 19
				2	1"	Out	Gate	MOV-*-1425	PWR	Ph A	Open	As Is	Closed	Yes	NA	Note 18
65A	ILRT Service Penetration (Non-Essential/None)	In/Out	Gas	1	8"	In	Flange	NA	NA	NA	Installed	NA	Installed	NA	B	Note 19
				2	8"	Out	Flange	NA	NA	NA	Installed	NA	Installed	NA	B	
65B	ILRT Service Penetration (Non-Essential/None)	Out	Gas	1	3/4"	In	Flange	NA	NA	NA	Installed	NA	Installed	NA	B	Note 19
				2	3/4"	Out	Globe	*-2025	Manual	NA	Closed	NA	Closed	NA	C	Note 18
65C	ILRT Service Penetration (Non-Essential/None)	Out	Gas	1	3/4"	In	Flange	NA	NA	NA	Installed	NA	Installed	NA	B	Note 19
				2	3/4"	Out	Globe	*-2026	Manual	NA	Closed	NA	Closed	NA	C	Note 18
66A,B	Sealed Closed/Spare	NA	NA	1	1"	In	Integral	NA	NA	NA	NA	NA	NA	NA	NA	Note 19

TABLE 6.6-2

SINGLE FAILURE ANALYSIS - CONTAINMENT PURGE VALVES

COMPONENT	FAILURE MODE	RESULTS
Mail Valve Operator	Fails to close or fails to seat or signal to close not received.	2nd purge air valve in series will provide the required isolation.
Instrument Air Supply to the Operator	Failure or air.	Purge air valves are closed by spring, air is NOT required for closure.
Solenoid Valve	Fails to operate (i.e., does NOT isolate the operator cylinder from air supply and does NOT provide air bleed off for the cylinder).	The 2nd purge air valve in series will provide the required isolation.



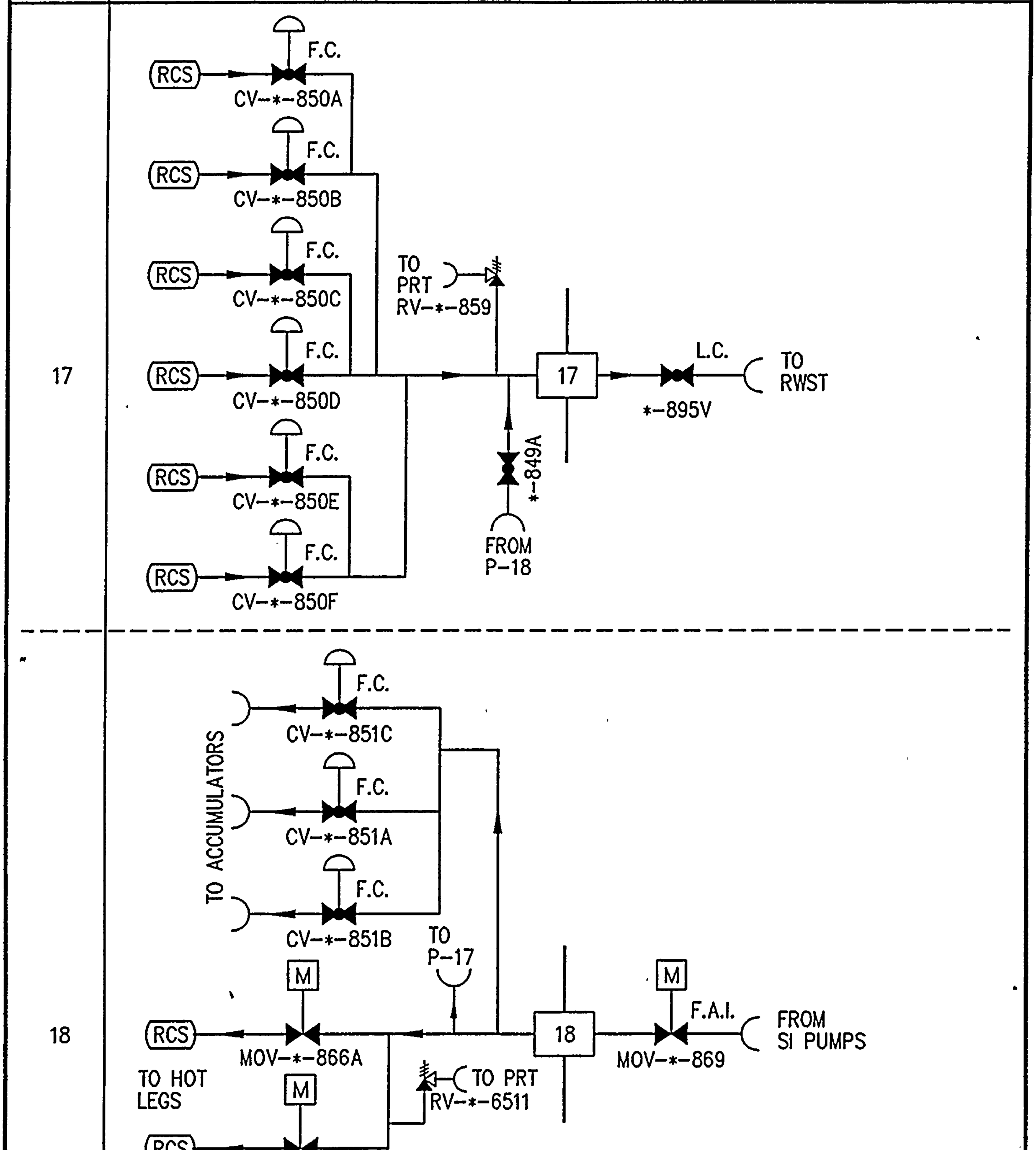
REV. 12 (5/95)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT NUCLEAR UNITS 3 & 4

VALVE ARRANGEMENT
SHEET 3
FIGURE 6.6-1

FTM00238.DWG

CIF	INSIDE CONTAINMENT	OUTSIDE CONTAINMENT



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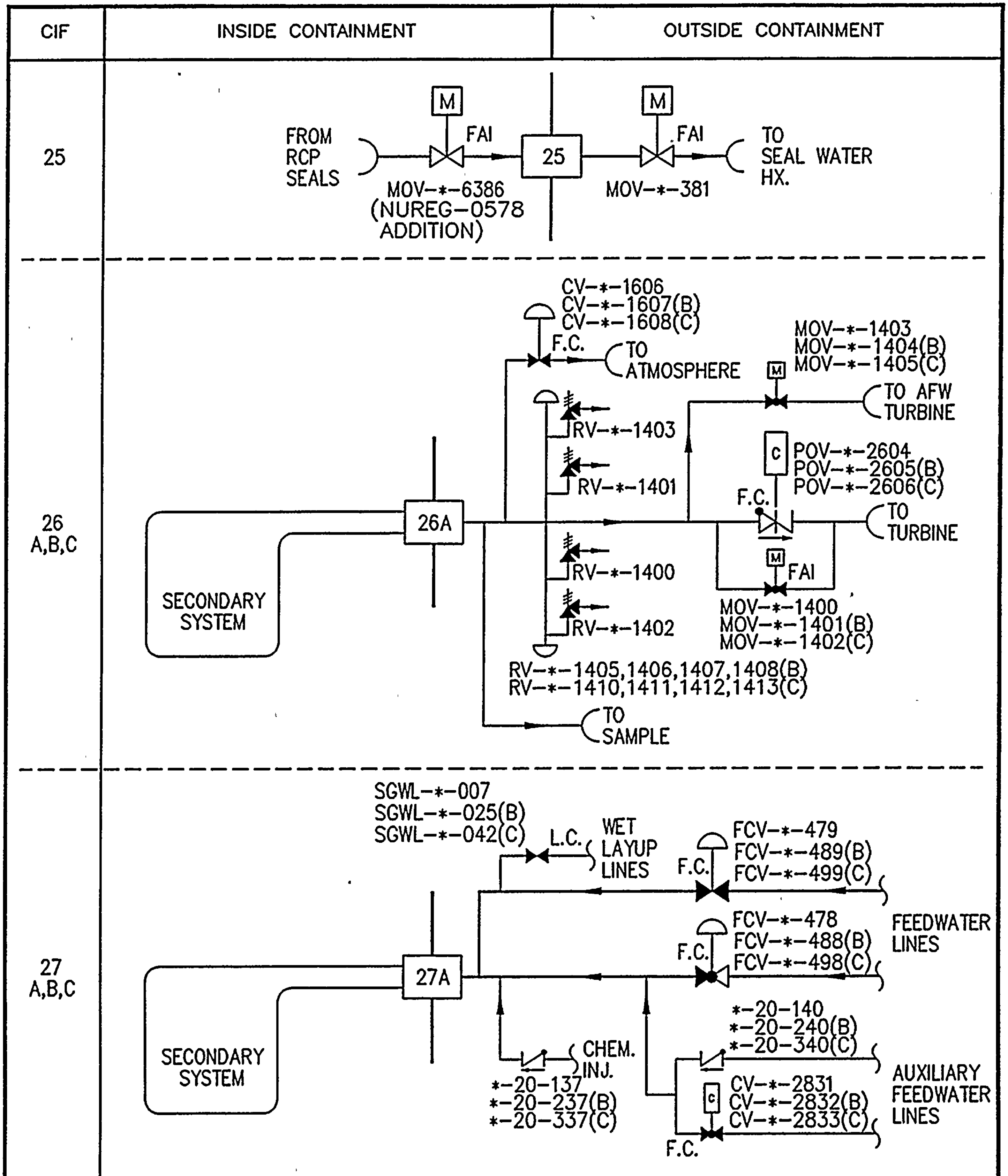
FLORIDA POWER & LIGHT COMPANY
TURKEY POINT NUCLEAR UNITS 3 & 4

VALVE ARRANGEMENT
SHEET 5
FIGURE 6.6-1

FTM00240.DWG



FLORIDA POWER & LIGHT COMPANY
TURKEY POINT NUCLEAR UNITS 3 & 4

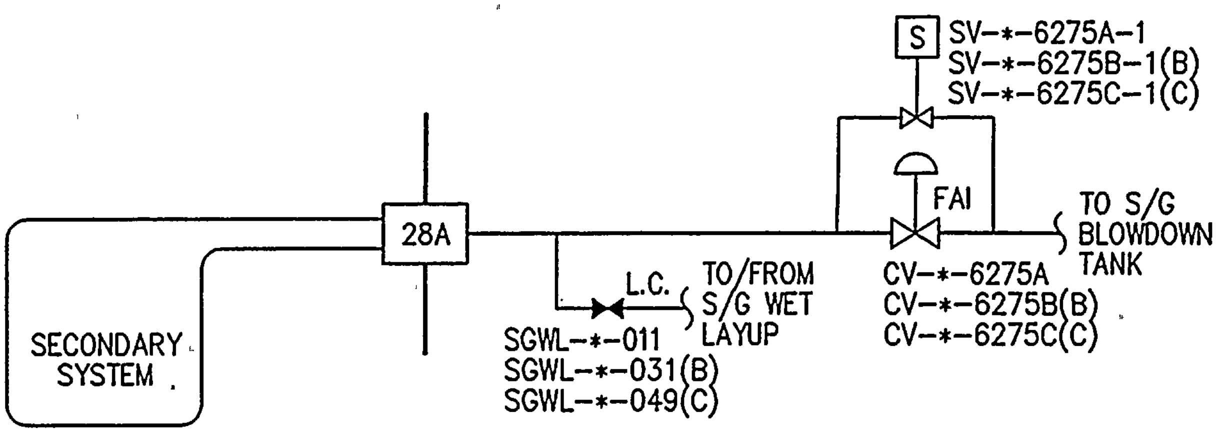
VALVE ARRANGEMENT
SHEET 8
FIGURE 6.6-1

REV. 12 (5/95)

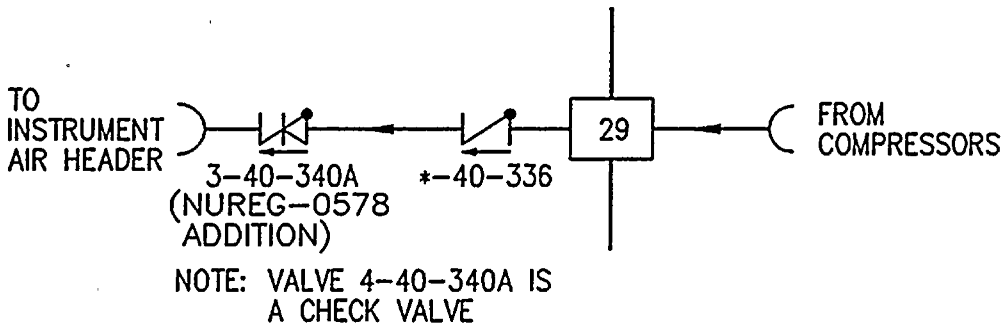
FTM00243.DWG

CIF	INSIDE CONTAINMENT	OUTSIDE CONTAINMENT

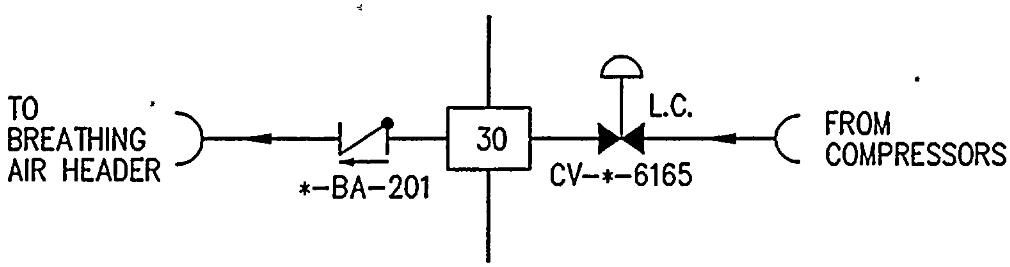
28 A,B,C



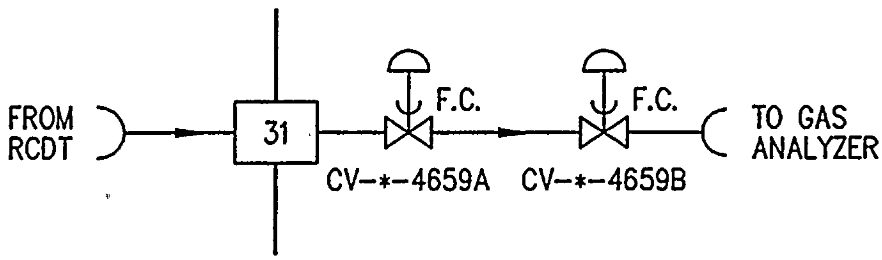
29



30



31



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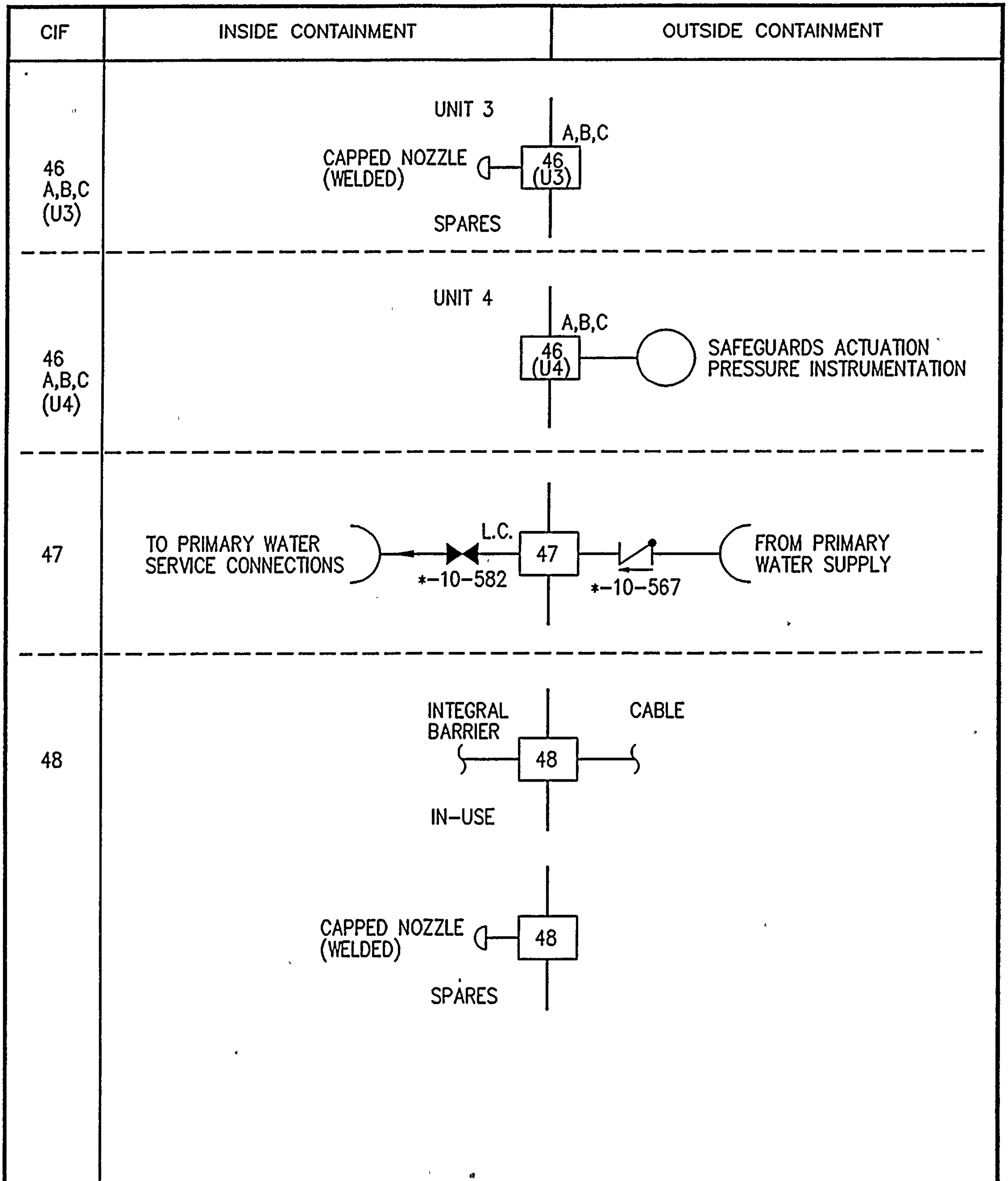
TURKEY POINT NUCLEAR UNITS 3 & 4

VALVE ARRANGEMENT
SHEET 9
FIGURE 6.6-1

FTM00244.DWG



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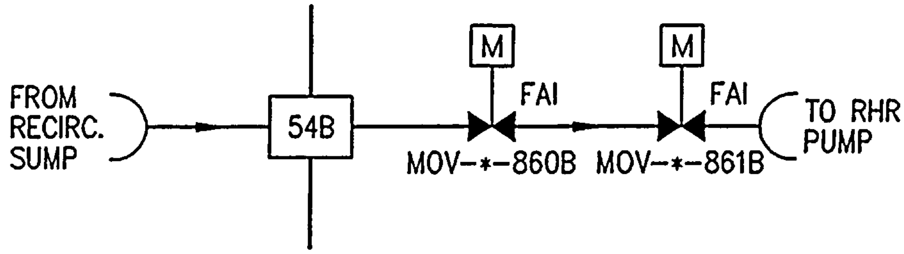
FLORIDA POWER & LIGHT COMPANY
TURKEY POINT NUCLEAR UNITS 3 & 4

VALVE ARRANGEMENT
SHEET 15
FIGURE 6.6-1

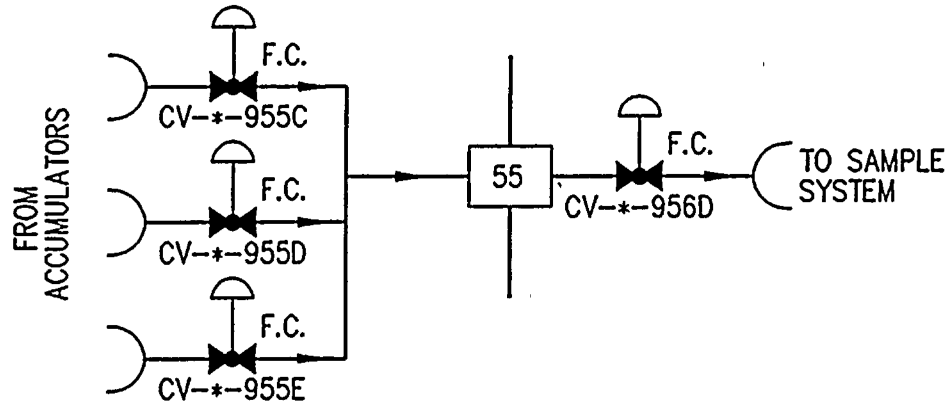
FTM00250.DWG

CIF	INSIDE CONTAINMENT	OUTSIDE CONTAINMENT

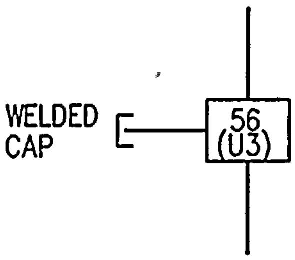
54B



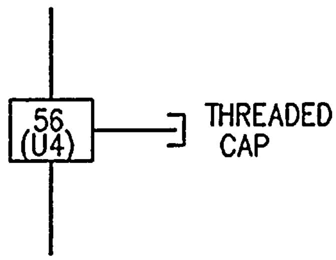
55



56 (U3)



56 (U4)



REV. 12 (5/95)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT NUCLEAR UNITS 3 & 4

VALVE ARRANGEMENT
SHEET 17
FIGURE 6.6-1

FTM00252.DWG

TABLE OF CONTENTS (Continued)

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Interlocking functions of the Reactor Protection System prevent control rod withdrawal when certain specified parameters reach values less than the values at which reactor trip is initiated.

For anticipated abnormal conditions, protective systems in conjunction with inherent characteristics and engineered safety features are designed to assure that limits for energy release to the containment and for radiation exposure (as in 10 CFR 100) are not exceeded.

Indication

All transmitted signals (flow, pressure, temperature, etc) which can lead to a reactor trip are either indicated or recorded for every channel.

All nuclear flux power range currents (top detector, bottom detector and algebraic difference and average of bottom and top detector currents) are indicated and/or recorded.

Annunciators

Annunciators are also used to alert the operator of deviation from normal operating conditions so that he may take corrective action to avoid a reactor trip. Further, actuation of any rod stop or trip of any reactor trip channel will actuate an alarm.

Digital Data Processing System (DDPS)

Various plant signals are connected to the Digital Data Processing System (DDPS). Information is displayed at consoles provided for the reactor control operators in the control room.

The DDPS provides the following information:

1. Sequence of events.
2. Data collection and limited processing for:
    a. Heat rate determination.
    b. Calorimetric reactor output measurement.
    c. Reactor core analysis.

d. Primary Coolant System Loose Parts Vibration.

3. Data collection and storage for post trip review.

Information for sequence of events is printed on a typer, located in the control room.

Safety Parameter Display System / Emergency Response Data Acquisition and Display System

The Safety Parameter Display System (SPDS) / Emergency Response Data Acquisition and Display System (ERDADS) consists of plant process and environmental signals that provide an electronic display (CRT) of plant parameters, from which the safety status of plant operation may be determined in the control room, Technical Support Center (TSC) and Emergency Operating Facility (EOF). The primary function of the Safety Parameter Display System (SPDS) is to aid operating personnel in the control room in making rapid assessments of the status of plant safety. Duplication of the SPDS displays in the Technical Support Center and Emergency Operating Facility improves the communication between these facilities and the control room and assists corporate and plant management in the recovery decision-making process.

The Emergency Response Data Acquisition and Display System (ERDADS), which includes the Safety Parameter Display System, is a real time computer based data acquisition and display system designed to assist control room personnel in evaluating the safety status of the plant. The ERDADS aids in the coordinated control of the reactor during upset conditions, while concurrently providing information of concern to the public. The SPDS includes a set of predetermined CRT displays designed to yield relevant, timely, accurate, and unambiguous information to the control room operators, the technical support advisors, and the offsite public safety officials. The SPDS displays a small but critical subset of the parameters available in the control room, thus reducing the problems associated with information overload and parameter selection. At the same time, by preselecting and grouping critical parameters for each display, the SPDS facilitates comprehension of the prevailing plant and public safety conditions. This is achieved by presenting high-level displays which summarize plant safety function status, plant system performance, and radiological and meteorological data. Printers and plotters are available for hard copy reports. For details on ERDADS refer to Section 7.5.4.

7.2.2 SYSTEM DESIGN

Reactor Protection System Description

Figure 7.2-1 illustrates typical core limits and shows the maximum trip points which are used for the protection system. The solid lines indicate a typical locus of DNBR equal to the safety analysis limit value (in this example, 1.30) at four pressures, and the dashed lines indicate maximum permissible trip points for the overtemperature ΔT reactor trip. Actual setpoints (the final setpoints will be given in the Technical Specifications) are lower to allow for measurement and instrumentation errors. The overpower ΔT reactor trip limits the maximum core power independent of the DNBR.

Adequate margins exist between the maximum nominal steady state operating point (which includes allowances for temperature, calorimetric, and pressure errors) and required trip points to preclude a spurious trip during design transients.

A block diagram of the Reactor Protection System showing various reactor trip functions and interlocks is shown in Figure 7.2-2.

System Safety Features

Separation of Redundant Protection Channels

The Reactor Protection System is designed to achieve separation between redundant protection channels. The channel design is applied to the process and the logic portions of the protection system, and is shown in Figure 7.2-3A. Also shown in Figure 7.2-3B is the configuration for the Engineered Safeguards System Actuation Logic. The reactor trip on loss of 4160V Bus voltage differs from Figure 7.2-3A, and it is illustrated by Figure 7.2-8c.

Separation of redundant process channels originates at the process sensors and continues along the field wiring and through containment penetrations to the process protection racks. Isolation of field wiring is achieved using separate wireways, cable trays, conduit runs and containment penetrations

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For the anticipated abnormal conditions, it is highly unlikely that the exact combination of conditions (reactor coolant pressure, temperature and core power, instrumentation inaccuracies, etc.) that cause a DNBR equal to the safety analysis limit value will be approached before a reactor trip. The simultaneous loss of power to all of the reactor coolant pumps is the accident condition most likely to approach the limit DNBR value for the calculated worst fuel rod. In any event the DNBR at the worst fuel rod is near the limit value for only a few seconds.

The hottest fuel rods are not adjacent to one another. They are located near the RCCA thimbles. Fuel rods located in the immediate vicinity of the hottest fuel rod have a DNBR higher than that rod.

The ΔT trip functions are based on the differences between measured hot leg and cold leg temperatures. These differences are proportional to core power.

The ΔT trip functions are provided with a nuclear flux feedback to reflect a measure of axial power distribution. This will assist in preventing an adverse axial distribution which could lead to exceeding the allowable core conditions.

In the event of a difference between the upper and lower power range detector signals that exceeds the desired range, automatic feedback signals are provided to reduce the overtemperature trip setpoints, block rod withdrawal and reduce the load to maintain appropriate operating margins to these trip setpoints.

Specific Control and Protection Interactions

Four power-range nuclear flux channels are provided for overpower protection. Isolated output from one of these channels is used for automatic control rod regulation of power. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection.

Two-out-of-four overpower trip logic will ensure an overpower trip if needed even with an independent failure in another channel.

Slow changes or drifts are compensated by the temperature control signals. Also, a rapid decrease of any nuclear flux signal will block automatic rod withdrawal as part of the rod drop protection circuitry. Finally, an overpower signal from any nuclear channel will block automatic rod withdrawal. The set point for this rod stop is below the reactor trip set point.

Coolant Temperature

Three T_{avg} channels are used for overtemperature-overpower protection. The median T_{avg} signal from three separate channels is used for automatic control rod regulation of power and temperature. Two out of three (2/3) trip logic is used to ensure that an overtemperature trip occurs if needed even with an independent failure in another channel.

Automatic rod withdrawal blocks will also occur if any one of four nuclear channels indicates an overpower condition or if any two of three temperature channels indicates an over -

TABLE NOTATIONS (Continued)

NOTE 3: OVERPOWER ΔT

$$\Delta T \left\{ \frac{1 + \tau_1 S}{1 + \tau_2 S} \right\} \left(\frac{1}{1 + \tau_3 S} \right) \leq \Delta T_o \left\{ K_4 - K_5 \left(\frac{\tau_7 S}{(1 + \tau_7 S)} \right) \left(\frac{1}{(1 + \tau_6 S)} \right) T - K_6 \left[T \left(\frac{1}{(1 + \tau_6 S)} \right) - T'' \right] - f_2 (\Delta I) \right\}$$

Where: ΔT = As defined in Note 1;

$\frac{1 + \tau_1 S}{1 + \tau_2 S}$ = As defined in Note 1;

$\frac{1}{1 + \tau_3 S}$ = As defined in Note 1;

ΔT_o = As defined in Note 1;

K_4 $\leq$ 1.10;

K_5 $\geq$ 0.02/°F for increasing average temperatue and 0 for decreasing average temperature;

$\frac{\tau_7 S}{1 + \tau_7 S}$ = The function generated by the rate-lag compensator for T_{avg} dynamic compensation;

τ_7 = Time constants utilized in the rate-lag compensator for T_{avg}, $\tau_7 \geq 10s$,

$\frac{1}{1 + \tau_6 S}$ = As defined in Note 1;

TABLE NOTATIONS (Continued)

NOTE 3: (Continued)

K_6	=	0.0016/°F for T > T" and K_6 = 0 for T ≤ T" ;
T	=	As defined in Note 1;
T"	≤	577.2 °F (Nominal T_{avg} at RATED THERMAL POWER);
S	=	As defined in Note 1, and
f_2 (ΔI)	=	0 for all ΔI

NOTE 4: The channel's maximum trip setpoint shall not exceed its computed trip setpoint by more than 0.96% of instrument span.

NOTE 5: Particulate (R-11)
≤6.1 x 10^5 CPM

Gaseous (R-12)

Containment Gaseous Monitor Setpoint = $\frac{(3.2 \times 10^4)}{(\quad F \quad)}$ CPM,

Containment Gaseous Monitor Allowable Value = $\frac{(3.5 \times 10^4)}{(\quad F \quad)}$ CPM,

where $F = \frac{\text{Actual Purge Flow}}{\text{Design Purge Flow (35,000 CFM)}}$

Setpoint may vary according to current plant conditions provided that the release rate does not exceed allowable limits provided in Plant Technical Specification 3.11.2.1.

7.4 NUCLEAR INSTRUMENTATION

7.4.1 DESIGN BASES

Fission Process Monitors and Controls

Criterion: Means shall be provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonably be anticipated to cause variations in reactivity of the core. (GDC 13)

Primary Nuclear Instrumentation

The Primary Nuclear Instrumentation is utilized primarily for reactor protection by permitting monitoring of neutron flux and by generating appropriate trip and alarm functions for various phases of reactor operating and shutdown conditions. It also provides a secondary control function and indicates reactor status during startup and power operation. The Primary Nuclear Instrumentation System utilizes information from three separate types of instrumentation channels to provide three discrete protection levels. Each range of Primary Instumentation (source, intermediate and power) provides the necessary overpower reactor trip protection required during operation in that range. The overlap of instrument ranges provides reliable continuous protection from source to intermediate and low power ranges. As the reactor power increases, the overpower protection level is increased administratively after satisfactory higher range instrumentation operation is obtained. Automatic reset to more restrictive trip protection is provided when reducing power.

Various types of neutron detectors, with appropriate solid state electronic circuitry, are used to monitor the leakage neutron flux from a completely shutdown condition to 120 percent of full power. The power range channels are capable of recording overpower excursions up to 200 percent of full power.

The neutron flux covers a wide range between these extremes. Therefore, monitoring with several ranges of instrumentation is necessary. The lowest range ("source range") covers six decades of leakage neutron flux.

The lowest observed count rate depends on the strength of the residual neutron source in the reloaded fuel and the primary and/or secondary neutron source(s) (if installed) in the core and the core multiplication associated with the shutdown reactivity. This is generally greater than one count per second. The next range ("intermediate" range) covers eight decades. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the intermediate range. The highest range of instrumentation ("power" range) covers slightly more than two decades of the total instrumentation range. This is a linear range that overlaps with the higher portion of the intermediate range. The overlap for all ranges is shown in Figure 7.4-1 in terms of leakage neutron flux for a typical PWR plant. Start-up-rate indication for the source and intermediate range channels is provided at the control console.

PARAMETER LISTING SUMMARY SHEETS
UNIT 3 TURKEY POINT

10/88

ITEM	TAG NO	VARIABLE DESCRIPTION	TYPE	CAT	INSTRUMENT RANGE EXISTING	INSTRUMENT RANGE REQUIRED	ENVIRON QUAL	SEISMIC QUAL	REDUNDANCE	POWER SUPPLY	DISPLAY LOCATION CR	TSC	EOF	SCHEDULE/ JUSTIFICATION
	NI 6649A 2	NEUTRON FLUX INDICATOR	A	1	1E 8 TO 200% FULL POWER	PLANT SPECIFIC	N/A	COMPLY	NI 6649B 2	NOTE 1	YES	–	–	
	ND 6649B	NEUTRON FLUX DETECTOR	A	1	1E 8 TO 200% FULL POWER	PLANT SPECIFIC	COMPLY	COMPLY	ND 6649A	NOTE 1	ERDADS	YES	YES	NOTES 1A,1B
	NI 6649B 2	NEUTRON FLUX INDICATOR	A	1	1E 8 TO 200% FULL POWER	PLANT SPECIFIC	N/A	COMPLY	NI 6649A 2	NOTE 1	YES	–	–	
A7		CORE EXIT TEMPERATURE												
	TE 1E THRU TE 51E	CORE EXIT TEMPERATURE	A	1	32 2300 F	PLANT SPECIFIC	N/A	COMPLY	2 CHANNEL PER QUADR	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY 'A'	A	1	32 2300 F	PLANT SPECIFIC	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	
	QSPDS B	DISPLAY 'B'	A	1	32 2300 F	PLANT SPECIFIC	N/A	COMPLY	QSPDS A	NOTE 1	YES	–	–	
A8		CONTAINMENT SUMP WATER LEVEL												
	LT 6309A	CTMT WATER LEVEL	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	COMPLY	COMPLY	LT 6309B	NOTE 1	–	YES	YES	NOTE 1C
	LI 6309A	CTMT WATER LEVEL IND	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	N/A	COMPLY	LI 6309B	NOTE 1	YES	–	–	NOTES 1C,1K
	LR 6308A	CTMT. WATER LEVEL	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	N/A	COMPLY	N/A	NOTE 1	YES	–	–	NOTE 1C
	LT 6309B	CTMT. WATER LEVEL	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	COMPLY	COMPLY	LT 6309A	NOTE 1	–	YES	YES	NOTE 1C
	LI 6309B	CTMT WATER LEVEL IND	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	N/A	COMPLY	LI 6309A	NOTE 1	YES	–	–	NOTES 1C,1K
	LR 6308B	CTMT WATER LEVEL	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	N/A	COMPLY	N/A	NOTE 1	YES	–	–	NOTE 1C
A9		PRESSURIZER WATER LEVEL												
	LT 459	PRZR LEVEL CH I	A	1	0 100%(150" TO 334")	PLANT SPECIFIC	COMPLY	COMPLY	LT-460;LT-461	NOTE 1	–	YES	YES	
	LI 459A	PRZR LEVEL CH. I IND	A	1	0 100%	PLANT SPECIFIC	N/A	COMPLY	LI 460;LI 461	NOTE 1	YES	–	–	
	LT 460	PRZR LEVEL CH II	A	1	0 100%(150" TO 334")	PLANT SPECIFIC	COMPLY	COMPLY	LT-459;LT-461	NOTE 1	–	YES	YES	
	LI 460	PRZR LEVEL CH II IND.	A	1	0 100%	PLANT SPECIFIC	N/A	COMPLY	LI-459A;LI 461	NOTE 1	YES	–	–	
	LT-461	PRZR LEVEL CH III	A	1	0 100%(150" TO 334")	PLANT SPECIFIC	COMPLY	COMPLY	LT-459;LT-460	NOTE 1	–	YES	YES	
	LI 461	PRZR LEVEL CH III IND.	A	1	0 100%	PLANT SPECIFIC	N/A	COMPLY	LI 459A,LI 460	NOTE 1	YES	–	–	
	LR 459	PRZR LEVEL RECORDER FOR LT 459, 460, 461	A	1	0 100%	PLANT SPECIFIC	N/A	COMPLY	N/A	NOTE 1	YES	–	–	
A10		STEAM GENERATOR PRESSURE												
	PT 474	S G. 'A' STEAM PRESSURE CH II	A	1	0 1400 PSIG	PLANT SPECIFIC	COMPLY	COMPLY	PT-475,PT 476	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	PI 474	S G. 'A' STEAM PRESSURE CH. II IND	A	1	0 1400 PSIG	PLANT SPECIFIC	N/A	COMPLY	PI 475,PI 476	NOTE 1	YES	–	–	
	PT 475	S G. 'A' STEAM PRESSURE CH. III	A	1	0 1400 PSIG	PLANT SPECIFIC	COMPLY	COMPLY	PT-474,PT 476	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	PI 475	S G. 'A' STEAM PRESSURE CH. III IND.	A	1	0 1400 PSIG	PLANT SPECIFIC	N/A	COMPLY	PI 474,PI 476	NOTE 1	YES	-	–	
	PT-476	S G. 'A' STEAM PRESSURE CH. IV	A	1	0 1400 PSIG	PLANT SPECIFIC	COMPLY	COMPLY	PT-474,PT-475	NOTE 1	SPDS	YES	YES	NOTES 1A,1B

TABLE 7.5-1

PARAMETER LISTING SUMMARY SHEETS
UNIT 3 TURKEY POINT

10/88

ITEM	TAG NO	VARIABLE DESCRIPTION	TYPE	CAT	INSTRUMENT RANGE EXISTING	INSTRUMENT RANGE REQUIRED	ENVIRON QUAL.	SEISMIC QUAL.	REDUNDANCE	POWER SUPPLY	DISPLAY LOCATION CR	DISPLAY LOCATION TSC	DISPLAY LOCATION EOF	SCHEDULE/ JUSTIFICATION
	TE 420B	RCS COLD LEG WTR TEMP LOOP "B"	B	1	0 750 F	50 700 F	COMPLY	COMPLY	TE 420A	NOTE 1	–	YES	YES	
	TE 430A	RCS COLD LEG WTR TEMP LOOP "C"	B	1	0 750 F	50 700 F	COMPLY	COMPLY	TE-430B	NOTE 1	–	YES	YES	
	TE 430B	RCS COLD LEG WTR TEMP LOOP "C"	B	1	0 750 F	50 700 F	COMPLY	COMPLY	TE-430A	NOTE 1	–	YES	YES	
	TR 410	RCS COLD LEG TEMP RECORD LOOP A, B, C FOR TR. A	B	1	0 750 F	50-700 F	N/A	COMPLY	N/A	NOTE 1	YES	–	–	
	QSPDS A	DISPLAY "A"	B	1	0 750 F	50-700 F	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	
	QSPDS B	DISPLAY "B"	B	1	0 750 F	50-700 F	N/A	COMPLY	QSPDS A	NOTE 1	YES	–	–	
B7		CORE COOLING - RCS PRESSURE												
	PT 404	RCS PRESSURE	B	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-406	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	PT-406	RCS PRESSURE	B	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-404	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY "A"	B	1	0 3000 PSIG	0 3000 PSIG	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	
	QSPDS B	DISPLAY "B"	B	1	0 3000 PSIG	0-3000 PSIG	N/A	COMPLY	QSPDS A	NOTE 1	YES	–	–	
B8		CORE COOLING - CORE EXIT TEMPERATURE												
	TE 1E THRU TE 51E	CORE EXIT TEMPERATURE	B	3	32 2300 F	200 2300 F	N/A	N/A	N/A	N/A	–	YES	YES	
	QSPDS A	DISPLAY "A"	B	3	32 2300 F	200 2300 F	N/A	N/A	N/A	N/A	YES	–	–	
	QSPDS B	DISPLAY "B"	B	3	32 2300 F	200 2300 F	N/A	N/A	N/A	N/A	YES	–	–	
B9		CORE COOLING - COOLANT INVENTORY												
	ICCS RVL A (HJTC)	REACTOR VESSEL WTR. LVL. CH. "A"	B	1	0 100% (CORE TOP/VSL TOP)	BTM HOT LEG TO TOP OF VESL	N/A	COMPLY	RVL-B	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	ICCS RVL B (HJTC)	REACTOR VESSEL WTR. LVL. CH. "B"	B	1	0 100% (CORE TOP/VSL TOP)	BTM HOT LEG TO TOP OF VESL	N/A	COMPLY	RVL-A	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY "A"	B	1	0 100% (CORE TOP/VSL TOP)	BTM HOT LEG TO TOP OF VESL	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	
	QSPDS B	DISPLAY "B"	B	1	0 100% (CORE TOP/VSL TOP)	BTM HOT LEG TO TOP OF VESL	N/A	COMPLY	QSPDS A	NOTE 1	YES	–	–	
B10		CORE COOLING - DEGREES OF SUBCOOLING												
	QSPDS A	RCS TEMP. SATURATION MARGIN CH. "A"	B	2	700 TO 2100 F	200 SUBCLNG TO 35 SUPRHT	N/A	N/A	N/A	NOTE 1	YES	YES	YES	
	QSPDS B	RCS TEMP. SATURATION MARGIN CH. "B"	B	2	700 TO -2100 F	200 SUBCLNG TO 35 SUPRHT	N/A	N/A	N/A	NOTE 1	YES	YES	YES	
B11		MAINTAINING RCS INTEGRITY - RCS PRESSURE												
	PT 404	RCS PRESSURE	B	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-406	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	PT 406	RCS PRESSURE	B	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT 404	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY "A"	B	1	0 3000 PSIG	0-3000 PSIG	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	

TABLE 7.5-1

PARAMETER LISTING SUMMARY SHEETS
UNIT 3 TURKEY POINT

10/98

ITEM	TAG NO	VARIABLE			INSTRUMENT RANGE		ENVIRON QUAL.	SEISMIC QUAL.	REDUNDANCE	POWER SUPPLY	DISPLAY LOCATION			SCHEDULE/ JUSTIFICATION
		DESCRIPTION	TYPE	CAT	EXISTING	REQUIRED					CR	TSC	EOF	
		CV 855 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	CV 9560 (LS)	ACCUMULATOR SAMPLE LINE	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 9560 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	MOV 843A (LS)	BORON INJ TANK OUT STOP VALVE	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	COMPLY	COMPLY	N/A	NOTE 2	–	YES	YES	NOTES 1H,2
		MOV 843A IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 2	YES	–	–	
	MOV 843B (LS)	BORON INJ TANK OUT STOP VALVE	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	COMPLY	COMPLY	N/A	NOTE 2	–	YES	YES	NOTES 1H,2
		MOV 843B IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 2	YES	–	–	
	CV 2821 (LS)	CTMT SUMP DISCH.	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 2821 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	CV 2822 (LS)	CTMT SUMP DISCH	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 2822 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	CV 2819 (LS)	INST. AIR BLEED	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	COMPLY	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 2819 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	CV 2826 (LS)	INST AIR BLEED	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 2826 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	MOV 6386 (LS)	RCP SEAL	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	COMPLY	COMPLY	N/A	NOTE 2	–	YES	YES	NOTES 1H,2
		MOV 6386 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 2	YES	–	–	
	CV 518 (LS)	GAS ANALYZER SAMPLE VLV.	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 518 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	SV 6385 (LS)	GAS ANALYZER SAMPLE VLV	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		SV 6385 IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	SV 6275A 1 (LS)	STEAM GEN BLOWDOWN BYPASS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	–	–	NOTES 1H,2
		SV 6275A 1 IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	SV 6275B 1 (LS)	STEAM GEN BLOWDOWN BYPASS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	–	–	NOTES 1H,2
		SV 6275B 1 IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	

PARAMETER LISTING SUMMARY SHEETS
UNIT 3 TURKEY POINT

10/88

ITEM	TAG NO	VARIABLE DESCRIPTION	TYPE	CAT	INSTRUMENT RANGE EXISTING	INSTRUMENT RANGE REQUIRED	ENVIRON QUAL	SEISMIC QUAL	REDUNDANCE	POWER SUPPLY	DISPLAY LOCATION CR	DISPLAY LOCATION TSC	DISPLAY LOCATION EOF	SCHEDULE/ JUSTIFICATION
	SV 6275C 1 (LS)	STEAM GEN BLOWDOWN BYPASS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	—	—	—	NOTES 1H,2
		SV 6275C 1 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	—	—	
B16		<u>MAINTAINING CTMT. INTEGRITY - CTMT. PRESSURE</u>												
	PT 6306A	CTMT WIDE RANGE PRESSURE	B	1	0 180 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PT 6306B	NOTE 1	—	YES	YES	
	PI 6306A	CTMT WIDE RANGE PRESS IND	B	1	0 180 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PI 6306B	NOTE 1	YES	—	—	
	PR 6306A	CTMT WIDE RANGE PRESS	B	1	0 180 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	N/A	NOTE 1	YES	—	—	
	PT 6306B	CTMT WIDE RANGE PRESS	B	1	0 180 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PT-6306A	NOTE 1	—	YES	YES	
	PI 6306B	CTMT WIDE RANGE PRESS IND	B	1	0 180 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PI 6306A	NOTE 1	YES	—	—	
	PR 6306B	CTMT WIDE RANGE PRESS	B	1	0 180 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	N/A	NOTE 1	YES	—	—	
	PT 6425A	CTMT NARROW RANGE PRESS	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PT-6425B	NOTE 1	—	YES	YES	
	PI 6425A	CTMT NARROW RANGE PRESS. IND.	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PI 6425B	NOTE 1	YES	—	—	
	PR 6306A	CTMT NARROW RANGE PRESS.	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	N/A	NOTE 1	YES	—	—	
	PT 6425B	CTMT NARROW RANGE PRESS	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PT-6425A	NOTE 1	—	YES	YES	
	PI 6425B	CTMT NARROW RANGE PRESS IND.	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PI 6425A	NOTE 1	YES	-	—	
	PR 6306B	CTMT NARROW RANGE PRESS.	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	N/A	NOTE 1	YES	—	—	
C1		<u>FUEL CLADDING - CORE EXIT TEMPERATURE</u>												
	TE 1E THRU TE 51E	CORE EXIT TEMPERATURE	C	1	32 2300 F	200 2300 F	N/A	COMPLY	2 CHANNEL PER QUADR	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY "A"	C	1	32 2300 F	200 2300 F	N/A	COMPLY	QSPDS B	NOTE 1	YES	—	—	
	QSPDS B	DISPLAY "B"	C	1	32 2300 F	200 2300 F	N/A	COMPLY	QSPDS A	NOTE 1	YES	—	—	
C2		<u>FUEL CLADDING - RADIOACTIVITY CONCENTRATION OR RADIATION LEVEL IN CIRCULATING PRIMARY COOLANT</u>												
	NONE	RADIOACTIVITY CONCENTRATION OR RADIATION LEVEL	C	1	GRAB SAMPLE	1/2 TO 100 X T.S. LIMIT	—	—	—	—	—	—	—	NOTE 3
C3		<u>FUEL CLADDING - ANALYSIS OF PRIMARY COOLANT</u>												
	AE 6372	Rx COOL WATER RADIOACTIVITY ANALYSIS	C	3	1E-7 Ci/CC TO 10 Ci/CC	10 micro Ci/ml to 10 Ci/ml	N/A	N/A	N/A	N/A	ERDADS	YES	YES	NOTE 1B
C4		<u>Rx COOLANT PRESSURE BOUNDARY - RCS PRESSURE</u>												
	PT 404	RCS PRESS.	C	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-406	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	PT 406	RCS PRESS.	C	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-404	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY "A"	C	1	0 3000 PSIG	0 3000 PSIG	N/A	COMPLY	QSPDS B	NOTE 1	YES	—	—	
	QSPDS B	DISPLAY "B"	C	1	0 3000 PSIG	0-3000 PSIG	N/A	COMPLY	QSPDS A	NOTE 1	YES	—	—	

7. This device does not electrically transmit a signal to ERDADS. The data is obtained by plant personnel and then manually inputted into ERDADS where it is stored and available for display.

8. The range of the existing plant instrumentation for this variable (i.e., Item E6) does not envelop the RG 1.97 required range. However, the difference in low end range (i.e., 1 versus 0.1 micro Ci/CC) is not critical to the monitoring of main steam line radiation.

TABLE 7.5-2

PARAMETER LISTING SUMMARY SHEETS
UNIT 4 TURKEY POINT

10/88

ITEM	TAG NO	VARIABLE			INSTRUMENT RANGE		ENVIRON QUAL	SEISMIC QUAL	REDUNDANCE	POWER SUPPLY	DISPLAY LOCATION			SCHEDULE/ JUSTIFICATION
		DESCRIPTION	TYPE	CAT	EXISTING	REQUIRED					CR	TSC	EOF	
	NI 6649A 2	NEUTRON FLUX INDICATOR	A	1	1E 8 TO 200% FULL POWER	PLANT SPECIFIC	N/A	COMPLY	NI 6649B 2	NOTE 1	YES	–	–	
	ND 6649B	NEUTRON FLUX DETECTOR	A	1	1E 8 TO 200% FULL POWER	PLANT SPECIFIC	COMPLY	COMPLY	ND 6649A	NOTE 1	ERDADS	YES	YES	NOTES 1A,1B
	NI 6649B 2	NEUTRON FLUX INDICATOR	A	1	1E 8 TO 200% FULL POWER	PLANT SPECIFIC	N/A	COMPLY	NI 6649A 2	NOTE 1	YES	–	–	
A7		CORE EXIT TEMPERATURE												
	TE 1E THRU TE 51E	CORE EXIT TEMPERATURE	A	1	32 2300 F	PLANT SPECIFIC	N/A	COMPLY	2 CHANNEL PER QUADR	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY 'A'	A	1	32 2300 F	PLANT SPECIFIC	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	
	QSPDS B	DISPLAY 'B'	A	1	32 2300 F	PLANT SPECIFIC	N/A	COMPLY	QSPDS A	NOTE 1	YES	–	–	
A8		CONTAINMENT SUMP WATER LEVEL												
	LT 6309A	CTMT. WATER LEVEL	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	COMPLY	COMPLY	LT-6309B	NOTE 1	–	YES	YES	NOTE 1C
	LI 6309A	CTMT WATER LEVEL IND.	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	N/A	COMPLY	LI 6309B	NOTE 1	YES	–	–	NOTES 1C,1K
	LR 6308A	CTMT. WATER LEVEL	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	N/A	COMPLY	N/A	NOTE 1	YES	–	–	NOTE 1C
	LT 6309B	CTMT. WATER LEVEL	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	COMPLY	COMPLY	LT-6309A	NOTE 1	–	YES	YES	NOTE 1C
	LI 6309B	CTMT. WATER LEVEL IND.	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	N/A	COMPLY	LI 6309A	NOTE 1	YES	–	-	NOTES 1C,1K
	LR 6308B	CTMT. WATER LEVEL	A	1	397" TO 487"	WIDE RANGE PLANT SPECIFIC	N/A	COMPLY	N/A	NOTE 1	YES	–	–	NOTE 1C
A9		PRESSURIZER WATER LEVEL												
	LT 459	PRZR LEVEL CH. I	A	1	0-100%(150" TO 334")	PLANT SPECIFIC	COMPLY	COMPLY	LT-460;LT 461	NOTE 1	–	YES	YES	
	LI 459A	PRZR LEVEL CH I IND.	A	1	0 100%	PLANT SPECIFIC	N/A	COMPLY	LI 460;LI 461	NOTE 1	YES	–	–	
	LT-460	PRZR LEVEL CH. II	A	1	0 100%(150" TO 334")	PLANT SPECIFIC	COMPLY	COMPLY	LT-459;LT-461	NOTE 1	–	YES	YES	
	LI 460	PRZR LEVEL CH. II IND.	A	1	0 100%	PLANT SPECIFIC	N/A	COMPLY	LI 459A;LI 461	NOTE 1	YES	–	–	
	LT-461	PRZR LEVEL CH. III	A	1	0 100%(150" TO 334")	PLANT SPECIFIC	COMPLY	COMPLY	LT-459;LT-460	NOTE 1	–	YES	YES	
	LI 461	PRZR LEVEL CH. III IND.	A	1	0 100%	PLANT SPECIFIC	N/A	COMPLY	LI 459A,LI 460	NOTE 1	YES	–	–	
	LR 459	PRZR LEVEL RECORDER FOR LT 459, 460, 461	A	1	0 100%	PLANT SPECIFIC	N/A	COMPLY	N/A	NOTE 1	YES	–	–	
A10		STEAM GENERATOR PRESSURE												
	PT-474	S G 'A' STEAM PRESSURE CH. II	A	1	0 1400 PSIG	PLANT SPECIFIC	COMPLY	COMPLY	PT-475;PT-478	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	PI 474	S G. 'A' STEAM PRESSURE CH. II IND.	A	1	0 1400 PSIG	PLANT SPECIFIC	N/A	COMPLY	PI 475,PI 478	NOTE 1	YES	–	–	
	PT-475	S G. 'A' STEAM PRESSURE CH. III	A	1	0 1400 PSIG	PLANT SPECIFIC	COMPLY	COMPLY	PT 474,PT-478	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	PI 475	S G. 'A' STEAM PRESSURE CH. III IND.	A	1	0 1400 PSIG	PLANT SPECIFIC	N/A	COMPLY	PI 474,PI 478	NOTE 1	YES	-	-	

TABLE 7.5-2

PARAMETER LISTING SUMMARY SHEETS
UNIT 4 TURKEY POINT

10/98

ITEM	TAG NO	VARIABLE DESCRIPTION	TYPE	CAT	INSTRUMENT RANGE EXISTING	INSTRUMENT RANGE REQUIRED	ENVIRON QUAL.	SEISMIC QUAL.	REDUNDANCE	POWER SUPPLY	DISPLAY LOCATION CR	DISPLAY LOCATION TSC	DISPLAY LOCATION EOF	SCHEDULE/ JUSTIFICATION
	TE 420A	RCS COLD LEG WTR TEMP LOOP "B"	B	1	0 750 F	50 700 F	COMPLY	COMPLY	TE 420B	NOTE 1	–	YES	YES	
	TE 420B	RCS COLD LEG WTR TEMP LOOP "B"	B	1	0 750 F	50 700 F	COMPLY	COMPLY	TE 420A	NOTE 1	–	YES	YES	
	TE 430A	RCS COLD LEG WTR TEMP LOOP "C"	B	1	0 750 F	50 700 F	COMPLY	COMPLY	TE 430B	NOTE 1	–	YES	YES	
	TE 430B	RCS COLD LEG WTR TEMP LOOP "C"	B	1	0 750 F	50 700 F	COMPLY	COMPLY	TE 430A	NOTE 1	–	YES	YES	
	TR 410	RCS COLD LEG TEMP. RECORD LOOP A, B, C FOR TR. A	B	1	0 750 F	50 700 F	N/A	COMPLY	N/A	NOTE 1	YES	–	–	
	QSPDS A	DISPLAY "A"	B	1	0 750 F	50 700 F	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	
	QSPDS B	DISPLAY "B"	B	1	0 750 F	50 700 F	N/A	COMPLY	QSPDS A	NOTE 1	YES	–	–	
B7		CORE COOLING - RCS PRESSURE												
	PT 404	RCS PRESSURE	B	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-408	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	PT 408	RCS PRESSURE	B	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-404	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY "A"	B	1	0 3000 PSIG	0 3000 PSIG	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	
	QSPDS B	DISPLAY "B"	B	1	0 3000 PSIG	0 3000 PSIG	N/A	COMPLY	QSPDS A	NOTE 1	YES	–	–	
B8		CORE COOLING - CORE EXIT TEMPERATURE												
	TE 1E THRU TE 51E	CORE EXIT TEMPERATURE	B	3	32 2300 F	200 2300 F	N/A	N/A	N/A	N/A	–	YES	YES	
	QSPDS A	DISPLAY "A"	B	3	32-2300 F	200 2300 F	N/A	N/A	N/A	N/A	YES	–	–	
	QSPDS B	DISPLAY "B"	B	3	32-2300 F	200 2300 F	N/A	N/A	N/A	N/A	YES	–	–	
B9		CORE COOLING - COOLANT INVENTORY												
	ICCS RVL A (HJTC)	REACTOR VESSEL WTR. LVL. CH. "A"	B	1	0 100% (CORE TOP/VSL TOP)	BTM HOT LEG TO TOP OF VESL	N/A	COMPLY	RVL B	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	ICCS RVL B (HJTC)	REACTOR VESSEL WTR. LVL. CH. "B"	B	1	0 100% (CORE TOP/VSL TOP)	BTM HOT LEG TO TOP OF VESL	N/A	COMPLY	RVL-A	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY "A"	B	1	0 100% (CORE TOP/VSL TOP)	BTM HOT LEG TO TOP OF VESL	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	
	QSPDS B	DISPLAY "B"	B	1	0 100% (CORE TOP/VSL TOP)	BTM HOT LEG TO TOP OF VESL	N/A	COMPLY	QSPDS A	NOTE 1	YES	–	–	
B10		CORE COOLING - DEGREES OF SUBCOOLING												
	QSPDS A	RCS TEMP SATURATION MARGIN CH. "A"	B	2	700 TO 2100 F	200 SUBCLNG TO 35 SUPRHT	N/A	N/A	N/A	NOTE 1	YES	YES	YES	
	QSPDS B	RCS TEMP. SATURATION MARGIN CH. "B"	B	2	700 TO 2100 F	200 SUBCLNG TO 35 SUPRHT	N/A	N/A	N/A	NOTE 1	YES	YES	YES	
B11		MAINTAINING RCS INTEGRITY - RCS PRESSURE												
	PT 404	RCS PRESSURE	B	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-408	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	PT 408	RCS PRESSURE	B	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-404	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY "A"	B	1	0 3000 PSIG	0 3000 PSIG	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	

TABLE 7.5-2

SHEET 15 OF 34

PARAMETER LISTING SUMMARY SHEETS
UNIT 4 TURKEY POINT

10/88

ITEM	TAG NO	VARIABLE			INSTRUMENT RANGE		ENVIRON QUAL.	SEISMIC QUAL.	REDUNDANCE	POWER SUPPLY	DISPLAY LOCATION			SCHEDULE/ JUSTIFICATION
		DESCRIPTION	TYPE	CAT	EXISTING	REQUIRED					CR	TSC	EOF	
		CV 855 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	CV 9560 (LS)	ACCUMULATOR SAMPLE LINE	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 9560 IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	MOV 843A (LS)	BORON INJ. TANK OUT STOP VALVE	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	COMPLY	COMPLY	N/A	NOTE 2	–	YES	YES	NOTES 1H,2
		MOV 843A IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 2	YES	–	–	
	MOV 843B (LS)	BORON INJ. TANK OUT STOP VALVE	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	COMPLY	COMPLY	N/A	NOTE 2	–	YES	YES	NOTES 1H,2
		MOV 843B IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 2	YES	–	–	
	CV 2821 (LS)	CTMT. SUMP DISCH.	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 2821 IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	CV 2822 (LS)	CTMT. SUMP DISCH	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 2822 IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	CV 2819 (LS)	INST. AIR BLEED	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	COMPLY	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 2819 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	CV 2826 (LS)	INST. AIR BLEED	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 2826 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	MOV 6386 (LS)	RCP SEAL	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	COMPLY	COMPLY	N/A	NOTE 2	–	YES	YES	NOTES 1H,2
		MOV 6386 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 2	YES	–	–	
	CV 516 (LS)	GAS ANALYZER SAMPLE VLV.	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		CV 516 IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	SV 6385 (LS)	GAS ANALYZER SAMPLE VLV.	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	YES	YES	NOTES 1H,2
		SV 6385 IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	SV 6275A 1 (LS)	STEAM GEN. BLOWDOWN BYPASS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	–	–	NOTES 1H,2
		SV 6275A 1 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
	SV 6275B 1 (LS)	STEAM GEN BLOWDOWN BYPASS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	–	–	NOTES 1H,2
		SV 6275B 1 IND. LIGHTS	B	1	OPEN/CLOSED	CLOSED,NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	

TABLE 7.5-2

PARAMETER LISTING SUMMARY SHEETS
UNIT 4 TURKEY POINT

10/98

ITEM	TAG NO	VARIABLE DESCRIPTION	TYPE	CAT	INSTRUMENT RANGE EXISTING	INSTRUMENT RANGE REQUIRED	ENVIRON QUAL.	SEISMIC QUAL.	REDUNDANCE	POWER SUPPLY	DISPLAY LOCATION CR	DISPLAY LOCATION TSC	DISPLAY LOCATION EOF	SCHEDULE/ JUSTIFICATION
	SV 6275C 1 (LS)	STEAM GEN BLOWDOWN BYPASS	B	1	OPEN/CLOSED	CLOSED/NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	–	–	–	NOTES 1H,2
		SV 6275C 1 IND LIGHTS	B	1	OPEN/CLOSED	CLOSED/NOT CLOSED	N/A	COMPLY	N/A	NOTE 3	YES	–	–	
B16		MAINTAINING CTMT. INTEGRITY - CTMT. PRESSURE												
	PT 6308A	CTMT WIDE RANGE PRESSURE	B	1	0 180 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PT 6308B	NOTE 1	–	YES	YES	
	PI 6308A	CTMT. WIDE RANGE PRESS. IND	B	1	0 180 PSIG	-5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PI 6308B	NOTE 1	YES	–	–	
	PR 6308A	CTMT. WIDE RANGE PRESS.	B	1	0 180 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	N/A	NOTE 1	YES	–	–	
	PT 6308B	CTMT WIDE RANGE PRESS.	B	1	0 180 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PT-6308A	NOTE 1	–	YES	YES	
	PI 6308B	CTMT. WIDE RANGE PRESS IND.	B	1	0 180 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PI 6308A	NOTE 1	YES	–	–	
	PR 6308B	CTMT. WIDE RANGE PRESS	B	1	0 180 PSIG	-5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	N/A	NOTE 1	YES	–	–	
	PT 6425A	CTMT. NARROW RANGE PRESS.	B	1	6 TO +18 PSIG	-5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PT 6425B	NOTE 1	–	YES	YES	
	PI 6425A	CTMT. NARROW RANGE PRESS. IND.	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PI 6425B	NOTE 1	YES	–	–	
	PR 6308A	CTMT NARROW RANGE PRESS.	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	N/A	NOTE 1	YES	–	–	
	PT 6425B	CTMT NARROW RANGE PRESS.	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PT-6425A	NOTE 1	–	YES	YES	
	PI 6425B	CTMT NARROW RANGE PRESS. IND.	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	PI 6425A	NOTE 1	YES	–	–	
	PR 6308B	CTMT. NARROW RANGE PRESS.	B	1	6 TO +18 PSIG	5 PSIG TO DESIGN PRESSURE	N/A	COMPLY	N/A	NOTE 1	YES	–	–	
C1		FUEL CLADDING - CORE EXIT TEMPERATURE												
	TE 1E THRU TE 51E	CORE EXIT TEMPERATURE	C	1	32-2300 F	200 2300 F	N/A	COMPLY	2 CHANNEL PER QUADR	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY "A"	C	1	32 2300 F	200 2300 F	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	
	QSPDS B	DISPLAY "B"	C	1	32-2300 F	200 2300 F	N/A	COMPLY	QSPDS A	NOTE 1	YES	–	–	
C2		FUEL CLADDING - RADIOACTIVITY CONCENTRATION OR RADIATION LEVEL IN CIRCULATING PRIMARY COOLANT												
	NONE	RADIOACTIVITY CONCENTRATION OR RADIATION LEVEL	C	1	GRAB SAMPLE	1/2 TO 100 X T.S. LIMIT	–	–	–	–	–	–	–	NOTE 3
C3		FUEL CLADDING - ANALYSIS OF PRIMARY COOLANT												
	AE 6372	Rx COOL WATER RADIOACTIVITY ANALYSIS	C	3	1E-7 Ci/CC TO 10 Ci/CC	10 micro Ci/ml to 10 Ci/ml	N/A	N/A	N/A	N/A	ERDADS	YES	YES	NOTE 1B
C4		Rx COOLANT PRESSURE BOUNDARY - RCS PRESSURE												
	PT 404	RCS PRESS.	C	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-406	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	PT 406	RCS PRESS.	C	1	0 3000 PSIG	0 3000 PSIG	COMPLY	COMPLY	PT-404	NOTE 1	SPDS	YES	YES	NOTES 1A,1B
	QSPDS A	DISPLAY "A"	C	1	0 3000 PSIG	0 3000 PSIG	N/A	COMPLY	QSPDS B	NOTE 1	YES	–	–	
	QSPDS B	DISPLAY "B"	C	1	0 3000 PSIG	0 3000 PSIG	N/A	COMPLY	QSPDS A	NOTE 1	YES	–	–	

For Tag No. Column

(LS) = Limit Switch Associated with Valve

For Existing Instrument Range Column

1. Portable sampling with onsite analysis capability is capable of providing a range from less than 1E-9 micro Ci/CC to greater than 1E-3 micro Ci/CC.

2. Portable instrumentation provides a range of:

   A. 1E-3 R/HR to values greater than 1E4 R/HR photons; and

   B. 1E-3 R/HR to values greater than 1E4 R/HR beta and low-energy photons

3. Existing range monitors up to 7.4E-2 micro Ci/CC. Plant specific analysis justifies smaller range. Particulates and halogens collected on filter cartridge and monitored in lab after sample collection period (30 minutes design for accident situations).

For Required Instrument Range Column

1. RG 1.97 requires the following ranges:

   A. 1E-3 R/HR to 1E4 R/HR photons; and

   B. 1E-3 R/HR to 1E4 R/HR beta and low-energy photons

For Environmental Qualification Column

1. The Safety Injection Accumulator Discharge Valves MOV-865A, B and C are administratively controlled and are required to be in the open position during normal operation. These valves are not required to change position under accident conditions. Administrative control is accomplished by locking open the associated motor control center circuit breakers. Since administrative control via electrical de-energization of the valves ensures that the valves will be in their safe position during

an accident, environmental qualification of the limit switches providing position indication is not required.

For Power Supply Column

Power source is identified as:

1. Class 1E, 120 VAC uninterruptable power supply (inverters)

2. Class 1E, 120 VAC power backed up by the Emergency Diesel Generator

3. Class 1E, 125 VDC safety-related battery

4. Non-Class 1E, 120 VAC uninterruptable power supply

5. Indication is powered from the circuits being monitored via PTs, CTs, etc.

6. Transducers internal to the inverter providing computer display signals for inverter current and voltage are powered by the inverter internals.

7. The SPING monitors communicate with both primary and backup control terminals which are powered from plant inverters and backed up by the safety-related batteries. SPING Monitors RAD-3(4)-6417 and RAD-6426 are powered from non-vital lighting panels capable of being powered from the emergency diesel generators. SPING Monitor RAD-6403 is powered from a vital AC power panel which is automatically backed up by an emergency diesel generator.

For Display Location

1. Control Room metering is credited for primary indication of Emergency Diesel Generator Output (MW). Recording capability for this variable is also available via ERDADS.

For Schedule/Justification Column

1. The following notes referenced under the "Schedule/Just" column of the

Parameter Listing Summary Sheets correspond to the technical justifications identified below:

A. This justification demonstrates the acceptability of the existing uninterruptable power source (UPS) associated with the SPDS/ERDADS computer for the monitoring of Category 1 variables. This acceptability is based upon the existing UPS allowing the SPDS/ERDADS computer to perform its credited RG 1.97 functions:

(1) Recording of Category 1 Variables -

Control Room indication is normally used to provide trending while SPDS/ERDADS is used only as a backup to those instruments. In those cases where SPDS/ERDADS is being used to trend Category 1 variables, either the trending is not necessary to the Control Room operator's decisions or the operator can obtain the real time information via the monitoring of Control Room indication.

(2) Indication of Category 1 Variables -

SPDS/ERDADS is only used as a backup means of indication for certain containment isolation valves but is not credited for RG 1.97 indication for any other Category 1 variable.

(3) Containment Isolation Valve Indication -

In the few instances where SPDS/ERDADS is credited for backup indication associated with containment isolation valves, computer power will be available from the UPS battery for at least the first 2 hours of the accident. This period of operability is sufficient to allow the completion of containment isolation.

B. This justification demonstrates that the SPDS/ERDADS computer, although classified as non-nuclear safety-related, is capable of providing the necessary Regulatory Guide functions for which it is credited.

(1) The SPDS/ERDADS computer is not essential to the monitoring of Category 1 variables. The computer is credited only for backup indication of a few containment isolation valves (i.e., valve position indication) but is not credited for either primary or backup indication for any other Category 1 variables.

(2) The SPDS/ERDADS computer is not essential in providing the Control Room operators with vital trending or recording information. Control Room indication is normally used to provide trending while SPDS/ERDADS is used only as a backup to those instruments. In those cases where SPDS/ERDADS is being used to trend Category 1 variables, either the trending is not necessary to the operator's decisions or the operator can obtain the real time information via the monitoring of Control Room indication.

(3) The SPDS/ERDADS computer provides primary indication of certain Category 2 and 3 variables. In general, the SPDS/ERDADS computer complies with the Category 2 and 3 design and qualification criteria identified in Table 1 of RG 1.97.

(4) The SPDS/ERDADS computer does not diminish the capability of the Control Room operators to obtain the necessary post-accident monitoring information or in achieving the safe shutdown of the plant. Based upon conclusions (1) and (2) above, it can be further concluded that the SPDS/ERDADS computer does not perform an essential function with respect to Category 1 post-accident monitoring.

C. This justification demonstrates that the lack of overlap between the ranges of Containment Sump Water Level narrow and wide range instrumentation does not jeopardize the capability of providing the Control Room operators the critical information required during plant accident conditions. This is based on an analysis which provides the following:

(1) The deadband in Containment Sump Water Level indication between 369" and 397" causes less than 6% error in indication.

(2) The resulting error in indication is introduced in a non-critical range of the required indication. Thus the deadband does not prevent the operator from obtaining the required information:

(a) Low level (narrow range) indication of the initial ingress of water into the sump to allow the assessment of water source and rate.

(b) High level (wide range) indication for operator response to containment flooding.

(c) Determination of the ability to transfer to cold leg recirculation in the event of loss of reactor or secondary coolant based upon having achieved minimum pump NPSH.

D. This justification clarifies the inconsistency between the Accumulator Tank Level ranges identified in the previous FPL RG 1.97 submittals of January 26, 1984 and May 10, 1985, and the existing Control Room instrumentation range of 6,500 to 6,750 gals. The existing Control Room range of 6,500 to 6,750 gals. uses the same basis for justification as identified and approved by NRC in its Safety Evaluation dated March 20, 1986. Accumulator tank pressure is also credited for determining accumulator tank level. As pressure drops in the accumulators, application of the Ideal-Gas state equation provides indication of how much water remains in the accumulator following actuation. As an operator aid, a curve has been made available to the operator which correlates accumulator pressure to accumulator level.

E. This justification clarifies the use of flow meters integral to hand indicating controllers as a means of providing valve position indication. The integral flow meters provide "closed" position indication by indicating zero flow and "not closed" position indication by indicating higher than zero flow.

F. This justification identifies alternative instrumentation being credited for the monitoring of Containment Spray Flow. An alternative method of monitoring this variable was identified in Attachment 1 to FPL RG 1.97 submittal dated May 10, 1985. The alternative instrumentation provides monitoring of the operation of the Containment Spray System, as intended by RG 1.97. This is accomplished by monitoring the proper alignment of Containment Spray valves and operation of the Containment Spray pumps. In addition, the monitoring of containment temperature and pressure assures that containment cooling systems are performing their required function. Monitoring of RWST level provides indirect indication of the Containment Spray flow function.

G. This justification identifies alternative instrumentation being credited for the monitoring of Containment Fan Heat Removal. An alternative method of monitoring this variable was identified in Attachment 1 to FPL RG 1.97 submittal dated May 10, 1985. The method used to address this variable monitors the operation of the Emergency Containment Cooling (ECC) fans and verifies that Component Cooling Water (CCW) flow has been established to the ECC coolers. In addition, the monitoring of containment pressure and temperature provides indirect indication of the Containment Fan Heat Removal function.

H. This justification provides the rationale for not recording containment isolation valve position (Category 1 variable). Recording of containment isolation valve position is not essential for operator action. Containment valve position is available to the operators via Control Room indicating lights. The operators depend on the real time information provided by indicating lights to verify containment isolation. Thus the operators do not need trending of valve position to verify isolation.

I. This justification provides the basis for the acceptability of the existing range for Containment Sump Water Level narrow range indication. The existing range of LI-6308A&B includes a 0-5 inch deadband (i.e., no specific reading can be obtained). However, since the 0-5 inch deadband is outside of the loop measurement range and insignificant compared to the span of 364 inches, the lower limit of the indicator scale of 0-5 inches is acceptable.

J. This justification provides the basis for the acceptability of the existing range for Containment Sump Water Level narrow range recording. The existing range of LR-6308A&B includes a 0-5 inch deadband (i.e., no specific reading can be obtained). However, since the 0-5 inch deadband is insignificant compared to the span of 364 inches, the lower limit of the recorder scale of 0-5 inches is acceptable.

K. Wide range monitoring for Steam Generator Level is provided via a single non-Class 1E wide range level loop. This justification demonstrates that, although wide range monitoring may not be available during an accident scenario, the Control Room operator will have sufficient information to identify and mitigate an accident and to determine the availability of the steam generators as heat sinks. This is based upon the following:

(1) Steam generator level will either remain within narrow range level indication or, if steam generator level has fallen below narrow range indication, that Auxiliary Feedwater has been initiated and will result in the recovery of steam generator level to within narrow range limits. This is accomplished via the associated emergency operating procedures.

(2) RCS temperature (i.e., hot and cold leg water temperature) and pressure are available to determine the effectiveness of the steam generators as heat sinks.

2. Since the original containment isolation design for Turkey Point was not required to provide redundant valve position indication, the redundancy

criteria of RG 1.97 are not applicable to the existing plant design. As a result, in order to address the RG 1.97 concern for ensuring Control Room capability to verify isolation status, an RG 1.97 Containment Isolation Valve Evaluation was performed. The evaluation considers the effects of single failure of valve indication and demonstrates the capability for the Control Room operator to verify isolation of Containment penetrations.

3. An exception to this variable has been accepted by NRC in its Safety Evaluation Report dated March 20, 1986.

4. All 24 channels of the Area Radiation Monitoring System (ARMS) have been replaced by PC/M 89-462 to comply with commitments made to the NRC in FPL letter L-88-290 (Reference 6). L-88-290 commitments require the use of instrumentation with a range of 10^{-3} R/hr to 10^{2} R/hr. Instrumentation installed under PC/M 89-462 has a range of 10^{-4} R/hr to 10^{4} R/hr, which exceeeds both Regulatory Guide 1.97 recommendations and L-88-290 commitments.

5. No instrumentation has been provided since effluent discharge is through a common plant vent.

6. No recording capability exists for 4KV Bus Voltage (Category 1 variable). The emergency operating procedures presently credit the monitoring of 4KV Bus Voltage to allow the Control Room operator to determine the loss of power to a 4KV bus. Based upon the loss of 4KV bus voltage, the operator is required to take manual action to restore power to the battery chargers. Control Room meter indication of 4KV bus voltage is available and is adequate to allow the operator to identify the loss of bus voltage on a realtime basis. Trending of bus voltage is not necessary to ensure accomplishment of this manual action. Therefore, recording of the variable is not essential.

7. This device does not electrically transmit a signal to ERDADS. The data is obtained by plant personnel and then manually inputted into ERDADS where it is stored and available for display.

8. The range of the existing plant instrumentation for this variable (i.e., Item E6) does not envelop the RG 1.97 required range. However, the difference in low end range (i.e., 1 versus 0.1 micro Ci/CC) is not critical to the monitoring of main steam line radiation.

7.6 IN-CORE INSTRUMENTATION

7.6.1 DESIGN BASIS

The in-core instrumentation is designed to yield information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations. Using the information obtained from the in-core instrumentation system, it is possible to confirm the reactor core design parameters and calculated hot channel factors. The system provides means for acquiring data and performs no operational control.

7.6.2 SYSTEM DESIGN

The in-core instrumentation system consists of the Inadequate Core Cooling System and flux thimbles, which run the length of selected fuel assemblies to measure the neutron flux distribution within the reactor core.

The Inadequate Core Cooling System (ICCS) consists of:

1. Core Exit Thermocouples System (CET)
2. Heated Junction Thermocouples System (HJTC)
3. Subcooled Margin Monitoring System (SMM)

These three systems are briefly discussed below:

1. Core-Exit Thermocouples System

   This system originally included 51 thermocouples positioned to measure fuel assembly coolant outlet temperature at preselected locations; some thermocouples have been abandoned in accordance with plant procedures. The temperatures measurement signals from these thermocouples are carried through mineral insulated cables routed in redundant channels. The thermocouples for the two channels have been selected in such a way that each channel indicates the temperature of the whole core. The thermocouple outputs are recorded in the computer room and indicated in the control room.

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2. Heated Junction Thermocouple System

This system includes eight pairs of heated/unheated thermocouples located axially in a probe assembly; some probes have had pairs of heated/ unheated thermocouples abandoned in accordance with plant procedures. There are two identical probe assemblies in each reactor vessel. The measurements from these thermocouples are carried through mineral insulated cables routed in two redundant channels. Two pairs of thermocouples are located in the upper head region above the upper support plate and six pairs are located in the upper plenum region between core alignment and support plates. These thermocouples provide information regarding reactor coolant inventory. The outputs from these thermocouples are processed in the computer room and indicated in the control room.

3. Subcooled Margin Monitoring System

This system includes two pressure transmitters to measure RCS pressure and one dual RTD in each hot and cold leg to measure RCS temperature. Reactor coolant system hot leg temperature (3/channel), cold leg temperature (3/channel) and pressurizer pressure (1/channel) are routed in two redundant channels to the computer room for saturation margin calculations.

In the computer room, the signals for these systems are processed by a microcomputer installed in a seismically qualified cabinet for each channel. A gas plasma display unit and page control module for each channel are installed in the control room for indication of processed parameters and these are connected to the microcomputer with a fiberoptic data link. Each ICCS (QSPDS) Channel is powered from a station vital power supply.

The measured data obtained from the in-core temperature and flux distribution instrumentation system, in conjunction with previously determined analytical information, can be used to determine the fission power distribution in the core at any time throughout core life. This method is more accurate than using calculations alone.

Once the fission power distribution has been established, the maximum power output is primarily determined by thermal power distribution and the thermal and hydraulic limitations determine the maximum core capability.

The incore instrumentation provides information which may be used to calculate the coolant enthalpy distribution, the fuel burnup distribution, and an estimate of the coolant flow distribution.

Both radial and azimuthal symmetry of power may be evaluated by combining the detector and thermocouple information from the one quadrant with similar data obtained from the other three quadrants.

The station blackout intertie is a cross connection between Turkey Point Units 3 and 4, 4.16 kV Switchgear 3D and 4D. Refer to Section 8.2.2.2 for additional details.

480V Bus Tie Breakers

The breakers associated with the bus ties on the 480V load centers are administratively controlled in the open position [with the exception of the swing load center (3H/4H) bus ties]. Overload protection is provided via direct acting/series or solid-state trip devices with long-term and short-time elements.

Each 480V swing load center (3H/4H) is provided with tie feeders to 480V load centers (3C/4C, 3D/4D) via two circuit breakers in series for each train. The C and D load centers are associated with the A and B power trains. Thus, a swing load center has a capability of receiving power from either power train. The tie breakers are interlocked so that the 480V swing load center is connected to only one source of power at any given time. Each breaker is closed/tripped as a result of any of the following actions: (1) operation of a local control switch; (2) operation of the transfer switch in the Control Room; (3) automatic transfer action; or (4) overcurrent conditions. Position indication is provided in the main Control Room.

Operation of the tie breakers is controlled through the use of a three-position, spring return to "AUTO", control switch in the Control Room installed in Vertical Panels 3C04 and 4C04 to allow manual or auto transfer of supply power between the A and B trains. Indicating lights, which indicate the breaker status are installed for each of the feeder and supply breakers that tie Load Center 3H/4H to Load Centers 3C-3D/4C-4D, respectively. Alarms in the Control Room include 480V swing load center undervoltage/trouble.

Manual alignment of the load center to either train can be accomplished by manual manipulation of the switch to either the "C" or "D" position. Manipulation of the selector switch to the "C" position, will result in the tie breakers aligned with Load Center D receiving a trip signal and the tie breakers aligned with Load Center C receiving a close signal. Manipulation of the selector switch to the "D" position, will result in the tie breakers aligned with Load Center C receiving a trip signal and the tie breakers aligned with Load Center D receiving a close signal. Once a power source is selected, the tie breakers are subject to an automatic transfer scheme as follows:

> If the voltage on the primary supply bus is not present, the auto-transfer circuit checks the voltage on the alternate supply bus. If the voltage on the alternate supply bus is available, the auto-transfer action to the alternate supply bus is initiated. The auto-transfer action issues a signal to trip the tie breakers to the primary supply bus and, once the primary supply breaker is in an open position, issues a signal to close the tie breakers to the alternate supply bus. However during a LOOP scenario, the failure of Charging Pump C to strip from Load Center H may result in an EDG overload after load center transfer; therefore, transfer will be blocked if stripping did not occur. After normal EDG loading by the load sequencer, Load Center H can be manually loaded by the operator, if desired.

<u>480V Load Center Supply Breakers</u>

Each breaker can be closed/opened at the 480V Load Center. The breaker is maintained in the closed position. With the exception of the swing load centers (3H/4H - refer to discussion above), these non-automatic breakers are opened only for maintenance purposes.

<u>480V Load Center Feeder Breakers to 480V MCCs</u>

Each breaker can be closed/opened with controls located at the load center and can be opened manually. Overload protection is provided via direct acting/series or solid-state trip devices with long- and short-time elements.

<u>480V Load Center Feeder Breakers to Motors</u>

Each breaker is automatically tripped under LOOP conditions, and the required breakers are automatically closed by the load sequencer. Overload protection is provided via direct acting/series or solid-state trip devices with long-time and instantaneous elements.

vital swing MCC of the opposite unit. The stability of the battery charger output is not load dependent, but is self-regulating over the working range from no load to full load.

The Technical Specifications require the performance of a battery service test at least once every 18 months and a battery performance test at least once every 60 months. In order to provide additional assurance for reliable and continuous operation of the reactors, it is desirable to keep the affected DC bus energized and connected to an equivalent battery during the testing of the station batteries. The spare station battery is an equivalent source for any of the four station batteries during maintenance or testing, and allows continuous operation of the units without entering into a Limiting Condition for Operation while performing these functions. The spare battery charger is non-safety related and is used to keep the spare battery charged when not in use. The spare battery charger is also used to recharge a battery following testing or maintenance prior to its return to service. The charger is fed from a non-vital MCC and is not used to feed plant loads.

All circuits related to engineered safeguards, such as automatic sequence equipment, loss of voltage logic, and containment isolation logic, have redundant circuits fed from separate DC buses. Also, as shown in Figures 8.2-4a through 8.2-4f, there are dual feeds to each 4.16 kV safety related switchgear. No credible single failure in any portion of the DC system can adversely affect the starting and loading of more than one EDG.

To protect the DC system against gross overvoltages from the battery chargers, an overvoltage relay is connected internally, across the output terminals of each charger. Actuation of this relay will trip the charger off the line and provide an alarm.

Two non-safety related switchyard batteries, each with two associated battery chargers, are provided for DC control power in the switchyard. Switchyard Oil Circuit Breaker (OCB) control, primary relaying with associated trip coils, and emergency lighting are supplied from switchyard Battery No. 1. This load can be transferred to fossil Units 1 and 2 station battery, if necessary, through a normally open tie breaker and interconnecting cable. Switchyard Battery No. 2 supplies the backup relaying and secondary trip coil on each

OCB, and additional emergency lighting. The switchyard batteries have no effect on plant equipment, load shedding or EDG operation.

Each unit also has a non-safety related DC bus, battery and battery charger. This non-vital bus supplies power to the non- safety related 4.16 kV C Bus, non-safety related 480V switchgear, non-safety related 120V AC inverter, C Bus transformer relay panels, and the turbine emergency oil pumps. A spare non-safety related charger is capable of being tied to the non-safety related DC bus of either unit.

No credible single failure in any portion of the DC System can adversely affect the shedding and loading of more than one EDG. The switchyard batteries have no effect on plant equipment, load shedding or EDG operation.

8.2.3 REFERENCES

1. NRC Supplemental Safety Evaluation of the Emergency Power System Enhancement Project dated October 1, 1991.

2. Engineering Evaluation JPN-PTN-SEIP-91-012, Revision 0, "Engineering Evaluation of Electromagnetic Interference (EMI) Testing for the Sequencers," dated February 20, 1992.

3. NRC Letter from Richard Croteau to J. H. Goldberg Dated May 20, 1994, TURKEY POINT UNITS 3 & 4 -ISSUANCE OF AMENDMENTS RE: ELIMINATION OF CRANKING DIESEL GENERATORS (TAC NOS. M87662 AND M87663).

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FINAL SAFETY ANALYSIS REPORT

FIGURE 8.2-4a

REFER TO ENGINEERING DRAWING

5613-E-11 , SHEET 1

REV. 13 (10/96)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNIT 3

ELECTRICAL 125V DC AND
120V INSTRUMENT AC
ON LINE DIAGRAM - SHEET 1

FIGURE 8.2-4a

b) Non safety electric equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions specified previously.

c) Certain post-accident monitoring equipment (Refer to Regulatory Guide 1.97, Revision 3, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs During and Following an Accident."

These components are identified on the Environmental Qualification (EQ) List for 10CFR50.49.

8A.4 QUALIFICATION OF COMPONENTS

If the equipment in question meets the requirement found in Subsection 8A.3 and is located in a harsh environment, it must be qualified to 10CFR50.49. The Equipment Qualification Documentation Package 1001 (Doc Pack 1001), "Environmental Qualification Generic Approach and Treatment of Issues," provides the information required to properly identify the environment to which the specific equipment must be qualified. Operability requirements associated with the component are discussed along with the required temperature, pressure, humidity, radiation, aging and submergence.

Harsh environments are characterized by abnormally high temperatures, pressures, radiation doses, exposure to chemical spray, high relative humidity or submergence which are postulated to result from a Design Basis Event.

A mild environment is an environment that would at no time be significantly more severe than the environment which would occur during normal operation, including operational occurrences. Mild environment operability is assured by: (a) engineering requirements during specification development for purchasing equipment; (b) periodic maintenance, inspection and/or a replacement program based on sound engineering judgement or manufacturer's recommendations.

Environments in which radiation is the only parameter of concern are considered to be mild if the total radiation dose (includes 40-year normal dose plus the post accident dose) is 1.0E5 rads or less. This value is the threshold for evaluation and consideration based on EPRI NP-2129. However, certain solid state electronic components and components that utilize teflon are considered to be in a mild environment only if total radiation dose is 1.0E3 rads or less.

For additional detail on the identification of environmental conditions refer to Equipment Qualification Documentation Package 1000, "Equipment Qualification Report and Guidebook."

8A.5 MAINTENANCE

The purpose of the Turkey Point Equipment Qualification Maintenance Program is the preservation of the qualification of systems, structures and components. In order to accomplish this task, the plants have developed approved Design Control, Procurement and Maintenance Procedures. In addition, the component specific documentation package contains the equipment's qualified life. The qualified life is developed based upon the qualification test report reviewed in conjunction with the environmental parameters associated with the area. After this review is completed a qualified life is established. Maintenance activities to be performed in addition to the vendor recommended maintenance are determined to insure that qualification of each piece of equipment is maintained throughout its qualified life.

8A.6 RECORDS/QUALITY ASSURANCE

A documentation package is prepared for the qualification of each manufacturer's piece of equipment under the auspices of 10CFR50.49. This package contains the information, analysis and justifications necessary to demonstrate that the equipment is properly and validly qualified as defined in 10CFR50.49 for the environmental effects of 40 years of service plus a design basis accident.

This documentation package is developed from the criteria stipulated in Doc Pack 1001.

A complete listing of equipment under the auspices of 10CFR50.49 is maintained.

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Reactivity Hold-Down Capability

Criterion: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public. (GDC 30)

Normal reactivity shutdown capability is provided by RCC assemblies, with boric acid injection used to compensate for the long term xenon decay transient and for cooldown. Any time that the unit is at power, the quantity of boric acid retained in the boric acid tanks and ready for injection will always exceed that quantity required to support a cooldown to cold shutdown conditions without letdown. Under these conditions, adequate boration can be achieved simply by providing makeup for coolant contraction from a boric acid tank and the refueling water storage tank. The minimum volume maintained in the boric acid tanks, therefore, is that volume necessary to increase the RCS boron concentration during the early phase of the cooldown of each unit, such that, subsequent use of the refueling water storage tank for contraction makeup will maintain the required shutdown margin throughout the remaining cooldown. In addition, the boric acid tanks have sufficient boric acid solution to achieve cold shutdown for each unit if the most reactive RCCA is not inserted. This quantity will always exceed the quantity of boric acid required to bring the reactor to hot standby and to compensate for subsequent xenon decay.

The boric acid solution is transferred from the boric acid tanks by boric acid pumps to the suction of the charging pumps which inject boric acid into the reactor coolant. Any charging pump and any boric acid transfer pump can be operated from diesel generator power on loss of power. Boric acid can be injected by one charging pump and one boric acid transfer pump at a rate which shuts the reactor down with no rods inserted in less than forty minutes, when a feed and bleed process is utilized (less than 30 minutes when the available pressurizer volume is utilized). In forty additional minutes, enough boric acid can be injected to compensate for xenon decay although xenon decay below the equilibrium operating level will not begin until approximately 12-15 hours after shutdown. If two boric acid pumps and two charging pumps are available, these time periods are reduced. Additional boric acid is employed if it is desired to bring the reactor to cold shutdown conditions.

On the basis of the above, the injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

Codes and Classifications

All pressure retaining components (or compartments of components) which are exposed to reactor coolant, comply with the following codes:

a) System pressure vessels - ASME Boiler and Pressure Vessel Code, Section III, Class C, including para. N-2113, original equipment; Section III, Class 3 or Class 2, post-steam generator repair equipment.

b) System valves, fittings and piping - USAS B31.1, including nuclear code cases.

System component code requirements are tabulated in Table 9.2-1.

The tube and shell sides on the regenerative heat exchanger and the tube side of the excess letdown exchanger are designed to ASME Section III, Class C. This designation is based on the following considerations: (a) each exchanger is connected to the reactor coolant system by lines equal to or less than 3", and (b) each is located inside the containment. Analyses show that the accident associated with a 3" line break does not result in clad damage or failure. Reactor coolant escaping during such an accident is confined to the containment building.

9.2.2 SYSTEM DESIGN AND OPERATION

Various components of the Chemical and Volume Control System are shared by the two units. These components are shown in Table 9.2-3 and discussion concerning the sharing is given in Appendix A. The following discussion is for the Chemical and Volume Control System for one unit and applies equally to either unit.

The Chemical and Volume Control System, shown in Figures 9.2-1 through 9.2-10, provides a means for injection of boric acid, chemical additions for corrosion control, and reactor coolant cleanup and degasification. This

system also adds makeup water to the Reactor Coolant System, reprocesses water letdown from the Reactor Coolant System, and provides seal water injection to the reactor coolant pump seals. Materials in contact with the reactor coolant are austenitic stainless steel or equivalent corrosion resistant materials.

System components whose design pressure and temperature are less than the Reactor Coolant System design limits are provided with overpressure protective devices.

System discharges from overpressure protective devices (safety valves) and system leakages are directed to closed systems. Effluents removed from such closed systems are monitored and discharged under controlled conditions.

During operation, reactor coolant flows through the letdown line from a loop cold leg on the discharge side of the pump and, after processing is returned to the cold leg of another loop on the discharge side of the pump via a charging line. An alternate charging connection is provided on a loop hot leg. An excess letdown line is also provided for removing coolant from the reactor coolant system. The largest required charging pump flow to maintain normal operation with 45 gpm letdown orifice, 9 gpm RCP seals runoff and 1 gpm RCS leakage is supplied by one charging pump in operation.

Each of the connections to the Reactor Coolant System has an isolation valve located close to the loop piping. In addition, a check valve is located downstream of each charging line isolation valve. Reactor coolant entering the Chemical and Volume Control System flows through the shell side of the regenerative heat exchanger where its temperature is reduced. The coolant then flows through a letdown orifice which reduces the coolant pressure. The cooled, low pressure water leaves the containment and enters the auxiliary building where it undergoes a second temperature reduction in the tube side of the non-regenerative heat exchanger followed by a second pressure reduction by the low pressure letdown valve. After passing through one of the mixed bed demineralizers, where impurities are removed, coolant flows through the reactor coolant filters and enters the volume control tank through a spray nozzle.

Hydrogen is automatically supplied, as determined by pressure control, to the vapor space in the volume control tank, which is predominantly hydrogen and water vapor. The hydrogen supply line has an excess flow valve (Figure 9.2-11) upstream and outside of the Charging Pump Room which will automatically close if the hydrogen flow increases beyond its specific flow setting due to a downstream pipe rupture thus eliminating possible release of hydrogen into the charging pump room. The hydrogen within this tank is supplied to the reactor coolant for maintaining a low oxygen concentration. Fission gases are periodically removed from the system by venting the volume control tank to the Waste Disposal System.

The charging pumps take suction from the volume control tank and return the coolant to the Reactor Coolant System through the tube side of the regenerative heat exchanger.

A newly borated bed of mixed resin ($H\text{-}BO_3$ form) is used intermittently to control cesium activity in the coolant and also to remove excess lithium which is formed from $B^{10}(n,\alpha)Li^7$ reaction. After saturation with lithium the mixed bed ($Li\text{-}BO_3$) is ready for service as a mixed bed demineralizer.

Boric acid is dissolved in hot water in the batching tank to a concentration of approximately 3.0 to 3.5 percent by weight. A transfer pump is used to transfer the batch to the boric acid tanks. Small quantities of boric acid solution are metered from the discharge of an operating transfer pump for blending with primary water as makeup for normal leakage or for increasing the reactor coolant boron concentration during normal operation. The solubility limit for 3.5 weight percent boric acid is reached at a temperature of 50°F. This temperature is sufficiently low that the normally expected ambient temperatures within the auxiliary building will maintain boric acid solubility.

Excess liquid effluents containing boric acid flow from the Reactor Coolant System through the letdown line and are collected in the holdup tanks. As liquid enters the holdup tanks, the nitrogen cover gas is displaced to the gas decay tanks in the Waste Disposal System through the waste vent header. The concentration of boric acid in the holdup tanks varies throughout core life from the refueling concentration to essentially zero at the end of the core cycle. A recirculation pump is provided to transfer liquid from one holdup tank to another and to recirculate the contents of individual holdup tanks.

Liquid effluent in the holdup tanks is processed as a batch operation. This liquid is pumped through the evaporator base and cation exchangers which primarily remove lithium and fission-products such as long-lived cesium. It then flows through the ion exchanger filter and into the gas stripper where dissolved gases are removed from the liquid. The gases are vented to the Waste Disposal System. The liquid effluent from the gas stripper enters the boric acid evaporator.

The vapor produced in the boric acid evaporator leaves the evaporator condenser and is pumped through a condensate cooler where the distillate is cooled to the operating temperature of the evaporator condensate demineralizers. After non-volatile evaporator carry over is removed by one of the two evaporator condensate demineralizers the condensate flows through the condensate filter and accumulates in one of two monitor tanks. The dilute boric acid solution originally in the boric acid evaporator remains as the bottoms of the distillation process and is concentrated to approximately 3.0 to 3.5 weight percent boric acid.

Subsequent handling of the condensate is dependent on the results of sample analysis. Discharge from the monitor tanks may be pumped to the primary water storage tank, recycled through the evaporator condensate demineralizers, returned to the holdup tanks for reprocessing in the evaporator train or discharged to the environment with the condenser circulating water when within the allowable activity concentration as discussed in Section 11. If the sample analysis of the monitor tank contents indicates that it may be discharged safely to the environment, two valves must be opened to provide a discharge path. As the effluent leaves, it is continuously monitored by the waste disposal system liquid effluent monitor. If an unexpected increase in radioactivity is sensed, one of the valves in the discharge line to the condenser circulating water closes automatically and an alarm sounds in the control room.

Boric acid evaporator bottoms are discharged through a concentrates filter to the concentrates holding tank. The solution is pumped to the holdup tanks for reprocessing by the evaporator train. The concentrated solution can also be pumped from the evaporator to the Waste Disposal System.

A fresh bed of mixed resin (H-OH form) can be used intermittently to remove boron from the reactor coolant near the end of core life. When the mixed bed has been saturated with Boron ($H-BO_3$), it is ready for use in removing cesium and lithium.

During cooldown when the residual heat removal loop is operating and the letdown orifices are not in service, a flow path is provided to remove corrosion impurities and fission products. A portion of the flow leaving the residual heat exchangers passes through the non-regenerative heat exchanger, mixed bed demineralizers, reactor coolant filters and volume control tank. The fluid is then pumped, via the charging pump, through the tube side of the regenerative heat exchanger into the Reactor Coolant System.

Expected Operating Conditions

Tables 9.2-2, 9.2-3, and 9.2-5 list the system performance requirements, data for individual system components and reactor coolant equilibrium activity concentration. Table 9.2-4 supplements Table 9.2-5.

Reactor Coolant Activity Concentration

The parameters used in the calculation of the reactor coolant fission product inventory, including pertinent information concerning the expected coolant cleanup flow rate and demineralizer effectiveness, are presented in Table 9.2-4. The results of the calculations are presented in Table 9.2-5. In these calculations defects in one percent of the fuel rods are assumed to be present at initial core loading and are uniformly distributed throughout the core and the fission product escape rate coefficients are therefore based upon an average fuel temperature.

The fission product activity in the reactor coolant during operation with small cladding pinholes or cracks in 1% of the fuel rods is computed using the following differential equations:

For parent nuclides in the coolant,

$$\frac{dN_{wi}}{dt} = D\nu_i N_{C_i} - \left(\lambda_i + R\eta_i + \frac{B'}{B_o - tB'}\right) N_{wi}$$

for daughter nuclides in the coolant,

$$\frac{dN_{wj}}{dt} = D\nu_j N_{C_j} - \left(\lambda_j + R\eta_j + \frac{B'}{B_o - tB'}\right) N_{wj} + \lambda_i N_{w_i}$$

where:

N = population of nuclide

D = fraction of fuel rods having defective cladding

R = purification flow, coolant system volumes per sec.

B_o = initial boron concentration, ppm

B' = boron concentration reduction rate by feed and bleed, ppm per sec

η = removal efficiency of purification cycle for nuclide

λ = radioactive decay constant

ν = escape rate coefficient for diffusion into coolant

Subscript C refers to core

Subscript w refers to coolant

Subscript i refers to parent nuclide

Subscript j refers to daughter nuclide

Tritium is produced in the reactor from ternary fission in the fuel, irradiation of boron in the burnable poison rods (during initial fuel cycle only) and irradiation of boron, lithium and deuterium in the coolant. The deuterium contribution is less than 0.1 curie per year and may be neglected. The parameters used in the calculation of tritium production rate are presented in Table 9.2-6.

Reactor Makeup Control

The reactor makeup control consists of a group of instruments arranged to provide a manually pre-selected makeup composition to the charging pump suction header or the volume control tank. The makeup control functions are to maintain desired operating fluid inventory in the volume control tank and to adjust reactor coolant boron concentration for reactivity and shim control.

Makeup for normal leakage is regulated by the reactor makeup control which is set by the operator to blend water from the primary water storage tank with concentrated boric acid to match the reactor coolant boron concentration.

The makeup system also provides concentrated boric acid or primary water to either increase or decrease the boric acid concentration in the Reactor Coolant System. To maintain the reactor coolant volume constant, an equal amount of reactor coolant is let down to the holdup tanks. Should the letdown line be out of service during operation, sufficient volume exists in the pressurizer to accept the amount of boric acid necessary for hot standby. Boration to the cold shutdown concentration is also achievable without letdown when boration is performed in conjunction with the plant cooldown through the required makeup for coolant contraction. Specifically, if boric acid is injected first from the boric acid tanks and then from the refueling water storage tank to maintain constant pressurizer level during the cooldown, sufficient boric acid will be added to the RCS to maintain the required shutdown margins.

Makeup water to the Reactor Coolant System is provided by the Chemical and Volume Control System from the following sources:

a) The primary water storage tank, which provides water for dilution when the reactor coolant boron concentration is to be reduced.

b) The boric acid tanks, which supply concentrated boric acid solution when reactor coolant boron concentration is to be increased.

c) The refueling water storage tank, which supplies borated water for normal or emergency makeup.

d) The chemical mixing tank, which is used to inject small quantities of solution when additions of hydrazine or pH control chemical are necessary.

Makeup is provided to maintain the desired operating fluid inventory in the Reactor Coolant System. The operator can stop the makeup operation at any time in any operating mode by remotely closing the makeup stop valves. One primary water makeup pump and one boric acid transfer pump are normally operated.

A portion of the high pressure charging flow is injected into the reactor coolant pumps between the pump impeller and the shaft seal so that the seals are not exposed to high temperature reactor coolant. Part of the flow is the shaft seal leakage flow and the remainder enters the Reactor Coolant System through a labyrinth seal on the pump shaft. The shaft seal leakage flow cools the lower radial bearing, passes through the seals, is cooled in the seal water heat exchanger, filtered, and returned to the volume control tank.

Seal water inleakage to the Reactor Coolant System requires a continuous letdown of reactor coolant to maintain the desired inventory. In addition, bleed and feed of reactor coolant are required for removal of impurities and adjustment of boric acid in the reactor coolant.

Automatic Makeup

The "automatic makeup" mode of operation of the reactor makeup control provides boric acid solution preset by the operator to match the boron concentration in the Reactor Coolant System. The automatic makeup compensates for minor leakage of reactor coolant without causing significant changes in the coolant boron concentration.

Under normal operating conditions, the mode selector switch and makeup stop valves are set in the "Automatic Makeup" position. A preset low level signal from the volume control tank level controller causes the automatic makeup control action to open the makeup stop valve to the charging pump suction, open the concentrated boric acid control valve and the primary water makeup control valve. The flow controllers then blend the makeup stream according to the preset concentration. Makeup addition to the charging pump suction header causes the water level in the volume control tank to rise. At a preset high level point, the makeup is stopped; the primary water makeup control valve closes, the concentrated boric acid control valve closes and the makeup stop valve to charging pump suction closes.

Dilution

The "dilute" mode of operation permits the addition of a pre-selected quantity of primary water makeup at a pre-selected flow rate to the Reactor Coolant System. The operator sets the makeup stop valves to the volume control tank and to the charging pump suction in the "auto" position, the mode selector switch to "dilute", the primary water makeup flow controller set point to the desired flow rate, and the primary water makeup batch integrator to the desired quantity. If the dilution flow deviates ±5 gpm from the preset flow rate, an alarm indicates the deviation. One primary water pump runs continuously to provide makeup water as required. Makeup water is added to the volume control tank and then goes to the charging pump suction header. Excessive rise of the volume control tank water level is prevented by automatic actuation (by the tank level controller) of a three-way diversion valve, which routes the reactor coolant letdown flow to the holdup tanks. When the preset quantity of primary water makeup has been added, the batch integrator causes the primary water makeup control valve to close.

Alternate Dilute

The "Alternate Dilute" mode of operation permits the addition of a pre-selected quantity of reactor makeup water at a pre-selected flow rate to the Reactor Coolant System. A primary water pump is normally operating. Before actuation of the "Start" Control Station, the operator sets the mode selector switch to "Alternate Dilute", the reactor makeup water flow controller set point to the desired flow rate, and the reactor makeup water "batch·integrator" to the desired quantity.

The operator actuates the "Start" Control Station. This mode of operation is similar to the "dilute" mode except both the makeup stop valves to the Volume Control tank and charging pump suction are opened. Primary water is simultaneously added in the volume control tank and in the charging pump suction header. By adding primary water at both locations the delay time for injecting primary water is reduced and hydrogen is added to a portion of the primary water flow. Excessive water level in the volume control tank is prevented by automatic actuation of a three-way diversion valve (by the tank level controller), which routes the reactor coolant letdown flow to the hold-up tanks. When the preset quantity of reactor makeup water has been added, the batch integrator causes the reactor makeup water control valves to close. This mode of control is used when there are daily load changes. After the "Alternate Dilute" mode requirements are satisfied, the operator may return the mode selector switch back to "Dilute" to permit the addition of reactor makeup water as required.

Boration

The "borate" mode of operation permits the addition of a pre-selected quantity of concentrated boric acid solution at a pre-selected flow rate to the Reactor Coolant System. The operator sets the makeup stop valves to the volume control tank and to the charging pump suction in the "Auto" position, the mode selector switch to "borate", the concentrated boric acid flow controller set point to the desired flow rate, and the concentrated boric acid batch integrator to the desired quantity. If the boration flow deviates 1.5 gpm from the preset flow rate, an alarm indicates the deviation. Placing the reactor makeup control switch in the "start" position starts the selected boric acid transfer pump, and permits the concentrated boric acid to be added to the charging pump suction header. The total quantity added in most cases is so small that it has only a minor effect on the volume control tank level. When the preset quantity of concentrated boric acid solution has been added, the batch integrator causes the concentrated boric acid transfer pump to stop and the concentrated boric acid control valve to close.

The capability to add boron to the reactor coolant is sufficient so that no limitation is imposed on the rate of cooldown of the reactor upon shutdown. The maximum rates of boration and the equivalent coolant cooldown rates are given in Table 9.2-2. One set of values is given for the addition of boric acid from a boric acid tank with one transfer and one charging pump operating. The other set assumed the use of refueling water but with two of the three charging pumps operating. The rates are based on full operating temperature and on the end of the core life when the moderator temperature coefficient is most negative.

By manual action of the operator, the boric acid transfer pump can discharge directly to the charging pump suction and bypass the blender and volume control tank.

Alarm Functions

The reactor makeup control is provided with alarm functions to call the operator's attention to the following conditions:

a) Deviation of primary water makeup flow rate from the control set point

b) Deviation of concentrated boric acid flow rate from the control set point

c) If the reactor makeup control selector is not set for the automatic makeup control mode, a volume control tank low level alarm occurs at 12% of tank level.

Charging Pump Control

Three positive displacement variable speed drive charging pumps are used to supply charging flow to the Reactor Coolant System.

The speed of each pump can be controlled manually or automatically. During normal operation, only one of the three pumps is automatically controlled. During normal operation, only one charging pump is operating and the speed is modulated in accordance with pressurizer level. During load changes the pressurizer level set point is varied automatically to compensate partially for the expansion or contraction of the reactor coolant associated with the Tavg changes. Tavg compensates for power changes by varying the pressurizer level set points in conjunction with pressurizer level for charging pump control. The level set points are varied between 20 and 60 percent of the adjustable range depending on the power level. Charging pump speed does not change rapidly with pressurizer level variations due to the reset action of the pressurizer level controller.

If the pressurizer level increases, the speed of the pump decreases, likewise if the level decreases, the speed increases. If the charging pump on automatic control reaches the high speed limit, an alarm is actuated and a second charging pump is manually started. The speed of the second pump is manually regulated. If the speed of the charging pump on automatic control does not decrease and the second charging pump is operating at maximum speed, the third charging pump can be started and its speed manually regulated. If the speed of the charging pump on automatic control decreases to its minimum value, an alarm is actuated and the speed of the pumps on manual control is reduced.

Components

A summary of principal component data is given in Table 9.2-3.

Regenerative Heat Exchanger

The regenerative heat exchanger is a multiple shell and U-tube unit which is designed to recover the heat from the letdown stream by reheating the charging stream during normal operation. This exchanger also limits the temperature rise which occurs at the letdown orifices during periods when letdown flow exceeds charging flow by a greater margin than at normal letdown conditions.

The letdown stream flows through the shell of the regenerative heat exchanger and the charging stream flows through the tubes. The unit is made of austenitic stainless steel, and is of all-welded construction.

Letdown Orifices

One of the three letdown orifices controls flow of the letdown stream during normal operation and reduces the pressure to a value compatible with the non-regenerative heat exchanger design. Two of the letdown orifices are each designed to pass normal letdown flow. These orifices are used in parallel to pass maximum purification flow at normal Reactor Coolant System operating pressure. The remaining orifice is designed to pass three-fourths of the normal letdown flow. The orifices are placed in and taken out of service by remote manual operation of their respective isolation valves. One or both of the standby orifices may be used in parallel with the normally operating orifice in order to increase letdown flow when the Reactor Coolant System pressure is below normal. This arrangement provides a full standby capacity for control of letdown flow. Each orifice consists of bored pipe made of austenitic stainless steel.

Non-Regenerative (letdown) Heat Exchanger

The non-regenerative heat exchanger cools the letdown stream to the operating temperature of the mixed bed demineralizers. Reactor coolant flows through the tube side of the exchanger while component cooling water flows through the shell. The letdown stream outlet temperature is manually controlled by throttling valve TCV-834-144. The unit is a multiple-pass-tube heat exchanger. All surfaces in contact with the reactor coolant are austenitic stainless steel, and the shell is carbon steel.

CVCS Letdown Demineralizers

Five flushable demineralizers maintain reactor water chemistry. The main demineralizers are the A, B, D, and E demineralizers. The C demineralizer has smaller capacity and may be connected in series with either the A or B demineralizers.

A hydrogen ion form cation resin and a hydroxyl form anion resin are initially charged into the demineralizers. This resin bed is used to reduce RCS boron concentration (usually near the end of core life).

When saturated with boron, the resin is converted to an $H\text{-}BO_3$ form and is used intermittently to control the concentration of lithium-7 which builds up in the coolant from the $B^{10}(n,\alpha)Li^7$ reaction. In addition, each of the main demineralizers have sufficient capacity to maintain the cesium-137 concentration in the coolant below 1.0 μc/cc with one percent defective fuel. The demineralizer would be used intermittently to control cesium.

When saturated with lithium, the resin is converted to an $Li^7\text{-}BO_3$ form and is used to maintain reactor coolant purity. This form of resin removes both fission and corrosion products. In this form, the resin bed is designed to reduce the concentration of isotopes in the purification stream (except for cesium, yttrium, and molybdenum) by a minimum factor of 10. Each of the main demineralizers has sufficient capacity after operation for one core cycle with one percent defective fuel rods to reduce the activity of the primary coolant to refueling concentration.

With the exception of the C demineralizer, each demineralizer is sized to accommodate the maximum letdown flow. The number of demineralizers available provides flexibility and ensures standby capacity should a demineralizer become exhausted during operation. Additionally, the demineralizers may be charged with specialized resins (OH^- Anion, H^+ Cation, or Li^7-OH mixed bed) if desired. The C demineralizer is limited in use to 60 gpm letdown flow, and if used, is placed in series with either A or B demineralizers..

The demineralizers are made of austenitic stainless steel and are provided with suitable connections to facilitate resin replacement when required. The vessels are equipped with resin retention screens.

Resin Fill Tank

The resin fill tank is used to charge fresh resin to the demineralizers. The line from the conical bottom of the tank is fitted with a dump valve and may be connected to any one of the demineralizer fill lines. The demineralizer water and resin slurry can be sluiced into the demineralizer by opening the dump valve. The tank, designed to hold approximately onethird the resin volume demineralizer A or B, is made of austenitic stainless steel.

Reactor Coolant Filter

The three filters collect resin fines and particulates larger than 25 microns from the letdown stream. The vessel is made of austenitic stainless steel, and is provided with connections for draining and venting. Design flow capacity of the filters shall at least be equal to the maximum purification flow rate. Stainless steel screen filter elements are used. Bases considered to determine when the reactor coolant filter will be replaced are: (1) a high pressure differential across the filter, (2) a set time limit after which the filter will be replaced, and (3) when a portable radiation monitor shows radiation in excess of established limits.

Volume Control Tank

The volume control tank collects the excess water released from zero power to full power, that is not accommodated by the pressurizer. It also receives the excess coolant release caused by the deadband in the reactor control temperature instrumentation. Overpressure of hydrogen gas is maintained in the volume control tank to control the hydrogen concentration in the reactor coolant at 25 to 50 cc per kg of water.

The reactor coolant hydrogen concentration can be reduced to 15 cc per kg prior to shutdown, provided that the operating period does not exceed two days and the reactor coolant hydrogen is monitored once per shift.

A spray nozzle is located inside the tank on the inlet line from the reactor coolant filter. This spray nozzle provides intimate contact of the gas and liquid phases. A remotely operated vent valve discharging to the Waste Disposal System permits removal of gaseous fission products which are stripped from the reactor coolant and collected in this tank. The volume control tank also acts as a head tank for the charging pumps and a reservoir for the leakage from the reactor coolant pump controlled leakage seal. The tank is constructed of austenitic stainless steel.

Charging Pumps

Three charging pumps inject coolant into the Reactor Coolant System. The pumps are the variable speed positive displacement type, and all parts in contact with the reactor coolant are fabricated of austenitic stainless steel and other material of adequate corrosion resistance. Pump seal leakage is collected and routed to the holdup tanks for disposal. In order to minimize this leakage, which has proven to be a burden on the waste disposal systems of previous nuclear units, the pumps were modified after installation. This modification which has been successful in other projects, consists of new design plungers and seals, with a seal head tank. The pump design precludes the possibility of lubricating oil contaminating the charging flow, and the integral discharge valves act as check valves. Oil which leaks past the drive train secondary seals will be diverted to local collection pots which will be emptied as required. Hydraulic accumulators are installed on the suction and discharge piping of the charging pumps to attenuate vibration and acoustically decouple this piping from the pumps.

Each pump is designed to provide the full charging flow and the reactor coolant pump seal water supply with normal seal leakage. Each pump is designed to provide rated flow against a pressure equal to the sum of the Reactor Coolant System maximum pressure (existing when the pressurizer power operated relief valve is operating) and the piping, valve and equipment pressure losses of the charging system at the design charging flows.

One of the three charging pumps can be used to hydrotest the Reactor Coolant System. The pumps are normally energized manually from the control room, and flow is automatically controlled by pressurizer level.

Chemical Mixing Tank

The chemical mixing tank is used to prepare caustic solutions for pH control and hydrazine for oxygen scavenging.

The capacity of the chemical mixing tank is determined by the quantity of 35 per cent hydrazine solution necessary to increase the concentration in the reactor coolant by 10 ppm. This capacity is more than sufficient to prepare the solution of pH control chemical for the Reactor Coolant System.

The chemical mixing tank is made of austenitic stainless steel.

Excess Letdown Heat Exchanger

The excess letdown heat exchanger cools reactor coolant letdown flow until the flow rate is equal to the nominal injection rate through the reactor coolant pump labyrinth seal, if letdown through the normal letdown path is blocked. The unit is designed to reduce the letdown stream temperature from the cold leg temperature to 195 F. The letdown stream flows through the tube side and component cooling water is circulated through the shell side. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel. All tube joints are welded.

Seal Water Heat Exchanger

The seal water heat exchanger removes heat from the reactor coolant pump seal water returning to the volume control tank and reactor coolant discharge from the excess letdown heat exchanger. Reactor coolant flows through the tubes and component cooling water is circulated through the shell side. The tubes are welded to the tube sheet because leakage could occur in either direction, resulting in undesirable contamination of the reactor coolant or component cooling water. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

The unit is designed to cool the excess letdown flow and the seal water flow to the temperature normally maintained in the volume control tank if all the reactor coolant pump seals are leaking at the maximum design leakage rate.

Seal Water Filter

The two filters collect particulates from the reactor coolant pump seal water return and from the excess letdown heat exchanger flow. The filter is designed to pass the sum of the excess letdown flow and the maximum design leakage from the reactor coolant pump seals. The vessel is constructed of austenitic stainless steel. Stainless steel screen filter elements are used.

Seal Water Injection Filters

Two filters are provided in parallel, each sized for the injection flow. They collect particulates from the water supplied to the reactor coolant pump seal. Stainless steel screen filter cartridges are used.

Boric Acid Filter

The boric acid filter collects particulates from the boric acid solution being pumped to the charging pump suction line. The filter is designed to pass the design flow of two boric acid pumps operating simultaneously. The vessel is constructed of austenitic stainless steel and the filter elements are disposable synthetic cartridges.

Boric Acid Tanks

The boric acid tank capacities are sized to store sufficient boric acid solution to support a cooldown to cold shutdown conditions without letdown. Under these conditions, adequate boration can be achieved simply by providing makeup for coolant contraction from a boric acid tank and the refueling water storage tank. The minimum volume maintained in the boric acid tanks, therefore, is that volume necessary to increase the RCS boron concentration during the early phase of the cooldown of each unit, such that, subsequent use of the refueling water storage tank for contraction makeup will maintain the required shutdown margin throughout the remaining cooldown. In addition, the boric acid tanks have sufficient boric acid solution to achieve cold shutdown for each unit if the most reactive RCCA is not inserted.

The concentration of boric acid solution in storage is maintained between 3.0 and 3.5 percent by weight. Periodic manual sampling is performed and corrective action is taken, if necessary, to ensure that these limits are maintained. Therefore, measured amounts of boric acid solution can be delivered to the reactor coolant to control the concentration. The combination overflow and breather vent connection has a water loop seal to minimize vapor discharge during storage of the solution. The tanks are constructed of austenitic stainless steel.

Batching Tank

The batching tank is sized to hold several days makeup supply of boric acid solution for the boric acid tank. The basis for makeup is reactor coolant leakage of 1/2 gpm at beginning of core life. The tank may also be used for solution storage. A local sampling point is provided for verifying the solution concentration prior to transferring it to the boric acid tank or for draining the tank.

The tank manway is provided with a removable screen to prevent entry of foreign particles. In addition, the tank is provided with an agitator to improve mixing during batching operations. The tank is constructed of austenitic stainless steel, and is not used to handle radioactive substances. The tank is provided with a steam jacket for heating the boric acid solution to above the solubility limit.

Boric Acid Transfer Pumps

Two 100% capacity centrifugal pumps per unit are used to circulate or transfer chemical solutions. The pumps circulate boric acid solution through the boric acid tanks and inject boric acid into the charging pump suction header.

Although one pump is normally used for boric acid batching and transfer and the other for boric acid injection, either pump may function as standby for the other. The design capacity of each pump is equal to the normal letdown flow rate. The design head is sufficient, considering line and valve losses, to deliver rated flow to the charging pump suction header when volume control tank pressure is at the maximum operating value (relief valve setting). All parts in contact with the solutions are austenitic stainless steel and other adequately corrosion-resistant material.

The transfer pumps are operated either automatically or manually from the control room or from a local control panel. The reactor makeup control operates one of the pumps automatically when boric acid solution is required for makeup or boration.

Boric Acid Blender

The boric acid blender promotes thorough mixing of boric acid solution and reactor makeup water from the reactor coolant makeup circuit. The blender consists of a conventional pipe fitted with a perforated tube insert. All material is austenitic stainless steel. The blender decreases the pipe length required to homogenize the mixture for taking a representative local sample.

Recycle Process

The recycle process is common to Units 3 and 4 and the description below is of the components furnished to serve both units.

Holdup Tanks

Three holdup tanks contain radioactive liquid which enters the tank from the letdown line. The liquid is released from the Reactor Coolant System during startup, shutdowns, load changes and from boron dilution to compensate for burnup. The contents of one tank are normally being processed by the gas stripper and evaporator train while another tank is being filled. The third tank serves as a shared standby.

The three liquid storage tanks' capacity is approximately four Reactor Coolant System volumes. The tanks are constructed of austenitic stainless steel.

Holdup Tank Recirculation Pump

The holdup tank recirculation pump is used to mix the contents of a holdup tank or transfer the contents of one holdup tank to another holdup tank. The wetted surface of this pump is constructed of austenitic stainless steel.

Gas Stripper Feed Pumps

The three gas stripper feed pumps supply feed to the gas stripper boric acid evaporator trains from a holdup tank. The capacity of each pump is equal to the gas-stripper evaporator design capacity for one unit. The non-operating pump is a standby and is available for operation in the event the operating pump malfunctions. These centrifugal pumps are constructed of austenitic stainless steel.

Base and Cation Ion Exchangers

Three flushable base and cation ion exchangers remove anions and cations (primarily cesium and lithium) from the holdup tank effluent. The resin is initially in the hydrogen form. Experiments performed by Westinghouse indicate that the decontamination factor for cesium (see Table 9.2-4) is conservative. The design flow rate is equal to the gas stripper-evaporator design capacity for one unit. The demineralizer vessel is constructed of austenitic stainless steel and contains a resin retention screen.

Ion Exchanger Filters

These two filters collect resin fines and particulates from the cation ion exchanger. The vessel is made of austenitic stainless steel and is provided with connections for draining and venting. Disposable synthetic filter cartridges are used. The design flow capacity is equal to the boric acid evaporator concentrates transfer pump flow rate.

Gas Stripper Equipment

Two gas strippers are provided. Each removes nitrogen, hydrogen and fission gases from the holdup tank effluent. The gas stripper consists of a preheater, stripping column with a reflux condenser and associated pumps, piping and instrumentation.

The gas stripper preheater, located upstream of the gas stripper, heats the liquid effluent from the holdup tanks from ambient temperature to approximately 205°F using the gas stripper bottoms. The bottoms are cooled in the preheater from approximately 220°F to 120°F. The preheater is a regenerative type shell and tube unit constructed of austenitic stainless steel.

The gas strippers consist of a hot well with heating coil to store stripped water, a stripping section packed with pall rings, a spray type liquid inlet header and an overhead integral reflux condenser. Liquid flowing to the gas strippers is controlled to constant rate by a flow controller. The gas strippers are designed for the same flow rate as the evaporator and are designed to reduce the influent gas concentration by a factor of 10^5.

Two gas stripper bottom pumps per gas stripper, operated from level control, transfer effluent from the gas stripper hot wells to the boric acid evaporator via the gas stripper preheaters. Each centrifugal pump is rated at the evaporator processing rate. The pumps are austenitic stainless steel and one is an installed standby for the operating pump.

Boric Acid Evaporator Equipment

Two boric acid evaporators concentrate boric acid for reuse in the Reactor Coolant System. Borated water enters the evaporator and the liquid is concentrated to approximately 3.0 to 3.5 weight per cent boric acid. Vapors leave the evaporator and are condensed. The solids decontamination factor between the condensate and the bottoms is approximately 10^6. All evaporator equipment is constructed of austenitic stainless steel and is supplied as a unit. Each boric acid evaporator package consists of the boric acid evaporator feed tank, two boric acid evaporator concentrates pumps, boric acid evaporator, boric acid evaporator condenser, two boric acid evaporator condensate pumps, boric acid evaporator condensate cooler, two vacuum pumps and associated piping and instrumentation.

The boric acid evaporator feed tank has sufficient capacity to hold approximately 6-7 hours production of 3.0 to 3.5 weight per cent boric acid solution produced from refueling concentration feed. The evaporator and condenser heat transfer area is sufficient to maintain the required feed rate. The evaporator is steam heated. Component cooling water flows through the tube of the condenser.

The boric acid distillate cooler reduces the temperature of the condensate to approximately 100°F. The condensate flows through the tubes and component cooling water through the shell.

Evaporator Condensate Demineralizers

Two anion demineralizers remove any boric acid contained in the evaporator condensate. Hydroxyl based ion-exchange resin is used to produce evaporator condensate of high purity. Connections are provided for regeneration of the resin. Spent resin is flushed to the spent resin storage tank.

Condensate Filters

Two filters collect resin fines and particulates from the boric acid evaporator condensate streams. Each vessel is made of austenitic stainless steel, and is provided with a connection for draining and venting. Disposable synthetic filter elements are used. The design flow capacity of each filter is equal to the boric acid evaporator flow rate.

Monitor Tanks

Two monitor tanks permit continuous operation of the evaporator trains. When one tank is filled, the contents are analyzed and either reprocessed, discharged to the Waste Disposal System, or pumped to the primary water storage tank. These tanks contain a diaphragm membrane and are stainless steel.

Monitor Tank Pumps

Two monitor tank pumps discharge water from the monitor tanks. Each pump is sized to empty a monitor tank in approximately 2.0 hours. The pumps are constructed of austenitic stainless steel.

Concentrates Filters

Two disposable synthetic cartridge type filters remove particulates from the evaporator concentrates. Design flow capacity of each filter is equal to the boric acid evaporator concentrates transfer pump capacity. The vessels are made of austenitic stainless steel.

Concentrates Holding Tank

The concentrates holding tank is sized to hold the production of concentrates from one batch of evaporator operation. The tank is supplied with an electrical heater which prevents boric acid precipitation and is constructed of austenitic stainless steel..

Concentrates Holding Tank Transfer Pumps

Two holding tank transfer pumps discharge boric acid solution from the concentrates holding tank to the hold up tanks. Each canned centrifugal pump is sized to empty the concentrates holding tank in approximately 10 minutes. The wetted surfaces are constructed of authentic stainless steel and other adequately corrosion-resistant material.

Valves

Valves that perform a modulating function are equipped with two sets of packing and an intermediate leakoff connection that discharges to the Waste Disposal System. All other valves have stem leakage control. Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage. Basic material of construction is stainless steel for all valves except the batching tank steam jacket valves which are carbon steel.

Isolation valves are provided at all connections to the Reactor Coolant System. Lines entering the reactor containment also have check valves inside the containment to prevent reverse flow from the containment.

Safety related power operated gate valves were evaluated for their susceptibility to pressure locking and thermal binding as required by NRC Generic Letters 89-10 and 95-07. The emergency boration valves (MOV-*-350) have a design feature (a hole drilled in the upstream disc to provide relief from the inter-disc space) which preclude the potential for pressure locking as described in the two generic letters.

Relief valves are provided for lines and components that might be pressurized above design pressure by improper operation or component malfunction. Pressure relief for the tube side of the regenerative heat exchanger is provided by a thermal relief valve which is designed to open when pressure under the seat exceeds 2735 psig. Relief valves settings and capacities are given in Table 9.2-3.

Turkey Point Unit 3 has installed manual operating features to selected air-operated valves (Table 9.6A-11) in the Chemical and Volume Control System. The installation of these features provides an alternate means of operating these valves if the valve misoperates due to receipt of a spurious electrical signal resulting from a postulated fire. These changes implement recommendations made as part of the Appendix R Safe Shutdown Analysis in order to meet the licensing commitments of 10CFR50 Appendix R (see Subsection 9.6A-5.6).

Piping

All Chemical and Volume Control System piping handling radioactive liquid is austenitic stainless steel. All piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing.

9.2.3 SYSTEM DESIGN EVALUATION

Availability and Reliability

A high degree of functional reliability is assured in this system by providing standby components where performance is vital to safety and by assuring fail-safe response to the most probable mode of failure.

The system has three charging pumps, each capable of supplying the normal reactor coolant pump seal and makeup flow.

The electrical equipment of the Chemical and Volume Control System is arranged so that multiple items receive their power from various 480 volt buses (refer to Section 8.2). Each of the three charging pumps is powered from separate

480 volt buses. The two boric acid transfer pumps are also powered from separate 480 volt buses. One charging pump and one boric acid transfer pump are capable of meeting cold shutdown requirements shortly after full-power operation. In cases of loss of AC power, a charging pump and a boric acid transfer pump can be placed on the emergency diesels if necessary.

Control of Tritium

The Chemical and Volume Control System is used to control the concentration of tritium in the Reactor Coolant System. Essentially all of the tritium is in chemical combination with oxygen as a form of water. Therefore, any leakage of coolant to the containment atmosphere carries tritium in the same proportion, as it exists in the coolant. Thus, the level of tritium in the containment atmosphere, when it is sealed from outside air ventilation, is a function of tritium level in the reactor coolant, the cooling water temperature at the cooling coils, which determines the dew point temperature of the air, and the presence of leakage other than reactor coolant as a source of moisture in the containment air.

There are two major considerations with regard to the presence of tritium:

a) Possible plant personnel hazard during access to the containment. Leakage of reactor coolant during operation with a closed containment causes an accumulation of tritium in the containment atmosphere. It is desirable to limit the accumulation to allow containment access.

b) Possible public hazard due to release of tritium to the plant environment.

Neither of these considerations is limiting in this plant.

The concentration of tritium in the reactor coolant is maintained at a level which precludes personnel hazard during access to the containment. This is achieved by discharging part of the condensate from the boric acid recovery process to the circulating water discharge.

Leakage Prevention

Quality control of the material and the installation of the Chemical and Volume Control valves and piping, which are designated for radioactive service, is provided in order to essentially eliminate leakage to the atmosphere. The components designated for radioactive service are provided with welded connections to prevent leakage to the atmosphere. However, flanged connections are provided in each charging pump suction and discharge, on each boric acid pump suction and discharge, on the relief valves inlet and outlet, on three-way valves and on the flow meters to permit removal for maintenance. Holdup tanks are provided with threaded vacuum breakers.

The positive displacement charging pumps stuffing boxes are provided with leakoffs to collect reactor coolant before it can leak to the atmosphere. All valves which are larger than 2 inches and which are designated for radioactive service at an operating fluid temperature above 212 F are provided with a stuffing box and lantern leakoff connections. Leakage to the atmosphere is essentially zero for these valves. All control valves are either provided with stuffing box and leakoff connections or are totally enclosed. Leakage to the atmosphere is essentially zero for these valves.

Diaphragm valves are provided where the operating pressure and the operating temperature permit the use of these valves. Leakage to the atmosphere is essentially zero for these valves.

Incident Control

The letdown line and the reactor coolant pumps seal water return line penetrate the containment. The letdown line contains three air-operated valves inside the containment and one air-operated valve outside the containment which are automatically closed by the containment isolation signal.

The reactor coolant pumps seal water return line contains one motor-operated isolation valve outside the containment which is automatically closed by the containment isolation signal.

The three seal water injection lines to the reactor coolant pumps and the charging line are inflow lines penetrating the containment. Each line contains two check valves inside the containment to provide isolation of the containment if a break occurs in these lines outside the containment.

Malfunction Analysis

To evaluate system safety, failures or malfunctions were assumed concurrent with a loss-of-coolant accident and the consequences analyzed and presented in Table 9.2-7. As a result of this evaluation, it is concluded that proper consideration has been given to unit safety in the design of the system.

If a rupture were to take place between the reactor coolant loop and the first isolation valve or check valve, this incident would lead to an uncontrolled loss of reactor coolant. The analysis of loss of coolant accidents is discussed in Section 14.

Should a rupture occur in the Chemical and Volume Control System outside the containment, or at any point beyond the first check valve or remotely operated isolation valve, actuation of the valve would limit the release of coolant and assure continued functioning of the normal means of heat dissipation from the core. For the general case of rupture outside the containment, the largest source of radioactive fluid subject to release is the contents of the volume control tank. The consequences of such a release are considered in Section 14.

When the reactor is subcritical; i.e., during cold or hot shutdown, refueling and approach to criticality, the relative reactivity status (neutron source multiplication) is continuously monitored and indicated by BF_3 counters and count rate indicators. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution rate (See Table 9.2-2), is slow enough to give ample time to start a corrective action (boron dilution stop and/or emergency boron injection) to prevent the core from becoming critical. The maximum dilution rate is based on the abnormal condition of two charging pumps operating at full speed delivering unborated primary water to the Reactor Coolant System at a particular time during refueling when the boron concentration is at the maximum value and the water volume in the system is at a minimum.

At least two separate and independent flow paths are available for reactor coolant boration; i.e., the charging line, or the reactor coolant pumps labyrinths. The malfunction or failure of one component will not result in the inability to borate the Reactor Coolant System. An alternate flow path is always available for emergency boration of the reactor coolant. As backup to the boration system the operator can align the refueling water storage tank outlet to the suction of the charging pumps.

Boration during normal operation to compensate for power changes will be indicated to the operator from two sources; (a) the control rod movement and (b) the flow indicators in the boric acid transfer pump discharge line. When the emergency boration path is used, three indications to the operator are available. The primary indication is a flow indicator in the emergency boration line. The charging line flow indicator will indicate boric acid flow since the charging pump suction is aligned to the boric acid transfer pump discharge for this mode of operation. The change in boric acid tank level is another indication of boric acid injection.

On loss of seal injection water to the reactor coolant pump seals, seal water flow may be reestablished by manually starting a standby charging pump. Even if the seal water injection flow is not reestablished, the unit can be operated indefinitely since the thermal barrier cooler has sufficient capacity to cool the reactor coolant flow which would pass through the thermal barrier cooler and seal leakoff from the pump volute.

Galvanic Corrosion

The only types of materials which are in contact with each other in borated water are stainless steels, Inconel, Stellite valve materials and Zircaloy fuel element cladding. These materials have been shown[(1)] to exhibit only an insignificant degree of galvanic corrosion when coupled to each other.

For example, the galvanic corrosion of Inconel versus 304 stainless steel resulting from high temperature tests (575 F) in lithiated, boric acid solution was found to be less than -20.9 mg/dm^2 for the test period of 9 days. Further galvanic corrosion would be trivial since the cell currents at the conclusion of the tests were approaching polarization. Zircaloy versus 304 stainless steel was shown to polarize at 180 F lithiated, boric acid solution in less than 8 days with a total galvanic attack of -3.0 gm/dm^2. Stellite versus 304 stainless steel was polarized in 7 days at 575 F in lithiated boric acid solution. The total galvanic corrosion for this couple was -0.98 mg/dm^2.

As can be seen from the tests, the effects of galvanic corrosion are insignificant to systems containing borated water.

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(1) WCAP 1844 "The Galvanic Behavior of Materials in Reactor Coolants" D. G. Sammarone, August, 1961 Non-Proprietary.

TABLE 9.2-1

CHEMICAL AND VOLUME CONTROL SYSTEM CODE REQUIREMENTS

Regenerative heat exchanger	ASME III [1], Class C
Non-regenerative heat exchanger	ASME III, Class C, tube side, ASME VIII, shell side
CVCS letdown demineralizers	ASME III, Class C
Reactor coolant filters	ASME III, Class C
Volume control tank	ASME III, Class C
Seal water heat exchanger	ASME III, Class C, tube side, ASME VIII, shell side
Excess letdown heat exchanger	ASME III, Class C, tube side, ASME VIII, shell side
Chemical mixing tank	ASME VIII
Seal water injection filters	ASME III, Class C
Holdup tanks	ASME III, Class C
Boric acid filter	ASME III, Class C
Gas stripper package	ASME III, Class C
Boric acid evaporator package vessels	ASME VIII
Evaporator condensate demineralizers	ASME III, Class C
Concentrates filter	ASME III, Class C
Cation ion exchanger	ASME III, Class C
Ion exchanger filter	ASME III, Class C
Condensate filter	ASME III, Class C
Hydraulic Accumulators	ASME III, Class 2, 1977 plus Summer 77 Addenda [4]
Piping and Valves [3]	USAS B31.1 [2]

NOTES :

1. ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code Section III, Nuclear Vessels.

2. USAS B31.1 - Code for Pressure Piping, and special nuclear cases where applicable.

3. Aloyco valve weld ends in accordance with Westinghouse Spec. No. G-676241, Dwg. No. 498B932, hydrostatically retested at system test pressures after installation.

4. Replacement parts are procured in accordance with NRC Generic Letter 89-09, since the original manufacturer has dropped their N-stamp.

TABLE 9.2-2

NOMINAL CHEMICAL AND VOLUME CONTROL SYSTEM PERFORMANCE [1]

Unit design life, years	40
Seal water supply flow rate, gpm [2]	24
Seal water return flow rate, gpm	9
Normal letdown flow rate, gpm	60
Maximum letdown flow rate, gpm	120
Normal charging pump flow (one pump), gpm	69
Normal charging line flow, gpm	45
Maximum rate of boration with one transfer and one charging pump from an initital RCS concentration of 1800 ppm, ppm/min	5.4
Equivalent cooldown rate to above rate of boration, °F/min	1.5
Maximum rate of boron dilution with two charging pumps from an initial RCS concentration of 2500 ppm, ppm/hour	350
Two-pump rate of boration, using refueling water, from initial RCS concentration of 10 ppm, ppm/min	6.2
Equivalent cooldown rate to above rate of boration, °F/min	1.7
Temperature of reactor coolant entering system at full power (design), °F	555.0
Temperature of coolant return to reactor coolant system at full power (design), °F	493.0
Normal coolant discharge temperature to holdup tanks, °F	127.0
Amount of 3.0 weight percent boron solution required to meet cold shutdown requirements, at end of life with peak xenon (including consideration for one stuck rod) gallons	7500

NOTES :

1. Reactor coolant water quality is given in Table 4.2-2.
2. Volumetric flow rates in gpm are based on 130°F and 2350 psig.

TABLE 9.2-3

PRINCIPLE COMPONENT DATA SUMMARY

	Quantity[1]	Heat Transfer Btu/hr	Letdown Flow lb/hr	Letdown ΔT F	Design Pressure psig,shell/tube	Design Temperature F,shell/tube
Heat Exchangers						
Regenerative	1	8.65×10^6	29,826	265	2485/2735	650/650
Non-regenerative	1	14.8×10^6	29,826	163	150/600	250/400
Seal water	1	2.17×10^6	126,756	17	150/150	250/250
Excess letdown	1	4.75×10^6	12,400	360	150/2485	250/650

	Quantity[1]	Type	Capacity Each gpm	Head	Design Pressure psig	Design Temperature F
Pumps						
Charging	3	Pos.displ.	77	2385 psi	3000	250
Boric acid transfer	4*	Centrifugal	60	235 ft.	150	250
Holdup tank recirculation	1*	Centrifugal	500	100 ft.	150	200
Monitor tank	2*	Centrifugal	100	150 ft.	150	200
Concentrates holdings						
Tank transfer	2*	Canned	20	150 ft.	75	250
Gas stripper feed	3*	Canned	25	185 ft.	150	200
Gas stripper bottom	2	Centrifugal	12.5	93 ft.	75	300

	Quantity[1]	Type	Volume,Each	Design Pressure psig	Design Temperature F
Tanks					
Volume	1	Vert.	300 ft^3	75 Int/15 Ext	250
Boric Acid	3*	Vert.	9100 gal	Atmos.	250
Chemical mixing	1	Vert.	6.0 gal	150	250
Batching	1*	Jacket Btm.	800 gal	Atmos.	250
Holdup	3*	Vert.	13,000 ft^3	15	200
RWST	1	Vert.	338,000 gal	Atmos.	200

	Quantity[1]	Type	Volume	Design Pressure psig	Design Temperature F
Tanks (continued)					
Concentrates holding	1*	Vertical	925 gal	Atmos.	250
Monitor	2*	Diaphragm	10,000 gal	Atmos.	150

	Quantity[1]	Type	Resin Volume ft^3	Flow gpm	Design Pressure psig	Design Temperature F
Demineralizer Vessels						
Mixed beds	2	Flushable	30	120	200	250
Cation beds	1	Flushable	20	60	200	250
Base and cation ion Exchangers	3*	Flushable	30	25	150	250
Evaporator condensate	2*	Fixed	30	25	200	250
Deborating	2	Fixed	43	120	200	250

	Quantity[1]	Relief Pressure psig	Capacity
Relief Valves			
Charging pumps	3	2735	100 gpm
Regenerative heat exchanger	1	2735	N/A
Holdup tank	3	12	120 gpm
Letdown line (intermediate pressure section)	1	600	240 gpm
Seal water return line	1	150	165 gpm
Batching tank heating jacket	1	20	320 lb/hr
Volume control tank	1	75	170 gpm
Holdup tank vacuum brks	2	3 in/WC	100 scfm

[1] Quantity per unit unless otherwise specified.

* Shared or capable of being shared by Unit 3 and Unit 4.

9.3 AUXILIARY COOLANT SYSTEM

9.3.1 DESIGN BASES

The Auxiliary Coolant System consists of three loops; the component cooling loop, the residual heat removal loop, and the spent fuel pit cooling loop as shown in Figures 9.3-1 through 9.3-11, 6.2-1, and 6.2-5. Each unit has an identical Auxiliary Coolant System and the description contained herein is equally applicable to either unit. The spent fuel pit cooling loop is described in more detail in Appendix 14D.

Performance Objectives

Component Cooling Loop

The component cooling loop (see figures 9.3-1 through 9.3-9) is the heat sink for the residual heat removal loop, the Chemical and Volume Control System, the spent fuel cooling loop and various Reactor Coolant System components.

The CCW system is designed with sufficient redundancy such that a single active failure will not prevent the system from accomplishing its support function of cooling safety related equipment.

The loop design provides for detection of radioactivity entering the loop from the reactor coolant source and also provides for isolation from this inleakage.

The CCW system design satisfies performance objective requirements for Thermal Power Uprate operation as indicated in Reference 10.

Residual Heat Removal Loop

The residual heat removal loop (see figures 6.2-1 and 6.2-5) is designed to remove residual and sensible heat from the core and reduce the temperature of the Reactor Coolant System during the second phase of plant cool down. During the first phase of cooldown, the temperature of the Reactor Coolant System is reduced by transferring heat from the Reactor Coolant System to the Steam and Power Conversion System.

All active loop components which are relied upon to perform their function are redundant.

The loop design precludes any significant reduction in the overall design reactor shutdown margin when the loop is brought into operation for residual heat removal or for emergency core cooling by recirculation. The loop design includes provisions to enable hydrostatic testing to applicable code test pressures during shutdown.

Loop components, whose design pressure and temperature are less than the Reactor Coolant System design limits, are provided with overpressure protective devices and redundant isolation means.

The RHR system design satisfies performance objective requirements for Thermal Power Uprate operation as indicated in Reference 10.

Spent Fuel Pit Cooling Loop

The spent fuel pit cooling loop on each unit is designed to remove the residual decay heat generated by the spent fuel elements which are stored in high-density fuel racks contained within each spent fuel pit.

The cooling loop design does not incorporate redundant active cooling components (primarily pumps), because of the large heat capacity of the spent fuel pit and its corresponding slow heat-up rate. Nonetheless, a 100 percent capacity spare pump which is permanently piped into the spent fuel pit cooling system has been installed. This spare pump, which must be manually aligned, is capable of operating in place of the originally installed pump. Alternate connections are also provided for connecting a temporary pump into the spent fuel pit loop.

The cooling loop has been analyzed and is designed to remain functional during and following a seismic event and to structurally withstand a design temperature of 212°F. The available NPSH exceeds the pump NPSH requirement at the design flow, for temperatures up to 212°F, for each of the installed pumps.

Loop piping is so arranged that failure of any pipeline does not drain the spent fuel pit to less than 6 feet above the top of the stored fuel elements.

Design Characteristics

Component Cooling Loop

One pump and three component cooling water heat exchangers are normally operated to provide cooling water for various components located in the auxiliary and containment buildings. The water is normally supplied to all components being cooled even though one of the components may be out of service.

Makeup water is taken from the water treatment plant, as required and delivered to the surge tank. A backup source of water is provided from the primary water storage tank.

The operation of the loop is monitored with the following instrumentation:

a. Temperature detectors in the inlet and outlet lines for the component cooling heat exchangers.

b. A pressure detector on the line between the component cooling pumps and the component cooling heat exchangers.

c. A temperature and flow indicator in the outlet headers from the heat exchangers.

d. A radiation monitor on the inlet headers to the component cooling pumps.

The CCW system is flow balanced each refueling outage to ensure adequate flow is available to system components during normal power operation. The flow balance further ensures that individual component minimum and maximum flow limits are not exceeded due to changes in the system configuration which would occur in response to a design basis accident.

Residual Heat Removal Loop

Two pumps and two residual heat exchangers perform the decay heat cooling functions for the reactor. After the Reactor Coolant System temperature and pressure have been reduced to 350°F and 450 psig respectively, decay heat cooling is initiated by aligning the pumps to take suction from the reactor outlet line and discharge through the heat exchangers into the reactor inlet line. If only one pump and one heat exchanger are available reduction of reactor coolant temperature is accomplished at a lower rate.

The equipment utilized for decay heat cooling is also used for emergency core cooling during loss-of-coolant accident conditions. This is described in Section 6.

Spent Fuel Pit Cooling Loop

The spent fuel pit cooling system is capable of removing decay heat from reload accumulations of up to nine full cores which are discharged during normal refueling periods. Decay heat loads for storage of up to nine full cores (1413 fuel assemblies) were determined in accordance with Standard Review Plan (SRP) Branch Technical Position ASB 9-2. Two equilibrium cases were performed to conservatively define the design basis heat removal capability of the spent fuel pit cooling system. When a 1/2 core is discharged 150 hours after reactor shutdown (SRP 9.3.1 "normal" heat load conditions), in addition to 8-1/2 cores which were previously discharged, the maximum bulk pool temperature is conservatively predicted to be less than 147°F (Reference 9). When a full core off-load is discharged 150 hours after reactor shutdown, in addition to 1/2 of a core discharged 36 days earlier and 7-1/2 cores from previous discharges (SRP 9.3.1 "abnormal" heat load conditions), the maximum bulk pool temperature is conservatively predicted to be less than 194.5°F (Reference 9). Refer to Appendix 14D for additional details of these design heat load capability evaluations for the spent fuel pit cooling system.

A refueling temperature limit of 150°F for peak pool temperature was selected as a reasonable acceptance criteria during refuelings with full core offloads. This temperature is supported by the first reracking performed at Turkey Point in 1977, where a full core off-load was found acceptable with a peak pool temperature of 150°F (References 6 and 7). The 150°F limit is also supported by thermal-hydraulic analyses performed for the current rack design as described in the FSAR. As a conservative measure, plant procedures ensure that fuel movement is stopped if spent fuel pit temperatures exceed 140°F while off-loading the core to the spent fuel pit. Stopping spent fuel movement at 140°F will prevent the spent fuel pool temperature from ever exceeding its operating acceptance limit of 150°F.

Following completion of a normal refueling, 1/3 of a core is permanently discharged and stored in the spent fuel pit along with previously discharged fuel assemblies. When 1/3 of the core has been discharged, the spent fuel pit cooling system is expected to remove the residual heat generated by the fuel and maintain a fuel pit equilibrium water temperature of less than 140°F (Reference 9).

A thermal-hydraulic analysis of the spent fuel pit cooling system has been performed for the Turkey Point Unit 4 Cycle 16 refueling outage. This analysis assumes a full core offload to the spent fuel pit commencing 150 hours after shutdown. Decay heat loads have been calculated consistent with the requirements of NRC Branch Technical Position ASB 9-2. The thermal-hydraulic model considers heat removal via the spent fuel pit heat exchanger, evaporation at the pool surface, and thermal capacitance of the pool water, fuel racks and pool liner. With an initial pool temperature of 100°F, a peak spent fuel pit temperature of 147°F was calculated. The maximum spent fuel pit temperature occurs approximately 40 hours after the start of core offload. Past operating experience has shown that the actual peak spent fuel pit temperature during a full core offload is well below the calculated value of 147°F.

Codes and Classifications

All piping and components of the Auxiliary Coolant System are designed to the applicable codes and standards listed in Table 9.3-4. The component cooling loop water contains a corrosion inhibitor to protect the carbon steel piping. Austenitic stainless steel piping is used in the residual heat removal loop, which contains reactor coolant, and in the spent fuel pit cooling loop, which contains water without corrosion inhibitor.

9.3.2 SYSTEM DESIGN AND OPERATION

Component Cooling Loop

Component cooling is provided for the following heat sources:

a. Residual heat exchangers (Auxiliary Coolant System, ACS)
b. Reactor coolant pumps (Reactor Coolant System)
c. Non regenerative heat exchanger (Chemical and Volume Control System, CVCS)
d. Excess letdown heat exchanger (CVCS)
e. Seal water heat exchanger (CVCS)
f. Boric acid recycle evaporator and condensate coolers (CVCS)
g. Sample heat exchangers (Sampling System)
h. Waste evaporator condenser (Waste Disposal System)
i. Waste gas compressors (Waste Disposal System)
j. Residual heat removal pumps (ACS)
k. Safety injection pumps (Safety Injection System, SIS)
l. Containment spray pumps
m. Spent fuel pit heater exchanger (ACS)
n. Charging pump (CVCS)
o. Normal containment coolers
p. Control rod drive coolers
q. Emergency containment coolers
r. Post Accident Sampling System (PASS)

At the reactor coolant pump, component cooling water removes the heat from the bearing oil and the thermal barrier. Since the heat is transferred from the component cooling water to the intake cooling water, the component cooling loop serves as an intermediate system between the reactor coolant and intake cooling water system. This double barrier arrangement reduces the probability of leakage of high pressure, potentially radioactive coolant to the intake cooling water system.

During normal full power operation, one component cooling water pump and two or three component cooling water heat exchangers accommodate the heat removal loads. Each of the two standby pumps provides 100% backup, during normal operation. Two pumps and three heat exchangers are utilized to remove the residual and sensible heat during unit shutdown to ensure the CCW shell side flow does not exceed established flow limits. Higher shell side flow rates are allowed for limited periods of time. If one of the pumps or one of the heat exchangers is not operated, safe shutdown of the unit is not affected, however, the time for cooldown is extended.

The surge tank accommodates expansion, contraction and in-leakage of water, and ensures a continuous component cooling water supply until a leaking cooling line can be isolated. Two surge lines separated by a partition are provided on the surge tank. The lines are connected to each of the two component cooling headers in the suction side of the component cooling water pumps. The CCW surge tank is normally vented to the Waste Holdup Tank. A radiation monitor in each component cooling water pump inlet header annunciates in the control room and closes a valve in the surge tank vent line in the unlikely event that the radiation level reaches a pre-set level above the normal background. Redundant component cooling water headers are provided (see Figure 9.3-1).

Design Bases

The design basis of the Component Cooling Water System is to provide sufficient heat removal from the Engineered Safety Features to the ultimate heat sink (ICW System), post accident.[1,2] The system, which is normally operated in an open configuration, is designed with sufficient capability to accommodate the failure of any single, active component without resulting in undue risk to the health and safety of the public following a Maximum Hypothetical Accident (MHA). The most limiting single failure considered was the loss of one diesel, which results in only one CCW pump starting automatically to mitigate the consequences of the MHA. This assumed single failure also results in the loss of a complete train of engineered safety features, including the inability to open the CCW isolation valve associated with one RHR heat exchanger and one Emergency Containment Cooler (ECC). Although a complete train of engineered safety feature components will be inoperable on loss of a diesel, CCW flow to these components will continue, except as noted above in the case of an RHR heat exchanger and one ECC. In support of the Thermal Uprate Project, detailed CCW System thermal analyses were performed to evaluate overall performance following worst-case design basis accidents. Maximum expected system operating temperatures were calculated for both the double-ended primary system pipe break and secondary (steam) pipe failure. In the thermal analyses, a consistent set of conservative cooling system operating parameters were defined for several analyzed single failure conditions. These included the failure of a diesel generator, a containment spray pump and ICW pump. To restrict CCW System post-accident operating temperatures to within acceptable ranges, a design basis change was required to limit the maximum number of ECCs automatically starting to no more than two when only two CCW heat exchangers are in operation. Previously, all three ECCs were allowed to auto start. The applicable Engineered Safety Features at Turkey Point Units 3 and 4 include:

a. Residual Heat Removal heat exchangers (Auxiliary Coolant System, ACS)
b. Residual Heat Removal pumps (ACS)
c. Safety Injection pumps (Safety Injection System, SIS)
d. Containment Spray pumps
e. Emergency Containment Coolers
f. Support systems for the above

The CCW system is periodically placed in a split header configuration for short periods of time to allow the performance of inservice testing of the CCW pumps and to allow spent fuel cask movements over CCW piping. During these periods of split header configuration, the CCW system is not able to serve the needs of a fully redundant and automatic two-train fluid system. Therefore Technical Specification provisions and certain other plant operating restrictions are imposed during these CCW system configurations (Reference 8).

With respect to the noted safety function, the Component Cooling Water System's performance is characterized by the minimum required and maximum allowable flow rates through the Engineered Safety Features listed above and through the other required and connected loads, and the corresponding heat transfer rates. In the various Thermal Uprate Project post-accident thermal analyses, a range of expected CCW System flows was analyzed based on detailed hydraulic flow calculations. The system flow calculations were based on revised CCW System flow balance criteria as provided in Table 9.3-6.

It should be noted that the Engineered Safety Features (with the exception of the Emergency Containment Coolers) operate in two sequential post-accident phases. The first, the injection phase, requires operation of the Safety Injection (SI), Containment Spray (CS) and Residual Heat Removal (RHR) pumps, taking suction from the Refueling Water Storage Tank (RWST). A safety injection signal automatically starts the SI and RHR pumps and aligns them for RCS cold-leg injection, which commences when the RCS pressure falls below the shutoff head of each pump. Containment Spray pump operation is initiated by coincident High and High-High Containment pressure signals (two-out-of-three). At least one of two Emergency Containment Coolers (ECC) will be started automatically upon receipt of a safety injection signal, and will continue to run throughout the injection and recirculation phases. To ensure the adequacy of long-term containment cooling following a failure of one of the two automatically actuated pumps, the third ECC will be manually started during the long-term recirculation recovery phase.

The recirculation phase is initiated after the RWST volume is depleted. This phase differs from the injection phase in that the RHR pumps are re-aligned to take suction from the containment sump. The RHR pumps discharge through the RHR heat exchangers and then into the RCS, or to the SI pump suction, depending upon the RCS pressure. The RHR pumps can also discharge to the CS pump suction when containment conditions are elevated.

The CCW system heat removal functions have been evaluated for the following operating configurations:

a. Power Operation (which includes hot shutdown and hot standby operations).

b. Residual Heat Removal (RHR) Cooldown (which includes hot shutdown, cold shutdown and refueling operations).

c. Post-Accident (which includes both the injection and recirculation phases of a LOCA and the injection mode of a MSLB).

In addition, the two CCW system headers can be periodically isolated (i.e., split header) to support special system evolutions. This configuration was also evaluated for post-accident operation.

The CCW heat exchanger heat removal capacity was relaxed to offer increased system operating margin. The capacity of the CCW heat exchangers were relaxed by increasing the apparent fouling factor from the design value of 0.00159 hr-ft^2-°F/BTU to 0.003 hr-ft^2-°F/BTU at 95°F ICW inlet temperature. For added conservatism, all Containment Integrity analyses, which explicitly model heat transfer to the ICW System, were performed at the Technical Specification maximum limit of 100°F.

Since the CCW system configuration can physically provide a shell side flow greater than the design maximum, Plant operation must be procedurally limited to prevent such configurations. To eliminate the potential for CCW heat exchanger shell side flows to exceed the maximum specified flow limits, both procedural controls and CCW system flow balancing limitations have been established. The operating procedure restrictions limit the number of operating CCW pumps to N-1, where N is the number of in-service CCW heat exchangers. Limitations on the number of major CCW system end users (emergency containment coolers, RHR heat exchangers and normal containment coolers) have also been established and proceduralized.

For the Power Operation and RHR Cooldown configurations, thermal performance calculations were performed using standard water-to-water heat exchanger heat transfer equations and generalized heat transfer methodology. For Power Operation, thermal analyses were performed at steady-state plant operating conditions to calculate maximum expected CCW heat exchanger operating temperatures.

During postulated design basis events, the CCW system major heat loads (ECCs and the RHR heat exchangers) are variable in nature and are dependent on containment operating conditions. As such, the COCO Computer Code, which was used in Containment Integrity analyses, was also used to conservatively calculate limiting CCW system and ICW system post-accident operating temperatures.

Peak CCW system operating temperatures occur during post-accident operations due to elevated containment temperatures and unrestricted heat rejection into the CCW system. A calculated maximum CCW System supply temperature of 150°F is acceptable for post-accident operation, and the basis for this temperature increase over the original design temperature of 125°F is validated for the Thermal Uprate project in the Westinghouse Engineering Report, WCAP-14291.

Numerous failure cases have been modeled to target containment integrity, CCW system and ICW system integrity. The most limiting scenarios that affect CCW system integrity were identified as the failure of one train of Emergency Power, failure of one Containment Spray pump, or failure of one ICW pump during a Large Break LOCA.

For the Power Operation configuration, the maximum CCW system supply temperature (CCW heat exchanger outlet temperature) is 105°F. For the RHR Cooldown configurations, adequate RCS cooldown performance is maintained with a CCW system supply temperature of 125°F. For post-accident operation, the following are the most critical CCW system operating temperatures:

a. CCW System heat exchanger shell side inlet (return) temperature.

b. CCW System heat exchanger Shell side outlet (supply) temperature.

c. ECC CCW System outlet temperature.

d. RHR heat exchanger CCW System outlet temperature.

e. CCW System heat exchanger ICW outlet temperature.

For the CCW system heat exchanger return temperature, the CCW system outlet temperature shall remain at or below the system design temperature (200°F) and within CCW pump Net Positive Suction Head (NPSH) limitations. The CCW system heat exchanger supply temperature shall remain within analyzed limits to ensure that equipment cooled by the system remains operable. The most limiting CCW system supply temperature is 150°F for up to 4 hours for the safeguards pumps, followed by a slow temperature decrease of 1°F/hr over the next 30 hours to 120°F where it is assumed to remain. This temperature profile is most critical for the Safety Injection pump lube oil cooler. For the ECCs, the upper limiting temperature due to piping stress limitations is 185°F.

Pump Performance

The plant design bases specify that the operation of one CCW pump and one RHR heat exchanger during an MHA is adequate for accident mitigation. Readjustment of CCW System valve positions will change the operating point of the CCW pumps, with respect to the CCW total system pressure drop, from the original start-up configuration. The CCW pump performance at these new valve positions has been demonstrated to meet the design requirements by a combination of tests and calculations.

The two criteria evaluated were adequate flow to the CCW System and adequate NPSH to the CCW pumps. Testing and CCW System hydraulic analyses have demonstrated that one pump could provide the required flow to the entire CCW System.

Based on correspondence from the pump manufacturer,the CCW pump can deliver flows up to 15,000 gpm provided that there is sufficient NPSH available. Based on calculation, the available NPSH for one pump at 15,000 gpm is more than 47 feet at 180°F. This is conservative since the calculated maximum post-accident temperatures at the CCW pump suction do not exceed 170°F, and the pump required NPSH at 15,000 gpm is in the range of 44 to 46 feet. Therefore, sufficient NPSH is available.

Maximum Flow Considerations for ECCs

Each cooler consists of 60 five-pass tubes in parallel with an additional 60 five-pass tubes to form a ten-row coil. From the standpoint of the component cooling water, this configuration can be represented by 120 parallel tubes. When the tubing cross-section (1-1/8 inch diameter, 0.049 inch wall) is considered, an average velocity of 6.4 feet per second is produced by a flow of 2000 gpm.

Flows to the ECCs may exceed the continuous design flow rating of 2000 gpm for short periods of time based on limiting the erosion rate of the Admiralty tubes to 5 mils/year. The shorter the time frame the greater the allowable flow rate. The relationship of allowable flow maximums versus time durations is as follows:

2000 gpm	Continuous Operation
3200 gpm	1 Month (Post-LOCA Recirculation Limit)
3600 gpm	1 Week
5000 gpm	24 Hours (Initial Safety Injection Limit)
5500 gpm	1 Hour

Pressure in the tubes is not a likely mechanism for failure, since the tubes have a design pressure well in excess of the pressure deliverable by the CCW pumps.

As shown above, during the injection phase of an MHA, flows to the ECCs could exceed those values cited in Table 9.3-6. This additional flow is not anticipated to adversely effect the ECCs ability to perform their safety function for the following reasons:

a. Duration of the injection phase is short in comparison to the recirculation phase.

b. The operator has the ability to decrease flow to the ECCs (i.e., aligning CCW to RHR) if he believes the ECCs are receiving excessive CCW flow.

c. The design of the ECCs, as described above, is such that additional flow above its design maximum should not degrade the coolers ability to perform its safety related function.

Spent Fuel Pit Heat Exchanger Minimum Flow

SFP Heat Exchanger CCW flow requirements are a function of the spent fuel being stored in the pit. The minimum CCW flow rate to the SFP heat exchanger has been established at 1,200 gpm during CCW System flow balancing. Actual CCW flow to the SFP heat exchanger would be higher during normal operation. Calculations conclude that CCW flow to the SFP heat exchanger would exceed 1850 gpm during normal plant operation. During refueling operations, CCW flow can be temporarily increased to 2800 gpm.

Residual Heat Removal Loop

The Residual Heat Removal (RHR) loop consists of heat exchangers, pumps, piping and the necessary valves and instrumentation. During shutdown, coolant flows from the Reactor Coolant System to the RHR pumps, through the tube side of the RHR heat exchangers and back to the Reactor Coolant System. The inlet line to the RHR loop starts at the hot leg of one reactor coolant pump and the return line normally connects to the low head Safety Injection System piping to the three cold legs. The RHR heat exchangers are used to cool the water during the latter phase of Safety Injection System operation. These duties are defined in Section 6. The heat loads are transferred by the RHR heat exchangers to the component cooling water.

During unit shutdown, the cooldown rate of the reactor coolant system is controlled by manually regulating the flow through the tube side of the RHR heat exchangers. A bypass line and an automatic flow control valve around the RHR heat exchangers are used to maintain a constant flow through the residual heat removal loop and to control cooldown.

Double, remotely operated valving in the inlet line is provided to isolate the RHR loop from the Reactor Coolant System. To protect the RHR system against excess pressure and to prevent an intersystem LOCA, the RHR inlet isolation valves, MOV-750 and MOV-751, are supervised by pressure switches which will automatically close these valves at or above 525 psig; an isolation alarm warns the operator. A pressure spike, either real or spurious, during low pressure operation could result in the closure of these valves. This event could lead to the loss of the letdown flow path, potentially leading to RCS overpressurization. To prevent this event from occurring, manual override of the automatic closure feature is provided to allow operation of the isolation valves when the overpressure modification system is in the low pressure mode. MOV-750 and MOV-751 are locked closed during normal plant operation and following a Loss of Coolant Accident to provide containment isolation. This is accomplished by locking the breakers for MOV-750 and MOV-751 open. Two remotely operated valves in parallel and two check valves in series isolate each line to the Reactor Coolant System cold legs from the RHR loop. Overpressure in the loop is prevented by a relief valve which discharges to the pressurizer relief tank.

The clarity and purity of the spent fuel pit water is maintained by passing approximately 5% of the loop flow through filters and demineralizer. The spent fuel pit pump suction line, which is used to drain the pit, penetrates the spent fuel pit wall above the fuel assemblies. The penetration location prevents loss of water as a result of a possible suction line rupture. The return line has a 1/2-inch hole in the pipe near the normal level for a siphon break function.

Component Cooling Loop Components

Component Cooling Heat Exchangers

The three component cooling heat exchangers are of the shell and straight tube type. Intake cooling water circulates through the tubes while component cooling water circulates through the shell side. Parameters are presented in Table 9.3-1.

Component Cooling Pumps

The three component cooling pumps are horizontal, centrifugal units. The pump casings are made from cast iron (ASTM 48) which is corrosion-erosion resistant. The material thickness is dictated by high quality casting practice and ability to withstand mechanical damage and as such are substantially overdesigned from a stress level standpoint. Parameters are presented in Table 9.3-1.

Component Cooling Surge Tank

The component cooling surge tank which accommodates changes in component cooling water volume is constructed of carbon steel. Parameters are presented in Table 9.3-1. In addition to piping connections, the tank has a flanged opening at the top which can be used, if required, for the addition of the chemical corrosion inhibitor to the component cooling loop.

Chemical Pot Feeder Tank

The chemical pot feeder tank provides for the direct addition of corrosion additive to the component cooling water. Parameters are listed in Table 9.3-1.

Component Cooling Valves

The valves used in the component cooling loop are normally constructed of carbon steel with bronze or stainless steel trim. Self-actuated spring loaded relief valves are provided for lines and components that could be pressurized to their design pressure by improper operation or malfunction.

Turkey Point Unit 3 has installed Manual-Operating features to selected air-operated valves (Table 9.6A-11) in the Component Cooling Loop. The installation of these features provides an alternate means of operating these valves if the valve misoperates due to receipt of a spurious electrical signal resulting from a postulated fire. These changes implement recommendations made as part of the Appendix R Safe Shutdown Analysis in order to meet the licensing commitments of 10CFR50 Appendix R (see Subsection 9.6A-5.6).

Component Cooling Piping

All component cooling loop piping is carbon steel with welded joints and connections except at components which might need to be removed for maintenance.

Residual Heat Removal Loop Components

Residual Heat Exchangers

The two residual heat exchangers located within the auxiliary building are of the shell and U-tube type with the tubes welded to the tube sheet. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell side. The tubes and other surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

Residual Heat Removal Pumps

The two residual heat removal pumps are in-line, centrifugal units with special seals to prevent reactor coolant leakage to the atmosphere. All pump parts in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

Spent Fuel Pit Filter

The three fuel pit filters remove particulate matter from the spent fuel pit water. The filter cartridge is synthetic fiber and the vessel shell is austenitic stainless steel.

Spent Fuel Pit Demineralizer

The demineralizer is sized to pass 5% of the loop circulation flow, to provide adequate purification of the fuel pit water for unrestricted access to the working area, and to maintain optical clarity.

Spent Fuel Pit Skimmer

A skimmer pump and three filters are provided for surface skimming of the spent fuel pit water. Flow from this pump is returned to the spent fuel pit.

Spent Fuel Pit Valves

Manual stop valves are used to isolate equipment and lines, and manual throttle valves provide flow control. Valves in contact with spent fuel pit water are austenitic stainless steel or equivalent corrosion resistant material.

Spent Fuel Pit Piping

All piping in contact with spent fuel pit water is austenitic stainless steel. The piping is welded except where flanged connections are used to facilitate maintenance.

9.3.3 SYSTEM EVALUATION

Availability and Reliability

Component Cooling Loop

For continued cooling of the reactor coolant pumps, and the excess letdown heat exchanger, most of the piping, valves, and instrumentation are located outside the primary concrete shield at an elevation well above the anticipated post-accident water level in the bottom of the containment. (The exception is the cooling lines for the reactor coolant pumps which can be isolated by two valves in series following the accident.) In this annular area the component cooling equipment is protected against credible missiles and from being flooded during post-accident operation. Also, this location provides radiation shielding which allows for maintenance and inspections to be performed during power operation.

Outside the containment, the residual heat removal pumps, the residual heat exchangers, the spent fuel heat exchanger, the component cooling pumps and heat exchangers, and associated valves, piping and instrumentation are maintainable and inspectable during power operation. System design provides for the replacement of one pump or one heat exchanger while the other units are in service.

Several of the components in the component cooling loop are fabricated from carbon steel. The component cooling water contains a corrosion inhibitor to protect the carbon steel. Welded joints and connections are used except where flanged closures are employed to facilitate maintenance. The entire system is seismic Class I design. The components are designed to the codes given in Table 9.3-4. In addition the components are not subjected to any high pressures (See Table 9.3-1) or stresses. Hence a rupture or failure of the system is very unlikely.

During the recirculation phase following a loss-of-coolant accident, one of the three component cooling water pumps delivers flow to the shell side of one of the residual heat removal heat exchangers.

Residual Heat Removal Loop

Two pumps and two heat exchangers are utilized to remove residual and sensible heat during unit cooldown. If one of the pumps and/or one of the heat exchangers is not operative, safe operation of the unit is not affected; however, the time for cooldown is extended. The function of this equipment following a loss-of-coolant accident is discussed in Section 6.

Spent Fuel Pit Cooling Loop

This manually controlled loop may be shutdown safely for reasonable time periods, as shown in Table 9.3-3, for maintenance or replacement of malfunctioning components.

Leakage Provisions

Component Cooling Loop

Welded construction is used where possible throughout the component cooling loop piping, valves and equipment to minimize the possibility of leakage. The component cooling water could become contaminated with radioactive water due to a leak in any heat exchanger tube in the Chemical and Volume Control, the Sampling, or the Auxiliary Coolant Systems, or a leak in the cooling coil for the reactor coolant pump thermal barrier.

Tube or coil leaks in components being cooled would be detected during normal operation as described in Sections 4.2.7 and 6.5.

Leakage from or to the component cooling loop can be detected by a change of level in the component cooling surge tank. The rate of water level cage and the area of the water surface in the tank permit determination of the leakage rate. In-leakage is detected anytime by radiation monitors located on the main return headers. To assure adequate determinations, the operator would check that temperatures are stable.

The component which is leaking can be located by sequential isolation or inspection of equipment in the loop. If the leak is in the on-line component cooling water heat exchanger, the standby exchanger would be put on line and the leaking exchanger isolated and repaired. During normal operation the leaking exchanger could be left in service with leakage up to the capacity of the makeup line to the system from the water treatment plant. By manual transfer, emergency power is available for makeup pump operation.

Volumetric expansion of the CCW system due to system temperature increases has been evaluated. For the CCW system, the most limiting temperature swing would occur following a design basis accident when heat rejection to the CCW system is not manually limited. For this condition, a CCW surge tank insurge would occur due to high heat loads and an overall increase in CCW system operating temperature. An increase of 100°F would result in a volumetric expansion of approximately 350 gallons/header or 700 gallons total which is within the capacity of the surge tank.

Should a large tube side to shell side leak develop to a residual heat exchanger, the water level in the component cooling surge tank would rise, and the operator would be alerted by a high water level alarm. An isolation valve in the vent line of the tank is automatically closed in the event of high radiation level at the component cooling water pump suction header. If the leaking residual heat exchanger is not isolated from the component cooling loop before the inflow completely fills the surge tank, the relief valve on the surge tank lifts. The discharge of this relief valve is routed to the auxiliary building waste holdup tank.

The severance of a cooling line serving an individual reactor coolant pump cooler would result in substantial leakage of component cooling water. However, the piping is small as compared to piping located in the missile protected area of the containment. Therefore, the water stored in the surge tank after a low level alarm together with makeup flow provides ample time for the closure of the valves external to the containment to isolate the leak before cooling is lost to the essential components in the component cooling loop.

The relief valves on the component cooling water header downstream from each of the reactor coolant pumps are designed to relieve the thermal expansion of liquid enclosed in the piping system that can occur if the thermal barrier cooling water return piping is isolated while a heat load continues to be imposed by the thermal barrier heat exchanger. These relief valves protect the cooling water supply and return piping associated with the reactor coolant pump thermal barrier heat exchanger from overpressurization.

The relief valves on the cooling water lines downstream from the sample, excess letdown, seal water, non-regenerative, spent fuel pit and residual heat exchangers are sized to relieve the volumetric expansion occurring if the exchanger shell side is isolated when cool, and high temperature coolant flows through the tube side. The set pressure equals the design pressure of the shell side of the heat exchangers.

The relief valve on the component cooling surge tank is sized to relieve the maximum flow rate of water which enters the surge tank following a rupture of a reactor coolant pump thermal barrier cooling coil. The set pressure equals the design pressure of the component cooling surge tank. Initial protection is provided by an isolation valve which automatically closes on high flow in the event of a thermal barrier coil rupture.

Residual Heat Removal Loop

During reactor operation all equipment of the residual heat removal loop is idle, and the associated isolation valves are closed. During the loss-of-coolant accident condition, water from the containment sump is recirculated through the exterior piping system. To obtain the total radiation dose to the public due to leakage from this system, the potential leaks have been evaluated and discussed in Sections 6 and 14.

Each of the two residual heat removal pumps is located in a shielded compartment with a floor drain. In each compartment the leakage drains to a sump and is then pumped to the waste holdup tank by sump pumps. Two 75 gpm sump pumps are provided in each compartment and each is capable of handling the flow which results from the failure of a residual heat removal pump seal. The residual heat exchangers are located in a third compartment with two sump pumps.

Each sump has a level indicator which will warn the operator of high water level. Both of the lines from the containment sump to the individual residual heat removal pumps has two remotely operated isolation valves in series.

Spent Fuel Pit Cooling Loop

Whenever a failed fuel assembly is transferred from the fuel transfer canal to the spent fuel storage pool, a small quantity of fission products may enter the spent fuel cooling water. A small purification loop is provided for removing these fission products and other contaminants from the water.

The probability of inadvertently draining the water from the cooling loop of the spent fuel pit is exceedingly low. The only means of draining the cooling loop is through such actions as opening a valve on the cooling line and leaving it open when the pump is operating. In the unlikely event of the spent fuel pit cooling loop being drained, the spent fuel storage pit itself cannot be drained and no spent fuel is uncovered since the spent fuel pit cooling connections enter near the top of the pit. The temperature and level indicators in the spent fuel pit would warn the operator of the loss of cooling. The slow heatup rate of the spent fuel pit, as indicated in Table 9.3-3, would allow sufficient time to take any necessary action to provide adequate cooling using the emergency cooling connections provided while the cooling capability of the spent fuel pit cooling loop is being restored.

Incident Control

Component Cooling Loop

Component Cooling Containment isolation valves MOV-1417, -1418, and CV-739, are automatically closed on a Phase A containment isolation signal. Component Cooling Containment isolation valves MOV-716A,-716B, -730, and -626 are automatically closed on a Phase B containment isolation signal. The cooling water supply header to the reactor coolant pumps contains a check valve inside and two remotely operated valves outside the containment wall. The cooling water supply line to the excess letdown heat exchanger contains a check valve inside the containment which is closed during normal operation. Except for the normally closed makeup line and equipment vent and drain lines, there are no direct connections between the cooling water and other systems. The equipment vent and drain lines outside the containment have manual valves which are normally closed unless the equipment is being vented or drained for maintenance or repair operations.

Following a loss-of-coolant accident, one component cooling pump and two component cooling heat exchangers accommodate the heat removal loads. If either a component cooling pump or component cooling heat exchanger fails, one of the two standby pumps provides 100% backup and the standby heat exchanger provides 50% backup. Valves on the component cooling return lines from the safety injection, containment spray and residual heat removal pumps are normally open. Each of the component cooling return lines from the residual heat exchangers has a normally closed remotely operated valve. If one of the valves fails to open at initiation of long-term recirculation, the valve which does open supplies a heat exchanger with sufficient cooling to remove the heat load.

Normally cross-connected, redundant component cooling headers are provided for the unlikely event of a single failure in the component cooling system following a loss of coolant accident. Header cross-connect valves are provided so that a passive failure (defined as 50 gpm leak) in the system can be isolated and cooling water flow can still be maintained to the necessary engineered safeguards equipment which require cooling water.

Residual Heat Removal Loop

The residual heat removal loop is connected to the reactor outlet line on the suction side and to the reactor inlet line on the discharge side. On the suction side, the connection is through two electric motor-operated gate valves in series. Both these valves are interlocked with reactor coolant system pressure. On the discharge side the connection is through two check valves in series and two electric motor operated gate valves in parallel. All of these are closed whenever the reactor is in the operating condition.

Spent Fuel Pit Cooling Loop

The most serious failure of this loop is complete loss-of-water in the storage pit when fuel is in the pit. To protect against this possibility, the cooling pump suction connection penetrates the pit wall and terminates near the normal water level so that a break in the pipe will not gravity drain the pit. The pit drain piping penetrates the pit wall at an elevation 6 feet above the top of the fuel assemblies. Complete siphon draining of the pit by a break in this line is prevented by a normally closed valve located near the pit wall at the same elevation as the penetration. A break in this line upstream of the valve will only drain the pool to an elevation 6 feet above the fuel assemblies. The cooling water return line penetrates the pit wall about one foot below normal water level and is prevented from siphon draining the pit by a 1/2 inch hole in the pipe at the penetration.

In the event of failure of the spent fuel pit pump alternate means for cooling the spent fuel pit water is provided. A 100% capacity spare pump which is permanently piped into the spent fuel pit cooling system is provided. This pump is capable of operating in place of the normal pump by manual transfer. Alternate connections are also provided for connecting a temporary emergency pump to the spent fuel pit cooling loop.

Malfunction Analysis

A failure analysis of pumps, heat exchangers and valves is presented in Table 9.3-5.

9.3.4 TEST AND INSPECTION CAPABILITY

The residual heat removal pumps flow instrument channels can be calibrated during shutdown.

The active components of the Auxiliary Coolant System are in either continuous or intermittent use during normal operation, thus no additional tests are required. Visual inspections and preventative maintenance can be conducted as necessary.

Samples are analyzed to determine the amount of radioactivity in the reactor coolant system. If the radioactivity level is high a reactor coolant sample is analyzed and an iodine extraction made and counted as an indication of defects in fuel cladding. The frequency of sampling for gross activity and for radiochemical analysis of the reactor coolant system, will be adequate to detect fuel clad defects to support operation as based on past experience.

Spent Fuel Pit Cooling Loop

In accordance with the requirements of ASME XI, Subsection IWP (Inservice Testing of Pumps in Nuclear Power Plants), instrumentation is provided for the Units 3 and 4 Spent Fuel Pit Cooling Pumps. Specifically, each unit is provided with a flow element (annubar type) with a local flow indicator in the common suction line of the pumps, and suction and discharge gauges for pressure measurements (refer to Figures 9.8-3 and 9.8-4).

9.3.5 REFERENCES

1. Bechtel Letter SFB-2345 from G.N. Nutnell (Bechtel) to E. Preast (FPL), dated March 24, 1986.

2. NRC Letter "Component Cooling Water Flow Balancing - Turkey Point Plant Units 3 and 4," from D. G. McDonald (NRC) to C.O. Woody (FPL), dated February 5, 1987.

3. Safety Evaluation, JPE-LR-87-45, "Justification for Continued Operation for ICW System Design," Revision 3, dated March 17, 1989.

4. NRC Safety Evaluation for Amendment No. 111 and 104 to Facility Operating Licenses for Turkey Point Units 3 and 4, respectively, dated November 21, 1984.

5. FPL letter L-84-264 to the NRC,"Spent Fuel Storage Facility Expansion - Additional Information," dated October 5, 1984.

6. FPL letter L-76-178, "Proposed License Amendment to Facility Operating Licenses DPR-31 and DPR-41 Supplemental Information," dated April 30, 1976.

7. NRC letter to R. E. Uhrig (FPL) from George Lear (NRC), Re: Amendment No. 23 to License DPR-31 and Amendment No. 22 to License DPR-41, dated March 17, 1977.

8. Safety Evaluation, JPN-PTN-SENP-95-026, Revision 03, "Safety Evaluation for CCW Flow Balancing and Post-Accident Alignment Requirements to Support Current and Uprated Conditions," dated October 12, 1995.

9. Westinghouse WCAP-14276,"Turkey Point Units 3 and 4 - Uprating Licensing Report," Revision 1, dated December 1995 (Section 5.5.5).

10. Westinghouse WCAP-14291, Vols 1 - 3,"Turkey Point Units 3 and 4 - Uprating Engineering Report for Thermal Power Uprate, dated December 1995.

TABLE 9.3-1

COMPONENT COOLING

LOOP COMPONENT DATA

Component Cooling Heat Exchangers

Quantity	3
Type	Shell and Straight Tube
Heat Transferred, Btu/hr (shutdown condition)	19.5×10^6
Heat Removal Capability, Btu/Hr	60.0×10^6
Shell Side (component cooling water) :	
- Inlet Temp.(for heat removal capability 60×10^6), °F	113
- Outlet Temp.(for heat removal capability 60×10^6), °F	107
- Maximum Allowable Unit 3 Flow Limits (gpm) :	
- Continuous Operation (TEMA limit)[1]	4,063
- Normal Plant Evolutions (testing, surveillance activities, heat exchanger cleaning, etc.; Represents manufacturer's limit without vibration concerns)	6,840
- 31 Day (erosion and vibration limit for long-term post-accident recirculation)	7,200
- Initial Safety Injection (erosion and vibration limit)	7,500
- Maximum Allowable Unit 4 Flow Limits (gpm) :	
- Continuous Operation (TEMA limit)[1]	6,756
- Normal Plant Evolutions (testing, surveillance activities, heat exchanger cleaning, etc.; Represents manufacturer's limit without vibration concerns)	8,000
- 31 day (erosion limit)	11,900
- Design Temperature, °F	200
- Design Pressure, psig	150
- Material	Carbon Steel
Tube Side (intake cooling water) :	
- Inlet Temperature, (nominal) °F	95[2]
- Outlet Temperature, °F	100
- Design Flow Rate, lb/hr	4.0×10^6
- Design Pressure, psig100	
- Design Temperature, °F	200
- Material	Aluminum Brass

NOTES :

1. Tubular Exchanger Manufacturers Association.
2. The inlet temperature of 95°F may be exceeded if the conditions are within those of Reference 3.

TABLE 9.3-1

Component Cooling Pumps	
Quantity	3
Type	Horizontal Centrifugal
Rated capacity, gpm, each	7500
Rated head, ft H_2O	185
Motor horsepower, hp	450
Casing material	Cast Iron
Design pressure, psig	150
Design temperature °F	200
Component Cooling Surge Tank	
Quantity	1
Volume, gal	2000
Normal water volume, gal.	1000
Design pressure, psig	100
Design temperature, °F	200
Construction material	Carbon Steel
Chemical Pot Feeder Tank	
Quantity	1
Volume, gal	3
Design pressure, psig	150
Design temperature, °F	150
Component Cooling Loop Piping and Valves	
Design pressure, psig	150
Design temperature, °F	200

TABLE 9.3-4

AUXILIARY COOLANT SYSTEM
CODE REQUIREMENTS

Component cooling heat exchangers	ASME VIII*
Component cooling surge tank	ASME VIII
Component cooling loop piping and valves	USAS B31.1**
Residual heat exhangers	ASME III***, Class C, tube side ASME VIII, shell side
Residual heat removal piping and valves	USAS B31.1
Spent fuel pit filter	ASME III, Class C
Spent fuel heat exchanger	ASME III, Class C, tube side ASME VIII, shell side
Spent fuel pit demineralizer	ASME III, Class C
Spent fuel pit loop piping and valves	USAS B31.1

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* ASME VIII - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section VIII

** USAS B31.1 - Code for Pressure Piping, and special nuclear cases where applicable

*** ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

TABLE 9.3-5

FAILURE ANALYSIS OF PUMPS, HEAT EXCHANGERS, AND VALVES

	Components	Malfunction	Comments and Consequences
1.	Component cooling water pumps	Rupture of a pump casing	The casing is designed for 150 psi and 200 F which exceeds maximum operating conditions. Pump is inspectable and protected against missiles. Rupture due to missiles is not considered credible. Each unit is isolable. One of the three pumps can carry the total emergency heat load.
2.	Component cooling water pumps	Pump fails to start	One operating pump supplies sufficient water for emergency cooling.
3.	Component cooling water pumps	Manual valve on a pump suction line closed	This is prevented by prestartup and operational checks. Further, during normal operation, each pump is checked on a periodic basis which would show if a valve is closed.
4.	Component cooling water pumps	Valve on discharge line sticks closed	The valve is checked open during periodic operation of the pumps during normal operation.
5.	Component cooling heat exchanger	Tube or shell rupture	Rupture is considered improbable because of low operating pressures. Each unit is isolable. Two units can carry total emergency heat load.
6.	Demineralized water makeup line check valve	Sticks open	The check valve is backed up by the manually operated valve. Manual valve is normally closed.
7.	Component cooling heat exchanger vent or drain valve	Left open	This is prevented by prestartup and operational checks. On the operating unit such a situation is readily assessed by makeup requirements to system. On the other units such a situation is ascertained during periodic testing.
8.	Component cooling water valve from residual heat exchanger	Fails to open	There is one valve on each outlet line from each heat exchanger. One heat exchanger remains in service and provides adequate heat removal during long term recirculation. During normal operation the cooldown time is extended.

rail hoist and placed on the new fuel elevator in the refueling canal in the spent fuel pit. The new fuel elevator lowers the new fuel assembly into the canal where it is picked up by the long handled tool attached to the spent fuel bridge crane. The fuel assembly is then placed in the transfer carriage which delivers it to the refueling canal, or it may be temporarily stored in the spent fuel pit.

The new fuel storage area is sized for storage of the fuel assemblies normally associated with the replacement of one-third of a core. The fuel for the initial core loading is stored temporarily in the spent fuel storage pit. The pit is kept dry during this period.

Major Structures Required for Fuel Handling

Refueling Cavity

The refueling cavity is a reinforced concrete structure that forms a pool above the reactor when it is filled with borated water for refueling. The cavity is filled to a depth that limits the radiation at the surface of the water to 2.5 milliroentgens per hour during fuel assembly transfer.

The reactor vessel flange is sealed to the bottom of the refueling cavity by a clamped, gasketed seal ring which prevents leakage of refueling water from the cavity. This seal is placed and secured after reactor cooldown but prior to flooding the cavity for refueling operations. The installed cavity seal ring assembly for both Units 3 and 4 is shown in Figure 9.5-2.

The cavity is large enough to provide storage space for the reactor upper and lower internals, the control cluster drive shafts, and miscellaneous refueling tools.

The floor and sides of the refueling cavity are lined with stainless steel.

Refueling Canal

The refueling canal is a passageway extending from the refueling cavity to the inside surface of the containment. The canal is formed by two concrete shielding walls, which extend upward to the same elevation as the refueling cavity. The floor of the canal is at a lower elevation than the refueling cavity to provide the greater depth required for the fuel transfer system tipping device and the control cluster changing fixture located in the canal. The transfer tube enters the reactor containment and protrudes through the end of the canal. The canal walls and floor are lined with stainless steel.

Refueling Water Storage Tank

The normal duty of the refueling water storage tank is to supply borated water to the refueling canal for refueling operations. In addition, the tank provides borated water for delivery to the core following either a loss-of-coolant or a steam line rupture accident. This is described in Chapter 6.

The capacity of the tank is based upon the requirement for filling the refueling cavity and refueling canal.

The water in the tank is borated to a concentration which assures reactor shutdown by at least 5% $\delta k/k$ when all RCC assemblies are inserted and the reactor is cooled down for refueling.

The tank design parameters are given in Chapter 6.

Spent Fuel Storage Pit

The spent fuel storage pit is designed for the underwater storage of spent fuel assemblies and control rods after their removal from the reactor.

The pit design parameters are listed in Table 9.5-1. Control rods are stored in fuel assemblies.

Spent fuel assemblies are handled by a long handled tool suspended from the spent fuel pit bridge overhead crane and manipulated by an operator standing on the movable bridge over the pit.

Suitable restraints are provided between the bridge and trolley structures and their respective rails to prevent derailing and the manipulator crane is designed to prevent disengagement of a fuel assembly from the gripper in the event of a maximum hypothetical earthquake.

Spent Fuel Handling Crane

The spent fuel handling crane is a traveling bridge with a top-running trolley mounted on an overhead structure. The trolley is equipped with two hoists, one on each side of the bridge. The crane spans the spent fuel pit so that it can transfer fuel from the fuel transfer canal into the storage racks located in the pit. The fuel assemblies are moved from the fuel transfer canal and within the spent fuel pit by means of a long handled tool suspended from one of the hoists on the trolley. The hoist travel and tool length are designed to limit the maximum lift of active fuel to a safe shielding depth.

Control consoles are roller mounted on each of the bridge handrails. All operator actions, including bridge, trolley and hoist travel can be performed from the control consoles, which in turn can be moved from one end of the bridge to the other. In addition to a fixed scale and pointer location indication system for the bridge and trolley, the crane is provided with a laser system that provides digital readout of the bridge and trolley position on the control consoles. Hoist position is also indicated.

The hoists are provided with limit switches, overload sensors and other safety features to withstand two-blocking, load hangups and other overloading, misreeving, and single cable failures. The capacity of each hoist is two tons. The crane has adjustable load summing weight sensors to limit the total load on both hoists combined to a maximum of two tons.

In addition, an in-line weight sensing system is provided for each hoist to limit the lifting load to preclude accidental fuel damage should binding occur. When lifting over spent fuel, the total load is limited to 1 ton by procedures, limit switches and load sensors.

Spent Fuel Cask Handling Crane

This bridge crane is arranged to serve both spent fuel pits. Limit switches prevent movement of the cask beyond the laydown area in the bottom of the pit, prevent interference of the cask crane bridge, trolley and hoist with fuel racks or building structures, and restrict vertical lift of the cask to an elevation of about six inches above the top of the pit wall. The interlocks are administratively initiated by a selector switch located in control cab. The crane has hurricane latches.

Fuel Transfer System

The Unit 4 fuel transfer system, shown in Figure 9.5-1, is an underwater conveyor car that runs on tracks extending from the refueling canal through the transfer tube and into the spent fuel pit. The conveyer car receives a fuel assembly in the vertical position from the manipulator crane. The fuel assembly is lowered to a horizontal position for passage through the tube, and then is raised by the upending machine to a vertical position in the spent fuel pit.

The fuel transfer system for each unit utilizes a transverse cable drive operated by two electric winches located on the Spent Fuel operating Floor (elev. 58') to drive the conveyor car.

During operation, the conveyer car is stored in the refueling canal. The gate valve is closed and a blind flange is bolted on the transfer tube to seal the containment.

Rod Cluster Control Changing Fixture

A fixture is mounted on the refueling cavity wall for removing rod cluster control (RCC) assemblies from spent fuel assemblies and inserting them into new fuel assemblies. The fixture consists of two main components; a guide tube mounted to the wall for containing and guiding the RCC assembly, and a wheel-mounted carriage for holding the fuel assemblies and positioning fuel assemblies under the guide tube. The guide tube contains a pneumatic gripper on a winch that grips the RCC assembly and lifts it out of the fuel assembly. By repositioning the carriage, a new fuel assembly is brought under the guide tube and the gripper lowers the RCC assembly and releases it. The manipulator crane moves the fuel assemblies into and out of the carriage.

Reactor Cavity Filtration System

In order to assure that the borated water in the reactor refueling cavity will be clear and allow good visibility for observation during refueling operations, a portable filtration system is installed only for the duration of refueling, afterwhich, it is removed from containment. The system consists of a set of filters, a pump, and associated stainless steel piping. The cavity water is recirculated through the filter as required during refueling operations.

Refueling Sequence of Operation

Preparation

a) The reactor is shutdown and cooled to ambient conditions.

b) A radiation survey is made and the containment is entered.

c) The control rod drive mechanism (CRDM) missile shield is removed to storage.

d) CRDM cables and cooling air ducts are disconnected from the CRDM and removed to storage.

e) The incore thimble tubes are withdrawn.

f) Reactor vessel head insulation and instrument leads are removed. The reactor vessel to cavity seal ring is clamped in place. Proper installation verified. In addition, the seal is inflated.

g) The reactor vessel head nuts are loosened with the hydraulic tensioners.

h) The reactor vessel head studs are removed to storage.

i) The refueling cavity drain valves are closed.

j) Checkout of the fuel transfer device and manipulator crane is started.

k) Guide studs are installed in two holes 180° apart and the remainder of the stud holes are plugged.

l) Final preparation of underwater lights and tools is made. Checkout of manipulator crane and fuel transfer system is completed.

m) The fuel transfer tube flange is removed.

n) The reactor vessel head is unseated and raised approximately one inch with the polar bridge crane and a level check is made.

o) The reactor vessel head is slowly lifted to clear the drive shafts.

p) The reactor vessel head is taken to the storage pedestal.

q) The old seal rings are removed from the reactor vessel head and the grooves cleaned.

r) The refueling cavity is filled with water to the vessel flange. The water is pumped from the refueling cavity by the Residual Heat Removal pumps from the refueling water storage tank. The normal Residual Heat Removal System inlet valves from the Reactor Coolant System are closed. Either or both of the reactor cavity filtration systems are started if required. When the reactor is filled, the residual heat removal loop is restored to normal operation.

s) The full length control rod drive shafts are unlatched.

t) The reactor vessel internals lifting rig is lowered into position by the polar bridge crane and latched to the support plate.

u) The reactor vessel upper internals are lifted out of the vessel and placed in the underwater storage rack.

v) The core is now ready for refueling.

Refueling

The refueling sequence is now started utilizing the manipulator crane. The sequence for fuel assemblies in non-control positions is as follows:

a) Spent fuel is removed from the core and placed into the fuel transfer carrige for relocation to the spent fuel pit. This could involve either a full or a partial core off-load during the refueling outage (Reference 1).

b) An insert shuffle (RCCAs and spent Wet Annular Burnable Absorber) is performed either in the reactor core or the spent fuel pit.

c) New and reused fuel assemblies are brought in from the spent fuel pit through the fuel transfer system and loaded into the core.

d) Whenever any fuel is being added to the reactor core, or is being relocated, a reciprocal curve of source neutron multiplication is recorded to verify the subcriticality of the core.

A transfer of the RCCA assemblies between fuel assemblies is required, when a fuel assembly containing a RCCA assembly is spent or relocated to an unrodded position in the core. The RCCA assembly change fixture is used to transfer the RCCA assembly to a fuel assembly which will be located in a rodded position in the core.

Reactor Reassembly

a) The fuel transfer car is parked and the fuel transfer tube isolation valve closed.

b) The reactor vessel internals package is picked up by the polar bridge crane and replaced in the vessel.

heat exchangers, which was designed to fail as-is (i.e., fail in its normally open position) to ensure adequate flow through the component cooling water heat exchangers.

During an evaluation of the two control valves CV-*-2201 and CV-*-2202, failure modes were discovered that could have prevented these valves from assuming their correct positions following design basis accidents (Reference 1). Consequently, two pneumatically operated valves, POV-*-4882 and POV-*-4883, were installed upstream of the turbine plant cooling water heat exchangers to replace the automatic isolation function originally intended for control valve CV-2201; these two POVs offer sufficient redundancy to isolate intake cooling water flow to assure adequate flow to the component cooling water heat exchangers in the event of an accident. Subsequent modifications to the plant removed CV-4-2201 and the associated manual isolation valve 4-50-403 on Unit 4 and replaced these valves with a piping spool piece of the same diameter. Certain portions of the instrumentation for the control valve were abandoned in place.

Similarly, the safety function for control valve CV-2202 (downstream of the component cooling water heat exchangers) to remain open was superceded by maintaining the manual bypass valves 3-50-406 (Unit 3) and 4-50-406 (Unit 4) under administrative control (i.e., throttled or locked open). The bypass flow paths for CV-*-2202 on both units are capable of accommodating sufficient flow through the component cooling water heat exchangers to remove post-accident heat loads. Subsequent modifications to the plant removed CV-*-2202 on each unit and replaced these valves with piping spool pieces of the same diameter. Certain portions of the instrumentation for these valves were abandoned in place.

Solenoid actuated pneumatically operated valves, POV-*-4882 and POV-*-4883, one on the inlet of each turbine plant cooling water (TPCW) heat exchanger, automatically isolate these heat exchangers in the event that air or electrical (DC) power is lost, when only one intake cooling water (ICW) pump is operated on the emergency diesel to supply essential cooling water to the component cooling water (CCW) heat exchangers. These valves do not automatically isolate upon loss of offsite power (LOOP). Controls are provided locally and in the control room to initiate closure in case of a LOOP. Additionally, in the event of a safety injection actuation signal, the pneumatically operated valves (POVs) will automatically isolate the TPCW heat exchangers. These valves are fail-closed valves. In addition, these valves are provided with the capability to remain open for a minimum of 2 hours following a loss of instrument air to avoid potential damage to turbine plant equipment.

The intake cooling water system is designed as Class I.

System Evaluation

During normal operations two Intake Cooling Water pumps provide flow to the three Component Cooling Water heat exchangers and to both Turbine Plant Cooling Water heat exchangers. During an accident, one or two ICW pumps can provide flow to two or three CCW heat exchangers. Measures are in place to ensure the heat transfer capability of the CCW heat exchangers meets the accident heat load. This heat transfer capability is ensured even if a single active failure resulted in a partial flow of intake cooling water through the turbine plant cooling water heat exchangers. The measures include performance monitoring, and periodic cleaning of the component cooling water heat exchangers. Periodic cleaning of the Unit 3 CCW heat exchangers by chemical injection can be performed to minimize tube-side fouling, thus preserving the heat transfer capability of the heat exchangers.

The Turbine Plant Cooling Water heat exchangers are provided with cathodic protection by means of rectifiers supplying anodes in the heat exchangers. The component cooling water heat exchangers are provided with cathodic protection by means of sacrificial anodes located in the heat exchanger inlet and outlet channel heads.

Water Treatment System

A common water treatment system (see Figures 9.6-10 through 9.6-14) is provided for Units 3 and 4 to provide the demineralized water of the required quality. The water treatment system is designed to provide all demineralized water requirements of Units 3 and 4.

Wastes from the Water Treatment Plant demineralizer regeneration process which have a pH between 2.0 and 12.5 are transferred to the neutralization basin where they are neutralized and discharged. If the pH of the demineralized regeneration waste is outside this range, it is sent to the waste neutralization tank where it is neutralized and then sent to the neutralization basin.

An automatic isolation valve is provided on the common Water Treatment Plant (WTP) discharge line to prevent discharge of high conductivity water from the WTP to the condensate storage tanks. A drain line with a manual isolation valve is located upstream and close to the automatic isolation valve.

Since the water treatment system is not required for safe shutdown of the units following a MHA, it is designated as Class III.

In addition to the existing Water Treatment Plant, connections are provided for an Alternate Water Treatment Plant. A raw water supply connection and a return treated water connection are provided (Reference FSAR Figures 9.6-10 and Figure 9.6-11). The purpose of these connections is to allow use of a complete vendor supplied water purification system typically furnished as a turnkey service. The Alternate Water Treatment Plant option is currently in use and purification equipment including all auxiliaries such as acid, caustic, demineralizer trailers, etc is provided by a vendor. Other vendors may be considered at contract extension time, or the original Water Treatment Plant could be returned to service.

Primary Water Make-up System

Adequate primary water storage is provided to fulfill the water requirements load fluctuations and leakage in the reactor coolant system during normal unit operation.

The primary water is unborated, deaerated, demineralized water suitable for in the reactor coolant system. Boric acid is added to this water in the desired concentration before it is used as the reactor coolant.

System Design

The demineralized water from the water treatment system is passed through the vacuum deaerator where the dissolved oxygen is removed.

The deaerated demineralized water is then transferred by the deaerated water transfer pump to the primary water storage tank. (See Figures 9.6-15 through 9.6-18).

The primary water storage tank is a carbon steel epoxy lined tank with a floating diaphragm.

One primary water storage tank and one vacuum deaerator with transfer pump is provided for each unit. The primary water storage tank is a carbon steel epoxy lined tank with a floating diaphram.

Two primary water make-up pumps per unit are provided. One pump is normally in operation and supplies primary water to the chemical and volume control system where boric acid is added before its injection as reactor coolant.

The primary water make-up system is designated as Class III, since it is not required for the safe shutdown of the unit following a MHA.

9.6.3 SYSTEM DESIGN EVALUATION

Malfunction Analysis

The intake cooling water system is designed to prevent a component failure from curtailing normal unit operation. Two normally cross-connected, parallel headers with necessary cross connections and isolation valves provide redundant flow paths. In addition to the loop isolation valves, each component also has individual isolation valves to permit removing any piece of equipment from the system.

A malfunction in the water treatment system or primary water make-up system does not create any abnormal condition in reactor operation; therefore, a component failure or temporary outage is not of primary importance for reactor safety.

Minimum Operating Conditions

Minimum operating requirements of the intake cooling water system are met by one pump and one loop header. The remote operated control valve permits isolation of the non-essential services for one-pump operation.

Tests and Inspections

All intake cooling water system components are hydrostatically tested prior to unit start-up and are accessible for periodic inspections during operation. all electrical components, transfer, and starting controls are tested.

9.6.4 REFERENCES

1. FPL Safety Evaluation JPE-LR-87-45,"Justification for Continued Operation of Turkey Point Unit 3 for ICW System Design," Revision 3, dated March 17, 1989.

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9.11 AUXILIARY FEEDWATER SYSTEM

9.11.1 DESIGN BASIS

The Auxiliary Feedwater System is designed to:

1) Keep the unit at hot standby, in case of loss of outside electric power, for a limited period of time and then to lower the reactor temperature and pressure to a level where the residual heat removal system can be put into operation if the outside power is not restored during hot standby.

2) Supply auxiliary feedwater to the steam generators within three minutes in case of a loss of the normal feedwater.

9.11.1.1 SYSTEM OPERATION

The Auxiliary Feedwater System is shown in Figures 9.11-2 through 9.11-9. Upon initiation of the Auxiliary Feedwater System, the turbine steam isolation valves open and actuate position switches. These position switches actuate the solenoid valves mounted on the Auxiliary Feedwater control valves. The instrument air, in conjunction with a signal generated from the controllers in the Main Control Room is then permitted to modulate the control valves. Manual and automatic modes of operation are provided and may be selected from the Main Control Room. Flow indication is provided locally and in the Main Control Room. Auxiliary Feedwater Flow Control Valves position are provided locally.

9.11.1.2 <u>Auxiliary Feedwater Flow Control Valves</u>

Each steam generator auxiliary feedwater line, Train 1 and Train 2, has a flow element, flow transmitter, and flow control valve. When the AFW system is in the standby mode controllers in the control room are set to a predetermined flow rate as delineated in the Technical Specifications and plant operating procedures.

The controller pneumatic output signal to the air operated flow control valve is blocked by a solenoid valve, thus the control valve is closed. Upon receipt of an AFW steam supply MOV open signal, either auto or manual, the solenoid valves associated with the flow control valves to the steam generators on the affected unit will be energized to open. This permits the predetermined output signal from the controller to be applied to the flow control valve, supplying AFW to the affected unit's steam generators. The flow control is normally set to supply at least 125 gpm to each steam generator. A travel limit stop is installed on each flow control valve and is adjusted to limit the stem travel to approximately 85% of full open, limiting AFW flow to approximately 525 gpm, should a flow control valve fail to the full open position.

Flow indicators for AFW Trains 1 and 2 are installed under the main feedwater platform for use during manual operation of the flow control valves. Flow indicators are also provided on the Main Feedwater Platform.

Impulse type steam traps are provided upstream of the MOVs and drain to the condenser. The turbine casing drains, the exhaust pipe drain, the gland seal drain, the governor valve and the HP and LP steam leakoffs in the throttle trip valve drain to a drain trough. The pump recirculation is controlled by an orifice in the recirculation piping. The pumps can continue to supply reduced amounts of water to the steam generators until steam pressure is reduced to 85 psig. The pump output in pounds per hour is greater than the steam consumption until the 85 psig point is reached. However, at 120 psig, the Residual Heat Removal System is started and the auxiliary feedwater pumps are shutdown.

Cooling water is supplied to the safety related auxiliary feedwater pump oil coolers from the second stage of the auxiliary feed pump and is discharged to the condensate storage tanks.

Standby Feedwater Pumps

Two non-safety grade motor driven standby feedwater pumps are provided. These pumps are normally used during plant startup and shutdown. One pump is motor driven and normally powered from the 4160 volt C-Bus. The other pump is diesel engine driven with an integral fuel tank and electric starting system. In case of loss of off-site power, the normal safety supply of feedwater to the steam generators is provided by the steam turbine driven auxiliary feedwater pumps. However, feedwater can also be supplied by the diesel engine driven standby feedwater pump (Reference 1).

9.11.3 CONDENSATE STORAGE TANKS

Normal water supply to the auxiliary feedwater pumps is from the two 250,000 gallon condensate storage tanks, through locked open gate valves and check valves. Each tank contains a 210,000 gallon minimum indicated volume which assures a minimum usable volume of 199,100 gallons of demineralized water for the auxiliary feedwater pumps.

With this quantity of water, the unit can be taken from full power to hot standby following a loss of offsite power, and:

1. Kept at hot standby for 15 hours and then cooled to 350°F in four hours, at which point the Residual Heat Removal System will be put in service, or

2. Kept at hot standby for about 24 hours.

This is shown graphically in Figure 9.11-1.

An additional auxiliary feedwater supply can be provided from the water treatment system. Demineralized water at a maximum rate of 200 gpm per unit will be available from the water treatment system. The auxiliary feedwater requirement after ten hours is less than 125 gpm. The condensate storage tanks are interconnected so that each of the pumps can take suction from either tank.

An alternate, non-safety source of water is the 500,000 gallon demineralized water storage tank. This tank provides the normal water source for the standby steam generator feedwater pumps.

9.11.4 REFERENCES

1. NRC Letter from Richard Croteau to J. H. Goldberg Dated May 20, 1994, TURKEY POINT UNITS 3 & 4 - ISSUANCE OF AMENDMENTS RE: ELIMINATION OF CRANKING DIESEL GENERATORS (TAC NOS. M87662 AND M87663).

9.12.1.4 OPERATION

The Post-Accident Containment Vent System is normally isolated by manually closed valves, and is only operated for valve operability and for filter efficiency during periodic tests. If the containment hydrogen concentration reaches 3.0 volume percent, low level pressurization of the containment from the air supplies will be started. Whenever the containment pressure exceeds 1.5 psig, flow through the HEPA and charcoal filters can be initiated and directed to the monitored plant vent or one waste gas compressor can be started to direct effluent to any available waste gas tank. The venting process will be shut down when the hydrogen concentration is reduced to 2.7 volume percent. The containment will remain isolated unless 3.0 volume percent is again reached at a later date.

9.12.2 PROVISIONS FOR A PORTABLE HYDROGEN RECOMBINER

9.12.2.1 DESIGN BASIS

Pursuant to the requirements of 10 CFR 50.44, as amended December 2, 1981, Turkey Point must have the capability to install an external hydrogen recombiner to control post-accident hydrogen concentration in containment. The recombiner functions to supplement the post-accident containment vent system, which is the primary means to control post-accident containment hydrogen. The following requirements and design conditions are identified for temporary increased combustible gas control.

Performance Requirements

The portable hydrogen recombiner must be capable of controlling the accumulation of combustible gas following a LOCA. The hydrogen concentration must be maintained below a maximum limit of 3 percent by volume.

Design Conditions and Constraints

1. The locations for the recombiner must be accessible following a postulated LOCA (radiologically and physically) and must not restrict access to equipment that must be accessible following a LOCA. The locations accessible to the heavy load lifting systems. The operating

station recombiner shall be located away from the recombiner and associated process piping to minimize exposure from these sources.

2. The permanently installed piping shall be compatible with operating conditions during recombination and the operating conditions of the piping systems to which they interface. The means shall be provided to isolate the recombiner when not in use, or not installed.

3. Per 10 CFR 50.44, the containment penetrations used by the recombiner shall meet the requirements of GDC 54 and 56. The penetrations shall be sized to allow for the required flow of the recombiner.

4. The power supply to the recombiner shall be compatible with the requirements of the recombiner and shall be reliable and available post-accident.

5. The flow rate through the recombiner shall be adequate to maintain post-accident containment hydrogen concentration below 3 percent by volume.

6. The recombiner and associated temporary components shall not adversely affect the permanently installed piping or adjacent safety related equipment.

9.12.2.2 SYSTEM DESCRIPTION

The accumulation of combustible gases following a LOCA is normally controlled by the Post-Accident Containment Vent (PACV) System, but provisions for an external hydrogen recombiner are required by 10 CFR 50.44. The provisions for installing and operating an external hydrogen recombiner at Turkey Point are based on the use of a 90 scfm (nominal) thermal recombiner manufactured by Rockwell International. The hydrogen recombiner system consists of two portable major components: (1) recombiner mechanical skid, and (2) power/ control cabinet. These components are stored and maintained off-site by another utility and will be brought on-site if required following an accident. The mechanical skid consists of the process gas handling equipment necessary to remove the hydrogen from containment, heat the gas to the point of thermal recombination, cool the gas and return the effluent to containment. The

9.14 POST ACCIDENT HYDROGEN MONITORING SYSTEM

The containment post-LOCA hydrogen monitoring equipment (see Figures 11.2-6 and 11.2-7) will provide reliable and accurate indication of the concentration of hydrogen gas in the containment atmosphere following a loss-of-coolant accident. Two completely independent systems are provided to monitor for free gaseous hydrogen in the range of 0 to 10 percent by volume in the containment atmosphere, with a system recorder accuracy of ± 2.5 full scale.

The sampling will be either educted or received under pressure based on the condition of the containment post-LOCA environment. These systems are complete closed loops; that is the sample is returned back to the containment atmosphere.

Both recording and indicating devices are provided and located in the Control

Room. Channel 1 of the containment post-LOCA hydrogen monitors will be located in the Post Accident Sampling Room. Channel 2 will be located in the access

area to the waste gas hold up tanks.

The samples will be tapped off of the hydrogen purge lines and will return via the containment atmospheric sample return line.

The other hydrogen monitor sample connections tie-in to the existing post accident containment ventilation system outside containment. The PACVS sample ports are placed in two separate pipe headers near the containment dome.

APPENDIX 9.6A

FIRE PROTECTION PROGRAM REPORT

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APPENDIX 9.6A

FIRE PROTECTION PROGRAM REPORT

1.0 PURPOSE AND SCOPE

This Appendix provides a comprehensive description of the Fire Protection Program as documented and discussed with the NRC. The history of Turkey Point Units 3 and 4 fire protection, as it evolved from Appendix A to Branch Technical Position APCSB 9.5-1 through the specific requirements of 10 CFR Part 50 Appendix R, has been assembled in this Appendix. The material included in this document involves information previously submitted to the NRC via formal FPL letters in response to inquiries. This report outlines how General Design Criterion 3, "Fire Protection," is met using the guidelines contained in Appendix A to Branch Technical Position APCSB 9.5-1 and the requirements contained in 10 CFR Part 50 Appendix R. The Fire Protection Program ensures that in the event of a fire at Unit 3 or 4 the Unit's reactor can be safely shut down and radioactive releases to the environment minimized. This program also implements the philosophy of defense-in-depth protection against fire hazards and effects of fire on safe shutdown equipment.

This Appendix addresses the systems and components associated with fire protection that are installed in the power block of Turkey Point Units 3 and 4. The power block includes the permanent structures associated with Units 3 and 4, and the land areas immediately adjacent to these structures. The power block is bounded by the land area on the south, the road along the west side, the passage between Unit 3 and Unit 2 on the north, and the security fence and intake canal on the east as shown in Figures 9.6A-8 through 11. Any exceptions are indicated in the text.

Details of compliance with the NRC requirements are delineated in this report as follows:

Section 2.0, Methodology, describes the three tiers of protection provided to ensure: (1) prevention of fires from occurring, (2) detection and mitigation of fires, that may occur, and (3) safe shutdown design such that were a fire to start and burn for an extended period despite prevention, detection, and mitigation measures, capability for safe plant shutdown is retained.

Section 3.0, Fire Protection Features, discusses the design of the fire detection and suppression systems and additional fire protection features at Turkey Point Units 3 and 4.

Section 4.0, Fire Hazard Analyses, presents the Appendix R Fire Areas established in the plant and details the physical description, essential equipment, combustible loadings, fire detection/suppression equipment and exemptions, if any, from the criteria provided by 10 CFR Part 50 Appendix R.

Section 5.0, Alternate Shutdown Capability, discusses use of the Alternate Shutdown Panels to provide shutdown capability for both Unit 3 and 4 independent of the Control Room (including Control Building roof), North-South Breezeway or Cable Spreading Room.

Section 6.0, Primary Coolant System Interfaces, delineates the protection provided to prevent a fire-induced LOCA through the low pressure interfaces with the RCS.

Section 7.0, Administrative Controls, summarizes various facets of the fire protection program and how they are administered.

Section 8.0, Quality Assurance Program, refers to the QA aspects of fire protection.

2.0 METHODOLOGY

The design of the Turkey Point Units 3 and 4 Fire Protection program is based upon the defense-in-depth concept. Multiple levels of protection are provided so that should a fire occur, it will not prevent safe plant shutdown and the risk of a radioactive release to the environment will be minimized. These levels of protection include Fire Prevention, Fire Detection and Mitigation, and the Capability to Achieve and Maintain Safe Shutdown should a fire occur. Each of these levels of the defense-in-depth design is discussed below.

2.1 FIRE PREVENTION

Noncombustible and fire resistant materials are used throughout the Turkey Point plant power block; walls, floors and ceilings are of reinforced concrete or concrete block construction and use of interior finish materials is limited to non-combustible material or those with a flame spread, smoke and fuel contribution of 50 or less (ASTM E-84) wherever practicable. Lightning protection is provided as discussed in Section 3.6.

Fire prevention also relies on safeguards and good housekeeping practice. Assurance that good housekeeping policies will be in place is provided by plant procedures and inspections. Housekeeping practices consist of adequate control of cleanliness, disposal of combustible materials and debris, access control, and personnel safety. Welding and other potential ignition sources are also controlled by plant procedures.

2.2 FIRE DETECTION AND SUPRESSION FEATURES

In addition to the fire prevention measures discussed above, equipment and systems designed to rapidly detect and extinguish any fire further enhance the overall fire protection program. These systems form the second level of the defense-in-depth concept. Fire detection and/or suppression systems are provided in areas containing equipment essential for safe plant shutdown and in areas for general plant property protection, as appropriate. These systems are described in Section 3.0, Fire Protection Systems.

2.3 PROTECTION OF SAFE SHUTDOWN CAPABILITY

The primary objective of the Fire Protection Program is to minimize both the probability and consequence of fires. In spite of steps taken to reduce the probability of fire in the design of the plant, the occurrance of fire must be postulated and the protection of safe shutdown capability must be assured. In order to assure safe shutdown capability, fire protection features have been installed and a safe shutdown analysis has been performed utilizing the guidance contained in Appendix A to BTP APCSB 9.5-1 and the requirements of 10CFR50 Appendix R. The safe shutdown analysis and fire hazards analysis are described in Sections 2.3.1, 2.3.2 and 2.3.3 and the fire protection features are described in Section 3.0.

2.3.1 CONFORMANCE TO APPENDIX A TO BTP APCSB 9.5-1 (AUGUST 23, 1976)

This Appendix (9.6A) provides the results of detailed design reviews initiated in 1977 which utilize the Fire Hazard Analyses (FHA) concept. A worst-case "exposure fire" was postulated, comprised of in situ combustibles, and the resulting fire hazard was analyzed in each critical plant area; i.e., areas of the plant where a fire could conceivably impair safe shutdown. To perform this fire hazard analysis, the Turkey Point Units were divided into separate plant areas. A list of the minimum essential equipment required for hot standby, cooldown and cold shutdown, which includes equipment locations with respect to the plant areas, was prepared (Reference 15). The power, control and instrumentation cables associated with the essential equipment were identified including each cable routing throughout the plant. Critical plant areas were then reviewed with respect to their physical descriptions, location of essential equipment therein, area and local combustible loadings, structural boundaries and penetrations, area and local fire detection/suppression equipment and a detailed analysis of the effects of the postulated fire in the area was performed. The results of this FHA have been updated to reflect the present plant design and are presented in Section 4.0. The lineup against the guidance in Appendix A to BTP APCSB 9.5-1 (August 23, 1976) is delineated in Section 2.4.

2.3.2 CONFORMANCE TO 10 CFR PART 50 APPENDIX R

Turkey Point Units 3 and 4 are required to conform to Sections III.A, G, H, I, J, L and O of 10 CFR Part 50 Appendix R with exceptions which have been submitted to the NRC as exemption requests. Additional details are given in Sections 2.4 (BTP Appendix A lineup) and 2.5 (Appendix R lineup) of this Appendix. The detailed Fire Hazard Analyses in Section 4.0 includes the Appendix R exemptions. The Turkey Point Fire Water Supply Systems, Standpipes and Hose Stations, Automatic Suppression Systems, Portable Fire Extinguishers, Fire Detection Systems, Lightning Protection, Emergency Lighting and Communication, Reactor Coolant Pump Oil Collection Systems and Fire Rated Assemblies are discussed in detail in Section 3.0 of this Appendix. Alternate Shutdown Capability is discussed in Section 5.0.

2.3.3 SAFE SHUTDOWN ANALYSIS

Section III.G.1 of Appendix R to 10CFR50 requires that fire protection features be provided for systems, structures and components important to safe shutdown. These features shall be capable of limiting fire damage so that:

- One train of systems necessary to achieve and maintain hot shutdown conditions from either the control room or emergency control station(s) is free of fire damage; and

- Systems necessary to achieve and maintain cold shutdown from either the control room or emergency control station(s) can be repaired within 72 hours.

In order to meet these requirements, all equipment required for safe shutdown, including the associated power and control cables, and any equipment which could adversely affect safe shutdown if spuriously actuated by fire-induced faults, have been identified for every fire area in the plant in order to assess the fire protection required. Safe shutdown is defined as hot standby conditions as a minimum, with the capability to proceed to cold shutdown should conditions warrant. Utilizing this information, a Safe Shutdown Analysis (Reference 14) was performed for Turkey Point Units 3 and 4 to determine the impact of a postulated fire on the safe shutdown equipment and circuitry within each fire area. Where a safe shutdown function was prevented, corrective actions (e.g., cable rerouting, cable protection, procedure changes, etc.) have been implemented to resolve the concern, or operator manual actions have been specified. In some cases credit is taken for equipment (other than the redundant counterpart) which provides a redundant function to the equipment affected by a postulated fire. Some examples include use of the Refueling Water Storage-Tank for a charging water source for a fire which affects flow from the Boric Acid Tank and use of the Standby Steam Generator Feed Pumps for a fire in the Auxiliary Feedwater Pump area. This analysis ensured that no single fire can prevent Turkey Point Units 3 and 4 from achieving a safe cold shutdown.

2.3.3.1 Analysis Methodology

Figure 9.6A-7 is a flow chart of the safe shutdown analysis process. The process first establishes the safe shutdown functions required to be performed, followed by selection of the systems, specific system equipment, and electrical/control circuits required to accomplish these functions. Reference 9 defines the functions required to achieve cold shutdown. These safe shutdown functions, and the systems required to accomplish these functions, are as follows:

a) Reactivity Control Function
   - Reactor Protection System
   - Chemical and Volume Control System

b) Reactor Coolant Makeup Function
   - Chemical and Volume Control System

c) Reactor Heat Removal Function
   - Reactor Coolant System
   - Main Steam System
   - Auxiliary Feedwater System
   - Chemical and Volume Control System
   - Component Cooling Water System
   - Intake Cooling Water System
   - Residual Heat Removal System

d) Process Monitoring Function
   - Nuclear (Source Range) Instrumentation System

e) Supporting Function
   - Component Cooling Water System
   - Intake Cooling Water System
   - Instrument Air System
   - Containment Cooling System
   - Control Room Ventilation System
   - Auxiliary Building Ventilation System
   - Electrical Power System (Emergency Diesel Generators, Vital AC Power and Vital DC Power)

Process flowpaths for each of the above listed systems have been traced on plant flow diagrams. Based on these system flowpaths, a list of the minimum equipment necessary to bring the plant to cold shutdown has been compiled. This list contains all power generation and distribution equipment (e.g., diesel generators, batteries, switchgear, motor control centers, power panels, etc.) that are required for the operation of the listed equipment. In addition, the list includes equipment which, although not required for safe shutdown, could adversely affect safe shutdown if spuriously actuated by a fire-induced electrical fault. This list is labeled the Appendix R Essential Equipment List (Reference 15).

Following development of the Appendix R Essential Equipment List, the applicable system electrical schematics and control loops (if applicable) have been reviewed to determine which cables (power, control and instrumentation) are required for the listed equipment to perform its intended safety function. The review considers both the loss of cable function and the corresponding failure mode of the equipment, as well as the spurious actuation of the equipment due to a hot short within the cable, a hot short from an external cable within common enclosures (e.g., tray, terminal box, control panel), open circuits, or shorts to ground (i.e., the equipment could be energized or de-energized by one or more failure modes). Specific attention has been given to interlocks that could prevent the equipment from performing its designed function and to power supplies for the equipment, and for control circuits and instrumentation loops as well. The cables associated with power supplies have been traced back through the entire distribution system to ensure power is available to support the equipment operation. The routing of each cable has been noted from starting point to end point with an identification of all fire zones through which the cable passes. This cable list is labeled the Appendix R Essential Cable List (Reference 16).

The next process in the development of the Appendix R Safe Shutdown Analysis was to establish fire areas and fire zones. Each fire area was then analyzed by assuming a fire would destroy all equipment and cables in that fire area. An Appendix R Fire Area is defined as any region that is typically enclosed (floors, walls and ceilings) by barriers that have a 3-hour rating including barrier penetrations. Fire zones are rooms, cubicles or other sub-divisions of fire areas. If the performance of a safe shutdown function was prevented due to a loss of redundant essential equipment or cables, a determination was made concerning whether the plant was able to achieve and maintain cold shutdown on one or, if required, both channels (A or B). All cables of equipment for the required channel(s) were analyzed to determine which, if any, required relocation or protection to assure safe shutdown. Where necessary, cables that could adversely affect the safe shutdown capability of the plant have been separated, relocated out of the fire area, and/or protected as defined in Section III.G.2 of Appendix R. In addition, credit may have been taken for manual actions to prevent or mitigate adverse effects of a fire on safe shutdown circuits when the necessary separation or protection is not feasible. In some cases, specific exemptions for Appendix R separation criteria have been granted.

The following assumptions have been adhered to during development of the Safe Shutdown Analysis:

a) Affected plant or plants are in Mode 1 (100% power) when the fire occurs;

b) Safe shutdown can be achieved using only equipment that is listed in Reference 15;

c) A loss of offsite power (LOOP) or offsite power availability is assumed, whichever provides a worse case condition;

d) No other accident (LOCA, MSLB, HELB, etc.) nor any natural event (earthquake, tornado, etc.) need be considered concurrently with a fire;

e) Access into containment for the performance of cold shutdown functions is acceptable;

f) Safe shutdown capability shall not be adversely affected by any one spurious actuation or signal resulting from a fire in any fire area;

g) Safe shutdown capability shall not be adversely affected by a fire in any fire area which results in the loss of all automatic function (signals, logic) from the circuits located in the fire area in conjunction with one worst case spurious actuation or signal resulting from the fire;

h) Safe shutdown capability shall not be adversely affected by a fire in any fire area which results in spurious actuation of redundant valves in any single high-low pressure interface line;

i) No credit is taken for post-fire repair of cold shutdown equipment, except for the replacement of fuses; and

j) Depending on the fire scenario involved, equipment/components from either train may be used to achieve safe shutdown.

Since Turkey Point Units 3 and 4 share common and cross-connected plant systems, as well as a common control room, a fire in certain plant areas may impact both units. The Safe Shutdown Analysis considers the safe shutdown requirements of both units, and demonstrates that following a fire, either in one unit or in common facilities, both units can achieve safe shutdown. The operating unit may achieve safe shutdown without reliance on the shutdown unit.

2.3.3.2 Associated Circuits

Section III.G of Appendix R requires that cables (power, control and instrumentation) associated with required safe shutdown equipment be protected. Those cables and circuits associated with non-safe shutdown equipment and which are not adequately protected from the effects of fire and whose failure could impact safe shutdown are reviewed as "associated circuits". References 9 and 18 define associated circuits as those that:

The results of the evaluation indicate that acceptable circuit protection and coordination is provided for the common enclosures and that cable faults in one fire area do not cause fire in a common enclosure in another fire area. In addition, adequate sealing of raceways leaving a fire area prevents the propagation of fire to other fire areas.

Based on the above, there are no associated circuits at Turkey Point Units 3 and 4 which could adversely affect safe shutdown.

2.3.4 APPENDIX R FIRE BARRIERS AND FIRE AREAS

Fire barriers having a 3-hour fire rating are shown on Figures 9.6A-8 through 9.6A-11. Where the Appendix R III.G 3-hour fire barrier criterion could not be met, exemptions were requested (see Section 4.0). In some cases, written calculations performed by a Fire Protection Engineer may be kept on file to demonstrate acceptability of a fire barrier in accordance with Reference 18, Paragraph C. Three-hour fire barriers (floors, walls and ceilings) define the Appendix R Fire Areas. The Appendix R Fire Areas are distinguished from the previously numbered plant zones by an alphabetic description (e.g., Fire Area "B") which may include or encompass several numeric-designated zones (e.g., Fire Area "B" encompasses Fire Zone 11, Fire Zone 12 and Fire Zone 13, where the zone designations trace back to the original FHA). Table 9.6A-1a provides a listing of Turkey Point Fire Zones, Table 9.6A-1b provides a Fire Area to Fire Zone cross reference list. Use of the term "fire barriers" in this report denotes the Appendix R fire barriers only.

Provision of these Appendix R fire barriers in conjunction with rerouting or protection of cables assures that, assuming all equipment and unprotected cables within an Appendix R Fire Area are made inoperable by a fire, one set of equipment remains available to bring the plant to a safe (cold) shutdown.

2.3.5 CONCLUSION

Based on the information presented in this report, which incorporates the information and analyses submitted for NRC review and approval, Turkey Point Units 3 and 4 conform to the guidelines given in BTP Appendix A and to the specific criteria set forth in 10 CFR Part 50 Appendix R with justified exemptions. Ongoing conformance is ensured by engineering guidelines (Reference 17) which identify general design criteria and regulatory requirements applicable to each type of engineered fire protection, and provide instructions for preparing and reviewing plant changes/modifications to ensure that fire protection requirements are addressed. Surveillance requirements and strict administrative controls ensure that the likelihood of a fire of severe magnitude is highly improbable at Turkey Point Units 3 and 4, and the defense-in-depth described herein provides assurance that were a fire to occur plant safe shutdown capability is retained.

2.4 <u>CONFORMANCE TO APPENDIX A TO BTP 9.5-1 GUIDELINES</u>

The information which follows is a lineup of the Turkey Point Units 3 and 4 plant against the guidelines of Appendix A to Branch Technical Position APCSB 9.5-1 (August 23, 1976) "Guidelines for Fire Protection for Nuclear Power Plants Docketed prior to July 1, 1976."

Appendix A Guidelines are given in the first (left-hand) column of the following tabulations, retaining the numbering sequence used in BTP Appendix A. Information on various aspects of the Turkey Point Units 3 and 4 Fire Protection Program is given in the second column as necessary to demonstrate conformance to the BTP Appendix A Guidelines, or in the third column to describe alternative approaches. The fourth column provides supplemental information as appropriate.

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
A.3 Backup Total reliance should not be placed on a single automatic fire suppression system. Appropriate backup fire suppression capability should be provided.	Provisions for fire suppression for the various plant areas avoids total reliance on any single system, automatic or manual. Appropriate backup fire suppression capability is provided.		Fixed water spray systems are provided for Main, Auxiliary, Startup and C Bus Transformers, Turbine Oil Reservoirs, and Hydrogen Seal Oil Units. Automatic preaction systems are provided for the Emergency Diesel Generator 3A, 3B, 4A & 4B Rooms, 3A & 3B Day Tank Rooms, and Charging Pump Rooms. Automatic wet pipe sprinkler systems are provided for the Turbine Piping Spray, Heater Drain Tanks, Steam Generator Feed Pumps and Condensate Pump Areas, as well as the RCA control point guardhouse and 4A & 4B Diesel Oil Transfer Pumps. The North-South Breezeway and the Component Cooling Area are provided with automatic deluge sprinkler systems. Halon fire suppression systems are provided for the Cable Spread Room and Inverter Rooms. A full complement of portable hand fire extinguishers is installed throughout the plant to provide initial firefighting capacity. As a backup to portable hand fire extinguishers and/or automatic suppression systems, a system of 1-1/2 inch hose lines and hose reels are distributed throughout Units 3 and 4. Hose connections are installed so that areas within each building are reached with hose lines attached to a standpipe connection. As a final backup to all of the protection outlined above, outside hydrants and hose houses are also provided.

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
A.4 Single Failure Criterion			
A single failure in the fire suppression system should not impair both the primary and backup fire suppression capability. For example, redundant fire water pumps with independent power supplies and controls should be provided.	The concept of redundancy is used to ensure that a single failure will not impair both primary and secondary fire suppression capability. In addition, the piping and valving is arranged such that a single break will not prevent the water supply from reaching both the primary and secondary fire supression capability. The plant fire protection water supply system is provided with redundant fire water pumps with independent power supplies and controls. Dedicated fire water is available in two separate storage tanks.		
Postulated fires or fire protection system failures need not be considered concurrent with other plant accidents or the most severe natural phenomena.	Postulated fires or fire protection system failures are not considered concurrent with other plant accidents or the most severe natural phenomena.		
The effects of lightning strikes should be included in the overall plant fire protection program.	Lightning protection is incorporated in the facility design (see Section 3.6).		
A.5 Fire Suppression Systems			
Failure or inadvertent operation of the fire suppression systems should not incapacitate safety related systems or components. Fire suppression systems that are pressurized during normal plant operation should meet the guidelines specified in APCSB Branch Technical Position 3-1, "Protection Against Postulated Piping Failures in Fluid Systems Outside Containment."	Selection of fire suppression systems for areas containing safety related equipment was such that failure or inadvertent suppression system operation would not incapacitate redundant essential equipment. For example, those areas requiring water suppression were provided with pre-action systems to reduce the probability of a false discharge occurring as a result of a single failure or inadvertent operation. Halon systems actuated by crossed zone detection are located in the Cable Spreading Room and the Inverter Rooms.		Refer to Section 3.3 of this Appendix for a discussion of the fire suppression systems.

	Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
B.3 (a)	Work involving ignition sources such as welding and flame cutting should be done under closely controlled conditions. Procedures governing such work should be reviewed and approved by persons trained and experienced in fire protection. Persons performing and directly assisting in such work should be trained and equipped to prevent and combat fires. If this is not possible, a person qualified in fire protection should directly monitor the work and function as a fire watch.	Prior to the start of work, a hot work (welding, cutting, etc.) permit is issued and posted, and the work area is made "fire safe". A fire watch is established and in effect during the operation.		
B.3 (b)	Leak testing, and similar procedures such as air flow determination, should use one of the commercially available aerosol techniques. Open flames or combustion generated smoke should not be permitted.	Open flames or combustion generated smoke are not permitted.		
B.3 (c)	Use of combustible material, e.g., HEPA and charcoal filters, dry ion exchange resins or other combustible supplies, in safety related areas should be controlled. Use of wood inside buildings containing safety related systems or equipment should be permitted only when suitable noncombustible substitutes are not available. If wood must be used, only fire retardant treated wood (scaffolding, lay down blocks) should be permitted. Such materials should be allowed into safety related areas only when they are to be used immediately. Their possible and probable use should be considered in the fire hazard analysis to determine the adequacy of the installed fire protection systems.	The use of combustible materials in safety related areas is kept at the minimum extent practicable. The methods for the controls of combustibles is included in plant procedures. The use of wood, with appropriate considerations, is kept to the minimum extent practicable.		

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
B.4 Nuclear power plants are frequently locatedin remote areas, at some distance frompublic fire departments. Also, first response fire departments are often volunteer. Public fire department response should be considered in the overall fire protection program. However, the plant should be designed to be self-sufficient with respect to fire fighting activities and rely on the public response only for supplemental or backup capability.	The primary fire fighting activities at Turkey Point are provided by the plant fire brigade. However, both Dade County and Homestead Air Force Base fire departments will respond to the plant to provide assistance.		Refer to Section 3.9 of this Appendix.
B.5 The need for good organization, training and equipping of fire brigades at nuclear power plant sites requires effective measures be implemented to assure proper discharge of these functions. The guidance in Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants," should be followed as applicable.	The organization, training, and equipping of the fire brigade are based on the requirements	Turkey Point is not required to comply with Regulatory Guide 1.101. provided in Appendix R to 10 CFR Part 50.	
(a) Successful fire fighting requires testing and maintenance of the fire protection equipment, emergency lighting and communication, as well as practice as brigades for the people who must utilize the equipment. A test plan that lists the individuals and their responsibilities in connection with routine tests and inspections of the fire detection and protection systems should be developed. The test plan should contain the types, frequency and detailed procedures for testing. Procedures should also contain instructions on maintaining fire protection during those periods when the fire protection system is impaired or during periods of plant maintenance, e.g., fire watches or temporary hose connections to water systems.	Plant procedures provide for maintaining the performance of plant fire protection systems and personnel; including the periodic inspection and testing of systems, and the alternate provisions to be made during temporary impairment of systems.		Refer to Sections III.H and III.I of 10 CFR Part 50 Appendix R Guidelines (Section 2.5).

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
(2) Turbine-generator oil and hydraulic control fluid systems	The Turbine Lube Oil Reservoirs are provided with fixed water spray systems.		
(3) Reactor coolant pump lube oil system	The Reactor Coolant Pumps in Containment have integral oil collection systems as required by Section III.O of 10 CFR Part 50 Appendix R.		
D.2 (b) Bulk gas storage (either compressed or cryogenic), should not be permitted inside structures housing safety-related equipment. Storage of flammable gas such as hydrogen, should be located outdoors or in a separate detached buildings so that a fire or explosion will not adversely affect any safety related systems or equipment. (Refer to NFPA 50A, "Gaseous Hydrogen Systems.")	Bulk storage of flammable gasses is located outdoors to avoid exposure to essential equipment, systems or structures.		
Care should be taken to locate high pressure gas storage containers with the long axis parallel to building walls. This will minimize the possibility of wall penetration in the event of a container failure. Use of compressed gases (especially flammable and fuel gases) inside buildings should be controlled. (Refer to NFPA 6, "Industrial Fire Loss Prevention.")	Procedures require containers to be secured to structures or vehicle racks. Safe permitted use of compressed gases inside buildings is controlled by operational procedures.		
D.2 (c) The use of plastic materials should be minimized. In particular, haloginated plastics such as polyvinyl chloride (PVC) and neoprene should be used only when substitute non-combustible materials are not available. All plastic materials, including flame and fire retardant materials, will burn with an intensity and BTU production in a range similar to that of ordinary hydrocarbons. When burning, they produce heavy smoke that obscures visibility and can plug air filters, especially charcoal and HEPA. The haloginated plastics also release free chlorine and hydrogen chloride when burning which are toxic to humans and corrosive to equipment.	Plant design minimizes the use of combustible materials. Cables within certain areas are generally coated with a fire retardant coating or are qualified to the requirements of IEEE 383, 1974. Where appropriate, in situ plastics are included in fire area combustible inventories utilized in the Fire Hazard Analyses, Section 4.0 of this Appendix.		

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
D.2 (d) Storage of flammable liquids should as a minimum, comply with the requirements of NFPA 30, "Flammable and Combustible Liquids Code."	Flammable liquid storage generally conforms to the guidance provided in NFPA 30.		
D.3 Electric Cable Construction, Cable Trays and Cable Penetrations			
D.3 (a) Only non-combustible materials should be used for cable tray construction.	Non-combustible material is used for cable tray construction.		
D.3 (b) See Section F3 for fire protection guidelines for Cable Spreading Rooms.	See F.3 of this Section.		
D.3 (c) Automatic water sprinkler systems should be provided for cable trays outside the Cable Spreading Room Cables should be designed to allow wetting down with deluge water without electrical faulting. Manual hose stations and portable hand extinguishers should be provided as backup.		Cables in certain areas are generally covered with an approved fire retardant coating or are qualified to the requirements of IEEE 383-1974. Hose stations and extinguishers are generally available for manual fire fighting.	Automatic suppression systems are provided in some areas to protect redundant safety related cables.
Safety related equipment in the vicinity of such cable trays, that does not itself require water fire protection, but is subject to unacceptable damage from sprinkler water discharge, should be protected from sprinkler system operation or malfunction. When safety related cables do not satisfy the provisions of Regulatory Guide 1.75, all exposed cables should be covered with an approved fire retardant coating and a fixed automatic water fire suppression system should be provided.	Open-ended electrical conduit is sealed if its physical configuration and location is such that automatic suppression water can be conducted into electrical equipment. New installation of equipment is required to be weatherproof or enclosed if located in areas susceptible to damage from automatic suppression systems.		Turkey Point is not required to conform to Regulatory Guide 1.75.

	Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
	Smoke and gases containing radioactive materials should be monitored in the fire area to determine if release to the environment is within the permissible limits of the plant Technical Specifications.	Non-recirculating ventilation systems are provided for fire areas which may contain airborne radioactive materials. Smoke from fires which might occur in areas containing radioactive materials are monitored for radioactivity using existing area monitors or monitors installed at the ventilation system discharging points.		
D.4	(b) Any ventilation system designed to exhaust smoke or corrosive gases should be evaluated to ensure that inadvertent operation or single failures will not violate the controlled areas of the plant design. This requirement includes containment functions for protection of the public and maintaining habitability for operations personnel.	Not applicable. See D.4(a) of this Section.		
D.4	(c) The power supply and controls for mechanical ventilation systems should be run outside the fire area served by the system.	To the extent practicable, power supply and controls for ventilation systems are installed outside the areas they serve or equipment isolation or protection is provided. One of the exhaust fans in the Auxiliary Building is required to remain operable for a fire in any area except the room where the fan is located. Credit is taken for one supply fan operable for a fire in the room containing the exhaust fan.		
D.4	(d) Fire suppression systems should be installed to protect charcoal filters in accordance with Regulatory Guide 1.52, "Design Testing and Maintenance Criteria for Atmospheric Cleanup Air Filtration."		Adequate fire extinguishers and hose stations are available.	Turkey Point is not required to comply with Regulatory Guide 1.52.

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
D.4 (e) The fresh air supply intakes to areas containing safety related equipment or systems should be located remote from the exhaust air outlets and smoke vents of other fire areas to minimize the possibility of contaminating the intake air with the products of combustion.	Fresh air intakes are remote from exhaust air outlets to minimize the possibility of of contaminating the intake air with the products of combustion.		
D.4 (f) Stairwells should be designed to minimize smoke infiltration during a fire. Staircases should serve as escape routes and access routes for fire fighting. Fire exit routes should be clearly marked. Stairwells, elevators and chutes should be enclosed in masonry towers with minimum fire rating of three hours and automatic fire doors at least equal to the enclosure construction, at each opening into the building. Elevators should not be used during fire emergencies.		The Turbine Building is an open air structure with open stairways. Stairways in the Auxiliary Building are such that seperation between elevations is maintained by three hour fire resistive construction.	
Where stairwells or elevators cannot be enclosed in three-hour fire rated barrier with equivalent fire doors, escape and access routes should be established by Pre-Fire Plan and practiced in drills by operating and fire brigade personnel.	Access and egress routes are established in the Pre-Fire Plans and practiced by operating and fire brigade personnel.		
D.4 (g) Smoke and heat vents may be useful in specific areas such as Cable Spreading Rooms and diesel fuel oil storage areas and switchgear rooms. When natural-convection ventilation is used, a minimum ratio of 1 sq. foot of venting area per 200 sq. feet of floor area should be provided. If forced-convection ventilation is used, 300 CFM should be provided for every 200 sq. feet of floor area. See NFPA No. 204 for additional guidance on smoke control.		The Cable Spreading Room, Diesel Generator 3A & 3B Day Tank Rooms and the Switchgear Rooms have doors that open to the outside. The 4A & 4B Diesel Oil Transfer Pump Rooms have doors to the outside and exhaust fans through the roof. Two 5,000 cfm portable smoke ejectors are available on site for manual ventilation.	

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
E. Fire Detection and Suppression			
E.1 Fire Detection			
E.1 (a) Fire detection systems should, as a minimum comply with NFPA 72D, "Standard for the Installation, Maintenance and Use of Proprietary Protective Signaling Systems."	The guidelines of NFPA 72D are utilized in the design of the fire detection systems.		Fire detection and suppression systems annunciate in the Control Room.
Deviations from the requirements of NFPA 72D should be identified and justified.			
E.1 (b) Fire detection system should give audible and visual alarm and annunciation in the control room. Local audible alarms should also sound at the location of the fire.	The fire detection system gives audible and visual alarms and annunciates in the Control Room and indicates detector location at selected local graphics panels.		
E.1 (c) Fire alarms should be distinctive and unique. They should not be capable of being confused with any other plant system alarms.	The fire alarm is distinctive and unique from those of other alarm systems.		
E.1 (d) Fire detection and actuation systems should be connected to the plant emergency power supply.	The fire detection system is connected to the plant emergency power supply.		
E.2 Fire Protection Water Supply Systems			
E.2 (a) An underground yard fire main loop should be installed to furnish anticipated fire water requirements.	The underground fire loop provides sufficient fire protection water to plant fire protection systems.		Refer to Section 3.1 of this Appendix for a discussion of the Fire Water Supply System.
NFPA 24, "Standard for Outside Protection," gives necessary guidance for such installation. It references other design codes and standards developed by such organizations as the American National Standards Institute (ANSI) and the American Water Works Association (AWWA).	The guidelines of NFPA 24 was used in the installation of the yard fire main loop.		
Visible location marking signs for underground valves is acceptable. Alternative valve position indicators should also be provided.	Not applicable.		

	Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
	Lined steel or cast iron pipe should be used to reduce internal tuberculation. Such tuberculation deposits in an unlined pipe over a period of years can significantly reduce water flow through the combination of increased friction and reduced pipe diameter. Means for treating and flushing the system should be provided.	Cast iron pipe is used for the yard main fire loop to minimize internal tuberculation. A means for flushing the system is provided. Water quality for fire protection is such that it requires no special treatment.		
	Approved visually indicating sectional control valves, such as Post Indicator Valves, should be provided to isolate portions of the main for maintenance or repair without shutting off the entire system.	The yard loop is equipped with visually indicating sectionalizing valves such that portions of the loop may be isolated without impairing operation of the rest of the system.		
	The fire main system piping should be separate from service or sanitary water system piping.	The fire main system piping is separate from the service and sanitary water system piping.		
	For operating plants, fire main system piping that can be isolated from service or sanitary water system piping is acceptable.	See above.		
E.2 (b)	A common yard fire main loop may serve multi-unit nuclear power plant sites, if cross-connected between units.	A common yard fire main loop services all Turkey Point Units (Fossil and Nuclear).		The loop section servicing the fossil units may be isolated without impairing the adequacy of service to Turkey Point Units 3 and 4. The Fossil Loop is, therefore, not subject to the Regulatory requirements for the loop servicing Units 3 and 4.
	Sectional control valves should permit maintaining independence of the individual loop around each unit. For such installations, common water supplies may also be utilized.		Sectionalizing valves permit various portions of the loop to be installed without impairing the remainder of the loop.	

	Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
E.3 (c)	Automatic sprinkler systems should as a minimum conform to requirements of appropriate standards such as NFPA 13, "Standard for the Installation of Sprinkler Systems," and NFPA 15, "Standard for Water Spray Fixed Systems."	Automatic sprinkler systems and fixed water spray systems generally conform to the guidelines of NFPA 13 and NFPA 15, respectively, as described in Section 3.3.2 of this Appendix.		
E.3 (d)	Interior manual hose installation should be able to reach any location with at least one effective hose stream. To accomplish this, standpipes with hose connections equipped with a maximum of 75 feet of 1-1/2 inch woven jacket lined fire hose and suitable nozzles should be provided in all buildings, including containment, on all floors and should be spaced at not more than 100 foot intervals.		Manual hose stations with up to 100 feet of 1-1/2 inch minimum fire hose are located throughout the plant. The hoses are provided with matching fog nozzles.	Hose stations are not generally located in radiological controlled areas or the control complex. Additional hose lengths may therefore be required for extremely remote areas.
	Individual standpipes should be of at least 4-inch diameter for multiple hose connections and 2-1/2 inch diameter for single hose connections.	Standpipes are 4 inches in diameter for multiple hose connections, and 2-1/2 inches in diameter minimum for single hose connections, or have been hydraulically calculated to verify the flow and pressure requirements of NFPA 14 are met.		
	These systems should follow the requirements of NFPA No. 14 for sizing, spacing and pipe support requirements (NELPIA).	The guidelines of NFPA 14 were used in the design and installation of standpipe and hose stations.		
	Hose stations should be located outside entrances to normally unoccupied areas and inside normally occupied areas.		Hose stations are generally located in hallways and other access routes to plant areas.	
	Standpipes serving hose stations in areas housing safety related equipment should have shut off valves and pressure reducing devices (if applicable) outside the area.	Sectional shutoff valves provided for standpipes serving the Control Room, Cable Spreading Room and Switchgear Room are located outside these rooms.		

	Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
E.3 (e)	The proper type of hose nozzles to be supplied to each area should be based on the fire hazard analysis. The usual combination spray/straight-stream nozzle may cause unacceptable mechanical damage (for example, the delicate electronic equipment in the Control Room) and be unsuitable. Electrically safe nozzles should be provided at locations where electrical equipment or cabling is located.	Electrically safe nozzles are provided at all hose stations. Provisions have been made to avoid the use of the straight stream nozzle.		
E.3 (f)	Certain fires such as those involving flammable liquids respond well to foam suppression. Consideration should be given to use of any of the available foams for such specialized protection application. These include the more common chemical and mechanical low expansion foams, high expansion foam and the relatively new Aqueous Film Forming Foam (AFFF).	Portable manual foam equipment is provided for Turkey Point Units 3 and 4.		

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
E.4 Halon Suppression Systems			
The use of Halon fire extinguishing agents should, as a minimum, comply with the requirements of NFPA 12A and 12B, "Halogenated Fire Extinguishing Agent Systems - Halon 1301 and Halon 1211." Only UL or FM approved agents should be used.	Halon 1301 total flooding systems are provided for the Cable Spreading Room and the Unit 3 and Unit 4 D.C. Equipment Rooms. The systems comply with the requirements of NFPA 12A; only approved agents are used.		
In addition to the guidelines of NFPA 12A and 12B, preventative maintenance and testing of the systems, including check weighing of the Halon cylinders should be done at least quarterly.	The Halon 1301 systems will be tested and maintained in accordance with NFPA 12A.	Check weighing of Halon cylinders is performed semiannually.	
Particular consideration should also be given to: (a) minimum required Halon concentration and soak time, (b) toxicity of Halon, and (c) toxicity and corrosive characteristics of thermal decomposition products of Halon.	The design and application considered concentration, soak time, toxicity and corrosive characteristics. The Cable Spreading Room/Cable Chase Halon system is designed to maintain a six percent concentration for a period of 30 minutes. The inverter Rooms Halon System, although designed to maintain a six percent concentration for a period of 30 minutes, can only maintain a five percent concentration for 10 minutes due to dilution of the halon as a result of continued HVAC system operation. (see Section 3.3.3.f)		
E.5 Carbon Dioxide Suppression Systems (details deleted)	Not applicable		
E.6 Portable Extinguishers			
Fire extinguishers should be provided in accordance with guidelines of NFPA 10 and 10A, "Portable Fire Extinguishers Installation, Maintenance and Use." Dry chemical extinguishers should be installed with due consideration given to cleanup problems after use and possible adverse effects on equipment installed in the area.	Fire extinguishers are provided in accordance with NFPA 10. Extinguisher selection considers the unique characteristics of the fire suppression agent and their effect on the proper application of the agent to the fire. Considerations include quantity required in relation to the size of the anticipated fire, cleanup after use, thermal shock effects of the agent or its fire decomposition products		

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
F. Guidelines for Specific Plant Areas			
F.1 Primary and Secondary Containment			
F.1 (a) Normal Operation			
Fire protection requirements for the primary and secondary containment areas should be provided on the basis of specific identified hazards. For example:	Fire extinguishers are provided in the containments as required for most effective fire control recognizing the different types of operations in the area, accessibility and available personnel usage.		
- Lubricating oil or hydraulic fluid system for the primary coolant pumps;	The Reactor Coolant Pumps are provided with a Lube Oil Collector System.		Refer to Section 3.10 of this Appendix.
- Cable tray arrangements and cable penetrations; or	Non IEEE-383 cables inside containment were sprayed with a fire retardant coating.		
- Charcoal filters.	A borated water spray system is installed in each containment filter unit to dissipate the radioactive heat decay.		
Fire suppression systems should be provided based on the fire hazards analysis.	A fire hazard analyses has been performed for the containments based on in situ conditions to serve as a basis for fire protection provisions. Details are provided in Section 4.0 of this Appendix.		
Fixed fire suppression capability should be provided for hazards that could jeopardize safe plant shutdown. Automatic sprinklers are preferred. An acceptable alternate is automatic gas (Halon or CO_2) for hazards identified as requiring fixed suppression protection.		Detectors are provided inside containment and around electrical penetration areas which alarm and annunciate in the Control Room. Protection is provided for redundant cables and equipment such that safe shutdown capability is retained. See Section 4.0 of this Appendix.	No fixed suppression systems are used in the containments.
An enclosure may be required to confine the agent if a gas system is used. Such enclosures should not adversely affect safe shutdown, or other operating equipment in containment.	Not applicable.		

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
F.3 (a) (3) Each Cable Spreading Room of each unit should have divisional cable separation, and be separated from each other and the rest of the plant by a minimum three-hour rated fire wall. (Refer to NFPA 251 or ASTM E-119 for fire test resistance rating.)	The Cable Spreading Room is common to both units and contains circuits for certain redundant Safe Shutdown features. As a result, alternative shutdown capability has been provided independent of the Cable Spreading Room. See Section 111.G.3 of 10 CFR 50 Appendix R Requirements (Section 2.5). The Cable Spreading Room is separated from the rest of the plant by three-hour rated barriers.		
(4) At least two remote and separate entrances are provided to the room for access by fire brigade personnel; and	At least two remote and separate entrances are provided for fire brigade access.		
(5) Aisle separation provided between tray stacks should be at least three feet wide and eight feet high.	Not applicable.		Not a design criterion for Turkey Point.
(b) For Cable Spreading Rooms that do not provide divisional cable separation of F.3(a)(3), in addition to meeting F.3(a)(1), (2), (4) and (5) above, the following should also be provided:			
(1) Divisional cable separation should meet the guidelines of Regulatory Guide 1.75, "Physical Independence of Electrical Systems."	See F.3(b)(4) of this section.		Turkey Point is not required to comply with Regulatory Guide 1.75.

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
F.3 (b) (2) All cabling should be covered with a suitable fire retardant coating.	Non IEEE-383 cables installed in cable tray in the Cable Spreading Room are provided with fire retardant coating.		
(3) As an alternate to F.3(a)(1) above, automatically initiated gas systems (Halon or CO_2) may be used for primary fire suppression, provided a fixed water system is used as a backup.		A Halon suppression system is provided in the Cable Spreading Room, and hose stations are available as backup.	
(4) Plants that cannot meet the guidelines of Regulatory Guide 1.75, in addition to meeting F.3(a)(1), (2), (4) and (5) above, an auxiliary shutdown system with all cabling independent of the Cable Spreading Room should be provided.	The Alternate Shutdown System is independent of the Cable Spreading Room.		
F.4 Plant Computer Room			
Safety related computers should be separated from other areas of the plant by barriers having a minimum three-hour fire resistant rating. Automatic fire detection should be provided to alarm and annunciate in the Control Room and alarm locally. Manual hose stations and portable water and halon fire extinguishers should be provided.	The computer room is separated from all other plant areas by three-hour rated fire barriers. Automatic ionization detection is provided to alarm and annunciate in the Control Room. Hose stations and portable extinguishers are provided for use in this area.		
F.5 Switchgear Rooms			
Switchgear rooms should be separated from the remainder of the plant by minimum three-hour rated fire barriers to the extent practicable. Automatic fire detection should alarm and annunciate in the Control Room and alarm locally. Fire hose stations and portable extinguishers should be readily available.	The Switchgear Rooms are separated from other plant areas by three-hour fire barriers. Ionization detectors which alarm and annunciate in the Control Room are provided. Fire hose stations and portable extinguishers are readily available to serve the area.		

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
Acceptable protection for cables that pass through the Switchgear Room is automatic water or gas agent suppression. Such automatic suppression must consider preventing unacceptable damage to electrical equipment and possible necessary containment of agent following discharge.		Portable fire extinguishers and Hose stations are provided for manual fire control. In addition, separation between redundant essential components is provided in accordance with Appendix R Section III.G.2.	No automatic suppression systems are provided.
F.6 Remote Safety Related Panels			
The general area housing remote safety related panels should be provided with automatic fire detectors that alarm locally and annunciate in the Control Room. Combustible materials should be controlled and limited to those required for operation. Portable extinguishers and manual hose stations should be provided.	Areas housing safety related equipment are generally equipped with detection and/or suppression systems. The plant housekeeping program limits the amount of combustibles in the plant. Portable fire extinguishers and hose stations are provided.		
F.7 Station Battery Rooms			
Battery rooms should be protected against fire explosions. Battery rooms should be separated from each other and other areas of the plant by barriers having a minimum fire rating of three hours inclusive of all penetrations and openings. (See NFPA 69, "Standard on Explosion Prevention Systems.") Ventilation systems in the battery rooms should be capable of maintaining the hydrogen concentration well below 2 vol. % hydrogen concentration. Standpipes and hose and portable extinguishers should be provided.	The battery rooms are separated from all other plant areas by three hour rated fire barriers. A ceiling vent is provided in each battery room with a direct exhaust to outside the building to maintain the concentration of hydrogen below 2% by volume within the battery rooms. Portable extinguishers, standpipes and hose stations are available.	Spare Battery Room (Fire Zone 25A) is located within Fire Area G and is enclosed with non-combustible construction. Fire Area G is enclosed by three hour rated fire barriers. Exhaust from that room is provided by the Auxiliary Building Ventilation system and will maintain the concentration of hydrogen below 2% by volume within the room. Portable extinguishers, standpipes and hose stations are available.	
Alternatives:	Not applicable.		
(a) Provide a total fire rated barrier enclosure of the battery room complex that exceeds the fire load contained in the room.			

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
(b) Reduce the fire load to be within the fire barrier capability of 1-1/2 hours.	Not applicable.		
OR			
(c) Provide a remote manual actuated sprinkler system in each room and provide the 1-1/2 hour fire barrier separation.	Not applicable.		
F.8 Turbine Lubrication and Control Oil Storage and Use Areas			
A blank fire wall having a minimum resistance rating of three hours should separate all areas containing safety related systems and equipment from the turbine oil system.	Blank fire walls having a three hour rating are provided in some areas. Where blank fire walls are not provided, provisions are made as stated below.		
When a blank wall is not present, open head deluge protection should be provided for the turbine oil hazards and automatic open head water curtain protection should be provided for wall openings.	The turbine oil hazards are protected by fixed water spray systems, and the turbine piping is protected by a wet pipe system. These hazards are located in outdoor fire zones; the turbine building is not enclosed.		
F.9 Diesel Generator Areas			
Diesel generators should be separated from each other and other areas of the plant by fire barriers having a minimum fire resistance rating of three hours.	The 3A & 3B and 4A & 4B Emergency Diesel Generator are separated from each other and other areas of the plant by fire barriers having a minimum fire resistance rating of three hours.		
Automatic fire suppression such as AFFF foam, or sprinklers should be installed to combat any diesel generator or lubricating oil fires.	Each diesel generator room is protected by pre-action automatic sprinkler systems.		
Automatic fire detection should be provided to alarm and annunciate in the Control Room and locally. Drainage for fire fighting water and means for local manual venting of smoke should be provided.	Each area is provided with automatic fire detection which alarms and annunciates in the Control Room and alarms locally. Drainage with oil separation provisions is available in the 3A & 3B Diesel Generator Rooms. Drainage from Emergency Diesel Generator 4A & 4B rooms is routed to an external holding sump. Natural ventilation and exhaust fans are provided in the rooms for smoke venting.		

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
Day tanks with total capacity up to 1100 gallons are permitted in the diesel generator area under the following conditions:			The 3A & 3B Emergency Diesel Generators have two day tanks: a 275 gallon integral day tank located in the same room as the diesel generator, and a 4,000 gallon day tank located in a separate room above. The 4A & 4B Emergency Diesel Generators each have a 650 gallon day tank located in the same room as the diesel generator.
(a) The day tank is located in a separate enclosure, with a minimum fire resistance rating of three hours, including doors or penetrations. These enclosures should be capable of containing the entire contents of the day tanks. The enclosure should be ventilated to avoid accumulation of oil fumes.	The 3A & 3B Emergency Diesel Generator 4000 gal. day tanks are located in separate fire areas. These enclosures are capable of containing the entire contents of the day tanks. The tanks are vented outside.		
(b) The enclosure should be protected by automatic fire suppression systems such as AFFF or sprinklers.	The 3A & 3B day tank rooms are protected by a preaction automatic sprinkler system.		
When day tanks cannot be separated from the diesel generator one of the following should be provided for the diesel generator areas: (a) Automatic open head deluge or open head spray nozzle system(s); (b) Automatic closed head sprinklers; (c) Automatic AFFF that is delivered by a sprinkler deluge or spray system; (d) Automatic gas system (Halon or CO_2) may be used in lieu of foam or sprinklers to combat diesel generator and/or lubricating oil fires.	The 275 gallon 3A and 3B day tanks are located in the same room as its associated diesel generator and each room is provided with a preaction automatic sprinkler system. The 4A & 4B Emergency Diesel Generators have 650 gallon day tanks located in the same room as its associated diesel generator and each room is provided with a preaction automatic sprinkler system.		

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
F.10 Diesel Fuel Oil Storage Areas			
Diesel fuel oil tanks with a capacity greater than 1100 gallons should not be located inside the buildings containing safety related equipment. They should be located at least 50 feet from any building containing safety related equipment, or if located within 50 feet, they should be housed in a separate building with construction having a minimum fire resistance rating of three hours. Buried tanks are considered as meeting the three hour fire resistance requirements. See NFPA 30, "Flammable and Combustible Liquids Code," for additional guidance.		The Unit 3 diesel storage tank is located 30 feet east of the Unit 3 Diesel Generator Building. The area where the Unit 3 Diesel Oil Storage Tank is installed is provided with a dike to contain oil spillage. A manually operated open head fixed water spray system is located above the air intakes located on the North, South and East sides of the Unit 3 Diesel Generator Building. The 4A & 4B Diesel Fuel Oil Tanks are integral to the Unit 4 diesel generator structure, but are totally enclosed by three hour rated fire barriers and are accessible only through removable concrete hatches located on the roof.	
When located in a separate building, the tank should be protected by an automatic fire suppression system such as AFFF or sprinklers.	Not applicable.		The Unit 3 diesel oil storage tank is not located in a building. Unit 4 diesel oil storage tanks are not located in separate buildings. The tank and oil transfer pump rooms are designated as one fire area. The transfer pump room contains a wet pipe sprinkler system. See item F.10 above.
Tanks, unless buried, should not be located directly above or below safety related systems or equipment regardless of the fire rating of separating floors or ceilings.	The fuel storage tank is not located above or below safety related systems or equipment.		
In operating plants where tanks are located directly above or below the diesel generators and cannot reasonably be moved, separating floors and main structural members should, as a minimum, have a fire resistance rating of three hours. Floors should be liquid tight to prevent leaking of possible oil spills from one level to another. Drains should be provided to remove possible oil spills and fire fighting water to a safe location.	See response to F.9 of this section.		
One of the following acceptable methods of fire protection should also be provided:			
(a) Automatic open head deluge or open head spray nozzle system(s);	Pre-action automatic sprinkler systems are provided for the day tanks.		
(b) Automatic closed head sprinklers; or			
(c) Automatic AFFF that is delivered by a sprinkler system or spray system.			

	Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
F.11	Safety Related Pumps			
	Pump houses and rooms housing safety related pumps should be protected by automatic sprinkler protection unless a fire hazards analysis can demonstrate that a fire will not endanger other safety related equipment required for safe plant shutdown. Early warning fire detection should be installed with alarm and annunciation locally and in the Control Room. Local hose stations and portable extinguishers should also be provided.		All essential pump areas have been evaluated to the criteria of Appendix R. Safe shutdown of the plant is assured for fire in any area by means of some combination of detection, suppression, fire rated barriers and availability of fire extinguishers and hose stations.	Refer to Section 4.0 of this Appendix, Fire Hazard Analyses, for specific provisions made in each zone.
	Equipment pedestals or curbs and drains should be provided to remove and direct water away from safety related equipment.	Floor drains, pedestals and curbs are provided to accommodate the removal of water away from safety related equipment.		
	Provisions should be made for manual control of the ventilation system to facilitate smoke removal if required for manual fire fighting operation.	Generally, normal ventilation systems are used for area smoke venting. In addition, portable smoke ejectors are available for use by the site fire brigade.		
F.12	New Fuel Area			
	Hand portable extinguishers should be located within this area. Also, local hose stations should be located outside but within hose reach of this area. Automatic fire detection should alarm and annunciate in the Control Room and alarm locally.	Hose stations are provided outside to service the new fuel areas.	There are portable extinguishers located near the new fuel areas.	Adequate fire hydrants and hose lines connected to the yard mainwater supply system are avail-able to provide fire protection for this area. No detection is provided in these areas.
	Combustibles should be limited to a minimum in the new fuel area. The storage area should be provided with a drainage system to preclude accumulation of water.	Combustibles in the new fuel areas are limited to a minimum and these areas are provided with adequate drainage to preclude the accumulation of water.		
	The storage configuration of new fuel should always be maintained as to preclude criticality for any water density that might occur during fire water application.	The storage configuration of the new fuel precludes criticality for water density that might occur during fire water application.		

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
F.13 Spent Fuel Pool Area			
Protection for the spent fuel pool area should be provided by local hose stations and portable extinguishers. Automatic fire detection should be provided to alarm and annunciate in the Control Room and to alarm locally.	A hose station and fire hydrants are available to provide adequate fire protection for this area. In addition, hand portable extinguishers can be utilized to combat fires.	Fire detection is not provided.	
F.14 Radwaste Building			
The radwaste building should be separated from other areas of the plant by fire barriers having at least three-hour ratings. Automatic sprinklers should be used in all areas where combustible materials are located. Automatic fire detection should be provided to annunciate and alarm in the Control Room and alarm locally.	Radwaste areas in the auxiliary building are separated from other areas by three hour fire barriers and fire protection provisions vary from one area to another. See See Section 4.0 of this Appendix, Fire Hazard Analyses, for information on each area. The Radwaste Building is not physically connected to any other plant structures and has reinforced concrete walls and floor. There are no significant combustible loads in the Radwaste Building and consequently no detection or automatic suppression is provided. There are portable extinguishers located in the building, and yard hydrants are also provided.		
During a fire, the ventilation systems in these areas should be capable of being isolated. Water should drain to liquid radwaste building sumps.	Water is drained to liquid radwaste sumps.	Where required, the Radwaste Building is provided with a ventilation system, and the ventilation system for radwaste areas in the Auxiliary Building is part of the normal Reactor Auxiliary Building ventilation system. The ventilation systems can be isolated as required.	Refer to Section 4.0 of this Appendix, Fire Hazard Analyses, for details on each area.
An acceptable alternative fire protection is an automatic fire detection to alarm and annunciate in the Control Room, in addition to manual hose stations and portable extinguishers consisting of hand held and large wheeled units.		See above.	There are no fire detectors provided in the Radwaste Building.

Appendix A Guidelines	Plant Conformance	Alternatives	Remarks
G.4 Materials Containing Radioactivity			
Materials that collect and contain radioactivity such as spent ion exchange resins, charcoal filters, and HEPA filters should be stored in closed metal tanks or containers that are located in areas free from ignition sources or combustibles. These materials should be protected from exposure to fires in adjacent areas as well. Consideration should be given to requirements for removal of isotopic decay heat from entrained radioactive materials.	Materials containing or collecting radioactivity are stored in closed metal containers in areas free of ignition sources or combustibles. Rated fire barriers are provided to preclude exposure to fire in adjacent areas. Requirements for control of decay heat are developed for specific storage materials.		

2.5 CONFORMANCE TO 10 CFR PART 50 APPENDIX R REQUIREMENTS

The information which follows is a lineup of the Turkey Point Units 3 and 4 designs against the requirements of Appendix R to 10 CFR Part 50. Also see the lineup against BTP Appendix A presented in Section 2.4 of this Appendix.

Appendix R requirements are given in the first (left-hand) column of the following tabulations, retaining the numbering sequence of Appendix R. Information on various aspects of the Turkey Point Units 3 and 4 Fire Protection Program is given in the second column as necessary to demonstrate conformance to the Appendix R Requirements, or in the third column to describe alternative approaches. The fourth column provides supplemental information as appropriate.

Based on the criteria established in 10 CFR Part 50.48, Turkey Point Units 3 and 4 are required to conform only to Sections III.G, III.J, and III.O of Appendix R. Additional Sections requiring conformance as a result of prior NRC review and acceptance of Turkey Point Units 3 and 4 design with respect to BTP APCSB 9.5-1 Appendix A are III.A, III.H, III.I and III.L. All other Sections of Appendix R are not applicable to Turkey Point Units 3 and 4.

	Appendix R Requirements	Plant Conformance	Alternatives	Remarks
II.C.6.	Fire detection and suppression systems shall be designed, installed, maintained, and tested by personnel properly qualified by experience and training in fire protection systems.	Fire detection and suppression systems are described in Section 3.0 of this Appendix.		
II.C.7.	Surveillance procedures shall be established to ensure that fire barriers are in place and that fire suppression systems and components are operable.	Surveillance procedures have been established to ensure that fire barriers are in place and that fire suppression systems and components are operable.		
II.D.	Alternative or Dedicated Shutdown Capability			
	In areas where the fire protection features cannot ensure safe shutdown capability in the event of a fire in that area, alternative or dedicated safe shutdown capability shall be provided.	Alternative shutdown is provided for the Control Room, Cable Spreading Room and North-South Breezeway. See Section 5.0 of this Appendix.		
III.	Specific Requirements			
III.A.	Water Supplies for Fire Suppression Systems			
	Two separate water supplies shall be provided to furnish necessary water volume and pressure to the fire main loop.	Two separate tanks are provided as redundant sources. One tank is a 500,000 gallon raw water storage tank, the other a 750,000 gallon raw water storage tank. Out of each tank, 300,000 gallons are dedicated for fire protection purposes.		
	Each supply shall consist of a storage tank, pump, piping and appropriate isolation and control valves. Two separate redundant suctions in one or more intake structures from a large body of water (river, lake, etc.) will satisfy the requirement for two separated water storage tanks. These supplies shall be separated so that a failure of one supply will not result in a failure of the other supply.	The tanks are cross connected such that either source may supply either of two fire pumps. A failure in one tank will not result in the failure of the other.		Refer to item E.2(d) in Appendix A to BTP 9.5-1 Guidelines of this Appendix.

Appendix R Requirements	Plant Conformance	Alternatives	Remarks
Each supply of the fire water distribution system shall be capable of providing for a period of 2 hours the maximum expected water demands as determined by the fire hazard analysis for safety-related areas or other areas that present a fire exposure hazard to safety-related areas.	Each 300,000 gallon supply is capable of meeting the largest design demand for a period of at least two hours for safety related areas.		
When storage tanks are used for combined service water/fire water uses, the minimum volume for fire uses shall be ensured by means of dedicated tanks or by some physical means such as a vertical standpipe for other water service. Administrative controls including locks for tank outlet valves are unacceptable as the only means to ensure minimum water volume.	Nozzles are provided high on the tanks to provide water for non fire water services such that 300,000 gallons in each tank is dedicated for fire protection.		
Other water systems used as one of the two fire water supplies shall be permanently connected to the fire main system and shall be capable of automatic alignment to the fire main system. Pumps, controls and power supplies in these systems shall satisfy the requirements for the main fire pumps. The use of other water systems for fire protection shall not be incompatible with their functions required for safe shutdown. Failure of the other system shall not degrade the fire main system.	Not applicable.		
III.B. Sectional Isolation Valves (Details deleted)	Not applicable.		See the introduction to this Section for the Sections of Appendix R to which Turkey Point is required to comply.
III.C. Hydrant Isolation Valves (Details deleted)	Not applicable.		
III.D. Manual Fire Suppression (Details deleted)	Not applicable.		
III.E. Hydrostatic Hose Tests (Details deleted)	Not applicable.		
III.F. Automatic Fire Detection (Details deleted)	Not applicable.		

Appendix R Requirements	Plant Conformance	Alternatives	Remarks
III.O Oil Collection System for Reactor Coolant Pump			
The reactor coolant pump shall be equipped with an oil collection system if the containment is not inerted during normal operation. The oil collection system shall be so designed, engineered and installed that failure will not lead to fire during normal or design basis accident conditions and that there is reasonable assurance that the system will withstand the Safe Shutdown Earthquake.	The RCP's are equipped with an oil collection system. The system is designed to remain in place following a safe shutdown earthquake in accordance with Regulatory Guide 1.29, paragraph C.2 to minimize the possibility of fire.		
Such collection systems shall be capable of collecting lube oil from all potential pressurized and unpressurized leakage sites in the reactor coolant pump lube oil systems. Leakage shall be collected and drained to a vented closed container that can hold the entire lube oil system inventory. A flame arrester is required in the vent if the flash point characteristics of the oil present the hazard of fire flashback.	No flame arrestors are needed because the tank is located away from the heat source of the Reactor Coolant System and because the flash point of the oil is over 450°F, while the maximum normal operating temperature of the oil is 200°F. Containment operating temperature is approximately 120°F, well below the flash point of the oil.	Leakage is collected and drained to a vented closed container. For Unit 4, the tank capacity (254 gallons) will hold the volume of one RCP motor (200 gallons) plus the normal expected leakage from the other two RCP motors (30 gallons) based on an eighteen month refueling cycle. For Unit 3, the collection tank capacity has been modified to 319 gallons. This will hold the volume of the "original spare" RCP motor (275 gallons) plus the normal expected leakage from the other two RCP motors (30 gallons) based on eighteen month refueling cycle. Refer to Section 3.10 of this Appendix.	An exemption has been granted that approves the tank capacity as described. Refer to Section 4.0 of this Appendix, Fire Hazard Analyses, for details.

Appendix R Requirements	Plant Conformance	Alternatives	Remarks
Leakage points to be protected shall include lift pump and piping, overflow lines, lube oil cooler, oil fill and drain lines and plugs, flanged connections on oil lines and lube oil reservoirs where such features exist on the reactor coolant pumps.	The system collects oil from the lift pump and piping, lube oil cooler, flanged connections on oil lines and the lube oil reservoirs. The upper bearing assembly overflow/vent path is protected because oil would first leak through a shaft seal located below the overflow/vent connection. This oil would then be collected in the lower bearing oil reservoir collection assembly. The fill lines are protected by being above normal operating levels and by being sealed with screw caps. The drain lines are protected by having valves and by being plugged with threaded caps to ensure leak-tight integrity.		
The drain line shall be large enough to accommodate the largest potential oil leak.	The 1-1/2 inch drain lines can accommodate a gravity induced flowrate in excess of 14 gpm. This flowrate exceeds the maximum expected leakage of 10 gallons per year and also exceeds the 10 gpm flowrate from an RCP lube oil lift pump discharge line break.		

3.0 FIRE PROTECTION FEATURES

3.1 FIRE WATER SUPPLIES

3.1.1 INTRODUCTION

The Fire Water Supply System provides a reliable source of water to the automatic and manually actuated water suppression systems, hose stations and hydrants. The fire water supply consists of water storage tanks, fire pumps, yard main distribution system and associated piping and valves, as described below.

3.1.2 DESIGN BASES

a) Two fire water supply pumps shall be provided such that either can supply 100% of the system's required capacity. One pump shall be electric driven with a rated capacity of 2000 gpm at 140 psi; the other shall be diesel driven with a rated capacity of 2500 gpm at 140 psi and 1700-2100 rpm. Their discharge shall be aligned to the water supply header, and sectionalizing valves should be provided between connections. The water supplies shall be interconnected such that either pump can take suction from either or both supplies. Each pump shall have its own driver with independent power supplies and controls. Installation of the fire pumps should conform to guidance provided in NFPA 20, "Standard for the Installation of Fire Pumps."

b) Two separate reliable water supplies shall be provided. Each shall be capable of supplying 100% of the required capacity. The supply capacity shall be calculated on the basis of the largest expected demand for a period of two hours, but not less than 300,000 gallons.

c) A flow path shall be provided capable of taking suction from Raw Water Tank I and Raw Water Tank II and transferring the water through distribution piping with sectionalizing control or isolation valves to the yard hydrants, the last valve ahead of the water flow alarm device on each sprinkler or hose standpipe and the deluge valve on each required deluge or spray system. This flow path shall include an underground yard loop, and the fire main piping system shall be able to be isolated from service or sanitary water piping. Control valves shall be visually indicating and capable of isolating portions of the main for maintenance or repair without shutting off the entire system. Modifications and new installations shall be in accordance with NFPA 24, "Private Fire Service Mains and their Appurtenances."

3.1.3 DESCRIPTION

Two separate tanks are provided as fire water sources. One is a 500,000 gallon Raw Water Tank (RWT I), and the other is a 750,000 gallon Raw Water Tank (RWT II). Water to these tanks is supplied from a 12 inch city water main. Each tank has 300,000 gallons of water dedicated to the fire water system, and the additional water storage volume is available to the plant service water system. The service water outlet nozzle from each tank is high on the tank wall in a manner equivalent to standpipes to prevent service water drawdown from the dedicated inventory of fire suppression water. Water levels above the service water outlet nozzle are maintained automatically.

Additional control of the water level in the RWTs is provided by isolation of non-firewater services (which draw from the standpipes as described above). There are high and low level alarms and continuous recording of service water levels. Additionally, the level in each raw water tank is checked on a daily basis as required by plant procedures.

Outlets for the fire suppression water are located near the bottom of each tank. The outlet from RWT I is aligned to an electrically driven fire pump and the outlet from RWT II is aligned to a diesel driven fire pump. A crossover line between outlets of the two tanks contains two normally closed valves. The crossover line makes the RWTs redundant to supply either fire pump. One of two jockey pumps is continuously running to maintain the downstream system headers, sections and regions water solid and maintained at pressure to prevent water hammer.

The electrically driven fire pump is rated at 2000 gpm at 140 psi, and the diesel driven pump is rated at 2500 gpm at 140 psi. The electrically driven pump is connected to a vital power source which can be manually loaded onto the diesel generator system provided an SIS signal is not present on either unit. The electrically driven pump is started at a pressure of 79 psi, the diesel driven at 70 psi. Activation of either pump is annunciated in the Control Room. A 500 gallon capacity diesel fuel oil tank is available to supply fuel to the diesel driven pump. Based on NFPA 20 criteria, 375 gallons (lower limit) has been established for this tank which will provide fuel to run this pump for at least 8 hours. The pumps start automatically through fire pump controllers with indication and alarm (manual starting capability is also provided) upon a low pressure condition in the fire water pump discharge header. A loss of power to the controllers will be alarmed in the Control Room.

The fire water pumps discharge into a 10 inch cast iron underground fire main that is provided on three sides of Units 3 and 4. This 10 inch line is connected to the 6 inch underground fire main loop that encircles Units 1 and 2. The arrangement of the fire water pumps and associated piping is shown diagrammatically on Figures 9.6A-1, 9.6A-2 and 9.6A-5.

The loop around Units 3 and 4 is capable of being isolated from the fossil portion of the system. This isolation can be achieved by closing valves PIV 12, PIV 4 and OSY 30 to the north and valve PIV 33 to the south.

Sectionalizing valves of the post-indicator type are provided to isolate various sections of the loop for maintenance and repairs. All post-indicator valves are administratively controlled by the use of locks and periodic inspections to verify that the valves are in the proper position. Additional isolation is provided in the fire main between post-indicator valves (PIV) 24 and 54 (Turbine Building and Auxiliary Building) in the event of a line break anywhere between these two PIVs. The fire main piping is separate from service and sanitary water system piping.

3.2 STANDPIPES, HOSE STATIONS AN HYDRANTS

3.2.1 INTRODUCTION

The standpipe and hose station system is an arrangement of piping, valves, hose outlets and associated equipment for the protection of buildings and structures which provides a reasonable degree of protection from fire.

3.2.2 DESIGN BASES

a) The guidelines of NFPA 14 shall be used in the design and installation of standpipe and hose stations. (Note that two hose stations, HS-RW-01 and HS-RW-02, are connected to the service water system and painted blue.)

b) The fire hose stations shown in Table 9.6A-5 ensure adequate protection of fire areas. This Table shall identify the minimum hose stations required.

c) Standpipe and hose stations are provided to ensure that all locations can be reached by at least one hose stream. Hose stations are not generally located in areas of radiological concern or the control complex. Thus, additional hose lengths may be required for remote areas.

d) The guidelines of NFPA 24 shall be used in the design and installation of the yard hydrant system to ensure the proper protection of fire areas.

3.2.3 DESCRIPTION

Standpipes and Hose Stations

Standpipe hose stations are provided in the plant (See Figures 9.6A-13 through 9.6A-15) so that any area containing essential equipment or components can be reached with an effective stream of water. These hose stations are equipped with a minimum of 75 feet and up to 100 feet of 1-1/2 inch (minimum) fire hose. Most areas are within 30 feet of a fog nozzle when attached to not more than a 100 foot length of hose. The RAB radioactive pipeway, the Containments, the Control Building, and the Diesel Generator Building may be reached with additional hose lengths. All nozzles are 1.5 inch (minimum), electrically safe fog nozzles. Threads on connections are those used by local fire departments.

Yard Hydrants

Yard hydrants are supplied by the fire mains located throughout the plant. Sectionalizing valves of the post-indicator type are provided to isolate the hydrant from the loop for repair or maintenance. (See Figures 9.6A-1 & 9.6A-2) Yard hydrants have connections which are compatible with local fire departments.

The hydrant spacing on the yard loop is a maximum of 250 feet, so that an effective fire stream can be applied to any plant location. The location of hydrants is indicated on Table 9.6A-6.

3.3 AUTOMATIC FIRE SUPPRESSIONS SYSTEMS

3.3.1 INTRODUCTION

The automatic fire suppression systems are designed to extinguish or minimize the effects of a fire.

The automatic fire suppression systems consist of water and Halon fire suppression systems. In addition, manually actuated fixed water suppression systems are addressed in this section.

3.3.2 DESIGN BASES

a) Automatic sprinkler systems shall be installed in the following fire zones using the guidelines of NFPA 13:

Fire Zones 47 and 54 - Component Cooling Water Areas
Fire Zones 45 and 55 - Charging Pump Rooms
Fire Zone 79A - North-South Breezeway
Fire Zones 72, 73, 74 and 75 - 3A and 3B Emergency Diesel Generator and Day Tank Rooms
Fire Zones 133, 136, 138 and 141 - 4A and 4B Emergency Diesel Generator and Diesel Oil Transfer Pump Rooms

b) Halon 1301 fire suppression systems shall be installed in the following fire zones using the guidelines of NFPA 12A, and the UL and FM Standards as appropriate:

Fire Zones 98 and 132 - Cable Spreading Room and Cable Chase
Fire Zones 108A and 108B - Inverter Rooms

c) The fire detection systems required to actuate these systems shall be designed using the guidelines of NFPA 72D and 72E.

d) Additional wet pipe and fixed water spray systems were installed in the following zones in accordance with standard industry practices at the time of installation:

Fire Zones 66 and 69 - Steam Generator Feed Pump Rooms
Fire Zones 72 and 73 - Emergency Diesel Generator Rooms (Air Intake Water Curtain)
Fire Zone 76 - Unit 4 Turbine Lube Oil Reservoir
Fire Zone 78 and 83 - Instrument Air Compressor Areas
Fire Zone 79 - Control Point Guardhouse
Fire Zones 80 and 85 - Main Condensor Areas
Fire Zones 81 and 86 - Main Transformer Zones
Fire Zones 82 and 87 - Auxiliary Transformer Zones
Fire Zone 88 - Ground Floor Vestibule
Fire Zone 105 - Turbine Building Mezzanine Deck

3.3.3 DESCRIPTION

Six types of fire suppression systems are installed which provide full or partial coverage Turkey Point Units 3 and 4:

a) Automatic preaction sprinkler systems are provided for:
- o 3A and 3B Emergency Diesel Generator Building (Fire Zones 72, 73, 74 and 75);
- o Charging Pump rooms (Fire Zones 45 and 55).
- o 4A and 4B Emergency Diesel Generator Rooms (Fire Zones 133 and 138).

b) Automatic deluge sprinkler systems are provided for:
- o Component Cooling Pump areas (Fire Zones 47 and 54).
- o North-South Breezeway (Fire Zone 79A)

c) Fixed water spray systems are provided to protect specific hazards in the following Fire Zones:
- o Instrument Air Compressor Areas (Fire Zones 78 and 83);

- o Main, Startup and Auxiliary Transformer Areas (Fire Zones 81, 82, 86 and 87);
- o Turbine Lube Oil Reservoir (Fire Zone 76).

d) A manually operated fixed water spray system provides a water curtain for:
- o 3A and 3B Diesel Generator Intake Louvers.

e) Wet Pipe Sprinkler Systems are provided in:
- o Instrument Air Compressor Areas (Fire Zones 78 and 83);
- o Main Condenser Areas (Fire Zones 80 and 85);
- o Control Point Guard House and area above Computer Maintenance Building (Fire Zone 79);
- o Unit 3 Steam Generator Feed Pump Area (Fire Zone 69)
- o Unit 4 Steam Generator Feed Pump Area (Fire Zone 66)
- o Auxiliary Transformer Area (Fire Zones 82 and 87);
- o Ground Floor Vestibule (Fire Zone 88);
- o Turbine Building Mezzanine Deck (Fire Zone 105)
- o 4A and 4B Emergency Diesel Generator Diesel Oil Transfer Pump Rooms (Fire Zones 136 and 141).

f) Halon Fire Suppression Systems are provided in:
- o Cable Spreading Room/Cable Chase (Fire Zones 98 and 132);
- o Inverter Room (Fire Zones 108A and B).

A review of plant configurations relative to information contained in NRC Information Notice 88-60 has indicated that actuation of, or leakage from, water-type automatic fire suppression systems does not affect any redundant train components in locations directly below the plant areas protected by the suppression systems due to water seepage through fire barrier penetration seals installed in the floor.

Refer to Figures 9.6A-3 and 9.6A-4 for schematic representations of the automatic fire suppression system components. The location of fire suppression systems which are shown on Figures 9.6A-13 through 9.6A-15.

a) <u>Preaction Sprinkler Systems</u>

The preaction systems consist of an isolation valve at the fire main, preaction deluge valve, distribution piping, closed sprinkler heads, thermal rate-compensated detectors and a local control panel. Discharge of the system activates an alarm in the Control Room and a local alarm. The sprinkler control panels for the 3A and 3B Emergency Diesel Generator Building are located outside the north wall of the building, and the sprinkler control panels for the 4A and 4B Emergency Diesel Generator Room sprinkler systems are located outside the north wall of that building. The sprinkler control panels for the Charging Pump Rooms are located in the Auxiliary Building north-south corridor on the stairwell enclosure wall outside each of the Charging Pump Rooms.

Automatic preaction sprinkler systems are provided in spaces where it is important to prevent accidental discharge of water into an area. The piping network, which is similar to that used for the wet-pipe system, is maintained dry until water is needed for fire suppression. A deluge valve (referred to as a preaction valve when used in a preaction system) is used to prevent water from entering the piping network.

Operation of the preaction system is initiated by a signal from a detection device in the protected space. This signal causes the deluge valve to open and subsequently fill the piping network. Actuation can also occur manually either by mechanical operation at the deluge valve or by an electric signal sent from an associated panel.

Water flow from the piping network onto the fire subsequently occurs when the heat in the protected space melts a fusible element. Water flow is stopped by manually closing the associated isolation valve.

The sprinkler control panels are solid state designed to operate on a 120V AC, 60 Hz, single phase power supply and are powered from an uninterruptible power supply, with battery backup provided in each control panel to allow operation on loss of station power. The internal panel detection and suppression system actuation circuitry is 24V DC. The panels are electrically supervised for open circuits and ground faults, battery circuit fuse, battery interconnecting wires, loss of AC power supply, and low standby battery voltage. The preaction system piping is normally pressurized with instrument air for supervisory purposes.

Low air pressure indicates a significant breach of system pressure boundary, such as opening of a sprinkler head, and is annunciated at the Fire Protection Panel via a trouble alarm. Air flow capacity is restricted so as not to interfere with water flow and spray pattern distribution. Graphic display of the protected area showing physical locations of the detectors is provided at the local control panel. The local control panel also provides for supervision of the preaction and deluge valve release circuit, system water control gate valve, and initiates audible and visual trouble alarms for abnormal conditions.

b) Deluge Sprinkler Systems

Deluge sprinkler systems are used to provide fire protection for areas where it is necessary to apply water quickly and with wider distribution than is provided by systems whose operation depends on opening of individual sprinkler heads.

Automatic deluge systems use a deluge valve, system isolation valve, associated piping and open head sprinklers. The system is actuated by detectors and can also be actuated manually.

The piping network for the deluge system consists of a pipe arrangement similar to the other systems previously described, except that the piping has open head sprinkler nozzles. Upon actuation, the entire area being protected is sprayed.

The control panels for these systems are similar to those described for the preaction systems.

c) Fixed Water Spray Systems

Fixed water spray systems are used to protect specific equipment that constitute a significant fire hazard. Fixed water spray systems are divided into two categories, automatically actuated and manually actuated.

circuitry is 24V DC. The circuits are electronically supervised for open circuits, ground faults, loss of AC power supply and low standby battery voltage. Independent manual actuation is provided by remotely located control panels (C286A, C288A, and C288B) for both the main and reserve banks. The main control panels are provided with a keyed-type manual dead man abort switch which overrides the discharge delay and alarm, if activated. On release of the abort switch the time delay is automatically reset. However, the associated isolation dampers will remain closed. The main control panel for the Cable Spreading Room including the Cable Chase (C286), and a graphic display panel identifying detector locations as well as a trouble horn and alarm bell are located outside the West door of the Cable Spreading Room at Elevation 30.00'. The single control panel for the Inverter Rooms (C288) is located on the South wall of the Control Room at Elevation 42.00'. Since the main fire detection panel (C39A) is also located in the Control Room with audible alarm, the panel for the Inverter rooms is not provided with audible alarms. A pressure switch is located in the system piping which provides indication at the main control panels that the system has discharged. The switch contact closes on high pressure.

The actual Halon discharge is initiated by an electrical signal to a control head on a nitrogen pilot cylinder which will cause the nitrogen to be released from this cylinder, which in turn, opens a control valve(s) on top of a Halon cylinder(s). The Halon is subsequently discharged to the header and associated piping system.

A low pressure switch for each of the eight nitrogen pilot cylinders is provided to actuate a trouble alarm on the main control panel in the event the nitrogen pressure falls below a preset value as established by the suppression system vendor. Liquid level indicators are provided on all Halon cylinders to provide physical measurement of Halon within the cylinder via a conversion chart.

Halon system operation is terminated by resetting the system controls, clearing any detection or manual actuation signals and switching the Halon bank selection switch from main to reserve. System operation of the reserve bank configuration is identical to that for normal main bank operation.

Cable Spreading Room/Cable Chase (Fire Zones 98 and 132)

The Halon fire suppression system which is provided for the Cable Spreading Room including the Cable Chase is supplied by two main Halon cylinders and two reserve cylinders which are connected to a common discharge header. The Halon is discharged through a network of distribution piping to blanket the entire room.

The actuation system for Halon consists of 15 ionization smoke detectors which are wired to the main control panel (C286) located outside the westdoor to the Cable Spreading Room at elevation 30'. Actuation of the Halon systems is initiated by two alarm zones. A local graphic annunciator panel (C287) provides indication for ionization detectors in alarm in the fire zone. The existing Cable Spreading Room exit doors are designed to ensure ease of personnel exit when the alarm bell in the zone signals system actuation and imminent Halon discharge.

Inverter Rooms (Fire Zones 108A and B)

The Halon fire suppression system for Fire Zone 108A is supplied by one main and one reserve cylinder which are connected to a common discharge header. The Halon is discharged throughout a network of distribution piping to blanket the entire room. The Halon system for Fire Zone 108B has a similar design.

The actuation system for each inverter room consists of four (4) ionization smoke detectors which are wired to the single control panel located in the Control Room. Actuation of the Halon systems are independent of one another and are initiated by two alarm zones. Actuation of the Halon Suppression System in either Fire Zone 108A or 108B initiates closure of isolation/fire dampers listed below for the HVAC ductwork to and from these zones, and initiates an alarm in the Control Room. The Inverter Rooms have access to an unlocked exit door to the Auxiliary Building roof for ease of personnel exit when the audible alarm in the zones provides warning of imminent Halon discharge.

The split-type HVAC unit provides supply and return ventilation for elevations 30' and 42' of the Control Building. The fire dampers (FD-66A, FD-67A, FD-74A, FD-76A, FD-79A) which are associated with supply and return ductwork for this HVAC unit are provided with electro-thermal links which release the fire dampers for closure upon an actuation signal for Halon suppression from either Fire Zone 108A or 108B. The isolation dampers (ID-2A, ID-3A, ID-5A, and ID-6A) which are installed in supply and return ductwork associated with two (2) roof-mounted A/C units are also provided with electro-thermal links which release these isolation dampers for closure in conjunction with the fire dampers above. The two roof-mounted A/C units and the split-type HVAC unit continue to operate upon Halon system actuation to provide ventilation and cooling to the RPI Inverter and MG Set Rooms below at elevation 30' (Fire Zones 101 and 104). The closure of the isolation/fire dampers upon Halon system actuation ensures that the integrity of the Halon system discharge boundary is maintained, thereby preventing Halon dispersion to unaffected fire zones. Due to continued operation of the HVAC units associated with the inverter rooms, the Halon concentration following Halon system actuation is diluted below the design requirements of 6.0 to 6.5 percent concentration maintained for a period of 30 minutes. The HVAC units continue to operate upon Halon system actuation to provide ventilation and cooling to the RPI inverter and MG set rooms (Fire Zones 101 and 104). However, the Halon concentration within the inverter rooms remains above a 5 percent concentration for 10 minutes assuming leakage past the closed fire dampers caused by the continued HVAC system operation. NFPA-12A, Section 2-4.2, states that soak time of 10 minutes with a 5 percent Halon concentration is adequate to extinquish solid surface fires (i.e., material prone to surface combustion).

Refer to Figure 9.6A-4 for a schematic representation of the Halon fire Suppression Systems components.

d) Thermal Detectors

The thermal detectors installed at Turkey Point Units 3 and 4 are spot type detectors. These detectors fall into three categories as described below:

1) Combination Fixed Temperature Rate-of-Rise Thermal Detectors

The combination detectors consist of two independently operated thermal elements. The rate-of-rise element is self-restoring, although the fixed temperature element is non-restorable. The fixed temperature elements are discussed below. The rate-of-rise element consists of an air chamber, a flexible metal diaphragm and a moisture-proof calibrated vent. The expansion and contraction of air in the chamber due to normal fluctuations in temperature is compensated for by the breathing action of the vent. When a fire occurs, the air temperature rises very rapidly and the air in the chamber expands faster than it can be vented. This expansion creates a pressure which distends the diaphragm and closes the electrical contacts. The rate-of-rise element does not respond at any fixed temperature level, and thus is not activated by a slow build-up of temperature due to environmental conditions. The detector is designed to respond when the rate of rise exceeds 15°F per minute.

2) Fixed Temperature Thermal Detectors

The fixed temperature detectors use a fusible alloy element. When the air temperature exceeds the detector's fixed design temperature (135°F or 200°F depending on the particular model) the fusible alloy element melts, causing an alarm. In addition, the external heat collector drops away to provide a quick visual indication that the detector has operated. These detectors are non-restorable.

3) Rate Compensation/Fixed Temperature Detectors

The rate compensation/fixed temperature detectors consist of an aluminum tubular shell containing two curved expansion struts under compression fitted with a pair of normally open, opposed contact points which are insulated from the shell. The tubular shell and the struts have different coefficients of expansion. When subjected to a rapid heat rise the tubular shell expands and lenghtens slightly. At the same time the interior struts lenghten but at a slower rate than the shell. The rapid lengthening of the shell allows the struts to come together, thereby closing the contact points and initiating the alarm.

When subjected to a very slow heat rise, the tubular shell and the interior struts lengthen at approximately the same rate. At the the detector's set temperature point, the interior struts are fully extended, thereby closing the contact points and initiating the alarm.

These detectors are self restoring.

4) Heat Actuated Devices

Heat Actuated Devices (HAD) are a type of rate-of-rise detectors which actuates pneumatically operated deluge valves.

Heat from a fire causes the air in the HAD to increase in pressure. An increased pressure impulse is transmitted via a copper air tube to the deluge valve causing it to trip. The detector itself does not produce an alarm.

e) Flame Detectors

The flame detectors installed at Turkey Point Units 3 and 4 fall into two categories: infrared and ultraviolet flame detectors. These detectors are spot-type detectors which operate in a restorable mode. These detectors are installed where smoke and thermal detectors may not be dependable due to environmental conditions.

The infrared flame detectors respond directly to infrared radiation emanating from flames. The detectors utilize a photoelectric cell located behind an infrared filter, and integrated circuitry to produce an output voltage used to lock in the alarm. The flames must be modulated (flickering) and must be sustained for a time greater than the preselected delay setting (typically 5 or 20 seconds) in order to produce an output voltage; therefore, the detectors are not responsive to constant radiation such as sunlight.

The ultraviolet detectors operate in a manner analogous to the infrared detectors.

f) Power Supply

The ionization and thermal detectors and the fire detection panel C39A are powered from a vital 120V AC power supply fed from Distribution Panel DP312A, which is normally powered from the vital section of MCC D through Distribution Panel DP412. In the event of a power loss to Distribution Panel DP312A, an alternate power source is made available by an automatic transfer device in Distribution Panel DP312A. The alternate source of power is from a vital section of MCC-3A through Distribution Panel DP312. In the event that all AC power is lost, battery packs in the Fire Detection Panel supply the vital alarming circuits in the fire detection system for a period of up to 24 hours. The flame detectors, located in outdoor areas at the Intake Structure, Component Cooling Water Equipment Area and on the Auxiliary Feedwater Platforms, are powered from uninterruptible non-vital Panel Boards 3P31 and 4P31 which are fed through Inverters 3Y111 and 4Y111, and are provided with battery backup.

g) Annunciation

Annunciation for the fire detection system is provided by the fire detection panel (C39A) in the Control Room and local graphic panels for selected areas. The local graphic panels have been provided for the piping and valve room and the RHR rooms on each unit. The Control Room panel has space available for 46 alarm points, each equipped with a trouble light to identify problems in a detection string and an alarm

3.10 REACTOR COOLANT PUMP OIL COLLECTION SYSTEM

3.10.1 INTRODUCTION

The RCP Oil Collection System collects and thereby prevents the spread of any lubricating oil leaking from the Reactor Coolant Pump motor housing. The RCP Oil Collection System decreases the fire hazard potential by collecting leaking oil and transferring it to a receptacle situated in a less hazardous area.

3.10.2 DESIGN BASES

The design bases of the RCP Oil Collection System are derived from the requirements of 10 CFR Part 50, Appendix R, Section III.0 and correspondence between FPL and the NRC. The design bases are listed below:

a) The system shall collect lubricating oil from all potential pressurized and unpressurized leakage sites of the reactor coolant pump motor lube oil system.

b) The system shall be designed to stay in place following a safe shutdown earthquake in accordance with Regulatory Guide 1.29 paragraph C.2.

c) The system shall be capable of collecting and containing the entire inventory of one Reactor Coolant Pump Motor Lube Oil system and normal leakage from the three Reactor Coolant Pump motors during one fuel cycle.

3.10.3 DESCRIPTION

The RCP Oil Collection System for each unit consists of a set of oil collection assemblies attached to each of the RCP's, connected drain piping and collection tank. The piping system is supported by seismic pipe supports to preclude interaction with safety related systems in a seismic event.

Oil collection assemblies are provided for the oil lift pump system, lower bearing oil reservoir and the bearing oil cooler. The bearing oil cooler collection assembly collects oil from the bearing oil cooler upper pipe flange, lower pipe flange, upper end flange and lower end flange.

The oil collection assemblies are connected by and drain into a 1-1/2 inch pipe. The same arrangement is provided on each Reactor Coolant Pump (RCP). These 1-1/2 inch drain lines from each RCP motor then converge to a common 1-1/2 inch line that drains to a 319 gallon collection tank for Unit 3, and a 254 gallon tank for Unit 4, both located outside the biological shield wall in their respective containment buildings.

The RCP oil collection tank is located away from high temperature piping. Piping in areas with service temperatures greater than 150°F is insulated. No flame arrestors are needed on the RCP oil collection tank vent because the tank is located away from the heat source of the Reactor Coolant System and because the flash point of the oil is over 450°F, while the maximum normal operating temperature of the oil is 200°F. Containment operating temperature is normally below 120°F, which is well below the flash point of the oil. The tank capacity is based on the total inventory of one RCP pump motor (275 gallons - Unit 3, and 200 gallons - Unit 4) plus the normal expected leakage, based on operating experience, from the other two RCP motors (30 gallons) based on eighteen month refueling cycle. The tank capacity was set at 319 gallons for Unit 3 and 254 gallons for Unit 4 to allow for an increase in leakage rates and extended refueling cycle durations (18 months), while still maintaining a 14 gallon reserve for Unit 3, and a 24 gallon reserve for Unit 4.

The 1-1/2 inch drain lines can accommodate a gravity induced flow rate in excess of 14 gpm. This flow rate exceeds the maximum expected leakage rate of 10 gallons per year for each pump and exceeds the 10 gpm flow rate expected from an RCP lube oil lift pump discharge line break.

An exemption was granted from that portion of 10 CFR 50, Appendix R Section III.O, which requires an oil collection tank to be capable of containing the lube oil inventory of all three reactor coolant pump motors. (Refer to Section 4.0 of this Appendix.)

3.11 FIRE RATED ASSEMBLIES - BARRIERS

3.11.1 INTRODUCTION

Fire barriers at Turkey Point Units 3 and 4 are provided as part of the protection to ensure that the function of one set of redundant safety-related equipment necessary to achieve and maintain hot standby conditions remains free of fire damage. Fire barriers provide a means of limiting fire travel by compartmentalization and containment. In some cases written calculations approved by a Fire Protection Engineer may be kept on file to demonstrate acceptability of a fire rated assembly or barrier. (Reference NRC Generic Letter 86-10 paragraph C.)

3.11.2 WALLS, FLOORS AND CEILINGS

3.11.2.1 Design Bases

a) Pursuant to Appendix R Section III.G.2(a), walls, floors and ceilings separating Fire Areas shall be fire barriers with a minimum rating of three hours as defined by ASTM E-119 (e.g. six inch solid concrete or greater, 8 inch concrete filled concrete block or greater; one inch thermolag or greater).

b) Walls, floors and ceilings installed as fire barriers shall be designed to maintain the class of the structure (refer to FSAR Appendix 5A) and to preclude damage to nearby safety related equipment.

3.11.2.2 Description

The plant is divided into fire zones, which are grouped into Appendix R Fire Areas. Fire Areas are separated from each other by rated fire barriers. These barriers are shown on Figures 9.6A-8 through 9.6A-11. The composition of these barriers is described for each fire zone in Section 4.0 of this Appendix.

Floor slabs which rest on soil foundations and earthbound walls may be designated as fire barriers but due to their underground nature will not be required to have a specific fire rating.

The Unit 3 or Unit 4 Containment Wall forms a portion of the fire barrier for several fire areas. Although the containment wall is not a tested configuration for fire barriers, its construction is of such substantial integrity as to justify its use as a three hour rated fire barrier.

Each Containment Building wall consists of a post-tensioned reinforced concrete cylinder (3 feet thick), connected to and supported by a massive reinforced concrete foundation slab. The inside surface is lined with a 1/4-inch thick welded steel plate to ensure a high degree of leak tightness. Numerous mechanical and electrical systems penetrate the containment through welded steel penetrations. although the penetration seals as well as the equipment hatch and personal air lock are not qualified fire rated commodities, they are of such substantial integrity that they are considered equivalent to fire rated barriers.

3.11.3 RACEWAY PROTECTION

3.11.3.1 Design Basis

a) The overall construction of raceway protection shall have a three or one hour fire rating as defined by ASTM E-119 fire exposure and ANI/MAERP Bulletin No. 5 (1979) where required.

b) Raceway fire protection shall be seismically designed to preclude damage to nearby safety-related equipment.

c) Protected raceways shall be wrapped the entire length within an indoor fire area that contains redundant equipment, as determined by the Safe Shutdown Analysis.

3.11.3.2 Description

The material used for raceway fire protection is Thermo-Lag fireproofing. This material is thermally activated when exposed to high temperatures and will abate and block heat to protect the coated raceways.

To provide 1-hour rated protection, a 1/2 inch layer is applied and for 3-hour rated protection a 1-inch layer is required.

The raceway fire resistive material is installed in a manner that allows the removal of covers from wireways, allows the removal of the cover plate off junction boxes and terminal boxes, and allows access to control station with a minimum of damage to the remaining fire barrier assembly.

3.11.4 STRUCTURAL STEEL FIREPROOFING

3.11.4.1 Design Bases

Structural steel supporting or forming part of a fire barrier shall be fire proofed as required by a heat loading analysis.

3.11.4.2 Description

Structural steel fireproofing is provided for steel supporting or forming a part of a fire barrier in order to maintain its integrity. A zone-by-zone heat loading analysis has been performed to determine the need for such protection.

Heat loading was based on compartment gas temperature established by time-temperature curves which, in turn, were based on the actual or conservatively assumed nature of the combustible material.

Based on industry standards and NRC Generic Letter 83-33, the average structural steel temperature should not exceed 1100°F. In order to meet this objective, all structural steel supporting or forming a part of an identified fire barrier, is provided with three-hour rated fireproofing if the postulated structural steel temperature in the applicable fire zone or area could exceed 1100°F and where no credit was taken for other fire protection measures, such as water suppression systems or fire brigade actions, which would serve to mitigate the effects on structural steel temperatures.

The structural steel fireproofing designs utilized at Turkey Point comply with standard details and designs tested by UL for a three-hour fire rating. The type of fireproofing material and minimum required thickness also complies with designs tested by UL for a three-hour fire rating. The required fireproofing thickness for structural steel members smaller than those tested by UL is determined in accordance with instructions contained in the UL Fire Resistance Directory - 1984 Edition.

Refer to Figures 9.6A-13 and 9.6A-14 for the zones in which structural steel fireproofing is installed.

The fireproofing material used is a formulated, lightweight, aerated, magnesium oxychloride fireproofing system for structural steel. The fireproofing material used is durable and resistant to abrasion, vibration, mechanical abuse and is an approved Underwriters Laboratories, Inc. design for fire resistance of structural steel.

3.11.5 MANHOLE COVERS AND HATCHES

3.11.5.1 Design Bases

a) Hatch assemblies in fire rated floors and ceilings should be constructed of such substantial integrity to justify their use as part of a three hour fire boundary although they need not be specifically rated as fire barriers.

b) The covers of manholes containing redundant safe shutdown cables shall be sealed to prevent the spread of flammable or combustible liquids into the manholes. All sealant material shall be chemically resistant to combustible liquids and shall not burn readily.

3.11.5.2 Description

Equipment hatches in floor or ceiling fire barriers are precast concrete plugs which overlap mating surfaces for support. The hatch assemblies are designed to provide structural integrity commensurate with that of the associated floor or ceiling, and as such, are more substantial than that required for three hour rated barriers. See Reference 10 for details of fire barrier penetration seals.

The covers of manholes containing redundant safe shutdown cable have been sealed to prevent the introduction of flammable liquids due to spills above or in the vicinity of the manholes. Although the manhole covers provide some fire and heat shielding, they are considered non-rated fire barriers, since their principal function is control of combustibles.

3.11.6 RADIANT ENERGY SHIELDS

3.11.6.1 Design Bases

Radiant energy shields shall be provided inside containment in accordance with Appendix R Section III.G.2.f requirements.

3.11.6.2 Description

Radiant energy shields are provided inside both containments as one of the means of separation of redundant safety-related equipment in accordance with Appendix R Section III.G.2. These shields have a rating of at least 1/2 hour. All the cables in cable trays are either coated with a fire retardant coating, Flamastic 71A or 77, or are qualified to the requirements of IEEE 383-1974. The fire retardant coating, although not a rated fire barrier, acts as a radiant energy shield to provide a substantial level of protection against postulated exposure fires.

3.12 FIRE RATED ASSEMBLIES - FIRE DOORS

3.12.1 INTRODUCTION

Fire door assemblies prevent the spread of fire through passageways and fire barriers. Fire door assemblies protect openings in walls and partitions against the spread of fire. In some cases written calculations approved by a Fire Protection Engineer may be kept on file to demonstrate acceptability of a fire rated assembly or barrier. (Reference 18, paragraph C.)

3.12.2 DESIGN BASES

The installation of fire door assemblies is based on the guidance/requirements set forth in BTP APCSB 9.5-1, Appendix A and 10 CFR 50 Appendix R Section III.G. The following criteria are applicable to fire door assemblies:

a) Fire door assemblies (door, frame, lockset, etc.) shall be UL listed or FM approved or be tested by a nationally recognized testing laboratory, and shall be so labeled.

b) Fire door assemblies shall be installed in accordance with the manufacturer's installation instructions, and applicable requirements of NFPA 80.

c) The installation of fire door assemblies shall not degrade ventilation system performance.

d) Fire door assemblies shall not interfere with the performance of the security system.

e) Fire door assemblies shall be installed such that they do not degrade the structural integrity and fire rating of the walls.

f) Doors in exterior walls are not required to be fire doors if the walls do not separate redundant safe shutdown equipment and no major combustibles exist within 50 feet of the building.

3.12.3 DESCRIPTION

Refer to Figures 9.6A-8 through 9.6A-11 and Table 9.6A-7 for the location and rating of the fire door assemblies installed in the plant. The numbers consist of the fire zone and an sequential number for that zone; e.g. D125-4 would be door assembly number four in Fire Zone 125. For identification these numbers have been printed on the face of the doors in the plant.

a) Classification of Fire Door Assemblies

Fire door assemblies may be classified by the following designation systems:

1) Hourly rating designation, or
2) Alphabetical letter designation, or
3) A combination of both (a) and (b).

The fire door assemblies at Turkey Point Units 3 and 4 use a combination of both hourly rating and alphabetical letter designation. The classification markings are typically located on the edge of the fire door on a label attached by the manufacturer.

b) Hourly Designation

The hourly designation indicates the duration of the fire test exposure and is called the "fire protection rating." Fire protection ratings of fire door assemblies are determined by a testing agency such as Underwriters Laboratories, Inc. or Factory Mutual. The fire door assemblies at Turkey Point Units 3 and 4 have fire protection ratings of either 3 hours or 1-1/2 hours or have been evaluated to show equivalent protection. Any modification of a fire door, frame or appurtenance that has the potential to affect the fire rating of the fire door assembly is accompanied by qualification documentation in order to retain its UL rating. The effect of proposed modifications on the rating of fire door assemblies is evaluated by engineering.

c) Alphabetical Letter Designation

The alphabetical letter designation following the hourly rating indicates the application for which the assembly is designed. The letter designations agree with definitions provided in NFPA 80.

d) Fire Door Frames

The fire door frames used at Turkey Point Units 3 and 4 are standard fire door frames. These frames are of the single unit or two-section type and consist of steel head and jamb members, including hardware reinforcements, wall anchors, door stops and provisions for anchoring to the floor.

Fire door frames are provided with a label similar to those on the fire doors. These labels may or may not have a specific hourly rating. When the fire ratings of the fire door and its frame differ, the protection provided is the lesser rating.

Frames which have labels without a specific fire rating are qualified to the same rating as the wall or door with which the frame is used, whichever is less. Therefore, a frame with a label without a specified rating installed in a 3-hour wall is qualified for 3 hours provided a 3-hour rated door is installed. If a 1-1/2 hour door were installed, the same frame assumes a 1-1/2 hour rating.

e) Door Hardware, Locksets and Appurtenances

Fire door hardware consists of surface mounted hinges, latches, locksets and closing devices. Any special modifications to the doors or frames to accommodate installation of security system devices or other field installed mechanisms are installed in accordance with the manufacturer's instructions. Any modification that potentially affects the fire rating of the fire door assembly is accompanied by qualification documentation in order to maintain the UL rating. Proposed modifications are evaluated by engineering for their effect on the rating of the fire door assembly except when the modifications are in compliance with the guidelines of NFPA 80.

3.13 FIRE RATED ASSEMBLIES - FIRE DAMPERS

3.13.1 INTRODUCTION

Fire dampers are provided to prevent the spread of fire through HVAC penetrations to protect safe shutdown capability. Fire dampers are also used to isolate an area prior to Halon system actuation. In some cases written calculations approved by a Fire Protection Engineer may be kept on file to demonstrate acceptability of a fire rated assembly or barrier. (Reference NRC Generic Letter 86-10 paragraph C)

3.13.2 DESIGN BASES

The installation of fire dampers is based on the general guidance/requirements set forth in Appendix A to BTP APCSB 9.5-1. The following are specific design guidelines for dampers installed in fire barriers:

a) Fire dampers shall be automatically closing, 3- or 1 1/2-hour rated fire dampers and shall be listed by Underwriters Laboratories, Inc. and/or approved by Factory Mutual or another nationally recognized testing laboratory.

b) Fire dampers shall be seismically analyzed to remain in place and not detach from their mountings as a result of a seismic event.

c) Fire dampers shall be qualified for a service life of 35 years.

d) The fire dampers shall comply with the applicable sections of the following codes:

Underwriters Laboratories, UL 555, "Standard for Fire Dampers and Ceiling Dampers."

National Fire Protection Association, NFPA No. 90A, "Air Conditioning and Ventilation Systems."

3.13.3 DESCRIPTION

Seismically qualified dampers are provided in the fire barrier penetrations of the Auxiliary Building ventilation system and the Control Building ventilation system or louvers. Refer to Table 9.6A-8 for a listing of fire dampers and to Figures 9.6A-9 through 9.6A-11 for the locations of fire dampers. These fire dampers are required to ensure the integrity of 1-1/2 or 3-hour rated fire barriers. Fire dampers are used in the Control Building ventilation system ductwork to isolate areas protected by Halon fire suppression systems.

Fire dampers are generally UL approved, 1-1/2 or 3-hour rated, curtain type dampers complete with sleeve and position switches. The fire dampers are provided with a fusible link rated at 165°F. The Halon fire suppression system isolation dampers are provided with an electro-thermal link rated at 165°F which can also be activated by a signal from the Halon fire suppression system upon Halon discharge.

The damper assemblies mounted in seismically analyzed walls, floor or ceiling are mounted with angles which are securely attached to the assemblies and to the walls, floor or ceiling. These attachments help to ensure the integrity of the dampers during a seismic event.

A local graphic indication panel displays position indication for the fire dampers in the Auxiliary Building ventilation system. The local graphic indication panel is located in the Auxiliary Building Corridor at Elevation 18.00'. Another local graphic indication panel displays position indiction for the fire dampers in the Control Building ventilation system. This panel is located in the Cable Spread Room at Elevation 30.00' on the East wall. In the event that a damper closes, a trouble alarm in the Control Room will be activated. The non-safety related position switches provided for identifying damper position are mounted in the fire damper sleeve between the fire dampers and either the access door or the removable duct section which is provided for access to the damper.

3.14 <u>FIRE RATED ASSEMBLIES - PENETRATION SEALS</u>

3.14.1 INTRODUCTION

Fire barrier penetration seals are provided to maintain the integrity of fire barriers at barrier penetrations. In some cases written calculations approved by a Fire Protection Engineer may be kept on file to demonstrate acceptability of a fire rated assembly or barrier. (Reference 18, paragraph C.)

3.14.2 DESIGN BASES

a) Penetration seals shall have a fire rating at least equal to the barrier in which they are installed unless previously approved under Appendix A to BTP APSCB 9.5-1.

b) Cable ampacity and derating factors should be considered for cable tray penetration seals.

c) Penetration seals should accommodate thermal movement.

.4d Smoke Venting:

Normal area ventilation is used for smoke removal (Exhaust Fan V-8A or V-8B). Should sufficient heat be generated by a fire to close automatic fire dampers, smoke removal capacity will be reduced. However, the exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

14.E.2 APPENDIX R EXEMPTIONS

No exemptions were requested for this fire area.

FIRE HAZARD ANALYSIS FOR FIRE AREA F

4.F DESCRIPTION OF FIRE AREA

Fire Area F is the common Units 3 and 4 Auxiliary Building Hallway and adjacent rooms, located on the 18.00′ elevation. The area is comprised of Fire Zones 31, 32, 33, 34, 35, 36, 37, 38, 39, 48, 49, 50, 51 and 58. Pertinent fire zone details are provided below.

Fire Area F and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.F.1 FIRE ZONE 31 - UNIT 4 CONTAINMENT SPRAY PUMP ROOM - EL. 18.00′

Fire Zone 31 is bounded on the floor as well as the West and South walls by 3-hour rated fire barriers; the North and East walls of this zone are of non-rated concrete construction. Major equipment in this zone includes the Safety Injection Piping, Containment Spray Pump, and associated instruments, piping and valves.

4.F.1.1 Essential Equipment Within Fire Zone 31

See Appendix R Essential Equipment List, Reference 15.

4.F.1.2 Fire Zone 31 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	538 lbs	6.99×10^6
.2b	Oils	10 gal	1.50×10^6
.2c	Others		
	Grease	5 gal	0.76×10^6
	Cured Paint	N/A	1.38×10^6
	Plastic	348 lbs	6.96×10^6
	Cloth	40 lbs	0.28×10^6
		TOTAL	17.87×10^6

Floor surface area (sq. ft.): 286
Heat load (BTU/sq. ft.): 6.25×10^4

4.F.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete Supported by Fireproofed Structural Steel

Floor: Reinforced Concrete

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There are two accessible fire extinguishers in adjacent Fire Zone 58, and another in Fire Zone 46. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in adjacent Fire Zone 58. (See Table 9.6A-5.)

.4d Smoke Venting:

Normal area ventilation is used for smoke removal (Exhaust Fan V-8A or V-8B). Should sufficient heat be generated by a fire to close automatic fire dampers, smoke removal capacity will be reduced. However, the exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.F.2 FIRE ZONE 32 - UNIT 4 SAMPLE ROOM - EL. 18.00'

Fire Zone 32 is bounded on the floor, ceiling and walls by a non-rated concrete barrier. Equipment in this zone includes sampling equipment and associated instruments.

4.F.2.1 Essential Equipment Within Fire Zone 32

See Appendix R Essential Equipment List, Reference 15.

2. Secondary

There are two available standpipe hose stations in adjacent Fire Zone 58. (See Table 9.6A-5.)

.4d Smoke Venting:

Normal area ventilation is used for smoke removal (Exhaust Fan V-8A or V-8B). The exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.F.14 FIRE ZONE 58 - UNITS 3 AND 4 AUXILIARY BUILDING HALLWAY - EL. 18.00'

Fire Zone 58 is bounded on the floor and Fire Area F walls by a 3-hour rated fire barrier with the exception of a ventilation penetration into Fire Zone 23. This ventilation penetration (023S-H001) does not contain a fire damper, but an evaluation detailed in Reference 21 determined that the present configuration of this penetration is acceptable. Equipment in this zone includes 480V MCCs, cable trays and various instruments.

4.F.14.1 Essential Equipment Within Fire Zone 58

See Appendix R Essential Equipment List, Reference 15.

4.F.14.2 Fire Zone 58 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	32,080 lbs	417.04×10^6
.2b	Oils	---	---
.2c	Others		
	Paper	800 lbs	6.24×10^6
	Cured Paint	N/A	16.65×10^6
	Plastic	73 lbs	1.46×10^6
	Wood	269 lbs	2.28×10^6
		TOTAL	443.67×10^6

Floor surface area (sq. ft.): 4112

Heat load (BTU/sq. ft.): 10.79×10^4

4.F.14.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
East: Reinforced Concrete
South: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Fireproofed Structural Steel.

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 58 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are five accessible fire extinguishers in Fire Zone 58, and one additional fire extinguisher in each of Fire Zones 21, 22, 46 and 79A. (See Table 9.6A-4.)

2. Secondary

There are three standpipe hose stations in Fire Zone 58, and at least one of them is available at each extension of the zone. (See Table 9.6A-5.)

.4d Smoke Venting:

Normal area ventilation is used for smoke removal (Exhaust Fan V-8A or V-8B). Should sufficient heat be generated by a fire to close automatic fire dampers, smoke removal capacity will be reduced. However, the exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.F.15 APPENDIX R EXEMPTIONS

Exemption F.1

Pursuant to 10 CFR Part 50.12, FPL requested (References 11 and 12) and was granted (Reference 13) exemption from the provisions of Section III.G.2.a of Appendix R to 10 CFR Part 50 that requires separation of cables and equipment and associated non-safety circuits of redundant trains by a fire barrier having a 3-hour rating.

Specifically, exemption was requested from providing 3-hour rated penetration seals in the fire barrier separating the Purification and Radwaste Demineralizer Rooms (Fire Area F - Fire Zones 48, 49 and 50) from the Radioactive Pipeway (Fire Area A - Fire Zone 10).

Justification for Exemption

Fire Zones 48, 49 and 50, and Fire Zone 10 are located in the Auxiliary Building at elevations 18.00' and 10.00' respectively. The floor separating these zones is considered a fire barrier by definition, in that it serves to separate defined fire areas (Fire Areas A and F). To satisfy the specific requirements of Appendix R, Section III.G.2.a, access to these zones would be required for the installation of 3-hour rated penetration seals. However, because these Zones or portions thereof are classified as "Locked High Radiation Areas" with radiation levels on the order of 50 Rem/hour during various modes of plant operation, access to this zone for the installation of penetration seals is considered highly undesirable and inconsistent with regulatory requirements for maintaining radiation exposures As Low As Reasonably Achievable (ALARA) for the following reasons:

batteries. Accordingly, the cables associated with the spare battery system do not require separation or protection from redundant trains of cables or equipment.

4.G.1.1 Essential Equipment Within Fire Zone 25

See Appendix R Essential Equipment List, Reference 15.

4.G.1.2 Fire Zone 25 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	293 lbs	3.82×10^6
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	1.85×10^6
	Plastic	58 lbs	1.16×10^6
		TOTAL	6.83×10^6

Floor surface area (sq. ft.): 492
Heat load (BTU/sq. ft.): 1.39×10^4

4.G.1..3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete (Concrete Block encloses Zone 25A)
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Fireproofed Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 25 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one fire extinguisher located in this fire zone and two accessible fire extinguishers in Fire Zone 58. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 58. (See Table 9.6A-5.)

.4d Smoke Venting:

Normal area ventilation is used for smoke removal (Exhaust Fan V-8A or V-8B). Should sufficient heat be generated by a fire to close automatic fire dampers, smoke removal capacity will be reduced. However, the exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.G.2 FIRE ZONE 25A - UNITS 3 AND 4 SPARE BATTERY ROOM - EL. 18.00'

Fire Zone 25A is bounded on the east and south walls by 3-hour rated fire barriers; the North and West walls are non-rated concrete block construction and the ceiling is non-rated steel construction. Equipment in this zone includes the Spare Station Battery.

4.G.2.1 Essential Equipment Within Fire Zone 25A

See Appendix R Essential Equipment List, Reference 15.

4.G.2.2 Fire Zone 25A - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	---	---
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	0.54×10^6
	Insulation	25 lbs	0.50×10^6
		TOTAL	1.04×10^6

Floor surface area (sq. ft.): 175
Heat load (BTU/sq. ft.): 5.94×10^3

4.G.2.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Concrete Block (Grouted Cells)
South: Reinforced Concrete
East: Reinforced Concrete
West: Concrete Block (Grouted Cells)

Ceiling: Checker plate supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 25A is provided with thermal detectors which initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one accessible fire extinguisher located in Fire Zone 25 and two accessible fire extinguishers in Fire Zone 58. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 58. (See Table 9.6A-5.)

.4d Smoke Venting:

Normal area ventilation is used for smoke removal (Exhaust Fan V-8A or V-8B). Should sufficient heat be generated by a fire to close automatic fire dampers, smoke removal capacity will be reduced. However, the exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.G.3 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and dampers mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6).

FIRE HAZARD ANALYSIS FOR FIRE AREA H

4.H DESCRIPTION OF FIRE AREA

Fire Area H is the Unit 3 Control Building West Electrical Penetration Room, located on the 12.50' elevation. The area is a single zone area comprised of Fire Zone 19. Pertinent fire zone details are provided below.

Fire Area H and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.H.1 FIRE ZONE 19 - UNIT 3 WEST ELECTRICAL PENETRATION ROOM - EL. 12.50'

Fire Zone 19 is bounded on all walls by a 3-hour rated fire barrier. The east wall of this zone is formed by the Unit 3 Containment Building. Refer to Section 3.11 of this report for a discussion on the rating of the Containment Building walls and non-rated floors and ceilings. Door D019-1 is a 1-1/2 hour rated door installed in the South wall of the zone, and two 1-1/2 hour rated dampers are installed in the north wall of the zone. Equipment in this zone includes the electrical penetration assemblies.

4.H.1.1 Essential Equipment Within Fire Zone 19

See Appendix R Essential Equipment List, Reference 15.

4.H.1.2 Fire Zone 19 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	5538 lbs	71.99×10^6
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	0.67×10^6
		TOTAL	72.66×10^6

Floor surface area (sq. ft.): 93
Heat load (BTU/sq. ft.): 78.2×10^4

4.H.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North:	Reinforced Concrete
South:	Reinforced Concrete
East:	Reinforced Concrete
West:	Reinforced Concrete

Ceiling: Reinforced Concrete

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 19 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are four accessible fire extinguishers in adjacent Fire Zone 84. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 83. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this fire zone. Smoke venting may be accomplished through the personnel door with portable smoke ejectors available onsite for fire brigade use.

4.H.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and damper(s) mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6). In addition, Enclosure 2 of Reference 18 indicates that fire area boundaries previously accepted under Appendix A to BTP 9.5-1 need not be reevaluated for compliance with Appendix R Section III.G. Since Fire Door D019-1 and the fire dampers mounted in the exterior walls bounding Fire Area H/Zone 19 were reviewed and found acceptable under Appendix A (Reference 1), no further modifications were necessary for Appendix R.

FIRE HAZARD ANALYSIS FOR FIRE AREA I

4.I DESCRIPTION OF FIRE AREA

Fire Area I is the Unit 3 Auxiliary Building South Electrical Penetration Room, located on the 10.50' elevation. The area is a single zone area comprised of Fire Zone 20. Pertinent fire zone details are provided below.

Fire Area I and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.I.1 FIRE ZONE 20 - UNIT 3 SOUTH ELECTRICAL PENETRATION ROOM - EL. 10.50'

Fire Zone 20 is bounded on three walls by a 3-hour rated fire barrier. The North wall of this zone is formed by the Unit 3 Containment Building. Refer to Section 3.11 of this Appendix for a discussion on the rating of the Containment Building walls. Door D020-1 is a 1-1/2 hour rated door installed in the West wall of this zone, and a 1-1/2 hour rated damper is also installed in the West wall. Equipment in this zone includes the electrical penetration assemblies.

4.I.1.1 Essential Equipment Within Fire Zone 20

See Appendix R Essential Equipment List, Reference 15.

4.I.1.2 Fire Zone 20 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	3179 lbs	41.32×10^6
.2b	Oils	—	—
.2c	Others		
	Cured Paint	N/A	0.88×10^6
	Plastic	29 lbs	0.58×10^6
	Grease	0.5 gal	0.08×10^6
		TOTAL	42.86×10^6

Floor surface area (sq. ft.): 165
Heat load (BTU/sq. ft.): 26.0×10^4

4.I.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete Supported by Fireproofed Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 20 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are four accessible fire extinguishers in adjacent Fire Zone 84, and one additional fire extinguisher in Fire Zones 79A. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 83. (See Table 9.6A-5.)

.4d Smoke Venting:

Normal area ventilation is used for smoke removal (Exhaust Fan V-8A or V-8B). Should sufficient heat be generated by a fire to close automatic fire dampers, smoke removal capacity will be reduced. However, the exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.I.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and damper(s) mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redudant safe shutdown equipment (Reference 6). In addition, Enclosure 2 of Reference 18 indicates that fire area boundaries previously accepted under Appendix A to BTP 9.5-1 need not be reevaluated for compliance with Appendix R Section III.G. Since Fire Door D020-1 and the fire dampers mounted in the exterior walls bounding Fire Area I/Zone 20 were reviewed and found acceptable under Appendix A (Reference 1), no further modifications were necessary for Appendix R.

FIRE HAZARD ANALYSIS FOR FIRE AREA J

4.J DESCRIPTION OF FIRE AREA

Fire Area J is the Unit 4 Auxiliary Building North Electrical Penetration Room, located on the 12.50' elevation. The area is a single zone area comprised of Fire Zone 26. Pertinent fire zone details are provided below.

Fire Area J and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.J.1 FIRE ZONE 26 - UNIT 4 NORTH ELECTRICAL PENETRATION ROOM - EL. 12.50'

Fire Zone 26 is bounded on three walls by a 3-hour rated fire barrier. The South wall of this zone is formed by the Unit 4 Containment Building. Refer to Section 3.11 of this report for a discussion on the rating of Containment Building walls. Door D026-1 is a 1-1/2 hour rated door installed in the West wall of this zone, and a 1-1/2 hour rated damper is also installed in the West wall. Equipment in this zone includes the electrical penetration assemblies.

4.J.1.1 Essential Equipment Within Fire Zone 26

See Appendix R Essential Equipment List, Reference 15.

4.J.1.2 Fire Zone 26 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	3883 lbs	50.48×10^6
.2b	Oils	----	----
.2c	Others		
	Grease	0.1 gal	0.02×10^6
	Plastic	29 lbs	0.58×10^6
	Cured Paint	N/A	0.93×10^6
		TOTAL	52.01×10^6

Floor surface area (sq. ft.): 224
Heat load (BTU/sq. ft.): 23.2×10^4

4.J.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete Supported by Fireproofed Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 26 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

- There are four accessible fire extinguishers in adjacent Fire Zone 79, and another in Fire Zone 58. (See Table 9.6A-4.)

2. Secondary

There is one available Standpipe Hose Station in Fire Zone 58. (See Table 9.6A-5.)

.4d Smoke Venting:

Normal area ventilation is used for smoke removal (Exhaust Fan V-8A or V-8B). Should sufficient heat be generated by a fire to close automatic fire dampers, smoke removal capacity will be reduced. However, the exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.J.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and damper(s) mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6). In addition, Enclosure 2 of Reference 18 indicates that fire area boundaries previously accepted under Appendix A to BTP 9.5-1 need not be reevaluated for compliance with Appendix R Section III.G. Since Fire Door D026-1 and the fire dampers mounted in the exterior walls bounding Fire Area J/Zone 26 were reviewed and found acceptable under Appendix A (Reference 1), no further modifications were necessary for Appendix R.

FIRE HAZARD ANALYSIS FOR FIRE AREA K

4.K DESCRIPTION OF FIRE AREA

Fire Area K is the Unit 4 Auxiliary Building West Electrical Penetration Room, located on the 12.50' elevation. The area is a single zone area comprised of Fire Zone 27. Pertinent fire zone details are provided below.

Fire Area K and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.K.1 FIRE ZONE 27 - UNIT 4 WEST ELECTRICAL PENETRATION ROOM - EL. 12.50'

Fire Zone 27 is bounded on three walls by a 3-hour rated fire barrier. The East wall of this zone is formed by the Unit 4 Containment Building. Refer to Section 3.11 of this Appendix for a discussion on the rating of the Containment Building walls. Door D027-1 is a 1 1/2-hour rated door installed in the North wall of this zone. Two 1 1/2-hour rated dampers are installed in the North and West walls. Equipment located within this zone includes the electrical penetration assemblies.

4.K.1.1 Essential Equipment Within Fire Zone 27

See Appendix R Essential Equipment List, Reference 15.

4.K.1.2 Fire Zone 27 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	4599 lbs	59.79×10^6
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	0.67×10^6
	Plastic	72.5 lbs	1.45×10^6
		TOTAL	61.91×10^6

Floor surface area (sq. ft.): 93
Heat load (BTU/sq. ft.): 66.6×10^4

4.K.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 27 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are four accessible fire extinguishers in adjacent Fire Zone 79, and another in Fire Zone 78. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 78. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this fire zone. Smoke may be vented to the outside through the personnel door with portable smoke ejectors available onsite for fire brigade use.

4.K.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and damper(s) mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6). In addition, Enclosure 2 of Reference 18 indicates that fire area boundaries previously accepted under Appendix A to BTP 9.5-1 need not be reevaluated for compliance with Appendix R Section III.G. Since Fire Door D027-1 and the fire dampers mounted in the exterior walls bounding Fire Area K/Zone 27 were reviewed and found acceptable under Appendix A (Reference 1), no further modifications were necessary for Appendix R.

FIRE HAZARD ANALYSIS FOR FIRE AREA L

4.L DESCRIPTION OF FIRE AREA

Fire Area L is the Unit 4 Auxiliary Building Fan Room, located on the 18.00' elevation. The area is a single zone area comprised of Fire Zone 28. Pertinent fire zone details are provided below.

Fire Area L and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.L.1 FIRE ZONE 28 - UNITS 3 AND 4 AUXILIARY BUILDING FAN ROOM - EL. 18.00'

Fire Zone 28 is bounded on three walls by a 3-hour rated fire barrier. The South wall of the fire zone is formed by the Unit 4 Containment Building. Refer to Section 3.11 of this Appendix for a discussion on the rating of the Containment Building walls and non-rated floors and ceilings. Equipment in this zone includes the Auxiliary Building exhaust fans.

4.L.1.1 Essential Equipment Within Fire Zone 28

See Appendix R Essential Equipment List, Reference 15.

4.L.1.2 Fire Zone 28 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	----	----
.2b	Oils	10 gal	1.50×10^6
.2c	Others		
	Plastic	232 lbs	4.64×10^6
	Cured Paint	N/A	6.00×10^6
	Rubber	30 lbs	0.61×10^6
	Filters	145 lbs	1.13×10^6
	Wood	105 lbs	0.89×10^6
		TOTAL	14.77×10^6

Floor surface area (sq. ft.): 1980
Heat load (BTU/sq. ft.): 0.75×10^4

4.L.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There are two available fire extinguishers in adjacent Fire Zone 58, another in Fire Zone 21, and a fourth in Fire Zone 22. (See Table 9.6A-4.)

2. Secondary

There are two available standpipe hose stations in adjacent Fire Zone 58. (See Table 9.6A-5.)

.4d Smoke Venting:

If a fire in this area incapacitates the Auxiliary Building Exhaust Fans, portable smoke ejectors available on site may be used in conjunction with collapsible duct to vent smoke to the outside.

4.L.2 APPENDIX R EXEMPTIONS

No exemptions were requested for this fire area.

FIRE HAZARD ANALYSIS FOR FIRE ZONE M

4.M DESCRIPTION OF FIRE AREA

Fire Area M is in the Unit 3 and 4 Auxiliary Building, located on the 18.00' elevation. The area is a single zone area comprised of Fire Zone 41. Pertinent fire zone details are provided below.

Fire Area M and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.M.1 FIRE ZONE 41 - UNITS 3 AND 4 AUXILIARY BUILDING BORIC ACID TANKS AND BORIC ACID TRANSFER PUMPS ROOM - EL. 18.00'

Fire Zone 41 is bounded on three walls by a 3-hour rated fire barrier. The West wall of this zone is formed by the Unit 3 Containment Building. Refer to Section 3.11 of this Appendix for a discussion on the rating of the Containment Building walls. Equipment in this fire zone includes the Boric Acid Storage Tanks and the Boric Acid Transfer Pumps which serve both Units 3 and 4.

4.M.1.1 Essential Equipment Within Fire Zone 41

See Appendix R Essential Equipment List, Reference 15.

4.M.1.2 Fire Zone 41 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	---	---
.2b	Oils	4 gal	0.60×10^6
.2c	Others		
	Cured Paint	N/A	3.75×10^6
	Plastic	319 lbs	6.38×10^6
	Grease	4 gal	0.60×10^6
		TOTAL	11.33×10^6

Floor surface area (sq. ft.): 1041
Heat load (BTU/sq. ft.): 1.09×10^4

4.M.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There are two accessible fire extinguishers in Fire Zone 58, and another in Fire Zone 54. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 58 and a fire hydrant in Fire Zone 124.. (See Tables 9.6A-5 and 9.6A-6)

.4d Smoke Venting:

Normal area ventilation is used for smoke removal (Exhaust Fan V-8A or V-8B). Should sufficient heat be generated by a fire to close automatic fire dampers, smoke removal capacity will be reduced. However, the exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.M.2 APPENDIX R EXEMPTIONS

No exemptions were requested for this fire area.

FIRE HAZARD ANALYSIS FOR FIRE AREA N

4.N DESCRIPTION OF FIRE AREA

Fire Area N is the Unit 4 Auxiliary Building Charging Pump Room, located on the 18.00' elevation. The area is a single zone area comprised of Fire Zone 45. Pertinent fire zone details are provided below.

Fire Area N and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.N.1 FIRE ZONE 45 - UNIT 4 CHARGING PUMP ROOM - EL. 18.00'

Fire Zone 45 is bounded on the floor and walls by a 3-hour rated fire barrier, except for a non-rated radiation shield door in the West wall. Equipment in this zone includes the three charging pumps for Unit 4.

4.N.1.1 Essential Equipment Within Fire Zone 45

See Appendix R Essential Equipment List, Reference 15.

4.N.1.2 Fire Zone 45 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	756 lbs.	9.83×10^6
.2b	Oils	123 gal	18.45×10^6
.2c	Others		
	Cured Paint	N/A	4.70×10^6
	Grease	3 gal	0.45×10^6
	Plastic	58 lbs.	1.16×10^6
		TOTAL	34.59×10^6

Floor surface area (sq. ft.): 1370
Heat load (BTU/sq. ft.): 2.52×10^4

4.R.1.2 Fire Zone 61 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	3360 lbs	43.68×10^6
.2b	Oils	——	——
.2c	Others		
	Plastic	58 lbs	1.16×10^6
	Cured Paint	N/A	0.68×10^6
	Misc. Cables	290	3.77×10^6
	Wood	17.5 lbs	0.15×10^6
		TOTAL	49.44×10^6

Floor surface area (sq. ft.): 504
Heat load (BTU/sq. ft.): 9.81×10^4

4.R.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete East: Reinforced Concrete
South: Reinforced Concrete West: Reinforced Concrete

Ceiling: Reinforced Concrete supported on Fireproofed Structural Steel.

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 61 is provided with ionization detection which actuates a Control Room alarm.

.4c Fire Protection Systems:

1. Primary

There are three accessible fire extinguishers in adjacent Fire Zone 79, and one in each of Fire Zones 79A, 58, 21 and 22. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 58, another in Fire Zone 83, and a third in Fire Zone 82. (See Table 9.6A-5.)

.4d Smoke Venting:

Smoke removal may be accomplished through the personnel doors with portable smoke ejectors available onsite for fire brigade use.

4.R.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading beyond existing rating, those doors and dampers which are mounted in exterior walls (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6).

FIRE HAZARD ANALYSIS FOR FIRE AREA S

4.S DESCRIPTION OF FIRE AREA

Fire Area S is the Control Building Computer Room, located on the 18.00' elevation. The area is a single zone area comprised of Fire Zone 62. Pertinent fire zone details are provided below.

Fire Area S and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.S.1 FIRE ZONE 62 - UNITS 3 AND 4 COMPUTER ROOM - EL. 18.00'

Fire Zone 62 is bounded on the floor, ceiling and walls by a 3-hour rated fire barrier. Significant equipment in this zone includes the Safety Assessment System and Qualified Safety Parameters Display System Computers.

4.S.1.1 Essential Equipment Within Fire Zone 62

See Appendix R Essential Equipment List, Reference 15.

4.S.1.2 Fire Zone 62 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	6317 lbs	82.12×10^6
.2b	Oils	1 gal	0.15×10^6
.2c	Others		
	Grease	0.5 gal	0.08×10^6
	Plastic	58 lbs	1.16×10^6
	Paper	290 lbs	2.26×10^6
	Butyl Insul.	120 lbs	2.40×10^6
	Misc. Plastic Pipes	50 lbs	1.00×10^6
	Cured Paint	N/A	4.07×10^6
		TOTAL	93.24×10^6

Floor surface area (sq. ft.): 1722
Heat load (BTU/sq. ft.): 5.41×10^4

4.S.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Concrete Block
West: Reinforced Concrete

Ceiling: Reinforced Concrete on Fireproofed Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 62 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are three accessible fire extinguishers in Fire Zone 79, and one in each of Fire Zones 79A, 21, 22 and two in Fire Zone 58. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 58, another in Fire Zone 83, and a third in Fire Zone 82. (See Table 9.6A-5.)

.4d Smoke Venting:

Smoke removal may be accomplished through the personnel doors with portable smoke ejectors available onsite for fire brigade use.

4.S.2 APPENDIX R EXEMPTIONS

No exemptions were requested for this fire area.

FIRE HAZARD ANALYSIS FOR FIRE AREA T

4.T DESCRIPTION OF FIRE AREA

Fire Area T is the Unit 3 Reactor Control Rod Equipment Room, located on the 18.00' elevation of the Control Building. The area is a single zone area comprised of Fire Zone 63. Pertinent fire zone details are provided below.

Fire Area T and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.T.1 FIRE ZONE 63 - UNIT 3 REACTOR CONTROL ROD EQUIPMENT ROOM - EL. 18.00'

Fire Zone 63 is bounded on the floor, ceiling and walls by a 3-hour rated fire barrier. Major equipment in this zone includes Motor Control Center 3B and Control Rod Cabinets.

4.T.1.1 Essential Equipment Within Fire Zone 63

See Appendix R Essential Equipment List, Reference 15.

4.T.1.2 Fire Zone 63 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	3347 lbs	43.51×10^6
.2b	Oils	----	----
.2c	Others		
	Plastic	58 lbs	1.16×10^6
	Cured Paint	N/A	0.68×10^6
		TOTAL	45.35×10^6

Floor surface area (sq. ft.): 546
Heat load (BTU/sq. ft.): 8.3×10^4

4.T.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 63 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are three available fire extinguishers in Fire Zone 79, and another in Fire Zone 83. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 83, and another in Fire Zone 82. (See Table 9.6A-5.)

.4d Smoke Venting:

Smoke removal may be accomplished through the personnel doors with portable smoke ejectors available onsite for fire brigade use.

4.T.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading doors and dampers which are mounted in exterior walls beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6).

FIRE HAZARD ANALYSIS FOR FIRE AREA U

4.U DESCRIPTION OF FIRE AREA

Fire Area U is the Unit 4 4160V Switchgear 4B Room, located on the 18.00' elevation. The area is a single zone area comprised of Fire Zone 67. Pertinent fire zone details are provided below.

Fire Area U and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.U.1 FIRE ZONE 67 - 4160V SWITCHGEAR 4B ROOM - EL. 18.00'

Fire Zone 67 is bounded on the ceiling and all walls by a 3-hour rated fire barrier. Equipment in this zone includes 4160V switchgear 4B, the Emergency Load Sequencer Cubicle 4B and the Unit 4 Alternate Shutdown Panel.

4.U.1.1 Essential Equipment Within Fire Zone 67

See Appendix R Essential Equipment List, Reference 15.

4.U.1.2 Fire Zone 67 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	9157 lbs	119.0×10^6
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	4.1×10^6
	Plastic	58 lbs	1.2×10^6
	Paper	116 lbs	0.9×10^6
	Vinyl Tarps	58 lbs	1.2×10^6
		TOTAL	126.4×10^6

Floor surface area (sq. ft.): 1026
Heat load (BTU/sq. ft.): 12.32×10^4

4.U.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Concrete Block and partly Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Fireproofed Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 67 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are three accessible fire extinguishers in Fire Zone 79, another two in Fire Zone 82, and a sixth in Fire Zone 83. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 83, another in Fire Zone 82, and a third in Fire Zone 105. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this Fire Zone. Smoke may be vented through personnel doors with portable smoke ejectors available onsite for fire brigade use.

4.U.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and dampers mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6).

FIRE HAZARD ANALYSIS FOR FIRE AREA V

4.V DESCRIPTION OF FIRE AREA

Fire Area V is the Unit 4 416V Switchgear 4A Room, located on the 18.00' elevation. The area is a single zone area comprised of Fire Zone 68. Pertinent fire zone details are provided below.

Fire Area V and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.V.1 FIRE ZONE 68 - 4160V SWITCHGEAR 4A ROOM - EL. 18.00'

Fire Zone 68 is bounded on the ceiling and all walls by a 3-hour rated fire barrier. Equipment in this zone includes 4160V Switchgear 4A and the Emergency Load Sequencer Cubicle 4A.

4.V.1.1 Essential Equipment Within Fire Zone 68

See Appendix R Essential Equipment List, Reference 15.

4.V.1.2 Fire Zone 68 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	6798 lbs	88.4×10^6
.2b	Oils		
.2c	Others		
	Cured Paint	N/A	3.3×10^6
	Plastic	58 lbs	1.2×10^6
		TOTAL	92.9×10^6

Floor surface area (sq. ft.): 1026
Heat load (BTU/sq. ft.): 9.05×10^4

4.V.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Concrete Block and partly Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Fireproofed Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 68 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are three accessible fire extinguishers in Fire Zone 79, another two in Fire Zone 82, and a sixth in Fire Zone 83. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in adjacent Fire Zone 83, another in Fire Zone 82, and a third in Fire Zone 105. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this fire zone. Smoke may be vented to the outside through the personnel doors with portable smoke ejectors available onsite for fire brigade use.

4.V.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and dampers mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6).

FIRE HAZARD ANALYSIS FOR FIRE AREA W

4.W DESCRIPTION OF FIRE AREA

Fire Area W is the Unit 3 4160V Switchgear 3B Room, located on the 18.00' elevation. The area is a single zone area comprised of Fire Zone 70. Pertinent fire zone details are provided below.

Fire Area W and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.W.1 FIRE ZONE 70 - 4160V SWITCHGEAR 3B ROOM - EL. 18.00'

Fire Zone 70 is bounded on the floor and all walls by a 3-hour rated fire barrier. Equipment in this zone includes 4160V Switchgear 3B, the Emergency Load Sequencer Cubicle 3B and the Unit 3 Alternate Shutdown Panel.

4.W.1.1 Essential Equipment Within Fire Zone 70

See Appendix R Essential Equipment List, Reference 15.

4.W.1.2 Fire Zone 70 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	9757 lbs	126.8×10^6
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	4.1×10^6
	Plastic	58 lbs	1.2×10^6
	Tarps, etc.	58 lbs	1.2×10^6
		TOTAL	133.3×10^6

Floor surface area (sq. ft.): 1026
Heat load (BTU/sq. ft.): 13.0×10^4

4.W.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete and Concrete Block
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced concrete supported by Fireproofed Structural Steel

Floor: Reinforced concrete

.4b Detection:

Fire Zone 70 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are two accessible fire extinguishers in adjacent Fire Zone 88, and two more in adjacent Fire Zone 87. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in adjacent Fire Zone 88, another in Fire Zone 87 and a third in Fire Zone 105. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this fire zone. Smoke may be vented to the outside through the personnel doors with portable smoke ejectors available onsite for fire brigade use.

4.W.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and dampers mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6).

FIRE HAZARD ANALYSIS FOR FIRE AREA X

4.X DESCRIPTION OF FIRE AREA

Fire Area X is the Unit 3 4160V Switchgear 3A Room located on the 18.00' elevation. The area is a single zone area comprised of Fire Zone 71. Pertinent fire zone details are provided below.

Fire Area X and the essential equipment and cables within have been evalulated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.X.1. FIRE ZONE 71 - 4160V SWITCHGEAR 3A ROOM - EL. 18.00'

Fire Zone 71 is bounded on the ceiling and all walls by a 3-hour rated fire barrier. Equipment in this zone includes 4160V Switchgear 3A and the Emergency Load Sequencer Cubicle 3A.

4.X.1.1 Essential Equipment Within Fire Zone 71

See Appendix R Essential Equipment List, Reference 15.

4.X.1.2 Fire Zone 71 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	10,477 lbs	136.3×10^6
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	3.3×10^6
	Plastic	58 lbs	1.2×10^6
		TOTAL	140.8×10^6

Floor surface area (sq. ft.): 1026
Heat load (BTU/sq. ft.): 13.72×10^4

4.X.1.3 Fire Control

.4a Physical Containment

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete and Concrete Block
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Fireproofed Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 71 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary:

There are two accessible fire extinguishers in adjacent Fire Zone 88, and another two in Fire Zone 87. (See Table 9.6A-4.)

2. Secondary:

There is one available standpipe hose station in adjacent Fire Zone 88, and another in Fire Zone 87. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust system is provided in this fire zone. Smoke may be vented to the outside through the personnel doors with portable smoke ejectors available onsite for fire brigade use.

4.X.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and dampers mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6).

FIRE HAZARD ANALYSIS FOR FIRE AREA Y

4.Y DESCRIPTION OF FIRE AREA

Fire Area Y is the Unit 3 Train B Diesel Generator Building located on the 18.00' elevation. The area is a single zone area comprised of Fire Zone 72. Pertinent fire zone details are provided below.

Fire Area Y and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.Y.1 FIRE ZONE 72 - UNIT 3 TRAIN B EMERGENCY DIESEL GENERATOR BUILDING - EL. 18.00'

Fire Zone 72 is bounded on the ceiling where it interfaces with Fire Zone 74 and walls by a minimum 3-hour rated fire barrier, with the exceptions of the east and south walls which contain a 9 ft. x 7 ft. louvered air intake vent protected by a water curtain. In addition, a ventilation penetration (072W-H001) in the west wall does not contain a fire damper, but an evaluation has been performed that determined that the present configuration of this ventilation penetration is acceptable. Significant equipment in this zone includes the Unit 3B Emergency Diesel generator, and associated equipment.

4.Y.1.1 Essential Equipment Within Fire Zone 72

See Appendix R Essential Equipment List, Reference 15.

4.Y.1.2 Fire Zone 72 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	---	---
.2b	Oils	250 gal	37.5×10^6
.2c	Others		
	Cured Paint	N/A	1.30×10^6
	Plastic	58 lbs	1.16×10^6
	Grease	.5 gal	0.08×10^6
	Diesel Fuel	300 gal	45.00×10^6
		TOTAL	85.04×10^6

Floor surface area (sq. ft.): 880
Heat load (BTU/sq. ft.): 9.66×10^4

4.Y.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete and Louvers
East: Reinforced Concrete, Louvers, and Concrete Block
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 72 is provided with flame and ionization type smoke detection. These detectors initiate an alarm in the Control Room. Thermal detectors initiate the preaction sprinkler system and actuate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one accessible fire extinguisher in Fire Zone 89, two more in Fire Zone 88, and a fourth in Fire Zone 86. (See Table 9.6A-4.) Fire Zone 72 is provided with preaction automatic sprinklers.

2. Secondary

There is one available standpipe hose station in Fire Zone 88. (See Table 9.6A-5.)

.4d Smoke Venting:

Exhaust Fan 4V-34 is used for smoke removal. Should sufficient heat be generated by a fire to close automatic fire dampers, smoke removal capacity will be reduced. However, the exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.Y.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading those doors and dampers which are mounted in exterior walls beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6).

FIRE HAZARD ANALYSIS FOR FIRE AREA Z

4.Z DESCRIPTION OF FIRE AREA

Fire Area Z is the Unit 3 Train A Emergency Diesel Generator Building located on the 18.00' elevation. The area is a single zone area comprised of Fire Zone 73. Pertinent fire zone details are provided below.

Fire Area Z and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.Z.1 FIRE ZONE 73 - UNIT 3 TRAIN A EMERGENCY DIESEL GENERATOR BUILDING - EL. 18.0'

Fire Zone 73 is bounded on the ceiling where it interfaces with Fire Zone 75 and walls by a 3-hour rated fire barrier, with the exceptions of the east and north walls which contain a 9 ft. x 7 ft. louvered air intake vent protected by a water curtain. In addition, a ventilation penetration (073W-H001) in the west wall does not contain a fire damper, but an evaluation has been performed that determined that the present configuration of this ventilation penetration is acceptable. Equipment in this zone includes the 3A Emergency Diesel Generator and associated equipment.

4.Z.1.1 Essential Equipment Within Fire Zone 73

See Appendix R Essential Equipment List, Reference 15.

4.Z.1.2 Fire Zone 73 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	---	---
.2b	Oils/Fuels	550 gal	82.50×10^6
.2c	Others		
	Cured Paint	N/A	1.30×10^6
	Plastic	58 lbs	1.16×10^6
	Grease	0.5 gal	0.08×10^6
		TOTAL	85.04×10^6

Floor surface area (sq. ft.): 880
Heat load (BTU/sq. ft.): 9.66×10^4

4.Z.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete and Louvers
South: Reinforced Concrete
East: Reinforced Concrete, Louvers and Concrete Block
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 73 is provided with flame and ionization type smoke detection. These detectors initiate an alarm in the Control Room. Thermal detectors are also provided which initiate the preaction sprinkler system and actuate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one accessible fire extinguisher outside Fire Zone 86, two more in Fire Zone 88, and a fourth in Fire Zone 89. (See Table 9.6A-4.) Fire Zone 73 is provided with preaction automatic sprinklers.

2. Secondary

There is one available standpipe hose station in Fire Zone 88. (See Table 9.6A-5.)

.4d Smoke Venting:

Exhaust Fan 3V-34 is used for smoke removal. Should sufficient heat be generated by a fire to close automatic fire dampers, smoke removal capacity will be reduced. However, the exhaust fan is supplemented by portable smoke ejectors available on site for fire brigade use.

4.Z.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading doors and dampers which are mounted in exterior walls beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not serve to separate redundant safe shutdown equipment (Reference 6).

FIRE HAZARD ANALYSIS FOR FIRE ZONE AA

4.AA DESCRIPTION OF FIRE AREA

Fire Area AA is the Unit 3 Train B Emergency Diesel Generator Building Day Tank Room located on the 31.00' elevation. The area is a single zone area comprised of Fire Zone 74. Pertinent fire zone details are provided below.

Fire Area AA and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.AA.1 FIRE ZONE 74 - UNIT 3 TRAIN B EMERGENCY DIESEL GENERATOR DAY TANK ROOM EL. 31.00'

Fire Zone 74 is bounded on the floor and all walls by a 3-hour rated fire barrier. Equipment in this zone includes the 3B Fuel Oil Day Tank and associated piping and valves.

4.AA.1.1 Essential Equipment Within Fire Zone 74

See Appendix R Essential Equipment List, Reference 15.

4.AA.1.2 Fire Zone 74 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	---	---
.2b	Oils/Fuels	4000 gal	664.00×10^6
.2c	Others		
	Cured Paint	N/A	0.45×10^6
		TOTAL	664.45×10^6

Floor surface area (sq. ft.): 220
Heat load (BTU/sq. ft.): 3.02×10^6

4.AA.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 74 is provided with thermal detectors which initiate the preaction sprinkler system and actuate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one available fire extinguisher in Fire Zone 89, another in Fire Zone 86, and two more in Fire Zone 88 (See Table 9.6A-4.). Fire Zone 74 is provided with preaction automatic sprinklers.

2. Secondary

There is one available standpipe hose station in Fire Zone 88. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this fire zone. Smoke may be vented to the outside through the personnel door with portable smoke ejectors available onsite for fire brigade use.

No positive exhaust is provided in this fire zone. Smoke may be vented through the personnel door with portable smoke ejectors available onsite for fire brigade use.

4.EE.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and dampers mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment.

FIRE HAZARD ANALYSIS FOR FIRE AREA FF

4.FF <u>DESCRIPTION OF FIRE AREA</u>

Fire Area FF is the Unit 3 480V Load Centers A and B Room located on the 31.00' elevation. The area is a single zone area comprised of Fire Zone 95. Pertinent fire zone details are provided below.

Fire Area FF and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.FF.1 FIRE ZONE 95 - UNIT 3 480V LOAD CENTERS A AND B ROOM - EL. 31.00'

Fire Zone 95 is bounded on the floor and walls by a 3-hour rated fire barrier. Equipment in this zone includes Load Centers 3A and 3B.

4.FF.1.1 <u>Essential Equipment Within Fire Zone 95</u>

See Appendix R Essential Equipment List, Reference 15.

4.FF.1.2 <u>Fire Zone 95 - Combustible Loadings</u>

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	1646 lbs	21.40×10^6
.2b	Oils	—	—
.2c	Others		
	Cured Paint	N/A	1.60×10^6
	Plastic	58 lbs	1.16×10^6
		TOTAL	24.16×10^6

Floor surface area (sq. ft.): 684
Heat load (BTU/sq. ft.): 3.53×10^4

4.FF.1.3 <u>Fire Control</u>

.4a Physical Containment:

<u>Fire Zone Boundary</u>

Walls

North: Reinforced Concrete
South: Reinforced Concrete and Concrete Block
East: Concrete Block
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 95 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one accessible fire extinguisher in Fire Zone 105. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 105. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this fire zone. Smoke may be vented through the personnel door with portable smoke ejectors available onsite for fire brigade use.

4.FF.2 APPENDIX R EXEMPTIONS

No exemptions were requested for this fire area.

FIRE HAZARD ANALYSIS FOR FIRE AREA GG

4.GG DESCRIPTION OF FIRE AREA

Fire Area GG is the Unit 3 480V Load Centers C and D Room, located on the 31.00' elevation. The area is a single zone area comprised of Fire Zone 96. Pertinent fire zone details are provided below.

Fire Area GG and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.GG.1 FIRE ZONE 96 - UNIT 3 480V LOAD CENTERS C AND D ROOM - EL. 31.00'

Fire Zone 96 is bounded on the floor and walls by a 3-hour rated fire barrier. Equipment in this zone includes Load Centers 3C and 3D.

4.GG.1.1 Essential Equipment Within Fire Zone 96

See Appendix R Essential Equipment List, Reference 15.

4.GG.1.2 Fire Zone 96 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	2070 lbs	26.91×10^6
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	1.60×10^6
	Plastic	29 lbs	0.58×10^6
		TOTAL	29.09×10^6

Floor surface area (sq. ft.): 684
Heat load (BTU/sq. ft.): 4.27×10^4

4.GG.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete and Concrete Block
East: Reinforced Concrete
West: Concrete Block

Ceiling: Reinforced Concrete supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 96 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one accessible fire extinguisher in adjacent Fire Zone 105. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in adjacent Fire Zone 105. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this fire zone. Smoke may be vented through the personnel door with portable smoke ejectors available onsite for fire brigade use.

4.GG.2 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading the fire door(s) and dampers mounted in exterior walls of this fire area beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment.

FIRE HAZARD ANALYSIS FOR FIRE AREA HH

4.HH DESCRIPTION OF FIRE AREA

Fire Area HH is the Unit 3 and 4 Cable Spreading and the Control Room Electrical Chase located on the 30.00' elevation of the Control Building. The area is comprised of Fire Zones 98 and 132. Pertinent fire zone details are provided below. Refer to Section 5.0 of this Appendix for the discussion of the Alternate Shutdown capabilities provided for this area.

Fire Area HH and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.HH.1 FIRE ZONE 98 - UNITS 3 AND 4 CABLE SPREADING ROOM - EL. 30.00'

Fire Zone 98 is bounded on the floor and walls by a 3-hour rated fire barrier with the exception of door 132-1, which is a 1-1/2 hour rated door. Equipment in this zone includes Reactor Protection Racks and General Transfer Relay Panels.

4.HH.1.1 Essential Equipment Within Fire Zone 98

See Appendix R Essential Equipment List, Reference 15.

4.HH.1.2 Fire Zone 98 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	32772 lbs	426.04×10^6
.2b	Oils	----	----
.2c	Others		
	Cured Paint	N/A	2.40×10^6
	Plastic	58 lbs	1.16×10^6
	Paper	116 lbs	0.90×10^6
		TOTAL	430.5×10^6

Floor surface area (sq. ft.): 2950
Heat load (BTU/sq. ft.): 14.59×10^4

4.HH.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete and Concrete Block
East: Reinforced Concrete
West: Reinforced Concrete and Concrete Block

Ceiling: Reinforced Concrete supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 98 is provided with ionization type smoke detection. These detectors will initiate the Halon Fire Suppression System and actuate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one available fire extinguisher in Fire Zone 98, two in adjacent Fire Zone 104, another in Fire Zone 101, and two more in Fire Zone 105. (See Table 9.6A-4.) Fire Zone 98 is provided with a Halon Fire Suppression System.

2. Secondary

There are two available standpipe hose stations in Fire Zone 105. (See Table 9.6A-5.)

.4d Smoke Venting:

Smoke removal may be accomplished through the personnel doors with portable smoke ejectors available onsite for fire brigade use.

4.HH.2 FIRE ZONE 132 - UNITS 3 AND 4 CONTROL ROOM ELECTRICAL CHASE EL. 42.00'

Fire Zone 132 is bounded on the walls and ceiling by a 3-hour rated fire barrier. There is no significant equipment in this zone.

4.HH.2.1 Essential Equipment Within Fire Zone 132

See Appendix R Essential Equipment List, Reference 15.

4.HH.2.2 Fire Zone 132 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	1222 lbs	15.87×10^6
.2b	Oils	—	—
.2c	Others		
	Plastic	14.5 lbs	0.29×10^6
		TOTAL	16.16×10^6

Floor surface area (sq. ft.): 18
Heat load (BTU/sq. ft.): 89.78×10^4

4.HH.2.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Concrete Block
South: Concrete Block
East: Concrete Block
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 132 is provided with ionization type smoke detection. These detectors initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are three accessible fire extinguishers in Fire Zone 106. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station in Fire Zone 79, and another in Fire Zone 117. (See Table 9.6A-5.) Fire Zone 132 is provided with a Halon Fire Suppression System.

.4d Smoke Venting:

No positive exhaust is provided in this fire zone. Smoke may be vented with portable smoke ejectors available on site for fire brigade use.

4.HH.3 APPENDIX R EXEMPTIONS

FPL requested exemption from upgrading doors and dampers which are mounted in exterior walls beyond existing rating (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6).

4.LL.2 APPENDIX R EXEMPTIONS

No exemptions were requested for this fire area.

FIRE HAZARD ANALYSIS FOR FIRE AREA MM

4.MM DESCRIPTION OF FIRE AREA

Fire Area MM is the Unit 3 and 4 Control Room located on the 42.00' elevation of the Control Building. The area is comprised of fire Zones 106, 106R, and 97. Pertinent fire zone details are provided below. Refer to Section 5.0 of this Appendix for a discussion of the Alternate Shutdown Capabilities provided for this fire area.

Fire Area MM and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.MM.1 FIRE ZONE 97 - UNITS 3 AND 4 CONTROL ROOM HVAC EQUIPMENT ROOM - EL. 30.00'

Fire Zone 97 is bounded on the floor and walls by a 3-hour rated fire barrier, with the exception of the West and South walls which contain non-rated dampers. Equipment in this zone includes 3 Air Handling Units and the Control Room HEPA filter unit.

4.MM.1.1 Essential Equipment Within Fire Zone 97

See Appendix R Essential Equipment List, Reference 15.

4.MM.1.2 Fire Zone 97 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	252 lbs	3.28×10^6
.2b	Oils	---	---
.2c	Others		
	Charcoal	250 lbs	4.52×10^6
		TOTAL	7.80×10^6

Floor surface area (sq. ft.): 377
Heat load (BTU/sq. ft.): 2.07×10^4

4.MM.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Concrete Block
South: Reinforced Concrete
East: Concrete Block
West: Reinforced Concrete

Ceiling: Reinforced Concrete supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 97 is provided with an air duct detector. This detector initiates an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one accessible fire extinguisher in adjacent Fire Zone 98, another in Fire Zone 101, a third in Fire Zone 79, and a fourth in Fire Zone 105. (See Table 9.6A-4.)

2. Secondary

There is an available standpipe hose station in Fire Zone 105. (See Table 9.6A-5.)

.4d Smoke Venting:

Portable smoke ejectors available onsite may be used to vent smoke.

4.MM.2 FIRE ZONE 106 - UNITS 3 AND 4 CONTROL ROOM COMPLEX - EL. 42.00'

Fire Zone 106 is bounded on all four walls by a 3-hour rated fire barrier. An exception to this barrier integrity includes non-rated door D106-2. However, this door has been demonstrated to have an equivalent 3 hour fire rating. Equipment in this zone includes the Unit 3 and 4 control and monitoring equipment.

4.MM.2.1 Essential Equipment Within Fire Zone

See Appendix R Essential Equipment List, Reference 15.

4.MM.2.2 Fire Zone 106 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	5162 lbs	67.11×10^6
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	1.50×10^6
	Plastic	385 lbs	7.70×10^6
	Paper	2320 lbs	18.09×10^6
		TOTAL	94.40×10^6

Floor surface area (sq. ft.): 3950
Heat load (BTU/sq. ft.): 2.39×10^4

4.MM.4 APPENDIX R EXEMPTIONS

Exemption MM.1

FPL requested (Reference 4) and was granted (Reference 6) exemption from that portion of Appendix R to 10.CFR Part 50 Section III.G.3 that requires installation of a fixed fire suppression system in the area, for which an alternate shutdown capability independent of cables, systems or components in that area, is provided. Specifically, exemption was requested from providing a fixed fire suppression system in Fire Area MM.

Exemption MM.2

FPL requested exemptions from upgrading beyond existing rating, those doors and dampers which are mounted in exterior walls (Reference 4). The NRC indicated that this exemption was not needed where exterior walls do not separate redundant safe shutdown equipment (Reference 6).

Justification for Exemption

The Control Room is an area that is continuously manned in accordance with existing technical specifications. This assures that any fire occurring within the Control Room will be quickly detected and extinguished by operating personnel. The Control Room is provided with portable CO_2 and pressurized water fire extinguishers and can be accessed by two hose stations located outside the area.

In accordance with the requirements of 10 CFR Part 50 Appendix R Sections III.L, alternate shutdown remote from the Control Room will be provided.

The in situ combustibles in the Control Room consist of cables and components located within control boards, panels and control consoles and miscellaneous paper in the form of books, manuals and computer printouts.

A review of potential transient combustibles for this fire area was conducted by the Factory Mutual Research Corporation for FPL. The results of this review indicate that there are no expected transient combustibles for this fire area.

Fire protection features existing for this fire area are active and passive in nature. Passive fire protection is provided by the steel cabinets and control consoles which serve to contain in situ combustibles in discrete quantities and the spatial separation between consoles and cabinets.

Active fire protection is provided by the installed fire detection system which will provide early warning of any fire in this area allowing the operators to respond before significant development occurs, and by the continuous presence of operators in this area.

In conclusion, it is FPL's position that the alternate shutdown system and the existing fire protection features combined with the continuous manning of this area provide a level of fire protection consistent with the fire hazards, both in situ and transient identified for this fire area and that these features provide assurance that at least one train of safe shutdown equipment and cables will be free of fire damage.

Exemption MM.3

See Exemption 76.1.

Exemption MM.4

See Exemption 76.2

FIRE HAZARD ANALYSIS FOR FIRE AREA NN

4.NN DESCRIPTION OF FIRE AREA

Fire Area NN is the Unit 3 and 4 Train "A" DC Equipment Room, located on the 42.00′ elevation of the Control Building. The area is comprised of Fire Zone 108A. Fire Zone 108 was subdivided as a result of Appendix R into Fire Zones 108A and 108B by the installation of a two hour rated fire barrier. This separation created Fire Area NN (Fire Zone 108A) and Fire Area OO (Fire Zone 108B). Fire Area OO contains "B" train equipment and Fire Area NN contains "A" train equipment. Pertinent fire zone details are provided below.

Fire Area NN and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III-G.2 to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.NN.1 FIRE ZONE 108A - UNIT 3 AND 4 A DC EQUIPMENT ROOM - EL. 42.00′

Fire Zone 108A is bounded on the floor and walls by a 3-hour rated fire barrier except for the dividing wall between Fire Zones 108A and 108B, which is a 2-hour rated fire barrier and non-rated door D106-1. An evaluation has been performed that determined that the present configuration of door D106-1 is acceptable. Equipment in this zone includes the Train "A" Safety Related Power Supplies, Battery Chargers and Inverters.

4.NN.1.1 Essential Equipment Within Fire Zone 108A

See Appendix R Essential Equipment List, Reference 15.

4.NN.1.2 Fire Zone 108A - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	2620 lbs	34.06×10^6
.2b	Oils	1 gal	0.15×10^6
.2c	Others		
	Cured Paint	N/A	1.60×10^6
	Plastic	29 lbs	0.60×10^6
	Paper	29 lbs	0.25×10^6
		TOTAL	36.66×10^6

Floor surface area (sq. ft.): 408
Heat load (BTU/sq. ft.): 8.99×10^4

4.NN.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

4.VV.2 APPENDIX R EXEMPTIONS

There are no exemptions applicable to this fire area.

FIRE HAZARD ANALYSIS FOR FIRE AREA WW

4.WW DESCRIPTION OF FIRE AREA

Fire Area WW is the Unit 4 Train A Emergency Diesel Oil Transfer Pump Room (Fire Zone 141) and Storage Tank 4A (Fire Zone 142) located on the 18.00' and 42.00' elevation. While this area is comprised of Fire Zones 141 and 142, Fire Zone 142 is enclosed with 3-hour fire rated barriers. Pertinent fire zone details are provided below.

Fire Area WW and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III.G.2c (one hour barriers, detection and suppression) for Fire Zone 141 and Section III.G.2.a (three barriers) for Fire Zone 142, to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.WW.1 FIRE ZONE 141 - UNIT 4 TRAIN A EMERGENCY DIESEL OIL TRANSFER PUMP ROOM - EL. 18.00'

Fire Zone 141 is bounded on the floor and all walls by a 3-hour rated fire barrier with the exception of the north wall which contains a louvered air intake vent. Equipment in this zone includes the 4A Diesel Oil Transfer Pump and associated piping and valves.

4.WW.1.1 Essential Equipment Within Fire Zone 141

See Appendix R Essential Equipment List, Reference 15.

4.WW.1.2 Fire Zone 141 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	---	---
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	1.15×10^6
	Grease	0.3 gals	0.05×10^6
	Diesel	0.5 gals	0.08×10^6
		TOTAL	1.28×10^6

Floor surface area (sq. ft.): 202
Heat load (BTU/sq. ft.): 6.34×10^3

4.WW.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 141 is provided with rate compensation thermal detectors which initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one available fire extinguisher outside the entrance Fire Zone 141 and one outside the entrance to Fire Zone 136 (see Table 9.6A-4.) Fire Zone 141 is provided with wet pipe automatic sprinklers.

2. Secondary

There is one available standpipe hose station located on the exterior north wall of the Unit 4 Diesel Generator Building. A fire hydrant and hose cabinet are within 200 feet of the building. (See Table 9.6A-5.)

.4d Smoke Venting:

Exhaust fan 4V70A can be used for smoke removal. The exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.WW.2 FIRE ZONE 142 - UNIT 4 TRAIN A EMERGENCY DIESEL OIL STORAGE TANK - EL. 18.00'

Fire Zone 142 is bounded on the floor and all walls by a 3-hour rated fire barriers. This zone consists entirely of the 4A Diesel Oil Storage Tank which is integral to the structure and is accessible only through a removable concrete hatch on the roof.

4.WW.2.1 Essential Equipment Within Fire Zone 142

See Appendix R Essential Equipment List, Reference 15.

4.WW.2.2 Fire Zone 142 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	---	---
.2b	Oils/Fuels	42,000 gal	6.97×10^9
.2c	Other		
	Cured Paint	---	---
		TOTAL	6.97×10^9

Floor surface area (sq. ft.): 200
Heat load (BTU/sq. ft.): 3.49×10^7

4.WW.2.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Steel Lined Reinforced Concrete
South: Steel Lined Reinforced Concrete
East: Steel Lined Reinforced Concrete
West: Steel Lined Reinforced Concrete

Ceiling: Reinforced Concrete

Floor: Steel Lined Reinforced Concrete

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There is one available fire extinguisher outside the entrance Fire Zone 142 and one outside the entrance to Fire Zone 136. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station located on the exterior north wall of the Unit 4 Diesel Generator Building. A fire hydrant and hose cabinet are within 200 feet of the building. (See Table 9.6A-5.)

.4d Smoke Venting:

Not applicable.

4.WW.3 APPENDIX R EXEMPTIONS

There are no exemptions applicable to this fire area.

FIRE HAZARD ANALYSIS FOR FIRE AREA XX

4.XX DESCRIPTION OF FIRE AREA

Fire Area XX is the Unit 4 Train B Emergency Diesel Oil Transfer Pump Room and Storage Tank 4B located on the 18.00 elevation. The area is comprised of Fire Zones 136 and 137. Pertinent fire zone details are provided below.

Fire Area XX and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section III.G.2c (one hour barriers, detection and suppression) to assure that the ability to safely shut down the plant is not adversely affected by a single fire event.

4.XX.1 FIRE ZONE 136 - UNIT 4 TRAIN A EMERGENCY DIESEL OIL TRANSFER PUMP ROOM - EL. 18.00'

Fire Zone 136 is bounded on the floor and all walls by a 3-hour rated fire barrier, with the exception of the north wall which contains a louvered air intake vent. Equipment in this zone includes the 4B Diesel Oil Transfer Pump and associated piping and valves.

4.XX.1.1 Essential Equipment Within Fire Zone 136

See Appendix R Essential Equipment List, Reference 15.

4.XX.1.2 Fire Zone 136 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	---	---
.2b	Oils	---	---
.2c	Others		
	Cured Paint	N/A	1.15×10^6
	Grease	0.3 gals	0.05×10^6
	Diesel	0.5 gal	0.08×10^6
		TOTAL	1.28×10^6

Floor surface area (sq. ft.): 202
Heat load (BTU/sq. ft.): 6.34×10^3

4.XX.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Reinforced Concrete

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 136 is provided with rate compensation thermal detectors which initiate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one available fire extinguisher outside the entrance Fire Zone 136 and one outside the entrance to Fire Zone 141. (See Table 9.6A-4.) Fire Zone 136 is provided with wet pipe automatic sprinklers.

2. Secondary

There is one available standpipe hose station located on the exterior north wall of the Unit 4 Diesel Generator Building. A fire hydrant and hose cabinet are within 200 feet of the building. (See Table 9.6A-5.)

.4d Smoke Venting:

Exhaust fan 4V70A can be used for smoke removal. The exhaust fan is supplemented by portable smoke ejectors available onsite for fire brigade use.

4.XX.2 FIRE ZONE 137 - UNIT 4 TRAIN B EMERGENCY DIESEL OIL STORAGE TANK - EL. 18.00'

Fire Zone 137 is bounded on the floor and all walls by a 3-hour rated fire barriers. This zone consists entirely of the 4B Diesel Oil Storage Tank which is integral to the structure and is accessible only through a removable concrete hatch on the roof.

4.XX.2.1 Essential Equipment Within Fire Zone 137

See Appendix R Essential Equipment List, Reference 15.

4.XX.2.2 Fire Zone 137 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	---	---
.2b	Oils/Fuels	42,000 gal	6.97×10^9
.2c	Other		
	Cured Paint	---	---
		TOTAL	6.97×10^9

Floor surface area (sq. ft.): 200
Heat load (BTU/sq. ft.): 3.49×10^7

4.XX.2.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Steel Lined Reinforced Concrete
South: Steel Lined Reinforced Concrete
East: Steel Lined Reinforced Concrete
West: Steel Lined Reinforced Concrete

Ceiling: Reinforced Concrete

Floor: Steel Lined Reinforced Concrete

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There is one available fire extinguisher outside the entrance Fire Zone 137 and one outside the entrance to Fire Zone 141. (See Table 9.6A-4.)

2. Secondary

There is one available standpipe hose station located on the exterior north wall of the Unit 4 Diesel Generator Building. A fire hydrant and hose cabinet are within 200 feet of the building. (See Table 9.6A-5.)

.4d Smoke Venting:

Not applicable.

4.XX.3 APPENDIX R EXEMPTIONS

There are no exemptions applicable to this fire area.

FIRE HAZARD ANALYSIS FOR FIRE AREA YY

4.YY DESCRIPTION OF FIRE AREA

Fire Area YY is the Emergency Diesel Generator Control Room 4B located on the 42.00' elevation of the Unit 4 Emergency Diesel Generator Building. The area is a single zone area comprised of Fire Zone 135. Pertinent fire zone details are provided below.

Fire Area YY and the essential equipment and cables within have been evaluated with respect to protection and separation criteria of Appendix R Section

4.AAA.6.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Pre-cast Concrete slab supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There is one fire extinguisher in Fire Zone 108B, and another four in Fire Zone 106. (See Table 9.6A-4.)

2. Secondary

There is one hose station located in Fire Zone 118. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this Fire Zone. Portable smoke ejectors are available on site for fire brigade use.

4.AAA.7 FIRE ZONE 24 - UNITS 3 AND 4 GAS DECAY TANK ROOM - EL. 18.00'

Fire Zone 24 is located on the 18.00' elevation of the Units 3 and 4 Auxiliary Building. Equipment in this zone includes Gas Decay Tanks and associated piping, valves and instruments.

4.AAA.7.1 Essential Equipment Within Fire Zone 24

See Appendix R Essential Equipment List, Reference 15.

4.AAA.7.2 Fire Zone 24 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	Negligible	----
.2b	Oils	----	----
.2c	Others	----	----
		TOTAL	----

Heat load (BTU/sq. ft.): Negligible

4.AAA.7.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Reinforced Concrete

Ceiling: Pre-cast Concrete slab supported by Structural Steel

Floor: Reinforced Concrete

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There is one fire extinguisher in Fire Zone 108B, and another four in Fire Zone 106. (See Table 9.6A-4.)

2. Secondary

There is one hose station located in Fire Zone 118. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided for this Fire Zone. Portable fire extinguishers are available onsite for fire brigade use.

4.AAA.8 FIRE ZONE 29 - UNIT 4 SPENT FUEL PIT - EL. 18.00'

Fire Zone 29 is located on the 18.00' elevation just east of the Unit 4 Containment Building. This is the spent fuel pit and contains associated instruments, piping and valves of the spent fuel system.

2. Secondary

There is an available standpipe hose station in Fire Zone 117. (See Table 9.6A-5.)

.4d Smoke Venting:

Ventilation provided by a gravity roof ventilator and an exhaust fan is used for smoke removal. The normal air handling systems are supplemented by portable smoke ejectors available onsite for fire brigade use.

4.OD.1 FIRE ZONE 47 - UNIT 4
COMPONENT COOLING PUMP AND HEAT EXCHANGER AREA - EL. 18.00'

Fire Zone 47 is the Unit 4 Component Cooling Water zone located on the 18.00' elevation near the Southeast corner of the Auxiliary Building. This is an outside zone containing the Component Cooling Water Pumps 4A, 4B, 4C and Unit 4 CCW Heat Exchangers A, B and C. The A and B train manholes (MH 408 and MH 410) are located within this fire zone.

4.OD.1.1 Essential Equipment Within Fire Zone 47

See Appendix R Essential Equipment List, Reference 15.

4.OD.1.2 Fire Zone 47 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	Negligible	---
.2b	Oils	---	---
.2c	Others	---	---
		TOTAL	---

Heat load (BTU/sq. ft.): Negligible

4.OD.1.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls
North: Reinforced Concrete East: Reinforced Concrete
South: Reinforced Concrete West: Reinforced Concrete

Ceiling: Steel Grating

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 47 is provided with a fire detection system which utilizes ultraviolet flame detectors. In addition, infrared flame and thermal detectors are installed which initiate the duplicate automatic deluge sprinkler systems for the component cooling water pumps and actuate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary
There are two accessible fire extinguishers in Fire Zone 58, and another in Fire Zone 46. (See Table 9.6A-4.) The component cooling water pumps are provided with duplicate, automatic deluge sprinkler systems actuated by thermal and infrared flame detectors.

2. Secondary

There is one available standpipe hose station in Fire Zone 58. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this fire zone. Smoke may be vented to the outside through the ceiling grating. Portable smoke ejectors are available onsite for fire brigade use.

4.OD.2 APPENDIX R EXEMPTIONS

Exemption 47.1

FPL requested (Reference 4) and was granted (Reference 6) exemption from that portion of Appendix R to 10 CFR Part 50 Section III.G.2.c which requires the enclosure of cable and equipment of one redundant train in a fire barrier having a one-hour rating. Specifically, exemption was requested from the enclosure of one Component Cooling Water Pump and associated power cable in a one-hour fire rated barrier.

Exemption 47.2

FPL requested (Reference 4) and was granted (Reference 6) exemption from that portion of Appendix R to 10 CFR Part 50 Section III.G.2.c which requires the installation of an automatic fire suppression system in the entire fire area. Specifically, exemption was requested from providing a fire suppression system that provides coverage for the remaining portion of the floor area of Fire Zone 47, which does not house the Component Cooling Water Pumps for Unit 4.

Justification for Exemption

Fire Zone 47 is an outdoor area bounded by concrete walls but having an open metal grating roof which precludes the buildup and stratification of hot gases, smoke or other products of combustion.

The in situ combustibles located in this fire zone consist of a small quantity of oil contained in the steel housings of the three Component Cooling Water Pumps (less than one gallon per pump) and cables located in cable trays. The only appreciable concentration of combustibles in this outdoor fire zone are the cable trays located in the Northwest corner of this area. All cables located in these cable trays are either coated with a fire propagation retardant (Flamastic 71A or 77) or qualified to the requirements of IEEE-383, 1974. Upon completion of the proposed modifications, safe shutdown of both units can be accomplished independent of the condition of these cable trays.

A review of potential transient combustibles for this fire zone was conducted by the Factory Mutual Research Corporation for FPL. The maximum expected transient source for this fire zone was identified as six gallons of lubricating oil.

Lubricating oil is transported only in original shipping containers or approved safety containers in this fire zone in accordance with existing procedures. The frequency of exposure to this transient generally would not be greater than annually during recommended maintenance. The infrequent exposure of this fire zone to a small quantity of combustible liquid transported in approved safety containers does not pose a significant risk to the safe shutdown equipment in this fire zone.

Fire protection features for this fire zone are both active and passive in nature. Passive protection is provided for the Component Cooling Water Pumps and associated power cables by the existing physical separation of approximately 12 feet on center. The power cables for all pump motors are routed underground in embedded conduit except for a short length in steel conduit from the floor to the motor terminal box. The local control stations for redundant pumps are separated by greater than 20 feet. In addition, control cables for component cooling Water Pump 4B are provided with a one-hour rated fire barrier.

Active fire protection is provided by ultraviolet fire detectors and the duplicate infrared flame and thermal fire detector-operated deluge automatic sprinkler systems installed to protect the CCW pumps. The fire detection system provides coverage for the entire fire zone, giving rapid early warning of fire before significant development occurs. The deluge systems, which provide a combined discharge density of 0.6 gpm/sq. ft., will provide exposure protection of the CCW pumps from any fire. The sprinkler pattern at design pressure will provide an approximate 13 foot throw. This will provide coverage approximately to the center of the travel path from the Auxiliary Building Hallway to the outside of the CCW area.

In conclusion, it is FPL's position that the fire protection features for Fire Zone 47 provide a level of fire protection consistent with the fire hazards, both in situ and transient, identified for this fire zone and that these features provide a high level of assurance that at least one train of safe shutdown equipment and cables will remain free of fire damage.

4.0D.3 FIRE ZONE 54 - UNIT 3
COMPONENT COOLING PUMP AND HEAT EXCHANGER AREA - EL. 18.00'

Fire Zone 54 is the Unit 3 Component Cooling Water zone located on the 18.00' elevation near the Northeast corner of the Auxiliary Building. This is an outside zone containing the Unit 3 Component Cooling Water Pumps 3A, 3B, 3C and Component Cooling Heat Exchangers A, B and C.

4.0D.3.1 Essential Equipment Within Fire Zone 54

See Appendix R Essential Equipment List, Reference 15.

4.0D.3.2 Fire Zone 54 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	Negligible	---
.2b	Oils	---	---
.2c	Others	---	---
		TOTAL	---

Heat load (BTU/sq. ft.): Negligible

4.0D.3.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete East: Reinforced Concrete
South: Reinforced Concrete West: Reinforced Concrete

Ceiling: Steel Grating

Floor: Reinforced Concrete

.4b Detection:

Fire Zone 54 is provided with a fire detection system which utilizes ultraviolet flame detectors. In addition, infrared flame and thermal detectors are installed which initiate the duplicate automatic deluge sprinkler systems for the component cooling water pumps and actuate an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary
There is one fire extinguisher in Fire Zone 54, another accessible fire extinguisher in Fire Zone 58. (See Table 9.6A-4.) The component cooling water pumps are provided with redundant, automatic deluge sprinkler systems actuated by thermal and infrared flame detectors.

2. Secondary
There is an available standpipe hose station in Fire Zone 58. (See Table 9.6A-5.)

.4d Smoke Venting:

No positive exhaust is provided in this fire zone. Smoke may be vented to the outside through the ceiling grating. Portable smoke ejectors are available onsite for fire brigade use.

.4c Fire Protection Systems:

1. Primary

There is one accessible fire extinguisher in Fire Zone 78. (See Table 9.6A-4.) The Turbine Lube Oil Reservoir is provided with fixed water spray suppression. The Secondary Chemistry Laboratory is provided with a wet pipe automatic sprinkler system.

2. Secondary

There is an available standpipe hose station in Fire Zone 78, and a hydrant in Fire Zone 76. (See Tables 9.6A-5 and 9.6A-6). The Secondary Chemistry Laboratory is provided with a standpipe and hose station.

.4d Smoke Venting:

This is an outside Fire Zone.

4.OD.6 APPENDIX R EXEMPTIONS

Exemption 76.1

Pursuant to 10 CFR Part 50.12, FPL requested (References 11 and 12) and was granted (Reference 13) exemption from the provisions of Section III.G.2.b of Appendix R to 10 CFR Part 50 that requires fire detection and automatic fire suppression systems for cables and equipment and associated non-safety circuits of redundant trains that are separated by a horizontal distance of 20 feet or greater with no intervening combustibles.

Specifically, exemption was requested from providing fire detection and automatic fire suppression systems throughout outdoor fire zones for the required redundant safe shutdown related cables having 20 feet or greater horizontal separation.

Exemption 76.2

Pursuant to 10 CFR Part 50.12, FPL requested (Reference 11 and 12) and was granted (Reference 13) exemption from the provision of Section III.G.2.c of Appendix R to 10 CFR Part 50 that requires installation of fire detection and automatic fire suppression systems for cables and equipment and associated non-safety circuits of one redundant train that is enclosed in a fire barrier having a one-hour rating.

Specifically, exemption was requested from providing fire detection and automatic fire suppression systems throughout outdoor fire zones for the required redundant safe shutdown related cables enclosed in a fire barrier having a one-hour rating where separation of 20 feet or more cannot be provided (Reference 11). NRC granted exemption by letter from S Varga to C O Woody, dated August 12, 1987 (Reference 13).

The following outdoor fire zones are affected:

Fire Zone	Elevation	Fire Suppression	Description
76	18.00′	Fixed Water Spray	Unit 4 Lube Oil Reservoir
77	18.00′	N/A	Unit 4 Laydown Area & Condensate Storage Area
78	18.00′	Fixed Water Spray	Unit 4 Turbine Lube Oil
		Part. Wet Pipe AS	Unit 4 Air Compressor Area
80	2.00′	Part. Wet Pipe AS	Unit 4 Main Condenser
81	18.00′	Fixed Water Spray	Unit 4 Main Transformer
			Unit 3 Turbine Lube Oil
			Unit 4 Start-up Transformer
82	18.00′	Fixed Water Spray	Unit 4 Aux. Transformer & Hydrogen Seal Oil Unit
		Part. Wet Pipe AS	Unit 4 Aux. Transformer Area
83	18.00′	Fixed Water Spray	Unit 3 Turb. Lube Oil
		Part. Wet Pipe AS	Unit 3 Air Compressor Area
85	2.00′	Part. Wet Pipe AS	Unit 3 Main Condenser
86	18.00′	Fixed Water Spray	Unit 3 Main Transformer & Startup Transformer
87	18.00′	Fixed Water Spray	Unit 3 Aux. Transformer & Hydrogen Seal Oil Unit
		Part. Wet Pipe AS	Unit 3 Aux. Transformer Area
88	18.00′	Part. Wet Pipe AS	Unit 3 Ground Fl. Vestibule
90	18.00′	N/A	Unit 3&4 DG Oil Storage Tank
91	5.00′	N/A	Unit 4 Condensate Pump
92	5.00′	N/A	Unit 3 Condensate Pump
105	30.00′	Part. Wet Pipe AS	Units 3&4 Turbine Building Mezzanine Deck
106R	58.50′	N/A	Control Room Roof
117	42.00′	N/A	Units 3&4 Turbine Building
118	61.00′	N/A	Units 3&4 Aux. Bldg. Roof

Justification for Exemption

The fire zones listed above are located in outside areas or within the perimeter of the open structure Turbine Building. Essential redundant safe shutdown cables routed through these zones are separated horizontally by a minimum distance of 20 feet or are provided with one-hour rated protection where 20 feet separation cannot be maintained.

The in situ combustible inventory consists of cables routed in cable trays or combustible liquids enclosed in stationary containers (i.e., Lube Oil Storage Tanks or Main and Auxiliary Transformers). The other combustible loads in these zones are attributed to the combustible liquids and were evaluated under Appendix A to BTP 9-5.1 resulting in the addition of fixed fire suppression systems.

The in situ combustible loading contributed by the cable is considered insignificant due to the outdoor nature of these zones. Similarly, in situ combustible liquids are high flash point liquids, they are contained in containers equivalent to NFPA 30 containers and automatic fire suppression systems have been provided.

4.0D.13.2 Fire Zone 80 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	Negligible	---
.2b	Oils	---	---
.2c	Others	---	---
		TOTAL	---

Heat load (BTU/sq. ft.): Negligible

4.0D.13.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Partly Reinforced Concrete, Partly Concrete Block

Ceiling: Reinforced Concrete, Bottom of Turbine and Partly Open

Floor: Reinforced Concrete

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There are two accessible fire extinguishers in Fire Zone 82, another three in Fire Zone 79, and one accessible extinguisher in each of Fire Zones 78 and 66. (See Table 9.6A-4.). Part of Fire Zone 80 is provided with Wet Pipe Fire Supression.

2. Secondary

There is one available standpipe hose station in each of Fire Zones 78 and 82. There is a hydrant in Fire Zone 81. (See Tables 9.6A-5 and 9.6A-6.)

.4d Smoke Venting:

No positive exhaust is provided in this Fire Zone. Smoke may be vented to the outside with portable smoke ejectors available onsite for fire brigade use.

4.OD.14 APPENDIX R EXEMPTIONS

Exemption 80.1

See Appendix R Exemption request and justification for Fire Zone 76 (Section 4.OD.6).

4.OD.15 FIRE ZONE 81 - UNIT 4 MAIN AND STARTUP TRANSFORMERS AND UNIT 3 TURBINE LUBE OIL RESERVOIR AREA - EL. 18.00'

Fire Zone 81 is the Unit 4 Main Transformer zone located on the 18.00' elevation north of Unit 4 Switchgear Rooms. This is an outside zone containing the Unit 4 Main Transformer and Startup Transformer and Unit 3 Turbine Lube Oil Reservoir.

4.OD.15.1 Essential Equipment Within Fire Zone 81

See Appendix R Essential Equipment List, Reference 15.

4.OD.15.2 Fire Zone 81 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	——	——
.2b	Oils	47,040 gal	7.08×10^9
.2c	Others	——	——
		TOTAL	7.08×10^9

Heat load (BTU/sq. ft.): 1.08×10^6

4.OD.15.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Open
South: Open
East: Open
West: Open

Ceiling: Open

Floor: Gravel

.4b Detection:

This Fire Zone is provided with thermal detection which actuates an alarm in the Control Room.

.4c Fire Protection Systems:

Fire Zone Boundary

Walls

North: Chain Link Fence
South: Concrete Block and Partly Open
East: Reinforced Concrete, Chain Link Fence and Partly Open

West: Chain Link Fence

Ceiling: Chain Link Fence

Floor: Reinforced Concrete

.4b Detection:

Smoke detectors (3) are installed in the D.C. Enclosure Building.

.4c Fire Protection Systems:

1. Primary

There are two accessible fire extinguishers in Fire Zone 79, another in Fire Zone 69, and a fourth in Fire Zone 83. (See Table 9.6A-4.)

2. Secondary

There is an available standpipe hose station in Fire Zone 83. (See Table 9.6A-5.)

.4d Smoke Venting:

This is an outside Fire Zone.

4.0D.22 APPENDIX R EXEMPTIONS

Exemption 84.1

FPL requested (Reference 4) and was granted (Reference 6) exemption from the provision of Section III.G.2.b of Appendix R to 10CFR Part 50 that requires fire detectors and automatic fire suppression for cables and equipment and associated circuits of redundant trains that are separated by a horizontal distance of 20' or greater. Specifically, exemption was requested from providing fire detection and automatic fire suppression for the required redundant safe shutdown related cables having 20' or greater horizontal separation listed below.

Exemption 84.2

FPL requested (Reference 4) and was granted (Reference 6) exemption from the provision of Section III.G.2.c of Appendix R to 10CFR Part 50 that requires installation of fire detectors and automatic fire suppression for cables and equipment and associated circuits of one redundant train that is enclosed in a fire barrier having a one-hour rating. Specifically, exemption was requested from providing fire detection and automatic fire suppression for the required redundant safe shutdown related cables enclosed in a fire barrier having a one-hour rating where separation of 20' or more cannot be provided.

The following cables are included in the above items:

Control Cables for Steam Generator 3A, 3B, 3C Level LT/LI-3-475, 485, 495; LT/LI-3-474, 484, 494.

Control Cables for Steam Generator Pressure PT/PI-3-474, 484, 494; PT/PI-3-476, 486, 496.

Control Cables for RCS Pressurizer Pressure PT/PI-3-455, 457.

Control Cables for Pressurizer Level LT/LI-3-459, 460.

Control Cables for RCS Temperature Hot Leg TE-3-413, 423, 433.

Control Cables for RCS Temperature Cold Leg TE-3-410, 420, 430.

Control Cables for Diesel Generator 4 Breaker to Bus 3B, Diesel Generator 3 Breaker to Bus 3A.

Control Cables for Auxiliary Feedwater to Steam Generator 3A, 3B, 3C Control Valves CV-3-2816, 2817, 2818 and Backup Control Valves CV-3-2813, 2832, 2833.

Control CAbles for Steam Generator Main Steam Isolation Valves 3A, 3B, 3C, SV-3-2604, 2605, 2606.

Justification for Exemption

Fire Zone 84 is an open outdoor area at grade elevation, partially covered by the Unit 3 Main Steam Platform, which approximately 35' above grade. The zone is bounded on the east by the Unit 3 Containment and on the remaining three sides by chain link fencing or missile shield grating. The open nature of this zone precludes the buildup or stratification of hot gases or other products of combustion should a fire occur in this zone.

Essential redundant safe shutdown cables routed through this zone are separated horizontally by a minimum distance of 20' or are provided with one-hour rated protection where 20' separation is not maintained.

The in situ combustible inventory for this outdoor zone consists of cable in trays which pass through the zone between 13' and 21' above grade, and lubricating oil contained in the steel reservoirs of the three Auxiliary Feedwater Pump turbines.

All cables in cable trays in this zone are either coated with a fire propagation retardant (Flamastic 71A or 77) or are qualified to the requirements of IEEE-383, 1974. The height above a grade level exposure fire combined with the fire retardant characteristics of the cables and coatings, and the open nature of this outdoor area serve to effectively exclude these cables from contributing to the fire load for this zone.

Each Auxiliary Feedwater Pump turbine has an independent, pressurized lubrication system containing approximately 24.5 gallons of lubricating oil. The oil system is of steel construction, seismically designed and qualified. During plant operation the oil system is not normally pressurized or operating, only on conditions of off-normal operation, accident or testing will the system be in operation. The design features of the Auxiliary Feedwater Pump oil system and the limited periods when the system would be operating are such that the potential for a fire from this in situ source is considered very unlikely.

A review of the potential transient combustibles for this fire zone was conducted by the Factory Mutual Research Corporation for FPL. The maximum expected transient source for this zone was identified as one hundred and thirty gallons of lubricating oil.

Lubricating oil is transported in this fire zone only in original shipping containers or approved safety cans. There are no sources of ignition such as high temperature piping, at floor level in this fire zone.

Fire protection features for this outdoor fire zone are both active and passive in nature. Active fire protection is provided by the fire watch patrol, which in accordance with Fire Protection Program procedures (Reference 28), patrols this fire zone at least once each hour. Passive fire protection is provided by the physical separation of redundant essential cables by 20' and by the provision of one-hour rated protection where 20' separation is not maintained.

In conclusion, it is FPL's position that the existing fire protection features for Fire Zone 84 provide a level of fire protection consistent with the fire hazards identified, both in situ and transient, and that these features provide a high level of assurance that at least one train of safe shutdown equipment and cables will remain free of fire damage.

4.OD.23 FIRE ZONE 85 - UNIT 3 MAIN CONDENSER AREA - EL. 2.00'

Fire Zone 85 is the Unit 3 Main Condenser zone located on the 2.00' elevation west of Auxiliary Feedwater Pumps. This is an outside zone containing the Unit 3 Main Condenser and associated piping, instruments and valves.

4.OD.23.1 <u>Essential Equipment Within Fire Zone 85</u>

See Appendix R Essential Equipment List, Reference 15.

4.OD.23.2 Fire Zone 85 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	Negligible	---
.2b	Oils	---	---
.2c	Others	---	---
		TOTAL	---

Heat load (BTU/sq. ft.): Negligible

4.OD.23.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Reinforced Concrete
South: Reinforced Concrete
East: Reinforced Concrete
West: Partly Reinforced Concrete and Partly Concrete Block

Ceiling: Reinforced Concrete supported by Structural Steel and partly open.

Floor: Reinforced Concrete

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There are two accessible fire extinguishers in Fire Zone 87, two more in Fire Zone 88, and a fifth in Fire Zone 69. Part of Fire Zone 85 is protected by a wet pipe sprinkler system. (See Table 9.6A-4.)

2. Secondary

There is an available standpipe hose station in Fire Zone 87, and a hydrant in Fire Zone 86. (See Tables 9.6A-5 and 9.6A-6.)

.4d Smoke Venting:

No positive exhaust is provided in this Fire Zone. Smoke may be vented to the outside with portable smoke ejectors available onsite for fire brigade use.

4.0D.41.2 Fire Zone 113 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	Negligible	---
.2b	Oils	---	---
.2c	Others	---	---
		TOTAL	---

Heat load (BTU/sq. ft.): Negligible

4.0D.41.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls	EL. 18.00 Feet	EL. 38.00 Feet
North:	Open	Reinforced Concrete
South:	Open	Open
East:	Reinforced Concrete	Reinforced Concrete
West:	Open	Reinforced Concrete
Ceiling:	Metal Plates	Reinforced Concrete supported by Structural Steel
Floor:	Reinforced Concrete	Metal Plates

.4b Detection:

Fire Zone 113 is provided with flame detection which actuates an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There is one accessible fire extinguisher in each of Fire Zones 66 and 78. (See Table 9.6A-4.)

2. Secondary

There are available standpipe hose stations in Fire Zone 78. (See Table 9.6A-5.)

.4d Smoke Venting:

This Fire Zone is open to the atmosphere.

Exemption 113.1

FPL requested (Reference 4) and was granted (Reference 6) exemption from that portion of Section III.G.2.a of Appendix R to 10 CFR Part 50 which requires the separation of cables and equipment and associated non-safety circuits of redundant trains by a fire barrier having a three-hour rating. Specifically, the exemption was requested from providing a three-hour rated barrier between redundant Auxiliary Feedwater supply valves.

Exemption 113.2

FPL requested (Reference 4) and was granted (Reference 6) exemption from that provision of Section III.G.2.b of Appendix R to 10 CFR Part 50 which requires providing an automatic fire suppression system in the fire zone where cables and equipment of redundant trains are separated by a horizontal distance of more than 20'. Exemption was requested from providing an automatic fire suppression system for the conduits carrying cables associated with redundant Auxiliary Feedwater supply valves, that are separated by 20' or more.

Exemption 113.3

FPL requested (Reference 4) and was granted (Reference 6) exemption from that provision of Section III.G.2.c of Appendix R to 10 CFR Part 50 which requires providing an automatic fire suppression system for cables enclosed in a barrier of one-hour rating. Specifically, exemption was requested from providing an automatic fire suppression system for the conduits, carrying cables associated with redundant auxiliary Feedwater Supply Valves CV-4-2831, 2832 and 2833, which are being provided with a one-hour rated barrier.

Justification for Exemption

Fire Zone 113 is a two level outdoor area. The 18' grade level is bounded on the east by the Unit 4 containment and is open on the remaining three sides. The upper level is separated from grade by a 1/4" steel platform located approximately 20' above grade and is bounded by concrete walls on the north and west and by the Unit 4 containment on the east. The south side is open which precludes the buildup and stratification of hot gases, smoke and other products of combustion. The ceiling is concrete.

Redundant Auxiliary Feedwater Supply valves are located in this fire zone. One set of valves are located in the lower level of the zone, approximately 12' above grade, below the steel platform. The redundant set of valves are located in the upper level of the zone, 24' above grade and 3 1/2' above the steel platform deck.

The main feedwater by-pass valves are also located in this zone on the upper level, above the steel platform.

The in situ combustible loading in this outdoor fire zone is negligible there are no cable trays or other in situ combustible materials of significance in the zone. A review of the potential transient combustibles for this fire zone was conducted by the Factory Mutual Research Corporation for FPL. The results of this review indicate that there are no transient combustibles expected in this zone.

The absence of in situ and transient combustibles in this zone assures a very low potential for the occurrence of a significant fire. The completely open nature of this zone prevents the build up and stratification of hot gases, smoke or other products of combustion from affecting redundant equipment should a fire occur. The large physical separation between redundant components and cables assures that a single credible fire will not impact more than one train of safe shutdown components.

In conclusion, it is FPL's position that the existing fire protection features for Fire Zone 115 provide a level of fire protection consistent with the fire hazards, both in situ and transient, and that these features provide a high level of assurance that the required safe shutdown equipment and cables will remain free of fire damage.

4.0D.47 FIRE ZONE 116 - UNIT 3 FEEDWATER PLATFORM - EL. 18.00' AND 39.75'

Fire Zone 116 is the Unit 3 Feedwater Platform zone located on the 18.00' and 39.75' elevations near the Unit 3 Containment and on the north-east end of the Unit 3 Turbine Deck. This is an outside zone containing the Auxiliary Feedwater System valves, piping and instruments.

4.0D.47.1 Essential Equipment Within Fire Zone 116

See Appendix R Essential Equipment List, Reference 15.

4.0D.47.2 Fire Zone 116 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	Negligible	---
.2b	Oils	---	---
.2c	Others	---	---
		TOTAL	---

Heat load (BTU/sq. ft.): Negligible

4.0D.47.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls:	EL. 18.00 Feet	EL. 39.75 Feet
North:	Open	Reinforced Concrete
South:	Open	Open
East:	Open & Reinforced Concrete	Reinforced Concrete
West:	Open	Reinforced Concrete

Ceiling:	Metal Plates	Reinforced Concrete supported by Structural Steel
Floor:	Reinforced Concrete	Metal Plates

.4b Detection:

Fire Zone 116 is provided with flame detection which actuates an alarm in the Control Room.

.4c Fire Protection Systems:

1. Primary

There are two accessible fire extinguishers in Fire Zone 88 and another in Fire Zone 89. (See Table 9.6A-4.)

2. Secondary

There is an available standpipe hose station in Fire Zone 117. (See Table 9.6A-5.)

.4d Smoke Venting:

This is an outside Fire Zone.

4.OD.48 APPENDIX R EXEMPTIONS

Exemption 116.1

FPL requested (Reference 4) and was granted (Reference 6) exemption from that portion of Section III.G.2.a of Appendix R to 10 CFR Part 50 which requires separation of cables and equipment and associated non-safety circuits of redundant trains by a fire barrier having a three-hour rating. Specifically, exemption was requested from providing a three-hour rated barrier between redundant Auxiliary Feedwater Supply Valves.

Exemption 116.2

FPL requested (Reference 4) and was granted (Reference 6) exemption from that portion of Section III.G.2.b of Appendix R 10 CFR Part 50 which requires providing automatic fire suppression system in the fire zone where cables and equipment of redundant trains are separated by a horizontal distance of more than 20'. Specifically, exemption was requested from providing automatic fire suppression system for the conduits carrying cables associated with redundant Auxiliary Feedwater Supply valves that are separated by 20' or more.

Fire protection features for this zone are both active and passive in nature. Active fire protection is provided by the fire detection system which will provide early warning of any fire in this area, allowing the operators to respond before significant development occurs.

Passive fire protection is provided by the physical separation of the Intake Cooling Water Pumps by 14 feet on center (28 feet between end pumps). Power cable for pump motors are routed in embedded conduit in this zone except for a short length from the floor up to the motor terminal box. This short length is provided with one-hour rated conduit protection for the Train B pump to further enhance the availability of at least one train of essential equipment.

In conclusion, it is FPL's position that the existing fire protection features for Fire Zone 120 provide a level of fire protection consistent with the fire hazards, both in situ and transient, identified for this fire zone and that these features provide a high level of assurance that at least one train of safe shutdown equipment and cables will remain free of fire damage.

4.OD.57 FIRE ZONE 121 - UNITS 3 AND 4 INTAKE LAYDOWN AREA - EL. 16.00'

Fire Zone 121 is the Units 3 and 4 Intake Laydown zone located on the 16.00' elevation near the Units 3 and 4 Intake Structure. This is an outside zone containing no safety-related equipment; however, safety related cables for Intake Cooling Water Pumps 4A, 4B and 4C are routed in underground ductbanks through this zone.

4.OD.57.1 Essential Equipment Within Fire Zone 121

See Appendix R Essential Equipment List, Reference 15.

4.OD.57.2 Fire Zone 121 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	Negligible	---
.2b	Oils	---	---
.2c	Others	---	---
		TOTAL	---

Heat load (BTU/sq. ft.): Negligible

4.OD.57.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Open
South: Open
East: Open
West: Open

Ceiling: Open

Floor: Reinforced Concrete, Metal Plates and Grating

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There is one accessible fire extinguisher in Fire Zone 119. (See Table 9.6A-4.)

2. Secondary

There are three hydrants in Fire Zone 123. (See Table 9.6A-6.)

.4d Smoke Venting:

This is an outside Fire Zone.

4.OD.58 APPENDIX R EXEMPTIONS

No exemptions were requested for this fire zone.

4.OD.59 FIRE ZONE 122 - UNITS 3 AND 4 WATER TREATMENT AREA - EL. 16.00'

Fire Zone 122 is the water treatment zone located on the 16.00' elevation north of the cooling water intake structure. This is an outside zone containing no safety-related equipment; however, safety related cables for Intake Cooling Water Pumps 3A, 3B and 3C and the Electric Fire Pump are routed in underground duct banks through this zone. The diesel-driven, electric-driven and jockey fire pumps are located in this zone.

4.OD.59.1 Essential Equipment Within Fire Zone 122

See Appendix R Essential Equipment List, Reference 15.

4.OD.59.2 Fire Zone 122 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	Negligible	---
.2b	Oils/Fuel	703 gal	1.17×10^8
.2c	Others	-	-
		TOTAL	1.17×10^8

Heat load (BTU/sq. ft.): 9.4×10^2

4.0D.59.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Open and Partly Fencing
South: Open and Partly Fencing
East: Open and Partly Fencing
West: Open

Ceiling: Open

Floor: Gravel

.4b Detection:

None

.4c Fire Protection Systems:

1. Primary

There are several fire extinguishers in Fire Zone 122, located in the Technical Support Center and I&C Building. (See Table 9.6A-4.)

2. Secondary

There is a hydrant in Fire Zone 124. (See Table 9.6A-6.)

.4d Smoke Venting:

This is an outside Fire Zone.

4.0D.60 APPENDIX R EXEMPTIONS

No exemptions were requested for this fire zone.

4.0D.61 FIRE ZONE 123 - UNITS 3 AND 4 REFUELING WATER STORAGE TANK AREA - EL. 18.00'

Fire Zone 123 is the Units 3 and 4 Refueling Water Storage Tanks zone located on the 18.00' elevation east of the Units 3 and 4 Auxiliary Building. This is an outside zone containing the Units 3 and 4 Refueling Water Storage Tanks as well as the Gas House and the H_2 supply trailer.

4.0D.61.1 Essential Equipment Within Fire Zone 123

See Appendix R Essential Equipment List, Reference 15.

4.OD.61.2 Fire Zone 123 - Combustible Loadings

	SOURCE	QUANTITY	(BTU)
.2a	Cable Insulation	Negligible	---
.2b	Oils	---	---
.2c	Others		
	Gas House	1,530 ft^3	4.44×10^5
	Hydrogen Gas	62,000 ft^3	179.00×10^5
		TOTAL	183.44×10^5

Heat load (BTU/sq. ft.): 8.0×10^0

4.OD.61.3 Fire Control

.4a Physical Containment:

Fire Zone Boundary

Walls

North: Open
South: Fencing
East: Open
West: Reinforced Concrete

Ceiling: Open

Floor: Reinforced Concrete

.4b Detection:
None

.4c Fire Protection Systems:

1. Primary

There is one accessible fire extinguisher in Fire Zone 123, another accessible fire extinguisher in adjacent Fire Zone 54, and a third in Fire Zone 58. (See Table 9.6A-4.)

2. Secondary

There are three hydrants in Fire Zone 123. (See Table 9.6A-6.)

.4d Smoke Venting:

This is an outside Fire Zone.

4.OD.62 APPENDIX R EXEMPTIONS

No exemptions were requested for this fire zone.

Justification for Exemption

Fire Zone 131 is an outdoor area bounded on three sides by a metal grating missile shield which precludes the buildup and stratification of hot gases, smoke and other products of combustion. The east wall and ceiling are concrete.

The in situ combustible located in this fire area consist of radiator fan belts and rubber hoses. There are no cable trays in this fire zone.

A review of potential transient combustibles for this fire zone was conducted by the Factory Mutual Research Corporation for FPL. The results of this review indicate that there are no expected transient combustible for this fire zone.

A 10-foot high fire barrier of three-hour construction separates redundant diesel generator radiators and provides protection for one unit from a floor level fire in the redundant unit. In addition, the west wall for this fire zone is open to the atmosphere, thereby allowing hot gases to vent and dissipate before redundant equipment is damaged. This combination of features compensate for the lack of a complete three-hour rated fire barrier.

In conclusion, it is FPL's position that the existing fire protection features for Fire Zone 131 provide a level of fire protection consistent with the fire hazards, both in situ and transient, identified in this fire zone. These features provide a high level of assurance that at least one train of redundant safe shutdown equipment and cables will remain free of fire damage.

4.OD.71 FIRE ZONE 999 - MISCELLANEOUS AREAS

Fire Zone 999 consists of miscellaneous areas including the Standby Steam Generator Feedwater Pump Area and those not contained in any other defined fire zone. These areas are located outside of the power block and inside the protected area fence. This zone is in open areas segregated from any significant combustibles. Equipment located within this zone is only required in the event of a fire in zones 79 or 84. Therefore, this fire zone is required as part of the fire protection program for these cases only.

A fire in this zone will have no impact on the safe shutdown capability of Unit 3 or 4.

5.0 ALTERNATE SHUTDOWN CAPABILITY

5.1 INTRODUCTION

Alternate Shutdown Capability for Turkey Point Nuclear Power Plant Units 3 & 4 is provided in accordance with the requirement of 10 CFR 50 Appendix R, Sections III.G.3 and III.L in the event of a fire in the Control Room Area (including the HVAC equipment room and a portion of the Control Room roof), the Cable Spreading Room Area, or the Auxiliary Building North-South Breezeway Area which requires the evacuation of the Control Room. Instrumentation and controls to achieve and maintain hot standby are provided on the Alternate Shutdown Panels (ASP) 3C264 and 4C264 and supplemented by manual actions at local stations for achieving cold shutdown. Design of the Alternate Shutdown

Capability is such that Channel "B" equipment necessary to achieve and maintain hot standby will not be rendered inoperable due to a postulated fire in any of the following areas:

- o Control Room including HVAC Equipment Room and a portion of the Control Room roof (Fire Area MM)
- o Cable Spreading Room (Fire Area HH)
- o Auxiliary Building North-South Breezeway (Fire Area CC)

Reference 15 lists the Appendix R essential equipment. Table 9.6A-2 lists components, instruments, and controls required for alternate shutdown.

Performance Goals:

Section III.L.2 of the 10 CFR 50, Appendix R states that performance goals for the shut down function shall be: (a) The reactivity control function shall be capable of achieving and maintaining cold shutdown reactivity condition; (b) The reactor coolant makeup function shall be capable of maintaining the reactor coolant within the level indication in the pressurizer; (c) The reactor heat removal functions shall be capable of achieving and maintaining decay heat removal; (d) The process monitoring function shall be capable of providing direct readings of the process variables necessary to perform and control above functions; (e) 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.

Discussion detailing how each performance goal is satisfied follows:

- o The reactivity control function shall be capable of achieving and maintaining cold shutdown reactivity conditions.

  The Reactor Control Rods and the Reactor Protection System (RPS) provide sufficient control to achieve hot standby without support of the Chemical Volume Control System (CVCS). The reactor trip breakers that de-energize the Rod Control Cluster (RCC) assemblies are the active RPS components. However, to maintain hot shutdown or commence cooldown, CVCS support is required for boration and Reactor Coolant System (RCS) make-up. To achieve and maintain cold shutdown, reactivity control is maintained by boric acid addition. Boration can be achieved via one charging pump and one Boric Acid Transfer Pump or via the Refueling Water Storage Tank (RWST) providing suction to the charging pumps.

  However, to achieve cold shutdown reactivity conditions with the minimum quantity of letdown waste generated, the Boric Acid Transfer Pump should be utilized instead of the RWST, if available.

- o The reactor coolant make-up function shall be capable of maintaining the reactor coolant within the level indication in the pressurizer.

To compensate for the losses from the RCS during hot shutdown and any contraction of the RCS volume due to cooldown, the CVCS provides RCS make-up using one charging pump. The reactor coolant make-up function is capable of maintaining the reactor coolant within the levels specified for the pressurizer using Plant Curve Book Section V Figure 3C to convert LI-*-462-1 to the hot calibration channel equivalent. The RWST is the source of borated water for RCS make-up. If flow path is available the Boric Acid Tanks (BAT) can provide an alternate temporary water source. Upon loss of off-site power (LOOP) the charging pump can be powered from the emergency diesel generators. Any sudden pressure surges in the RCS can be relieved through the pressurizer safety valves discharging into pressurizer relief tanks.

- The reactor heat removal function shall be capable of achieving and maintaining decay heat removal.

  During hot standby conditions and initial cooldown conditions, decay heat removal is accomplished by Atmospheric Dump Valve operations and Auxiliary Feedwater pump turbine exhaust.

  During subsequent cooldown and cold shutdown conditions decay heat removal is accomplished by the Residual Heat Removal (RHR) system. The decay heat removed by the RHR heat exchanger is transferred to the Component Cooling Water (CCW) system which in turn transfers heat to the Intake Cooling Water (ICW) system. RHR cuts in approximately 19 hours after start of cooldown if reactor was initially at normal operating temperature. Condensate inventory in the condensate storage tank for the above duration is adequate.

  Decay heat added to the containment atmosphere through radiative and convective heat transfer processes from RCS equipment and piping is removed by the Normal Containment Coolers. Since the Reactor Coolant Pumps are tripped as part of the Alternate Shutdown process, a minimum of one Normal Containment Cooler per unit is required to provide heat removal. Control and indication is provided at the Alternate Shutdown Panels for two fans per unit. For some fire scenarios, only one fan is assured to be available.

- The process monitoring function shall be capable of providing direct readings of the process variables necessary to perform and control the above functions.

  The necessary process monitoring controls and indications, as appropriate are provided. A reactor ex-core Neutron Flux Monitoring system has been added. However, the necessary indicators are provided on the Alternate Shutdown Panel.

- 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 availability of necessary supporting functions has been evaluated and provided as required.

5.2 DESIGN BASES

5.2.1 SAFETY DESIGN BASES

(a) The alternate shutdown systems and components shall be independent of the Control Room (including the HVAC Equipment Room and a portion of the Control Room roof), the Cable Spreading Room, and the North-South Breezeway.

(b) Capability shall be provided to bring both Units 3 & 4 to hot standby and achieve cold shutdown conditions within 72 hours of Control Room evacuation and maintain cold shutdown thereafter.

(c) The single failure criterion shall not apply to the design of the alternate shutdown systems and components, except to account for adverse equipment actions caused by the postulated fire, and the resultant effect on the safe shutdown systems. The Alternate Shutdown System shall be designed such that electrical interfaces with existing safe shutdown equipment do not compromise the original design of the safe shutdown systems, including qualifications for nuclear, seismic, and environmental codes and standards.

(d) Fire-induced spurious actuation of systems and components due to hot short, open circuit or short to ground shall be assumed to render equipment unusable or place it in undesirable mode.

(e) No credit shall be taken for repairs in the Control Room (including HVAC Equipment Room and the affected portion of the Control Room roof), Cable Spreading Room, or North-South Breezeway to achieve or maintain hot standby; local manual actions shall be permitted to achieve and maintain hot standby condition. No credit shall be taken for the replacement of the fuses to achieve hot standby condition. However, to achieve cold shutdown minor repairs such as replacement of fuses will be acceptable.

(f) The Alternate Shutdown System shall be designed to accomplish safe shutdown using the normal shift staffing level, less personnel needed for fire brigade.

(g) No design basis accident or natural phenomenon (earthquake, hurricane, tornadoes or any other design basis events) shall be postulated concurrent with fire, or during the recovery period immediately following a fire.

(h) A Loss of Off-site Power (LOOP) shall be postulated concurrent with fire and worst case scenario (with or without off-site power) shall be considered.

(i) Only operator action to trip the reactor from the Control Room prior to Control Room evacuation shall be taken credit for achieving hot standby condition.

(j) One train of safe shutdown equipment remains free from fire damage after the fire.

(k) The Alternate Shutdown System shall rely on Emergency Diesel, AC and DC power to achieve safe shutdown functions.

(l) The Alternate Shutdown System shall include a dedicated communication system to coordinate operator actions.

(m) The Alternate Shutdown Panels shall be located in an inhabitable area, with security and controlled access.

5.2.2 POWER GENERATION DESIGN BASES

There are no power generation bases.

5.3 DESIGN COMPLIANCE

Turkey Point Plant Units 3 and 4 comply with the safety design compliance as described below in a chronological order for the alternate shutdown capability:

5.3.1 SAFETY DESIGN COMPLIANCE

(a) Selected components required for alternate shutdown capability are provided on the Alternate Shutdown Panel for each unit in its own "B" switchgear room, which is independent of Control Room, Cable Spreading Room and North-South Breezeway.

(b) Instrumentation and controls for selected components are provided to bring the plant to hot standby from the Alternate Shutdown Panel (ASP). Operator action at the ASP supplemented by manual actions at local stations are required to achieve and maintain cold shutdown thereafter.

(c) The alternate shutdown system ensures and takes credit for the availability of Channel "B" components of the safe shut down systems for a fire postulated in any of the defined alternate shutdown areas. The isolation switches isolate the essential controls routed to the Alternate Shutdown Panel from the postulated fire areas MM, HH and CC. Control functions are provided by addition of transfer and control switches, and control devices. Isolation and control switches and devices are located on the Alternate Shutdown Panel and/or the alternate shutdown instrument cabinet inside each of the switchgear rooms 3B/4B. Additional controls are provided locally where necessary to supplement those available at the alternate shutdown panel. Vital electrical power for this system is provided from sources located outside the postulated fire areas. The equipment added is nuclear qualified where required, meeting the appropriate seismic and environmental qualification requirements. The installation meets the FSAR seismic requirements and codes and standards. All cables associated with the equipment and components are either protected or routed outside the alternate shutdown fire areas.

(d) In order to prevent fire-induced spurious actuation of systems and components, components designated for alternate shutdown system are provided with isolation/transfer switches and controls and/or indications on the Alternate Shutdown Panel (ASP).

(e) The alternate shutdown system is provided with a dedicated train "B" of equipment necessary to bring the unit to hot standby and subsequently to a cold shutdown from the ASP and local stations. No credit is taken for any cold shutdown repairs, except for replacement of fuses, although certain minor repairs are allowed by Appendix R to 10 CFR part 50.

(f) Adequate manpower is available on site at all times to bring the plant to hot standby, achieve and maintain cold shutdown, as well as fight a fire at the same time.

(g) All components for the alternate shutdown system are nuclear qualified and seismically installed. Worst case fire scenario is not postulated to be concurrent with non-fire related failures in safety systems, plant accidents or the most severe natural phenomena.

(h) Electrical power for this system is provided from sources located outside the postulated fire areas. Loss of off-site power, concurrent with a fire, will not render the alternate shutdown system inoperable because at least one diesel generator per unit (Train B) is available to supply power to support the alternate shutdown system.

(i) In the event of a fire in one of the three postulated alternate shutdown fire areas, if subsequent Control Room evacuation is required, prior to leaving the Control Room the respective unit reactors and turbines are tripped, if possible. Upon Control Room evacuation, reactor and turbine trip will be initiated or verified at local control stations as necessary.

(j) Credit has been taken for one train of equipment required for alternate shutdown to be free from fire damage after the postulated fire.

(k) The alternate Shutdown Panels are located in the "B" switchgear room of each unit. Emergency diesel generators 3B and 4B are dedicated to the alternate shutdown system. The Channel "B" electrical distribution system is made available by local operator actions by stripping the 'B' bus to avoid spurious and non-safe shutdown loads which could over load the diesels. In order to provide isolation of trip and close coils from alternate shutdown fire areas, transfer switches are provided for the related breakers at the switchgear panels. In addition, Channel 'A' and 'C' buses are deenergized to preclude spurious actuation and adverse effects on the system parameters.

The AC and DC uninterruptible control power is available from the emergency diesel power for the alternate shutdown system to accomplish safe shutdown functions.

(l) A dedicated communication system, independent of and normally isolated from the three postulated fire areas is provided to enable the operators to coordinate various manual operations and to monitor plant status. The system provides communication between the two Alternate Shutdown Panels, the Technical Support Center, 3B Diesel Generator Room, 4B Diesel Generator Control Room, and those stations requiring local control to achieve cold shutdown. A key lock isolation switch is provided to isolate the portion of the communication circuit to the Control Room during normal plant operation.

The communication system is powered by the new Vital 120 volt AC Power Panel 3P93. The power feed fuse to the communication system is coordinated to assure the Class 1E system is protected from the non-Class 1E communication systems fed by the power panel.

(m) The alternate shutdown system panels are located in the Units 3 and 4 4160V "B" switchgear rooms. Ventilation to these rooms can be enhanced by opening the doors to establish cross-ventilation.

5.3.2 POWER GENERATION DESIGN COMPLIANCE

None required.

5.4 GENERAL DESCRIPTION

In the unlikely event that a fire in the Control Room including HVAC Equipment Room and a portion of the Control Room roof, the North-South Breezeway, or the Cable Spreading Room requires evacuation of the Control Room, plant shutdown will be accomplished and monitored from the Alternate Shutdown Panels (ASP's) with local operation of selected equipment. The ASP for each unit is installed in the associated 4160V "B" switchgear room.

Alternate Shutdown will be accomplished in accordance with Plant Procedures.

5.5 GENERAL OPERATION

The following paragraphs provide description of systems used to achieve alternate shutdown and alternate shutdown panel controls/indication:

Auxiliary Feedwater System

Auxiliary Feedwater Pump operation is automatic in response to the following for both Units (3 & 4):

- o Both Main Feedwater Pumps (i.e., the last running) Trip or
- o Low-Low Steam Generator Level or
- o Safety Injection Actuation Signal or
- o Under-voltage on one of the A, B, C or D 480 volt load centers and diesel generator breaker open, or
- o Loss of voltage on one 4KV Bus

Unit 3

Should the AFW pumps not start automatically due to a fire in one of the three postulated fire areas for alternate shutdown, AFW Pump C control is available on the Alternate Shutdown Panel. AFW Pump C control is provided by the following:

- o Transfer switch isolation and control switches for the AFW Steam Supply Valve and Trip and Throttle Valve.

- o Transfer switch isolation and manual controller operation for the discharge flow control valves.

- o AFW discharge flow indication to each steam generator.

- o Level indication for each steam generator.

Unit 4

Should the AFW pumps not start automatically due to a fire in one of the three postulated fire areas for alternate shutdown, AFW Pump B Control is available on the alternate shutdown panel. AFW Pump B Control is provided by the following:

- o Transfer switch isolation and control switches for the AFW Steam Supply Valve and Trip and Throttle Valve.

- o Transfer switch isolation and manual controller operation for the discharge flow control valves.

- o AFW discharge flow indication to each steam generator.

- o Level indication for each steam generator.

The inventory of Condensate Storage Tank (CST) is limited but is sufficient to bring the plant to cold shutdown within 19 hours in the natural circulation mode without Control Rod Drive Mechanism (CRDM) cooling fans. For an extended hot standby, means to replenish the makeup water inventory in the Condensate Storage Tank is needed. The Alternate Shutdown System is not designed to replenish the makeup water. However, Water Treatment Plant, Primary Water Pumps or Condensate Transfer Pumps can be used to replenish makeup water to the CST if this equipment is available. Since none of the above equipment is protected, there is no assurance that this equipment will be available. Therefore, a very careful assessment of the water inventory should be made before the hot standby is extended. If makeup water is not available, the Units must be brought to cold shutdown within a time period which depends on the CST inventory and availability of CRDM fans. Adequate procedures are in place to enable the operators to cooldown with CRDM fans and to determine the extension of the hot shutdown.

Main Steam System

Subsequent to turbine generator and reactor trip, Main Steam Isolation Valve (MSIV) closure isolates the steam generators so that steam removal to maintain hot shutdown temperature limits will be directed to the atmospheric dump valves and AFW Pump turbines. If MSIV actuation is impaired by fire in one of the postulated areas, valve closure can be initiated at the ASP. The decay heat generated during an extended hot standby condition is dissipated by operation of the atmospheric dump valves and the AFW pump turbine exhaust. Operation of the atmospheric dump valves are provided on the Alternate Shutdown Panel by transfer switches and manual loaders for each valve. These controls are independent of the three postulated fire areas for alternate shutdown. There are no controls directly associated with the AFW Pump turbine exhaust. Main Steam System control and status at the ASP are as follows:

- o Pressure indication for each steam generator.

o Heating and Ventilation for Alternate Shutdown Panels (3C264 and 4C264)

The above panels are located in Units 3 and 4 switchgear rooms. Ventilation to these rooms can be enhanced by opening the doors to establish cross-ventilation.

5.6 VALVE HAND OPERATORS

Turkey Point Unit 3 has installed manual operating features to selected air operated valves (Table 9.6A-11) in the Chemical and Volume Control System (CVCS), Residual Heat Removal (RHR) System, and the Component Cooling Water (CCW) System. The installation of these features provides an alternate means of operating these valves if the valve misoperates due to receipt of a spurious electrical signal resulting from a postulated fire.

This improper signal is postulated to be caused by a fire that could produce a conductor short, short to ground or open circuit in cables associated with the subject valves. Instrument air to the valve operator is assumed to still be available. These changes implement recommendations made as part of the Appendix R Safe Shutdown Analysis in order to meet the licensing commitments of 10 CFR 50, Appendix R. These modifications have been done in lieu of providing fire protection for the cables associated with the operators.

6.0 PRIMARY COOLANT SYSTEM INTERFACES

Several low pressure systems are connected to the high pressure Reactor Coolant System (RCS). These low pressure systems are provided with isolation valves at the interface with the RCS. The isolation valves and their associated cables are postulated to be subject to a single fire hazard. An evaluation has been performed to ensure that in the event of such a fire the isolation valves do not open spuriously and result in a fire-initiated LOCA. This section identifies the low pressure systems that are connected to the RCS and summarizes the results of the evaluation that ensures the spurious operation of a component will not create a LOCA.

The evaluation utilizes the following as basis for spurious actuation of the low pressure system isolation valves interfacing with the RCS:

1) The safe shutdown capability should not be adversely affected by a fire in any fire area and the postulated loss of all automatic functions (signals, logic) from the circuits located in the fire area; and

2) The safe shutdown capability should not be adversely affected by a fire in any fire area and the postulated spurious actuation of the redundant isolation valves in any one low pressure system/RCS interface line.

Spurious actuations of low pressure system/RCS interface valves due to three phase hot shorts of the proper sequence on AC circuits, or two hot shorts of the proper polarity on the 125V DC system, are not considered credible. However, while not considered credible, multiple spurious actuations have been evaluated for each low pressure system/RCS interface line individually.

The low pressure systems connected to the RCS are listed in Table 9.6A-10, and a description of each system connected to the RCS is provided below:

1. Primary Sampling Systems

The RCS has sample lines connected to three locations: the hot leg, the pressurizer steam space and the pressurizer liquid space. Each sampling line has redundant isolation valves which fail closed on loss of air or power. The sample lines are kept isolated with manual isolation valves at all times other than when a sample is being taken. A fire-induced spurious operation of any of the valves would therefore not initiate a LOCA. In addition, the loss of RCS inventory through these small (3/8-inch diameter) lines is well within the capacity of the charging pumps.

2. Residual Heat Removal (RHR) Return Line

The RHR return line (from the RCS) is provided with redundant motor operated isolation valves at the interface with the RCS hot leg. When RCS pressure exceeds the design pressure of the residual heat removal loop, an interlock from the RCS wide range pressure controllers prevents the valves from opening or closes them if open. In addition, each isolation valve is also normally closed and the circuit breaker is administratively locked open when the RCS pressure is in excess of the RHR design pressure. Because the power to each motor-operated isolation valve is administratively removed whenever the RCS pressure is above the RHR design pressure, spurious operation is not postulated to initiate a LOCA.

3. Reactor Coolant Gas Vent System (RCGVS)

The RCS vent system consists of two separate lines, one from the reactor vessel head and the other from the pressurizer relief line. The vent lines discharge to the containment sump and/or to the pressurizer relief tank. The isolation valves are solenoid operated valves that close on loss of power. Their motive power is administratively removed (fuses removed) during power operation as stated in Reference 24. Consequently, spurious operation cannot cause these valves to open and initiate a LOCA.

4. Pressurizer Power Operated Relief System

The pressurizer has one relief line that splits into two lines. Each of the two lines has a Power Operated Relief Valve (PORV) and a PORV block valve in series. The PORVs are air operated valves that close on loss of power. The PORV block valves are normally open motor operated valves.

In the event that a spurious signal were to open a PORV, the flow path can be blocked by using the series PORV block valve. Cables for the control of the PORV and PORV block valves are separated by more than 20 feet up to the area of the pressurizer missile shield that surrounds the pressurizer. The cables enter the pressurizer cubicle in flexible steel conduit up to the valves that are located at the top of the pressurizer. Because the cables that control operation of these valves are separated by more than 20 feet, a single fire is not postulated to result in an uncontrolled LOCA.

2) The diesel starts from ambient conditions and operates for at least 30 minutes on recirculation flow.

(b) At least once per 92 days by verifying that a sample of diesel fuel from the fuel storage tank obtained in accordance with ASTM-D270-1975 is within the acceptable limits Specified in Table 1 of ASTM-D975-1977 when checked for viscosity and water and sediment; and

(c) At least once per 18 months by subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for the class of service.

(3) The fire pump diesel starting 24-volt battery bank and charger shall be demonstrated operable:

(a) At least once per seven (7) days by verifying that:

1) The electrolyte level of each battery is above the plates, and

2) The over all battery voltage is greater than or equal to 24 volts.

(b) At least once per 92 days by verifying that the specific gravity is appropriate for continued service of the battery, and

(c) At least once per 18 months by verifying that:

1) The batteries, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration, and

2) The battery-to-battery and terminal connections are clean, tight, free of corrosion and coated with anti-corrosion material.

e. Bases

(1) The operability of the Fire Suppression Systems ensures that adequate fire suppression capability is available to confine and extinguish fires occurring in any portion of the facility where safety-related equipment is located. The Fire Suppression System consists of the Water System, spray, and/or sprinklers, fire hose stations and yard fire hydrants. The collective capability of the Fire Suppression Systems is adequate to minimize potential damage to safety-related equipment and is a major element in the facility Fire Protection Program.

7.2.2.1 FIRE WATER SUPPLY AND DISTRIBUTION SYSTEM (Continued)

(2) In the event that portions of the Fire Suppression Systems operable, alternate backup fire-fighting equipment is required to be made available in the affected areas until the inoperable equipment is restored to service. When the inoperable fire-fighting equipment is intended for use as a backup means of fire suppression, a longer period of time is allowed to provide an alternate means of fire fighting than if the inoperable equipment is the primary means of fire suppression.

(3) The surveillance requirements provide assurance that the minimum operability requirements of the Fire Suppression Systems are met.

(4) In the event the Fire Suppression Water System becomes inoperable, immediate corrective measures must be taken since this system provides the major fire suppression capability of the plant.

7.2.2.2 SPRAY AND/OR SPRINKLER SYSTEMS

a. Operability Requirements - The following spray and/or Sprinkler Systems shall be operable:

(1) Fire Zones 47 and 54 - Component Cooling Water Areas

(2) Fire Zones 45 and 55 - Charging Pump Rooms

(3) Fire Zones 79A - North - South Breezeway

(4) Fire Zones 72, 73, 74 and 75 - Emergency Diesel Generator and Day Tank Rooms (Unit 3)

(5) Fire Zones 133, 136, 138 and 141 - Emergency Diesel Generator and Fuel Transfer Pump Rooms (Unit 4)

b. Applicability - Whenever equipment protected by the Spray/Sprinkler System is required to be operable.

c. Action

(1) With one or more of the above required Spray and/or Sprinkler Systems inoperable, within one (1) hour establish a continuous fire watch with backup fire suppression equipment. This action applies to both units simultaneously for Subsection 7.2.2.2.a.(3) .

d. Surveillance Requirements - Each of the above required Spray and/or Sprinkler Systems shall be demonstrated operable:

(1) At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path is in its correct position,

7.2.3 FIRE RATED ASSEMBLIES (Continued)

(2) The fire detectors on at least one side of the affected barrier must be verified OPERABLE and hourly fire watch patrol established until the barrier is restored to functional status.

7.2.4 FIRE BRIGADE

1. Fire Brigade Minimum Shift Specifications

a. Operability Requirements - A site Fire Brigade of at least five members shall be maintained on site. The Fire Brigade shall not include the Shift Supervisor and the other members of the minimum shift crew necessary for safe shutdown of the unit and any personnel required for other essential functions during a fire emergency.

b. Applicability - At all times

c. Action - The Fire Brigade staffing may be less than the minimum requirements for a period of time not to exceed two hours, in order to accommodate unexpected absence, provided immediate action is taken to fill the required positions.

7.2.5 ADMINISTRATIVE RESPONSIBILITY

The PNSC shall be responsible for review of the Fire Protection Program and implementing procedures in accordance with PTN Technical Specification 6.5.1.6.

8.0 QUALITY ASSURANCE PROGRAM

The QA program for fire protection is part of the overall company QA program. The details of the Florida Power and Light QA program are contained in the Florida Power and Light Topical Quality Assurance Report which has been reviewed and approved by the Nuclear Regulatory Commission.

Engineering Packages impacting fire protection are required to be handled under the FPL QA program requirements to ensure conformance with Appendix R requirements and FPL commitments.

9.0 REFERENCES

1. Letter, A. Schwencer (NRC) to Dr. R.E. Uhrig (FPL), "Safety Evaluation," dated March 21, 1979.

2. FPL letter L-83-225 from Dr. R.E. Uhrig (FPL) to Mr. D.G. Eisenhut (NRC), "10 CFR 50 Appendix R Fire Protection," dated April 8, 1983.

3. FPL letter L-83-295 from Dr. R.E. Uhrig (FPL) to Mr. D.G. Eisenhut (NRC), "10 CFR 50 Appendix R III.O - Oil Collection System," dated May 12, 1983.

4. FPL letter L-83-347 from Dr. R.E. Uhrig (FPL) to Mr. D.G. Eisenhut (NRC), "10 CFR 50 Appendix R Fire Protection," dated June 6, 1983.

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5. FPL letter L-83-503 from Dr. R.E. Uhrig (FPL) to Mr. S.A. Varga (NRC), "10 CFR 50 Appendix R Fire Protection Supplemental Information," dated September 30, 1983.

6. Letter, S.A. Varga (NRC) to J.W. Williams, Jr. (FPL), "Exemption Requests for Turkey Point Plant Units 3 and 4 - 10 CFR 50 Appendix R Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," dated March 27, 1984.

7. Drawings 5610-M-142, Fire Protection Plan EL. 18.00'
5610-M-143, Fire Protection Plan EL. 42.00' and 58.00'
5610-M-144, Fire Protection Plan EL. 10.00' and 30.00'

8. Drawings 5610-E-059, Control Building Underground Conduit and Grounding EL. 18.00'
5610-E-061, Electrical Underground Conduit and Grounding
5610-E-204, Electrical Lighting
5610-E-785, Diesel Generator Building - Grounding and Lightning Protection
5610-E-786, Control Building Roof - Grounding and Lightning Protection

9. NRC Generic Letter 81-12, "Fire Protection Rule," issued February 20, 1981.

10. Drawing 5610-A-178, Fire Barriers and Penetrations

11. FPL letter L-86-164 from Dr. R.E. Uhrig (FPL) to Mr. D.G. Eisenhut (NRC), "10 CFR 50 Appendix R Fire Protection," dated April 25, 1986.

12. FPL letter L-87-68, C.O. Woody (FPL) to U. S. NRC, "Request for Additional Information - Exemption to 10 CFR 50 Appendix R," dated February 11, 1987.

13. Letter, S.A. Varga (NRC) to C.O. Woody (FPL), "Exemption from Requirements of Appendix R to 10 CFR 50 Section III.G.2 - Turkey Point Units 3 and 4," dated August 12, 1987.

14. Drawing 5610-M-722, Appendix R Safe Shutdown Analysis.

15. Drawing 5610-M-723, Appendix R Essential Equipment List.

16. Drawing 5610-E-2000, Appendix R Essential Cable List.

17. FPL Standard No. MN-3.8, Engineering Guidelines for Fire Protection For Turkey Point Units 3 & 4.

18. NRC Generic Letter 86-10, "Implementation of Fire Protection Requirements," issued April 24, 1986.

19. Letter, D.G. Eisenhut (NRC) to Dr. R.E. Uhrig (FPL), "Exemption Request-Fire Protection Rule Schedular Requirements of 10 CFR 50.48(c) - Turkey Point Plant Units 3 and 4," dated May 10, 1982.

20. Drawing 5610-A-62, Sheet 3, Emergency Lighting Tabulation.

21. PCM 83-145, "Fire Dampers for Appendix R Modifications."

22. Drawing 5177-J-539, Alternate Shutdown Panel Arrangement Units 3 and 4.

23. FPL Letter L-83-516 from Dr. R. E. Uhrig (FPL) to Mr. D. G. Eisenhut (NRC), "Alternate Shutdown Capability Report," dated October 7, 1983.

24. Letter, S. A. Varga (NRC) to J. R. Williams (FPL), "Alternate Shutdown Capability. Fire Protection, Sections III.G.3 and III.L of Appendix R to 10 CFR 50, Turkey Point Plant Units 3 and 4" Safety Evaluation dated April 16, 1984.

25. NRC Generic Letter 88-12, "Removal of Fire Protection Requirements from Technical Specifications," issued August 2, 1988.

26. FPL Letter L-93-192 from T.F. Plunkett (FPL) to U.S.N.R.C., "Proposed License Amendments - Fire Protection Technical Specifications," dated August 17, 1993.

27. NRC letter for Operating License Amendments No.159 (Unit 3) and No.153 (Unit 4), L. Raghavan (NRC-NRR) to J.H. Goldberg (FPL), "Turkey Point Units 3 and 4 - Issuance of Amendments RE: Fire Protection Program (TAC Nos. M87314 and M87315)," dated February 25, 1994.

28. Turkey Point Units 3 and 4 Procedure 0-ADM-016, "Fire Protection Program," latest Revision.

29. Florida Power & Light, Safety Evaluation, Evaluation of AP Armaflex Insulation for Condensation During Temporary Containment Cooling, Turkey Point Units 3 & 4, JPN-PTN-SEMP-96-004 (PTN-FPER-96-001), Revision 0.

TABLE 9.6A-1a (Con't)

IDENTIFICATION OF FIRE ZONES

FIRE ZONE	FIRE AREA	DESCRIPTION
127	OD	Units 1 and 2 Fuel Oil Storage Tank Area
128	OD	Units 3 and 4 Distribution Switchyard
129	AAA	Units 3 and 4 Nuclear Entrance Building
131	OD	Units 3A and 3B Diesel Generator Radiator Rooms
132	HH	Units 3 and 4 Control Room Electrical Cable Chase
133	SS	Unit 4 Train B Emergency Diesel Generator Room
134	TT	Unit 3 Switchgear Room 3D
135	YY	Unit 4 Train B Emergency Diesel Generator Control Room
136	XX	Unit 4 Train B Diesel Oil Transfer Pump Room
137	XX	Unit 4 Train B Diesel Oil Storage Tank
138	RR	Unit 4 Train A Emergency Diesel Generator Room
139	UU	Unit 4 Switchgear Room 4D
140	VV	Unit 4 Train A Emergency Diesel Generator Control Room
141	WW	Unit 4 Train A Diesel Oil Transfer Pump Room
142	WW	Unit 4 Train A Diesel Oil Storage Tank
999	OD	Miscellaneous Areas

TABLE 9.6A-1b

FIRE AREA TO FIRE ZONE CROSS REFERENCE LIST

FIRE AREA	FIRE ZONE
A	4, 5, 6, 7, 8, 9, 10, 17, 18
B	11, 12, 13
C	14, 15, 16
D	30
E	40
F	31, 32, 33, 34, 35, 36, 37, 38, 39, 48, 49, 50, 51, 58
G	25, 25A
H	19
I	20
J	26
K	27
L	28
M	41
N	45
O	55
P	59
Q	60
R	61
S	62
T	63
U	67

TABLE 9.6A-1b (Con't)

FIRE AREA TO FIRE ZONE CROSS REFERENCE LIST

FIRE AREA	FIRE ZONE
V	68
W	70
X	71
Y	72
Z	73
AA	74
BB	75
CC	79A
DD	93
EE	94
FF	95
GG	96
HH	98, 132
II	101
JJ	102
KK	103
LL	104
MM	97, 106, 106R
NN	108A
OO	108B
PP	109
QQ	110

TABLE 9.6A-1b (Con't)

FIRE AREA TO FIRE ZONE CROSS REFERENCE LIST

FIRE AREA	FIRE ZONE
RR	138
SS	133
TT	134
UU	139
VV	140
WW	141, 142
XX	136, 137
YY	135
AAA	1, 2, 3, 21, 22, 23, 24, 29, 42, 43, 44, 46, 56, 57, 65, 111, 112, 126, 129
BBB	52, 53
CCC	64
DDD	66
EEE	69
FFF	107

OUTDOOR (OD) FIRE ZONES

47, 54, 76, 77, 78, 79, 80, 81, 82, 83, 84, 85, 86, 87, 88, 89, 90, 91, 92, 105, 113, 114, 115, 116, 117, 118, 119, 120, 121, 122, 123, 124, 125, 127, 128, 131, 999

TABLE 9.6A-11

VALVE HAND OPERATORS

Valve Function	FPL Tag Number	Failure/Normal Mode /Position	Needed Capability
CVCS VALVES			
Charging to Loop A Cold Leg	CV-3-310A	FO/O	Manual operation to close valves, even when valve fails open on loss of air or electrical control signal.
Charging to Loop C Hot Leg	CV-3-310B	FO/C	
Auxiliary Spray to Pressurizer	CV-3-311	FC/C	Manual operation to open valve, even when valve fails closed on loss of air or electrical control signal.
Letdown Isolation (inside containment)	CV-3-200C	FC/O	Manual operation to open valve, even when valve fails closed on loss of air or electrical control signal.
Letdown Isolation (outside containment)	CV-3-204	FC/O	Manual operation to open valve, even when valve fails closed on loss of air or electrical control signal.
RHR to CVCS Cross-Connect Line Isolation	HVC-3-142	FC/O	Manual operation to open valve, even when valve fails closed on loss of air or electrical control signal.
RHR SYSTEM VALVES			
RHR HX Outlet Flow Control	HCV-3-758	FO/O	Manual operation to throttle the valve, even when valve fails open on loss of electrical control signal.

TABLE 9.6A-11 (Cont'd)

VALVE HAND OPERATORS

Valve Function	FPL Tag Number	Failure/Normal Mode /Poistion	Needed Capability
RHR HX Bypass Flow Control	FCV-3-605	FC/C	Manual operation to throttle the valve, even when valve fails closed on loss of electrical control signal.
COMPONENT COOLING WATER VALVES			
CCW to Emergency Containment Coolers Supply Isolation	CV-3-2903 CV-3-2905	FO/O	Manual operation to close valve, even when valve fails open on loss of electricity.

The turbine is equipped with a slow speed, motor driven, spindle turning gear which is side mounted on an outboard bearing of the low pressure turbine.

Condensate and Feedwater

The condensate system flow diagrams are shown in Figures 10.2-15 through 10.2-20, the feedwater system on Figures 10.2-21 through 10.2-28. The feedwater train is the closed type with deaeration accomplished in the condenser. Condensate is pumped from the condenser hotwell by the condensate pumps through the condensate polishing demineralizer system, air ejectors, gland steam condenser and low pressure heaters to the suction of feedwater pumps. The feedwater pumps then deliver feedwater through the high pressure heaters to the steam generators. All feedwater heaters are provided with internal drain coolers except heater No. 5. The No. 1 and 2 low pressure heaters are installed in the condenser neck.

Two 60% capacity, vertical, multi-stage, pit type centrifugal heater drain pumps with vertical motor drives are provided (see Figures 10.2-32 and 10.2-38). These pumps pass collected drains from the drain tank forward to the suction of the steam generator feed pumps. The condenser is the twin shell, double flow, deaerating type with semi-cylindrical water boxes bolted at both ends. It has required manholes, a water gauge glass to indicate the condensate level and one condensate outlet per shell. Expansion joints for all circulating water inlet and outlet connections are provided. There are three 60% capacity multi-stage, vertical, pit-type, centrifugal condensate pumps with vertical motor drives. Normally only two condensate pumps are operating.

The steam-jet air ejector (see Figures 10.2-58, 59) has two first stage elements and two secondary stage elements mounted on the shell of the intermediate and after condensers. The ejector is supplied with steam from the main steam line as is the hogging ejector for the condenser steam space.

Two 60% capacity, horizontal, split case, motor-driven, constant speed, steam generator feedwater pumps are provided and each is equipped with minimum flow protection devices. The design discharge pressure is the required steam generator pressure plus feedwater system losses to include feedwater heaters, piping and valves, feedwater regulator plus static head allowance.

Circulating Water System

The circulating water system is designed to provide water from the canal, regardless of weather conditions, to the suction of the condenser circulating pumps, and intake cooling water pumps. Refer to Figures 10.2-60 through 10.2-65 and 9.6-1 through 9.6-7.

Canal water flows into four separated screen wells through steel trash racks. The trash racks protect the traveling screens against damage from heavy debris. The water passes through traveling screens where the smaller debris is removed. The debris picked up by the screen is removed by water supplied by motor driven screen wash pumps, taking suction from the intake structure.

Water from each individual screen well flows to the suction of the motor driven, vertical, mixed flow circulating water pumps. Each of the four circulating water pumps provide a design flow of 156,250 GPM.

An on-line condenser cleaning system using sponge rubber balls is used to prevent scale build-up on condenser tubes, thus helping to maintain the thermal efficiency of the condenser.

The three intake cooling water pumps are also installed in the intake structure. Their capacity is 16,000 GPM each.

Turbine Controls

High pressure steam enters the turbine through the stop valves and governing control valves. Each stop valve is an oil operated, spring closing valve controlled primarily by the turbine over speed trip devices. The turbine overspeed trip pilot is actuated by one of the following to close the stop valves:

Turbine thrust bearing trip	Any generator fault
Low bearing oil pressure trip	Generator lockout
Low condenser vacuum	Hi-hi steam generator level
Solenoid trip	Safety injection signal
Overspeed trip	Reactor trip (above P-7)
Manual trip	

The hydraulically operated control valves of the plug type open and close in sequence to control steam admission to the turbine. They are actuated by the turbine speed governor which is responsive to turbine speed, and which includes:

A speed changer or synchronizing device

A load limit device which must be reset after operation of the overspeed trip before the control valves can be opened

An overspeed protection controller which senses a sudden loss of load and closes control and intercept valves

The governing emergency trip valve, actuated when the stop valves are tripped, to close the control valves

An auxiliary governor, responsive to the rate of turbine speed increase, to close the control valves

A motor controlled hydraulic pilot valve is provided for each control valve to test the operation of the valve. Test switches with indicating lights are provided on the control board turbine section. Removable strainers are located in each control valve body to protect the valves and turbine from foreign material in the steam. Temporary fine mesh strainers are installed during initial operation.

The reheat stop and interceptor valve assemblies are incorporated into the reheater piping to prevent overspeeding of the turbine by reheater steam. The interceptor valves are under governor control. On a load rejection, the interceptor valves and governor valves are closed rapidly.

The normal governing devices, which operate through hydraulic relays to operate the control valves are as follows:

> The governor handwheel at the unit
>
> The governor synchronizing motor, which is controlled by a switch on the electrical section of the control board and is used for raising or lowering turbine speed or load
>
> The load limit motor, which is controlled by a switch on the turbine section of the control board and by a reactor control rod drop run back signal

The pre-emergency device functions similar to the normal governing devices by operating the control valves in case of abnormal operating conditions in the auxiliary governor. This pre-emergency device closes the control valves on rapid increase in turbine speed. The control valves will be actuated by either the speed governor or load limit, and the device delivering the lowest oil pressure will be in control. Pressure gauges on the control board indicate the oil pressure from these devices.

The emergency devices which will trip the stop valves, the control valves and the air relay dump valve are as follows:

1. Overspeed trip
2. Solenoid trip (also actuated from reactor trip, electrical faults, AMSAC signal, and a manual push button); Unit 3 has a backup turbine overspeed trip function based on main oil pump discharge pressure (refer to discussion below).
3. Low condenser vacuum trip
4. Low bearing oil pressure trip
5. Thrust bearing trip
6. Manual trip at unit

The mechanical overspeed trip mechanisms consist of an eccentric weight mounted in the end of the turbine shaft, which is balanced in position by a spring until the speed reaches approximately 108% of rated speed (the tripping speed). Its centrifugal force then overcomes the restraining spring and the eccentric weight flies out striking a trigger which trips the overspeed trip valve and releases the autostop fluid to drain. The resulting decrease in autostop pressure causes the governing emergency trip valve to release the control oil pressure, and this closes the main stop and governing valves. An air pilot-valve used to control the extraction non-return valves is also actuated from the autostop pressure.

The autostop valve is also tripped when any one of the protective devices is actuated. The protective devices include a low bearing oil pressure trip, a solenoid trip, a thrust bearing trip and a low vacuum trip. These devices are all included in a separate assembly, but connected hydraulically to the overspeed trip valve. An additional protective feature includes a turbine trip following a reactor trip.

A diverse backup turbine overspeed trip function is installed on Unit 3. The trip function senses main oil pump discharge high pressure and actuates both primary and backup autostop solenoid valves. This backup trip function is redundant to the speed control and overspeed protection functions and is not required to be in service at any time. A keylock switch allows this trip function to be disabled.

Trip of the turbine-generator initiates a reactor trip when power is greater than 10% to prevent excessive reactor coolant temperature and/or pressure.

10.2.3 SHIELDING

No radiation shielding will be required for the components of the steam and power conversion system. Continuous access to the components of this system will be possible during normal operation.

10.2.4 CORROSION PROTECTION

10.2.4.1 CHEMICAL ADDITION

Ammonium Hydroxide and hydrazine are added to the condensate at the condensate pump discharge to control pH and oxygen, respectively.

10.2.4.2 CONDENSATE POLISHING DEMINERALIZER SYSTEM

A condensate polishing demineralizer system is provided to purify the condensate by filtration and demineralization to provide high quality condensate water to Turkey Point Units 3 and 4 steam generators and is shown on Figures 10.2-47 through 10.2-54. The condensate polishing demineralizer system is unitized, one for Unit 3 and one for Unit 4.

When in use, the system treats full condensate flow discharged from the condensate pumps. The condensate polishing demineralizer system includes precoat and spent resin handling subsystems. The precoat subsystem is used to evenly distribute powdered resins across the resin retention elements within the filter/demineralizers. The spent resin handling subsystem is not utilized at Turkey Point. Resin slurry is delivered to the back wash reciever tank only. Water and spent resin disposal is accomplished under Chemistry and Health Physics supervision utilizing portable equipment as required.

As discussed in the following sections, the condensate polishing system is used in conjunction with the feedwater recirculation system, secondary system wet lay-up system, steam generator wet lay-up system, and steam generator blowdown recovery system to maintain proper water quality during various modes of plant operation.

10.2.4.3 STEAM GENERATOR BLOWDOWN RECOVERY SYSTEM

A steam generator blowdown recovery system is installed to assist in maintaining required steam generator water chemistry by providing a means for removal of foreign matter which concentrates in the evaporator section of the steam generator.

The steam generator blowdown recovery system is shown on Figures 10.2-41 and 10.2-42. The system is fed by three independent blowdown lines (one per steam generator) which tie into a common blowdown flash tank. The steam generator blowdown is continuously monitored for radioactivity during plant operation. A radiation monitor is provided for the steam generator blowdown sample lines in each unit. The blowdown sample lines can be isolated using the manual isolation valves downstream of the motor operated isolation valves.

The Steam Generator Blowdown Isolation By-pass valves are continuously energized to remain in the normally open position, see Figures 10.2-41 and 10.2-42. The main function of these valves is to warm-up steam generator blowdown valves to prevent hydraulic transients during system operation. These solenoid valves also receive a containment isolation signal in order to prevent loss of water inventory after an auxiliary feedwater system start.

A completely self-contained on-line Chemistry Monitoring System is connected to each blowdown line through a manifold. This allows an operator to manually select an input sample by opening a sample valve from any one of the Steam Generator Secondary Sampling Systems. These sample valves are also used to completely isolate the on-line Chemistry Monitoring System from the Steam Generator Blowdown Recovery System. The Monitoring System provides a means by which the various levels of pH, cation conductivity, specific conductivity, dissolved oxygen, sodium, and chloride can be monitored (see Section 4.2.5).

Blowdown condensate from the flashtank is dumped to the discharge canal.

10.2.4.4 SECONDARY WET LAY-UP SYSTEM

A secondary wet lay-up system is provided to recirculate water through the condenser, condensate system, and feedwater system, including the shell side of the feedwater heaters, to prevent stratification and to provide a means to degasify and add chemicals to prevent any excursions of water quality in the secondary system during extended unit shutdowns. This system is shown on Figures 10.2-43 through 10.2-46.

The secondary system wet lay-up system consists of two closed loops which circulate the contents of the secondary system. Cleanup of the secondary system is provided through the condensate filter/demineralizers..

Nitrogen capping for oxygen control is provided through connections in the extraction steam piping (see Figure 10.2-57). Chemicals are added to each loop via a common chemical feed pot.

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The Waste Disposal System collects and processes potentially radioactive reactor plant wastes prior to release or removal from the plant site within limitations established by applicable governmental regulations. The fluid wastes are sampled prior to release using an isotopic identification as necessary. Radiation monitors are provided to maintain surveillance over the release operation. Permanent record of Waste Disposal System releases is provided by radiochemical analysis of known quantities of waste. The system is capable of processing all wastes generated during continuous operation of the Reactor Coolant System assuming that fission products escape from one per cent of the fuel elements into the reactor coolant.

At least two valves must be manually opened to permit discharge of liquid or gaseous waste from the Waste Disposal System. One of these valves is normally locked closed. During release, the effluent is monitored, and the release terminated if the radioactivity level exceeds a predetermined value. Activity release limits are given in the Technical Specifications.

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As secondary functions, system components supply hydrogen and nitrogen to RCS components as required during normal operation and provide facilities to transfer fluids from inside the containment to other systems outside the containment.

The waste disposal system is controlled primarily from a local control board in the auxiliary building and four local control boards in the radwaste facility with appropriate indicators and alarms. Off normal conditions are annunciated in the control room. All system equipment is located in or near the auxiliary building and in the radwaste facility except for the reactor coolant drain tank and pumps, which are located in the containment.

System Description

Liquid Processing

During normal plant operation the Waste Disposal System can process liquids from the following sources:

a) Equipment drains, floor drains, tank overflows, containment sumps, and leak-offs.
b) Hot laboratory, and cold laboratory drains.
c) Radioactive laundry and shower drains.
d) Decontamination area drains.
e) Resin transfer flush water and boron recycle waste water.
f) Refueling water from fuel transfer canal and/or reactor cavity.

Additionally, each Unit's blowdown tank can be connected by a hose to the Waste Disposal System via the Waste Holdup Tank.

The system also collects and transfers liquids directly from the following sources to the Chemical and Volume Control System for processing:

a) Reactor coolant loop drains.
b) Reactor coolant pump No. 2 seal leakoff.
c) Excess letdown during startup.
d) Accumulators.
e) Valve and reactor vessel flange leakoffs.

These liquids flow to the reactor coolant drain tank and are discharged directly to the CVCS holdup tanks by the reactor coolant drain tank pumps which are operated automatically by a level controller in the tank. These pumps also return water from the refueling canal and cavity to the refueling water storage tank. There are one reactor coolant drain tank and two reactor coolant drain tank pumps inside each containment.

Waste liquids are collected by various drains and sumps. The liquid drains flow by gravity, or are pumped, to the waste hold up tank (See Figure 11.1-9). The activity level of waste liquid from the laundry and hot shower area will usually be low enough to permit discharge from the site without processing. The liquid is pumped to the waste holdup tanks or one of the waste monitor tanks or monitor tanks where its activity can be determined for record before it is discharged through a radiation monitor. Otherwise, the liquid is pumped to the waste holdup tanks for processing.

The liquids requiring cleanup before release are normally processed by the waste disposal demineralizer or in batches by the waste evaporators if available. The liquid from the waste disposal demineralizer is routed directly to one of three radwaste facility waste monitor tanks.

If the waste evaporators are operated, then the distillate is designed to be routed to one of two distillate demineralizers or returned to the radwaste facility waste holdup tank. From the distillate demineralizers the liquid can also be conveyed to one of the three radwaste facility waste monitor tanks by way of the distillate demineralizer filters.

When one of the waste monitor tanks is filled, it is isolated and sampled for analysis while the second of the three tanks is in service. If analysis confirms the activity level is suitable for discharge, the liquid is pumped through a flowmeter and a radiation monitor and then released to the circulating water system.

Otherwise, it can be recirculated through the distillate demineralizers or returned to a waste holdup tank for reprocessing. Although the radiochemical analysis forms the basis for recording activity releases, the radiation monitor provides surveillance over the operation by automatically closing the discharge control valve if the liquid activity level exceeds a preset value.

If the waste evaporators are used, the concentrated bottoms are discharged to the solidification system where they are packaged in containers for removal to a disposal facility.

Gas Processing

During plant operation, gaseous wastes originate from:

a) Degassing reactor coolant discharge to the Chemical and Volume Control System
b) Displacement of cover gases as liquids accumulate in various tanks
c) Miscellaneous equipment vents and relief valves
d) Sampling operations and gas analysis for hydrogen and oxygen in cover gases.

During normal operation the Waste Disposal System supplies nitrogen from a Dewar vessel and hydrogen from a tube trailer to waste disposal components. Dual manifolds are provided, one for operation and one for backup. The system is sufficiently instrumented and alarmed to ensure continuous supply of gas.

Most of the gas received by the Waste Disposal System during normal operation is cover gas displaced from the Chemical and Volume Control System holdup tanks as they fill with liquid (see Figures 11.1-16, 11.1-17 and 11.1-18). Since this gas must be replaced when the tanks are emptied during processing, facilities are provided to return gas from the decay tanks to the holdup tanks. A backup supply from the nitrogen header is provided for makeup if return flow from the gas decay tanks is not available. To prevent hydrogen concentration from exceeding the combustible limit during this type of operation, components discharging to the vent header system are restricted to those containing no air or aerated liquids and the vent header itself is designed to operate at a slight positive pressure (1.0 psig minimum to 4.0 psig maximum) to prevent in-leakage. On the other hand, out-leakage from the system is minimized by using Saunders patent diaphragm valves, bellows seals, self contained pressure regulators and soft-seated packless valves throughout the radioactive portions of the system.

Gases vented to the vent header flow to the waste gas compressor suction header. One of the two compressors is in continuous operation with the second unit instrumented to act as backup for peak load conditions or failure of the first compressor. From the compressors, gas flows to one of the gas decay tanks. The control arrangement on the gas decay tank inlet header allows the operator to place one tank in service and to select one tank for backup if the tank in operation becomes fully pressurized. When the tank in service becomes pressurized to approximately 100 psig, a pressure transmitter automatically closes the inlet valve to that tank, opens the inlet valve to the backup tank and sounds an alarm to alert the operator of this event so that he may select a new backup tank. Pressure indicators are supplied to aid the operator in selecting the backup tank.

Gas held in the decay tanks can either be returned to the Chemical and Volume Control System holdup tanks, or discharged to the atmosphere if it has decayed sufficiently for release. Generally, the last tank to receive gas will be the first tank emptied back to the holdup tanks in order to permit the maximum decay time before releasing to the environment.

However, the header arrangement at the tank inlet gives the operator freedom to fill, re-use or discharge gas to the environment simultaneously without restricting operation of the other tanks. During degassing of the reactor coolant prior to a refueling shutdown, it may be desirable to pump the gas purged from the volume control tank into a particular tank and isolate that tank for decay rather than re-use the gas in it. This is done by aligning the control to open the inlet valve to the desired tank and closing the outlet valve to the re-use header.

However, one of the other tanks can be opened to the re-use header at this time if desired, while still another might be discharged to atmosphere.

Before a tank can be emptied to the environment, it must be sampled and analyzed to determine and record the activity to be released, and only then discharged to the plant vent at a controlled rate through a radiation monitor. Samples are taken manually by opening an isolation valve to discharge from the gas decay tank to the gas analyzer and collecting the gas in one of the sampling system gas sample vessels. After sampling, the isolation valve in the line from the tank to the gas analyzer is closed, the isolation valve in the plant vent discharge line is opened and the tank contents are released through the plant vent if sampling has shown that sufficient decay has occurred. During release a trip valve in the discharge line is closed automatically by loss of air flow from auxiliary building exhaust fans. In the event of a high activity level in the discharge line, the plant vent isolation valve RCV-014 will either be closed automatically (PVGM R-14 in service) or manually (RAD 6304 in service).

During operation, a gas sample is drawn from the particular gas decay tank being filled at the time, and analyzed to determine its hydrogen and oxygen content. The hydrogen analysis is for surveillance since the concentration range can vary considerably from tank to tank. Also, the capability exists for manual grab sample analysis of cover gases from tanks discharging to the waste gas vent header.

Solids Processing

The Waste Disposal System is designed to package all solid wastes in containers for removal to disposal facilities. Refer to Figures 11.1-17, 11.1-18 and 11.1-19 for the spent resin processing flow diagrams. After filling, the containers are moved to a shielded storage area by a bridge and trolley crane until they can be shipped to a disposal facility. The same crane is then used to place the containers on the carrier for removal to a disposal facility.

The spent resins from the CVCS demineralizers are normally deposited in the spent resin storage tank. After resin in the spent resin storage tank has been agitated by bubbling nitrogen through the tank to the vent header, water is pumped through the tank at a controlled rate to sluice the slurry to the container area. There it is received in shielded containers and dewatered for disposal.

Provisions for dry bulk packaging of liquid waste system spent resins also exist. Spent resin is pumped as a water-resin slurry into a disposable container, which has connections for a dewatering line. The sluice water is removed by using a dewatering pump, which is piped to the waste hold-up tank through the floor drains.

All system components and piping can be internally decontaminated with flushing water from the primary water system. The permanently installed flushing water pipes can be isolated with manually operated valves.

All control valves and pumps handling radioactive fluids are functionally grouped together and located within the mixing tank rooms behind shield walls. The equipment is installed to permit easy access for maintenance work, tests, inspections, and replacement with minimum exposure to personnel.

Shielding is provided for each container as necessary to reduce the dose rate in work areas. The basis for all dose rate calculations is for one cycle of core operation with one percent defective fuel in each unit.

Components

Codes applying to components of the Waste Disposal System are shown in Table 11.1-2. Components summary data are shown in Table 11.1-3.

Laundry and Hot Shower Tanks

Three stainless steel tanks collect liquid wastes originating from the laundry and hot shower. When a tank has been filled, its contents are pumped to one of the monitor tanks or waste monitor tanks after passing through a strainer and filter. If the radioactivity level is within permissible limits, the liquid is released to the circulating water system. Otherwise, the liquid is pumped to one of the waste holdup tanks for processing.

Reactor Coolant Drain Tanks

The reactor coolant drain tanks are all-welded austenitic stainless steel. There is one tank inside the containment of each of the two units. This tank serves as a drain collecting point for the Reactor Coolant System and other equipment located inside the containment.

Waste Holdup Tanks

The two waste holdup tanks can receive radioactive liquids from the Chemical and Volume Control System, floor drains, chemical drains, reactor coolant drain tanks, and laundry and hot shower tanks. The tanks are of stainless steel welded construction. The 24,300 gallons and 10,000 gallons waste hold-up tanks are located in the auxiliary building and radwaste facility, respectively. Contents of the auxiliary building tank can be transferred to the radwaste facility tank, but not vice-versa.

Spent Resin Storage Tank

The spent resin storage tank retains spent resin normally discharged from some of the demineralizers. Normally, the tank is filled over a long period of time, the contents are allowed to decay. A layer of water is maintained over the resin surface to prevent resin degradation due to heat generation from decaying fission products. The tank is all welded austenitic stainless steel.

Gas Decay Tanks

Six welded carbon steel tanks are provided to contain compressed waste gases (hydrogen, nitrogen, and fission gases). After a period for radioactive decay, these gases may be released at a controlled rate to the atmosphere through the plant vent. All discharges to the atmosphere will be monitored.

Compressors

Two compressors are provided for removal of gases to the gas decay tanks from all equipment that contains or can contain radioactive gases. These compressors are of the water-sealed centrifugal displacement type. The operation of the compressors is automatically controlled by the gas manifold pressure. Construction is primarily carbon steel. A mechanical seal is provided to minimize leakage of seal water. While one unit is in operation, the other serves as a standby for unusally high flows or failure of the first unit.

Waste Evaporator Package

The evaporator concentrates dissolved and suspended solids in the liquid waste. Each evaporator package consists of an evaporator, absorption tower, evaporator condenser, vent condenser, distillate cooler, feed preheater assembly, stripping column assembly, concentrate pump, and distillate pump. The capacity of each evaporator package is 15 gpm of distillate. The evaporator receives liquid wastes from the waste holdup tanks. The distillate proceeds to one of the distillate demineralizers or to the auxiliary building waste holdup tank for further processing. The concentrated wastes are pumped to the solidification system for packaging when sample analysis indicates that one of the following maximums has been reached: 40 uCi/ml activity concentration, 12% boric acid or a total solids concentration of 20%.

The length of an evaporator operating cycle is determined either by solids content or activity concentration of the solution. The evaporator is primarily austenitic stainless steel of welded construction.

Distillate Demineralizers

Distillate from the waste evaporators is designed to be processed through one of the two distillate demineralizers. The two stainless steel demineralizers are fabricated in accordance with ASME Section III requirements. Each contains 30 cubic feet of ion exchange resin to remove trace ionic contaminants. From the demineralizers, the distillate proceeds to the waste monitor tanks after passing through the distillate demineralizer filters.

Waste Monitor Tanks

The contents of one of the three waste monitor tanks are analyzed for levels of radioactivity. If the activity is sufficiently low, the contents are released to the circulating water system by one of two waste monitor pumps. Otherwise, the contents are returned to the waste holdup tanks, the distillate demineralizers, or the waste condensate tanks for reprocessing. These tanks, are fabricated from stainless steel and meet the requirements of ASME Section VIII. Each tank provides the capability of storing 5,000 gallons of processed distillates.

Monitor Tanks

See description in Section 9.2.2.

Waste Disposal Demineralizer

Waste water in the waste holdup tank is processed primarily by the waste disposal demineralizer to reduce the level of activity. The liquid passes through a filter and two stages of demineralization in the demineralizers before it is conveyed to the waste monitor tanks or monitor tanks.

Waste Condensate Tanks

The contents of the auxiliary building waste holdup tank can be transferred to one of the two waste condensate tanks by either the waste transfer pump or the auxiliary building waste evaporator feed pump. The contents are sampled and analyzed for radioactivity before discharge. The condensate is transferred by one of two waste condensate pumps to the auxiliary building waste holdup tank, either directly or through the waste polishing demineralizer, if the activity is high or to the condenser circulating water if the activity is sufficiently low. These tanks are constructed of all-welded stainless steel.

Waste Polishing Demineralizer

The waste polishing demineralizer may be used to further reduce the activity level of liquid in the waste condensate tank prior to discharging. The liquid is re-circulated through the waste polishing demineralizer by the waste condensate pumps until the desired activity level is attained. The demineralizer removes both cation and anion impurities from the process flow. The demineralizer is designed to pass the rated flow of one waste condensate pump.

Waste Holdup/Mixing Tanks

The two waste holdup/mixing tanks are of stainless steel construction with a capacity of 800 gallons each. They are fabricated to the requirements of ASME Section VIII. The tanks are provided with level detectors and instrumentation to permit remote readout of the tank's liquid and/or spent resin volume. Automatic shutoff of feedlines when the tank is full and automatic shutoff of the tank when the tank is empty are also provided. The tank vents are piped to the floor drain. Two redundant, 100% capacity, electric strip heaters are installed near the bottom of each tank to maintain the temperature of the tank contents at 165°F. The tanks receive concentrates from the waste evaporators.

Each holdup/mixing tank is provided with a horizontal centrifugal pump. The waste holdup/mixing tank pumps take suction from the bottom of the tank and discharge into cross tied, redundant headers piped to the cement mixers through parallel takeoffs.

Recirculation lines with air operated control valves are provided for recirculation of tank contents during waste processing.

Cement Mixers

The two motor-driven inline waste/cement mixers are located in the container filling rooms and discharge directly to the disposable containers. Each mixer has four connections: one for wastes from the holdup/mixing tanks, one for cement from the batching tank, one for flushing water, and the discharge connection to the containers.

Compactor

A hydraulically operated compactor is used to compress solid wastes into containers. The compactor is operated manually from a local station and is supplied with a HEPA filter.

Nitrogen Manifold

A dual manifold supplies nitrogen to purge the vapor space of various components to reduce the hydrogen. concentration or to replace fluid that has been removed. A large volume Dewar vessel which is maintained above a preset level, assures a continuous supply of gas. Additionally, bottled gas is provided for short-term maintenance and backup requirements.

Hydrogen Manifold

A dual manifold supplies hydrogen to the volume control tank to maintain the hydrogen partial pressure as hydrogen dissolves in the reactor coolant. A pressure controller, which is manually switched from one manifold to the other, assures a continuous supply of gas.

Gas Analyzer

Manual sampling and laboratory analysis is conducted to monitor the concentrations of oxygen and hydrogen in the cover gas of various Waste Disposal System tanks, Chemical and Volume Control System tanks, the pressurizer relief tank and gas stripper. Upon indication of a high oxygen level, provisions are made to purge the equipment to the gaseous waste system with an inert gas.

Continuous sampling of the gas decay tank being filled is performed by on-line equipment. A local alarm warns of a potentially explosive condition.

Pumps

Pumps used throughout the system for draining tanks and transferring liquids shown in Figures 11.1-1a and 11.1-1b are either canned motor or mechanically sealed types to minimize leakage. The wetted surfaces of all pumps are stainless steel or other materials of equivalent corrosion resistance.

Piping

The permanent piping which carries liquid wastes is stainless steel. All gas piping is carbon steel. Piping connections are welded except where flanged connections are necessary to facilitate equipment maintenance.

Valves

All valves exposed to gases are carbon steel. All other valves are stainless steel. All valves have stem leakage control. Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage. Stop valves are provided to isolate equipment for maintenance, to direct the flow of waste through the system, and to isolate storage tanks for radioactive decay.

Relief valves are provided for tanks containing radioactive wastes if the tanks might be overpressurized by improper operation or component malfunction. Tanks containing wastes which are normally of low radioactivity level are vented locally.

11.1.3 DESIGN EVALUATION

Liquid Releases

Based on the estimated total liquid discharge to the Waste Disposal System in Table 11.1-4 and the capacity of the waste monitor and monitor tanks, the estimated number of yearly releases is 1000.

The estimated annual liquid release is indicated in Table 11.1-5. The maximum activity discharge rate will be controlled to assure that the circulating water concentration during releases is as low as practicable below the requirements of 10CFR20.

The liquid waste processing facilities have been evaluated and demonstrated to be in compliance with 10CFR50, Appendix I requirements. This is addressed in supplementary licensing documents*.

Liquid Wastes (Without Primary - Secondary Leakage)

Liquid wastes are generated primarily by plant maintenance and service operations, and consequently, the quantities and activity concentrations of influents to the system, Tables 11.1-4 and 11.1-5, are estimated values. Therefore, considerable operational margin has been assigned between the estimated system load and the design capability as indicated by Table 11.1-4. A conservative estimate of activity released in the liquid phase is summarized in Table 11.1-5. This tabulation is generated as follows:

1. All liquid waste is initially at peak reactor coolant activity concentrations based on continuous full power operation with 1% defective fuel clad in each unit.
2. Allow 500 minutes for decay, the time required to process a 1000 gallon batch at 2 gallons per minute.**
3. Concentrate the waste to a bottoms activity concentration of 40uc.cc, the packaging facility design limit.**

*Letter L-76-212, "Appendix I Evaluation" dated June 4, 1976 from R.E. Uhrig of Florida Power and Light to D. R. Muller of the USNRC.

**These values are based on original system design and operating characteristics. While changes have been made to the original system, actual releases continue to meet the guidelines of 10CFR20.

4. Divide by the waste evaporator and polishing demineralizer combined DF of at least 10^6 which yields 4 x 10^{-5}uc/cc in the waste condensate.

5. Multiply by the quantity released from both units, listed in Table 11.1-4, to obtain the total estimated annual release in Table 11.1-5.

6. Add to this the activity released through waste disposal by the CVCS monitor tanks. This is estimated to be less than 2 mc/yr.

7. The tritium estimate in Table 11.1-5 assumes that one percent of the tritium that is formed in the fuel (the predominant source) diffuses through the zircaloy clad and enters the reactor coolant. Tritium discharges will be evaluated and accounted for by analyzing a composite sample. All of the sources of tritium accumulating in the reactor coolant, shown in Table 9.2-6, are included in the annual release.

8. When the liquid in the waste monitor or monitor tanks has been properly determined to have an activity level low enough for discharge according to the MPC requirements of 10CFR20 for unidentified isotopes, the monitor tank pumps or waste monitor pumps are started and the liquid can be discharged to the seal wells of either Unit 3 or Unit 4 or both. The valves at the seal wells are electrically interlocked with the circulating water pumps to prevent liquid from being discharged into an inactive well, thus ensuring complete mixing at all times. Discharge piping is shown schematically in Figure 11.1-3.

9. A radiation monitor (described in Section 11.2.3 and Table 11.2-7a) automatically closes the discharge from the waste monitor tank pumps or monitor tank pumps if the activity level exceeds the monitor set point. This ensures that the activity in the circulating water discharge canal will be below the MPC requirements of 10CFR20.

Liquid Waste With Primary - Secondary Leakage

The isotopic equilibrium activity concentration in the secondary coolant for any given radioisotope is related to the reactor coolant activity, the steam generator blowdown (cleanup) flow, the isotopic natural decay and the primary to secondary leakage flow by the following equation:

$$C_{si}=\frac{L_{ps}C_{pi}\mu c/cc}{\lambda_i V_s+F_s}$$

where:

C_{si} = Secondary coolant activity, c/cc

C_{pi} = Primary coolant activity, c/cc

L_{ps} = Primary to secondary leakage, gpm

F_s = Secondary blowdown flow, gpm

λ_i = Isotopic natural decay constant, min. $^{-1}$, and

V_s = Liquid volume of the secondary coolant, gal.

The relationship assumes that the reactor coolant equilibrium is independent of leakage rate. Consideration is given to I-131 as the major contributor to environmental activity release, because noble gas concentrations in the secondary will be quite low, being continuously entrained with the normal steam flow and released to the atmosphere through the air ejector.

The above relation is plotted in Figure 11.1-5 for I-131 as the primary to secondary leak rate versus the ratio of secondary to primary activity as a function of various blowdown flows.

The steam generators blowdown system, shown in Figures 10.2-41 and 10.2-42, consists of three independent blowdown lines (one per steam generator) which tie into a common blowdown flash tank. The high activity liquid contained in the flash tank can be directed to the radioactive liquid waste system through manual valve alignment and a portable hose connection. The flashing component is discharged to the atmosphere. The blowdown tank liquid overflow standpipe discharge goes to the circulating water discharge at the sealwell. A radiation monitor of 10^{-5}uC$_i$/cc maximum sensitivity in that line will actuate solenoid valves to automatically isolate the blowdown discharge lines and sound an alarm in the control room. Because the iodine preferentially remains in the liquid phase, the air ejector monitor would be less sensitive than the liquid effluent monitor to iodine activity.

Blowdown will occur routinely, typically on a daily basis over a one to several hour period at which times a flowrate of approximately 50 gpm is maintained. Assuming a permissible limit for the 624,000 gpm, condenser cooling water iodine concentration at ten times MPC for a one-hour blowdown, then, for several values of percent failed fuel, the allowable maximum primary to secondary leak rates can be read from Figure 11.1-5. At these limiting values, the combined secondary coolant and radwaste releases would be below 10CFR20 requirements provided blowdown did not exceed 2.5 hours per day.

In addition to the ranges of normal operating conditions with tolerable amounts of failed fuel and primary to secondary leak rates, the site boundary I-131 equivalent dose is estimated under the following assumptions:

a. Steam line break outside the containment under no load conditions,

b. Releasing the contents of one steam generator,

c. Secondary I-131 activity = Primary I-131 activity = 1.5 µCi/cc from 1% failed fuel, and

d. One tenth the iodine content in the steam generator reaches the site boundary.

The site boundary thyroid dose equals approximately 1.78 rem.

Gaseous Wastes

Gaseous wastes consist primarily of hydrogen stripped from coolant discharged to the CVCS holdup tanks during boron dilution, nitrogen and hydrogen gases purged for the CVCS volume control when degassing the reactor coolant, and nitrogen from the closed gas blanketing system. The gas decay tank capacity will permit 45 days decay of waste gas before discharge. Table 11.1-6 contains an estimate of annual noble gas activity release based on the following assumptions:

For Xe-133:

1. The quantity of Xe-133 removed from the plant over a core cycle is determined assuming all gaseous waste is initially at peak reactor coolant activity concentration based on 1% defective fuel clad, and each unit at 2300 Mwt power with daily load reduction to 15% power.

2. Using the same reactor coolant activity concentrations as in (1), the total Xe-133 removed to the Waste Disposal System by degassing the Reactor Coolant System for three cold shutdowns are combined. The cold shutdowns occur at the following times: (a) during the second week of operation, (b) at the peak xenon level and (c) during refueling.

3. Using the same reactor coolant activity concentrations as in (1), the total Xe-133 removed from the reactor coolant to the Waste Disposal System as a result of 4 hot shutdowns occurring at equal intervals in the core cycle.

4. Sum items 1, 2 and 3 for two units to obtain the total Xe-133 removed to the Waste Disposal System and allow for 45 days decay to obtain the total estimated annual release of Xe-133.

For Kr-85:

Since there is not significant decay of Kr-85 during the operating periods involved, the total Kr-85 that enters the reactor coolant during the core cycle is assumed to be eventually released through the Waste Disposal System.

In comparison to Kr-85 and Xe-133, there will be no significant activity release after 45 days of decay from the remaining gaseous wastes since the isotopes half lives are short and/or the quantities present in the reactor coolant are small.

Gaseous Release Rate:
In order to illustrate the conservatism that is available for gaseous releases from Turkey Point an estimate has been made of the maximum release rate that would conform to 10 CFR 20. Considering Xe-133 and Kr-85 as the only nuclides, Table II, Column 1, in Appendix B of 10 CFR 20 gives an MPC value of 3 x 10^{-7} Ci/m^3, applicable at the site boundary.

The average annual dilution factors for all 10 degree sectors of the site boundary are given in Figure 2D-1 and Table 2D-1, both in Appendix 2D of Section 2. For the three years of wind data taken at the site the largest dilution factor (X/Q) occurs in the 360 degree sector. The average value for the three year period, 1968-1970, is 1.02 x 10^{-6} sec/m^3. For purposes of calculating the allowable gaseous routine release rate limit, this value is used.

Using the above given MPC value and X/Q value, the allowable average annual routine gaseous release limit is 0.29 Ci/sec, for Units 3 and 4 combined. In Table 11.1-6 the estimated release of Xe-133 and Kr-85 is 14,758 Ci/yr for Units 3 and 4 combined, and is equivalent to an average annual release rate of 0.47 x 10^{-3}) Ci/sec (which is much less than the 10 CFR 20 limit) using the conservative assumptions above.

The estimated annual releases are as follows:

	No.	Ci/release	Release time, hrs.
Min.	6	2460	7
Max.	20	760	2.1

The maximum release rate would be 97m Ci/sec. The site boundary MPC will not be exceeded. Hold up for further natural decay of xenon for an additional month as feasible, and proportionally fewer releases per year, would about half total activity released.

The iodine activity release to the atmosphere from the secondary system and from the waste processing system under the limiting operating conditions of 1% failed fuel and the steam generator tube leakage (0.135 gpm) described in this section, and an expected 0.8 plant availability factor for Turkey Point Units 3 and 4 is estimated to be 259 millicuries per year. The corresponding maximum thyroid dose at the site boundary would be 0.38 millirem. The computations are based upon the data in Table 9.2-4, use a stripping and plateout fraction for iodine of 4×10^{-3}, include a 45 day gas decay tank holdup and yield an annual release from the steam system of 252 millicuries and from the waste processing system of 7 millicuries. Under normal expected operating conditions these activity releases will be less than one-one hundredth of those indicated.

The exposure of minors within the restricted area; if continuously present at the Scout Camp would be considerably below the limits established by 10 CFR 20.104, and 10 CFR 20.202.

The maximum probable exposure for this on site facility would be for an individual in the Scout Camp area during a release when the wind is blowing into this sector. That exposure would be 0.007 rem, assuming:

$$X/Q = 1.9 \times 10^{-4} \text{ sec/m}^3$$

$\bar{E}$ = 0.205 (based on 48% contribution from Xe-133 and 52% from Kr-85 after 45 day gas storage)

$\dot{S}$ = 0.105 Ci/sec.

The provisions for monitoring iodine release paths are as follows:

1. Both the plant vent and Unit 3 spent fuel building exhaust vent have fixed filter iodine monitors.

2. The iodine release via the blowdown tanks will be calculated from the integrated flow through the blowdown flow meters and the quality of iodine measured in the secondary side of the steam generators.

3. The iodine release from the:
   a. hogging jets
   b. main steam safety valves
   c. waterbox priming jets

   will be calculated from steam flow and the iodine measured weekly in the main steam samples. Steam flow will be calculated from time in use times maximum flow capacity of the device.

4. The iodine release via the steam jet air ejectors on the main condenser will be calculated from a weekly sampling for iodine at the air ejector discharge and a concurrently made air flow measurement or from time in use multiplied by maximum flow capacity of the device.

The testing and/or measurements outlined in 2, 3, and 4 above shall only be made if iodine is detected in the secondary coolant by sampling required by Technical Specification Table 4.1-2.

In addition, there are air and particulate monitors for the plant vent, and there are monitors for the condenser air ejectors and steam generator blowdown as described in Section 11.2 and listed in Table 11.2-7. The alarm set points are set low to alert the operator before a significant release could occur.

The gaseous waste processing facilities have been evaluated and the as-built arrangement and potential radioactive releases to the environment are demonstrated to be in compliance with 10CFR50, Appendix I requirements. This is addressed in supplementary licensing documents.*

<u>Solid Wastes</u>

Solid wastes can consist of waste liquid concentrates, spent resins, and miscellaneous materials. All solid wastes are packaged in containers for removal to a disposal facility.

*Letter L-76-212, "Appendix I Evaluation", dated June 4, 1976 from R. E. Uhrig of Florida Power and Light to D. R. Muller of the USNRC.

TABLE 11.1-2

WASTE DISPOSAL COMPONENTS CODE REQUIREMENTS

Component	Code
Reactor Coolant Drain Tanks	ASME III, [1] Class C
Spent Resin Storage Tank	ASME III, [1] Class C
Gas Decay Tanks	ASME III, [1] Class C
Waste Holdup Tank, Auxiliary Building	No Code
Waste Holdup Tank, Radwaste Building	ASME III, [1] Class 3
Waste Condensate Tanks	No Code
Laundry and Hot Shower Tanks	No Code
Waste Evaporator	ASME III, [1] Class 3
Waste Filter	ASME III, [1] Class C
Piping and Valves	USAS-B31.1 [2] Section I
Waste Gas Compressor	No Code
Chemical Addition Tank	ASME VIII
Distillate Demineralizers	ASME III, [1] Class 3
Waste Monitor Tanks	ASME VIII
Monitor Tanks	See Table 9.2-3
Waste Holdup/Mixing Tanks	ASME III, [1] Class 3
Cement Mixers	No Code

NOTES:

1. ASME III-American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels

2. USAS-B31.1-Code for pressure piping and special nuclear cases where applicable

TABLE 11.1-3

COMPONENT SUMMARY DATA

TANKS	Quantity	Type	Volume Each Tank	Design Pressure	Design Temperature °F	Material
Reactor Coolant Drain	1 per Unit	Horiz	350 gal.	25 psig	267	ss
Laundry & Hot Shower	3[3]	Vert	600 gal.	Atm	180	ss
Waste Holdup, Aux.Bldg.	1[3]	Horiz	3242 ft^3	Atm	150	ss
Waste Holdup, Rad. Fac.	1[3]		10000 gal	Atm	200	ss
Spent Resin Storage	1[3]	Vert	300 ft^3	100 psig	150	ss
Waste Condensate	2[3]	Vert	1000 gal	Atm	180	ss
Gas Decay	6[3]	Vert	525 ft^3	150 psig	150	cs
Chemical Addition Tank	1[3]	Vert	5 gal	150 psig	200	ss
Waste Evaporator	2[3]			150 psig	225	
Distillate Demineralizer	2[3]	Vert	43 ft^3	200 psig	250	ss
Waste Monitor Tank	3[3]	Vert	5000 gal	Atm	200	ss
Monitor Tank			See TABLE 9.2-3			
Waste Holdup/Mixing Tank	2[3]	Vert	800 gal	25 psig	300	ss
Cement Mixer	2[3]					

PUMPS	Quantity	Type	Flow each unit gpm	Head ft.	Design Pressure psig	Design Temperature °F	Material[1]
Reactor Coolant Drain Unit 3	2 per unit	Horiz. cent.	75/125	175/175	100	267	ss
Reactor Coolant Drain Unit 4	2 per unit	Horiz. cent. canned	75/125	150/120	100	267	ss

NOTES:

1. Material contacting fluid.
3. Shared by Units 3 and 4.

COMPONENT SUMMARY DATA

Pumps	Quantity	Type	Flow Each Unit gpm	Head Ft.	Design Pressure, psig	Design Temperature, F	Material (1)
Laundry	2	Horiz cent (2)	100	250	150	180	ss
Waste Evaporator Feed (Aux. Building)	1*	Horiz cent (2)	20	100	150	180	ss
Waste Condensate	2*	Horiz cent (2)	20	100	150	180	ss
Auxiliary Building Sump	14	Vert. Duplex	75	70	45	220	cs
Containment Sump	2	Vert. Duplex	75	70	45	220	cs
Radwaste Facility Sump	2	Vert.	35	70			ss
Waste Evaporator Feed	2*	Horiz cent	35/100	250/200	150	200	ss
Waste Monitor Tank	2*	Horiz cent	35/100	250/200	150	200	ss
Holdup/Mixing Tank	2*	Horiz cent	135	46.2			ss
Miscellaneous							
Waste Evaporator	2*	-	15	-	-	-	-
Waste Gas Compressors	2*	Horiz (2) cent	40 (CFM)	-	-	-	-
Waste Polishing Demineralizer Vessel	1*	-	20	-	150	180	ss

(2) Mechanical Seal Provided
* Shared by Unit 3 and Unit 4

2. A flowmeter to indicate the flow rate.
3. A flowmeter to indicate the flow adjustment.
4. A flow alarm assembly to provide low and high flow alarm signals.

c) Selector valves are used to direct the sample to the detector for monitoring and to block normal flow when the channel is in maintenance or "purging" condition.

d) A pressure sensor is used to protect the system for high pressure. This unit automatically closes the inlet and outlet valves upon a containment high pressure condition.

e) Purging is accomplished with a valve control arrangement whereby the normal sample flow is blocked and the detector purged with a "clean" sample. This facilitates detector calibration by establishing the background level and aids in verifying sample activity level.

f) The flow control panel in the control room radiation monitoring racks permits remote operation of the flow control assembly. By operating a switch on the control panel, either the containment or purge sample may be monitored,

g) A sample flow rate indicator is calibrated linearly from 0 - 14 cubic feet per minute.

Alarm lights are actuated by the following:

a. Flow alarm assembly (low and high flow).
b. The pressure sensor assembly (high pressure).
c. The filter paper sensor (paper drive malfunction).
d. Pump power off

On both units, one common alarm light is turned off, an annunciator is actuated, and supplemental information is available to the control room operator.

Plant Vent Gas Monitors (R-14 and RaD 6304)

The plant vent gas monitors detect radiation passing through the plant vent to the atmosphere. Each detector consists of a thin-walled, self-quenching type

Geiger-Mueller tube (high sensitivity beta-gamma detector) operated in parallel with an impedance matching network. Monitor R-14 has a maximum sensitivity of 5 x 10^{7} microcuries per cubic centimeter. The alarm setpoint for this monitor is determined by and set in accordance with the methodology and parameters of the Turkey Point Offsite Dose Calculation Manual (ODCM). ODCM implementation is required by Technical Specification 6.8.

Remote indication and annunciation of R-14 is provided on the Waste Disposal System control board in the Control Room. On high radiation level alarm the gas release valve in the Waste Disposal System is automatically closed.

Monitor RaD 6304 covers a range from 10^{-7} to 10^{5} microcuries per cc for Xe-133. It transmits a pulse signal to the console in the cable spread room. High radiation, intermediate radiation and rate of rise alarms are provided. RaD-6304 also functions to collect halogens and particulates on filter elements for later analysis in compliance with NUREG-0737, Item II.F.1.2, "Sampling and Analysis of Plant Effluents".

Condenser Air Ejector Monitors (R3-15, R4-15, RaD3-6417 & RaD4-6417)

Each channel monitors the discharge from the air ejector exhaust header of the condenser for gaseous radiation which is indicative of a primary to secondary system leak.

Beta-gamma sensitive Geiger-Mueller tubes are used to monitor the gaseous radiation level. The detectors are inserted into an in-line fixed volume container which includes adequate shielding to reduce the background radiation to where it does not interfere with the detectors maximum sensitivity. monitors R3-14 & R4-15 have a maximum sensitivity of 10^{-6} microcuries per cc. Monitors RaD3-6417 & RaD4-6417 cover a range from 10^{-7} to 10^{5} microcuries per cc for Xe-133. The alarm setpoints for these monitors are determined by and set in accordance with the methodology and parameters of the Turkey Point Offsite Dose Calculation Manual (ODCM). ODCM implementation is required by Technical Specification 6.8.

Component Cooling Liquid Monitors (R3-17A, R3-17B, R4-17A & R4-17B)

Each channel continuously monitors the component cooling loop of the Auxiliary Coolant System for radiation indicative of a leak of reactor coolant from the Reactor Coolant System and/or the residual heat removal loop in the Auxiliary Coolant System. A scintillation counter is located in an inline well. A high-radiation level alarm signal initiates closure of the valve located in the component cooling surge tank vent line to prevent radioactive gas release.

The measuring range of each monitor is 10^{-5} to 10^{-2} microcuries per cubic centimeter. The alarm setpoints for these monitors are determined by and set in accordance with the methodology and parameters of the Turkey Point Offsite Dose Calculation Manual (ODCM). ODCM implementation is required by Technical Specification 6.8.

Waste Disposal System Liquid Effluent Monitor (R-18)

This channel continuously monitors all Waste Disposal System liquid releases from the plant. Automatic valve closure action is initiated by this monitor to prevent further release after a high-radiation level is indicated and alarmed. A scintillation counted and holdup tank assembly monitors these effluent discharges. Remote indication and annunciation are provided on the Waste Disposal System control board.

The measuring range of this monitor is 10^{-5} to 10^{-2} microcuries per cubic centimeter. The alarm setpoint for this monitor is determined by and set in accordance with the methodology and parameters of the Turkey Point Offsite Dose Calculation Manual (ODCM). ODCM implementation is required by Technical Specification 6.8.

Steam Generator Liquid Sample Monitors (R3-19 & R4-19)

Each channel monitors the liquid phase of the secondary side of the steam generators for radiation, which would indicate a primary-to-secondary system leak, providing backup information to that of the condenser air removal gas monitor. Samples from the bottom of each of the steam generators are mixed in a common header and the common sample is monitored by a scintillation counter and holdup tank assembly. Upon indication of a high-radiation level, blowdown is automatically isolated. Each steam generator is sampled in order to determine the source of the activity. This sampling sequence is achieved by manually obtaining steam generator liquid samples at the primary sample sink for laboratory analysis after allotting sufficient time for sample equilibrium to be established.

A high-radiation level signal will close the isolation valves in the sample lines, the blowdown discharge to the circulating water discharge and the blowdown recovery flow control valves.

The measuring range of each monitor is 10^{-5} to 10^{-2} microcuries per cubic centimeter. The set point is selected to transfer the blowdown as noted above, at an activity concentration equivalent to no more than 6.1 x 10^{-8} uCi/cc in the circulating water. The alarm setpoints for these monitors are determined by and set in accordance with the methodology and parameters of the Turkey Point Offsite Dose Calculation Manual (ODCM). ODCM implementation is required by Technical Specification 6.8.

In channels R-18, and R-19, a photomultiplier tube-scintillation crystal (NaI) combination, mounted in a hermetically sealed unit, is used for liquid effluent radiation actuation. Lead shielding is provided to reduce the background level so it does not interfere with detector's sensitivity. The in-line, fixed volume container is an integral part of the detector unit.

Main Steam Line Monitor (RAD 6426)

The Main Steam Line Monitor detects radiation passing through the main steam lines. The monitor was installed to meet the requirements of NUREG-0578. This monitor is required to be operable in accordance with Technical Specifications and is used to meet the requirements of Regulatory Guide 1.97 for post accident monitoring. The monitor receives a steam sample from piping tied into each steam line, upstream of the main steam isolation valves, and can be isolated using the outlet isolation valves for the main steam line sample coolers.

The thermal and jet impingement effects of a break in the tubing at this monitor would neither affect accessibility to the outlet isolation valves nor impact any safety related equipment.

A Geiger-Mueller tube is used to monitor the gaseous radiation level. It covers a range from 1.0 to 10^5 microcuries/cc for Xe-133. Indication and alarms are provided locally and the parameter is displayed on the ERDADS.

Reactor Coolant Letdown Line Activity Monitors (R3-20 & R4-20)

One channel for each unit is provided for detection of fuel clad failure which consists of a fixed position gamma sensitive GM detector, local indication and signal transmission to a radiation monitoring rack in the control room, where it is indicated and alarmed on high activity level. A remotely operated check source is included in this channel. The detector is located on the CVCS reactor coolant letdown outside the Containment Building where background radiation is relatively low and the flow transit time from the core is greater than 40 second to permit 7.2 second N-16 activity to decay to an acceptable level. A channel alarm induced by a rapid rise in coolant activity signals the requirement to take and count a coolant sample. The alarm setpoints for these monitors are determined by and set in accordance with the methodology and parameters of the Turkey Point Offsite Dose Calculation Manual (ODCM). ODCM implementation is required by Technical Specification 6.8.

Spent Fuel Pool Vent Monitor - Unit 3 (RaD-3-6418)

The Spent Fuel Pool Vent Monitor detects radiation passing through the Unit 3 spent fuel pool vent to atmosphere. A beta-gamma sensitive Geiger-Mueller tube is used to monitor the gaseous radiation level. Monitor RaD-3-6418 covers a range from 10^{-7} to 10^{5} microcuries per cc for Xe-133. Indication and alarms are provided on the console in the cable spreading room. RaD-3-6418 also functions to collect halogens and particulates on filter elements for later analysis in compliance with NUREG-0737, Item II.F.1.2, "Sampling and Analysis of Plant Effluents".

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Area Radiation Monitoring System

This system consists of channels which monitor radiation levels in various areas. These areas are as follows:

Detector Tag No.	Channel No.	Area Monitor
RD-3-1401	1	Unit 3 Cntmt Personnel Access Hatch
RD-3-1402	2	Unit 3 Cntmt Refueling Floor El. 58'
RD-3-1403	3	Unit 3 Cntmt Incore Instr. Equip.
RD-4-1404	4	Unit 4 Cntmt Personnel Access Hatch
RD-4-1405	5	Unit 4 Cntmt Refueling Floor El. 58'
RD-4-1406	6	Unit 4 Cntmt Incore Instr. Equip.
RD-3-1407	7	Unit 3 Spent Fuel Pit Transfer Canal
RD-4-1408	8	Unit 4 Spent Fuel Pit Transfer Canal
RD-1409	9	Aux. Bldg. Laundry Tank and Pump Room
RD-1410	10	Aux. Bldg. Chemical Storage Area
RD-4-1411	11	Unit 4 Cask Wash Area
RD-3-1412	12	Unit 3 Cask Wash Area
RD-3-1413	13	Aux. Bldg. Outside Unit 3 Sample Room
RD-4-1414	14	Aux. Bldg. Outside Unit 4 Sample Room
RD-3-1415	15	Aux. Bldg. North End of N/S Corridor
RD-4-1416	16	Aux. Bldg. South End of N/S Corridor
RD-1417	17	Aux. Bldg. East End of E/W Corridor
RD-1418	18	Aux. Bldg. West End of E/W Corridor
RD-3-1419	19	Unit 3 Spent Fuel Pit Exhaust
RD-1420	20	Control Room
RD-3-1421	21	Unit 3 Spent Fuel Building North Wall
RD-4-1422	22	Unit 4 Spent Fuel Building South Wall
RD-3-1423	23	Unit 3 New Fuel Building
RD-4-1424	24	Unit 4 New Fuel Building

System Description

Each of the channels is identical, and each channel is comprised of a detector, preamplifier, local indicator and a remote cabinet mounted indicator in the Control Room.

The Detector

This is composed of a matched ion chamber and preamplifier pair. Calibration constants determined by the manufacturer are used by the preamplifier assembly to optimize the combined detector and preamplifier response curve. The calibration constants for a channel are entered at the remote indicator in the Control Room. The ion chamber and the preamplifier are mounted separately. The preamplifier converts current from the ion chamber into an analog logarithmic DC output to drive the local meter. The preamplifier also converts the ion chamber current into a digital signal which is transmitted to the remote indicator. Any failure of the preamplifier will activate an alarm at the channel indicator in the Control Room. High voltage for the ion chamber is developed and controlled in the preamplifier assembly.

The Local Indicator

The DC output from the detector passes through this indicator which is located in a separate box from the preamplifier. Radiation levels are indicated on a logarithmic scale which is calibrated from 10^{-1} to 10^{7} mR/hr. High radiation levels actuate a horn and a red flashing light locally. The lowest decade of the meter scale is corrected for "live zero".

Personnel decontamination showers are located in the Decontamination Shower Facility, located just north of the dress facility.

The cask wash area has facilities to handle the decontamination of large items of equipment.

A decontamination area is also provided within the auxiliary building for the decontamination of hand tools and small equipment, and also in the radwaste facility for large equipment.

All personnel monitor themselves on leaving the radiation controlled areas.

Administrative and physical security measures are employed to prevent unauthorized entry of personnel to any designated high radiation area or contaminated area. These measures include the following:

1. Areas accessible to individuals, in which radiation levels could result in an individual receiving a dose equivalent in excess of 0.100 rem in one (1) hour at 30 centimeters from the radiation source or from any surface that the radiation penetrates, are barricaded and conspicuously posted as "high radiation areas." Administrative controls require the issuance of a Radiation Work Permit (RWP) prior to entry to any high radiation areas or contaminated area.

2. Locked doors are provided to prevent unauthorized entry into those areas in which the radiation levels could result in an individual receiving a dose equivalent in excess of 1.0 rem in one (1) hour at 30 centimeters from the radiation source or from any surface that the radiation penetrates. Doors shall remain locked, except during periods of access by personnel under an approved RWP. For individual high radiation areas that are located within large areas, such as, the pressurized water reactor (PWR) containment, where no enclosure exists for purposes of locking, and where no enclosure can be reasonably constructed around the individual area, that individual area shall be barricaded, conspicuously posted, and a flashing light shall be activated as a warning device.

3. Any individual or group of individuals permitted to enter a high radiation area is provided with or accompanied by one or more of the following:

   a. A radiation monitoring device which continuously indicates the radiation dose rate in the area.

   b. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose levels in the area have been established and personnel have been made knowledgeable of them.

   c. An individual qualified in radiation protection procedures with a radiation dose rate monitoring device, who is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by the health physics supervisor on the Radiation Work Permit.

4. All personnel are required to wear protective clothing for entry into designated contamination areas. The areas involved are decontaminated as necessary to prevent the spread of contamination. Decontamination is performed under the direction of health physics personnel.

<u>Personnel Monitoring</u>

The official and permanent record of accumulated external radiation exposure received by individuals is obtained principally from the interpretation of thermoluminescent dosimeters (TLD). Direct reading dosimeters (which include both self-reading pocket ionization chambers and digital alarming dosimeters) provide day-by-day indication of external radiation exposure.

All plant assigned personnel subject to occupational radiation exposure are issued beta-gamma thermoluminescent dosimeters (TLDs) and are required to wear them at all times while within the Radiation Controlled Area. Neutron sensitive TLDs are issued to personnel whenever a significant neutron exposure

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14.1.1 UNCONTROLLED RCCA WITHDRAWAL FROM A SUBCRITICAL CONDITION

An RCCA withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core by withdrawal of rod cluster control assemblies resulting in power excursion. While the probability of a transient of this type is extremely low, such a transient could be caused by a malfunction of the reactor control or control rod drive systems. This could occur with the reactor either subcritical or at power. The "at power" case is discussed in Section 14.1.2.

Reactivity is added at a prescribed and controlled rate in bringing the reactor from a shutdown condition to a low power level during startup by RCCA withdrawal. Although the initial startup procedure uses the method of boron dilution, the normal startup is with RCCA withdrawal. RCCA motion can cause much faster changes in reactivity than can be made by changing boron concentration.

The rod cluster drive mechanisms are wired into preselected banks, and these bank configurations are not altered during core life. The rods are therefore physically prevented from withdrawing in other than their respective banks. Power supplied to the rod banks is controlled such that no more than two banks can be withdrawn at any time. The rod drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable speed rod travel. The maximum reactivity insertion rate is analyzed in the detailed plant analysis assuming the simultaneous withdrawal of the combination of the two rod banks with the maximum combined worth at maximum speed which is well within the capability of the protection system to prevent core damage.

Should a continuous RCCA withdrawal be initiated and assuming the source and intermediate range indication and annunciators are ignored, the transient will be terminated by the following automatic protective functions.

a) Source range flux level trip - actuated when either of two independent source range channels indicates a flux level above a preselected, manually adjustable value. This trip function may be manually bypassed when either intermediate range flux channel indicates a flux level above the source range cutoff power level. It is automatically reinstated when both intermediate range channels indicate a flux level below the source range cutoff power level.

b) Intermediate range rod stop - actuated when either of two independent intermediate range channels indicates a flux level above a preselected, manually adjustable value. This rod stop may be manually bypassed when two out of the four power range channels indicate a power level above approximately ten percent power. It is automatically reinstated when three of the four power range channels are below this value.

c) Intermediate range flux level trip - actuated when either of two independent intermediate range channels indicates a flux level above a preselected, manually adjustable value. This trip function may be manually bypassed, when two of the four power range channels are reading above approximately ten percent power and is automatically reinstated when three of the four channels indicate a power level below this value.

d) Power range flux level trip (low setting) - actuated when two out of the four power range channels indicate a power level above approximately 25 percent. This trip function may be manually bypassed when two of the four power range channels indicate a power level above approximately ten percent and is automatically reinstated when three of the four channels indicate a power level below this value.

e) Power range flux level trip (high setting) - actuated when two out of the four power range channels indicate a power level above a preset setpoint, usually $\leq$109 percent of full-power. This trip function is always active.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the initial power burst results from a fast negative fuel temperature feedback (Doppler effect) and is of prime importance during a startup accident since it limits the power to a tolerable level prior to external control action. After the initial power burst, the nuclear power is momentarily reduced and then if the accident is not terminated by a reactor trip, the nuclear power increases again, but at a much slower rate.

Termination of the startup accident by the above protection channels prevents core damage. In addition, the reactor trip from high pressurizer pressure serves as backup to terminate the accident before an overpressure condition could occur.

Method of Analysis

The analysis of the uncontrolled RCCA bank withdrawal from subcritical accident is performed in three stages. First, a spatial neutron kinetics computer code, TWINKLE (Reference 1), is used to calculate the core average nuclear power transient, including the various core feedback effects, i.e., Doppler and moderator reactivity. Next, the FACTRAN computer code (Reference 2) uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the average heat flux and temperature transients. Finally, the average heat flux calculated by FACTRAN is used in the THINC computer code (References 3 & 4) for transient DNBR calculations.

In order to give conservative results for the uncontrolled RCCA bank withdrawal from subcritical accident analysis, the following assumptions are made concerning the initial reactor conditions:

a) Since the magnitude of the nuclear power peak reached during the initial part of the transient, for any given rate of reactivity insertion, is strongly dependent on the Doppler Power reactivity coefficient, the least negative design value is used for the uncontrolled RCCA bank withdrawl from subcritical accident analysis.

b) The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and moderator is much longer than the nuclear flux response time constant. However, after the initial nuclear flux peak, the succeeding rate of power increase is affected by the moderator reactivity coefficient. Accordingly, the conservative value of 7 pcm/°F is used, since this yields the maximum rate of power increase.

c) The analysis assumes the reactor to be at hot zero power conditions with a nominal temperature of 547°F. This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-to-water heat transfer coefficient, a larger specific heat of the water and fuel, and a less-negative (smaller absolute magnitude) Doppler coefficient. The less-negative Doppler coefficient reduces the Doppler feedback effect, thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel specific heat and larger heat transfer coefficient yields a larger peak heat flux. The analysis assumes the initial effective multiplication factor (K_{eff}) to be 1.0 since this results in the maximum neutron flux peak.

d) Reactor trip is assumed to be initiated by power range high neutron flux (low setting). The most adverse combination of instrumentation error, setpoint error, delay for trip signal activation, and delay for trip signal actuation, and delay for control rod assembly release is taken into account. The analysis assumes a 10 percent uncertainty in the power range flux trip setpoint (low setting), raising it from the nominal value of 25 percent to a value of 35 percent; no credit is taken for the source and intermediate range protection. Figure 14.1.1-1 shows that the rise in nuclear power is so rapid that the effect of error in the trip setpoint on the actual time at which the rods release is negligible. In addition, the total reactor trip reactivity is based on the assumption that the highest worth rod cluster control assembly is stuck in its fully withdrawn position.

e) The maximum positive reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the two sequential control banks

14.1.4 ROD CLUSTER CONTROL ASSEMBLY (RCCA) DROP

14.1.4.1 IDENTIFICATION OF CAUSES AND ACCIDENT DESCRIPTION

A dropped rod event is a Condition II event that is assumed to be initiated by a single electrical or mechanical failure which causes any number and combination of rods from the same group of a given bank to drop to the bottom of the core. The resulting negative reactivity insertion causes nuclear power to rapidly decrease. An increase in the hot channel factor may occur due to the skewed power distribution representative of a dropped rod configuration. Since this is a Condition II event, it must be shown that the DNB design basis is met for the combination of power, hot channel factor, and other system conditions which exist following the dropped rod.

If an RCCA drops into the core during power operation, it would be detected by either a rod bottom signal, by an excore detector, or both. The rod bottom signal device provides an indication signal for each RCCA. The other independent indication of a dropped RCCA is obtained by using the excore power range channel signals. This rod drop detection circuit is actuated upon sensing a rapid decrease in flux and is designed such that normal load variations do not cause it to be actuated.

Following a dropped rod event in manual rod control (or with automatic rod withdrawal defeated), the plant will establish a new equilibrium condition. The equilibrium process is monotonic, in that, there is no power overshoot without control bank withdrawal. The Turkey Point units have deleted the automatic rod withdrawal capability.

14.1.4.2 METHOD OF ANALYSIS

The transient following a dropped rod event is determined by a detailed digital simulation of the plant using the LOFTRAN code (Reference 1). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressure spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures and power level. Since LOFTRAN employs a point neutron kinetics model, a dropped rod event is modeled as a negative reactivity insertion corresponding to the reactivity worth of the dropped rod(s) regardless of the actual configuration of the rod(s) that drop. The system transient is calculated by assuming a constant turbine load demand at the initial value (no turbine runback) and no bank withdrawal. A spectrum of dropped rod worths from 100 pcm to 1000 pcm was analyzed.

Statepoints are calculated and nuclear models are used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary conditions from the transient and the hot channel factor from the nuclear analysis, the DNB design basis is shown to be met. The transient response, nuclear peaking factor analysis, and DNB design basis confirmation are performed in accordance with the methodology described in WCAP-11394 (Reference 2).

Results

For a dropped RCCA event, with no automatic rod withdrawal, power may be reestablished by reactivity feedback.

Following a dropped RCCA(s) event, with no automatic rod withdrawal, the plant will establish a new equilibrium condition. Figures 14.1.4-1 and 14.1.4-2 show a typical transient response (specifically for the 100 pcm, 0 pcm/°F case) to a dropped RCCA(s). Uncertainties in the initial conditions are included in the DNB evaluation as described in Reference 2. In all cases, the minimum DNBR remains greater than the limit value.

14.1.4.3 CONCLUSIONS

Following a dropped RCCA(s) event, without automatic rod withdrawal, the plant will return to a stabilized condition at less than or equal to the initial power. Results of the analysis show that a dropped RCCA event does not adversely affect the core, since the DNBR remains above the limit value for a range of dropped RCCA worths.

14.1.6 START-UP OF AN INACTIVE REACTOR COOLANT LOOP

Operation of the unit with an inactive loop causes reversed flow through the inactive loop because there are no isolation valves or check valves in the reactor coolant loops.

If the reactor is operated at power in this condition, there is a decrease in the coolant temperature in that loop in comparison with the other loop. The subsequent re-start of the idle reactor coolant pump, without bringing the loop temperature closer to average temperature would result in the injection of the cold water into the core. This cold water causes a rapid reactivity increase.

METHOD OF ANALYSIS

This transient is analyzed using three digital computer codes. The LOFTRAN Code (Ref. 1) is used to calculate the loop and core flow, nuclear power, and core pressure and temperature transients following the startup of an inactive coolant loop. FACTRAN (Ref. 2) is used to calculate the core heat flux transient based on core flow and nuclear power from LOFTRAN. The THINC code is then used to calculate the departure from nucleate boiling ratio (DNBR) during the transient based on system conditions (pressure, temperature, and flow) calculated by LOFTRAN and the heat flux as calculated by FACTRAN.

In order to obtain conservative results for the startup of an inactive loop accident, the following assumptions are made:

A. Initial conditions of maximum core power and reactor coolant average temperature and minimum reactor coolant pressure resulting in minimum initial margin to DNB. These values are consistent with maximum steady-state power level allowed with two loops in operation. The high initial power gives the greater temperature difference between the core inlet temperature and the inactive loop hot leg temperature.

B. Following initiation of startup of an inactive loop, the inactive loop flow reverses and accelerates to its nominal full-flow value in approximately 17 seconds.

C. A conservatively large positive moderator density coefficient of reactivity of $.43\Delta\rho$/gm/cc (corresponds to a moderator temperature coefficient of approximately -50 pcm/^{o}F over the range of the transient) was used.

D. A least negative Doppler-only power coefficient was used.

E. The initial reactor coolant flows are at the appropriate values for one pump out of service.

F. The reactor trip is assumed to occur on low coolant loop flow when the power range neutron flux exceeds the P8 setpoint. The P8 setpoint is assumed to be 74 percent of rated power.

RESULTS

The results following the startup of an inactive loop with the above listed assumptions are shown in Figures 14.1.6-1 through 14.1.6-3. As shown in these curves, during the first part of the transient the increase in core flow with cooler water results in an increase in nuclear power and a decrease in core average temperature. The minimum DNBR during the transient is considerably greater than the limit value.

Reactivity addition for the inactive loop startup accident is due to the decrease in core water temperature. During the transient this decrease is due to both the increase in reactor coolant flow and, as the inactive loop flow reverses, the colder water entering the core from the hot leg side (colder temperature side prior to the start of the transient) of the steam generator in the inactive loop. Thus, the reactivity insertion rate for this transient changes with time. The resultant core nuclear power transient, computed with consideration of both moderator and Doppler reactivity feedback effects, is shown in Figure 14.1.6-1.

The calculated sequence of events for this accident is shown in Table 14.1.6-1. The transient results illustrated in Figures 14.1.6-1 through 14.1.6-3 indicate that a stabilized plant condition, with the reactor tripped, is rapidly approached. Plant cooldown may subsequently be achieved by following normal shutdown procedures.

CONCLUSIONS

The transient results show that the core is not adversely affected. There is considerable margin to the limiting DNBR value.

REFERENCES

1. Burnett, T W T., et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary), WCAP-7907-A (Non-proprietary), April 1984.

2. Hargrove, H G, "FACTRAN-A FORTRAN-IV Code for Thermal Transients in UO_2 Fuel Rod," WCAP-7908, June 1972.

d. For the zero-load condition, feedwater temperature is at a conservatively low value of 32°F.

e. The initial water level in all the steam generators is at a conservatively low level.

f. No credit is taken for the heat capacity of the RCS and steam generator thick metal in attenuating the resulting plant cooldown.

g. No credit is taken for the heat capacity of the steam and water in the unaffected steam generators.

h. The feedwater flow resulting from a fully open control valve is terminated by the steam generator high-high water level signal that closes all feedwater main control and feedwater control-bypass valves, and trips the main feedwater pumps and turbine generator.

   Note that the steam generator overfill protection function, utilizing the Steam Generator high-high water level, is not part of the Engineered Safety Features Actuation System (ESFAS), but was added to the ESFAS Technical Specification tables without modification of the existing design. This function was specifically developed to meet commitments to the NRC criteria contained in Generic Letter 89-19, dated September 20, 1989. Although the steam generator overfill protection feature uses much of the same instrumentation as the steam generator low-low trip (reactor trip circuitry), portions of the circuitry for steam generator high-high level overfill protection may not meet all the criteria which apply to ESFAS functions. This is because the steam generator high-high level function was not originally designed to be part of the ESFAS system.

Normal reactor control systems and engineered safety systems (e.g., Safety Injection) are not required to function. The reactor protection system may actuate to trip the reactor due to an overpower condition or a turbine trip. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

Results

Opening of a low-pressure heater bypass valve and trip of the heater drain pumps causes a reduction in the feedwater temperature which increases the thermal load on the primary system. The reduction in the feedwater temperature is less than 60°F, resulting in an increase in the heat load on the primary system of less than 10 percent of full power. The increased thermal load due to the opening of the low-pressure heater bypass valve would result in a transient very similar (but of reduced magnitude) to the Excessive Load Increase incident presented in Section 14.1.8. Thus, the results of this event are bounded by the Excessive Load Increase event and, therefore, not presented here.

In the case of an accidental full opening of one feedwater control valve with the reactor at zero power (assumed to be 0.01% power) and the above-mentioned assumptions, the maximum reactivity insertion rate is conservatively calculated to be 93 pcm/sec (1 pcm=10^{-5} $\Delta k/k$). A DNB analysis was performed to demonstrate that the DNB design basis is met. A reactivity insertion rate of 100 pcm/sec was assumed in order to bound the value calculated for the zero power feedwater malfunction analysis. The method of analysis used is the same as described in Section 14.1.1, Uncontrolled RCCA Bank Withdrawal from a Subcritical Condition, except that the analysis assumed that all three reactor coolant pumps are in operation as required by the plant Technical Specifications in operating Mode 2. Although the zero power feedwater malfunction reactivity insertion rate is calculated assuming reactivity parameters representative of EOL core conditions, the DNB analysis was conservatively performed at BOL conditions. The results of the DNB analysis show that the DNBR remains above the safety analysis limit value. It should be noted that for the case with the unit just critical at no-load, the reactor may be tripped by the power range high neutron flux trip (low setting) set at approximately 25%.

The full-power case (EOL maximum reactivity feedback with automatic rod control) gives the largest reactivity feedback and results in the greatest power increase. A turbine trip, which results in a reactor trip, is actuated when the steam generator water level in the affected steam generator reaches the high-high level setpoint. Assuming the reactor to be in manual rod control results in a slightly less-severe transient. The rod control system is not required to function for this event.

For all cases of excessive feedwater flow, continuous addition of cold feedwater is prevented by automatic closure of all feedwater control valves, closure of all feedwater bypass valves, a trip of the feedwater pumps, and a turbine trip on high-high steam generator water level. In addition, the feedwater pump discharge valves will automatically close upon receipt of the feedwater pump trip signal.

Following turbine trip, the reactor will automatically be tripped, either directly due to the turbine trip or due to one of the reactor trip signals discussed in Section 14.1.10 (Loss of External Electrical Load).

Transient results (see Figures 14.1.7-1 through 14.1.7-3) show the core heat flux, pressurizer pressure, core average temperature, and DNBR, as well as the increase in nuclear power and loop ΔT associated with the increased thermal load on the reactor. Steam generator water level rises until the feedwater addition is terminated as a result of the high-high steam generator water level signal. The DNBR does not drop below the limit value at any time.

Since the power level rises during this event, the fuel temperature will also rise until the reactor trip occurs. The core heat flux lags behind the neutron flux due to the fuel rod thermal time constant and, as a result, the peak core heat flux value does not exceed 118% of nominal. Thus, the peak fuel melting temperature will remain well below the fuel melting point.

The calculated sequence of events is shown in Table 14.1.7-1. The transient results show that the DNBR does not fall below the limit value at any time during the feedwater flow increase transient; thus, the ability of the primary coolant to remove heat from the fuel rods is not reduced. Therefore, the fuel cladding temperature does not rise significantly above its initial value during the transient.

Conclusion

The decrease in feedwater temperature transient due to an opening of the low-pressure heater bypass valve is less severe than the excessive load increase event (see Section 14.1.8). Based on the results presented in Section 14.1.8, the applicable acceptance criteria for the decrease in feedwater temperature event have been met.

For the excessive feedwater addition at power transient, the results show that the DNB ratios encountered are above the limit value; hence, no fuel damage is predicted. The limiting minimum DNBR was obtained with rods in automatic. Additionally, an analysis at zero power demonstrates that the minimum DNBR remains above the safety analysis limit for a maximum reactivity insertion rate corresponding to an excessive feedwater addition at no-load conditions. The limiting minimum DNBR for all four cases was at zero power.

REFERENCES

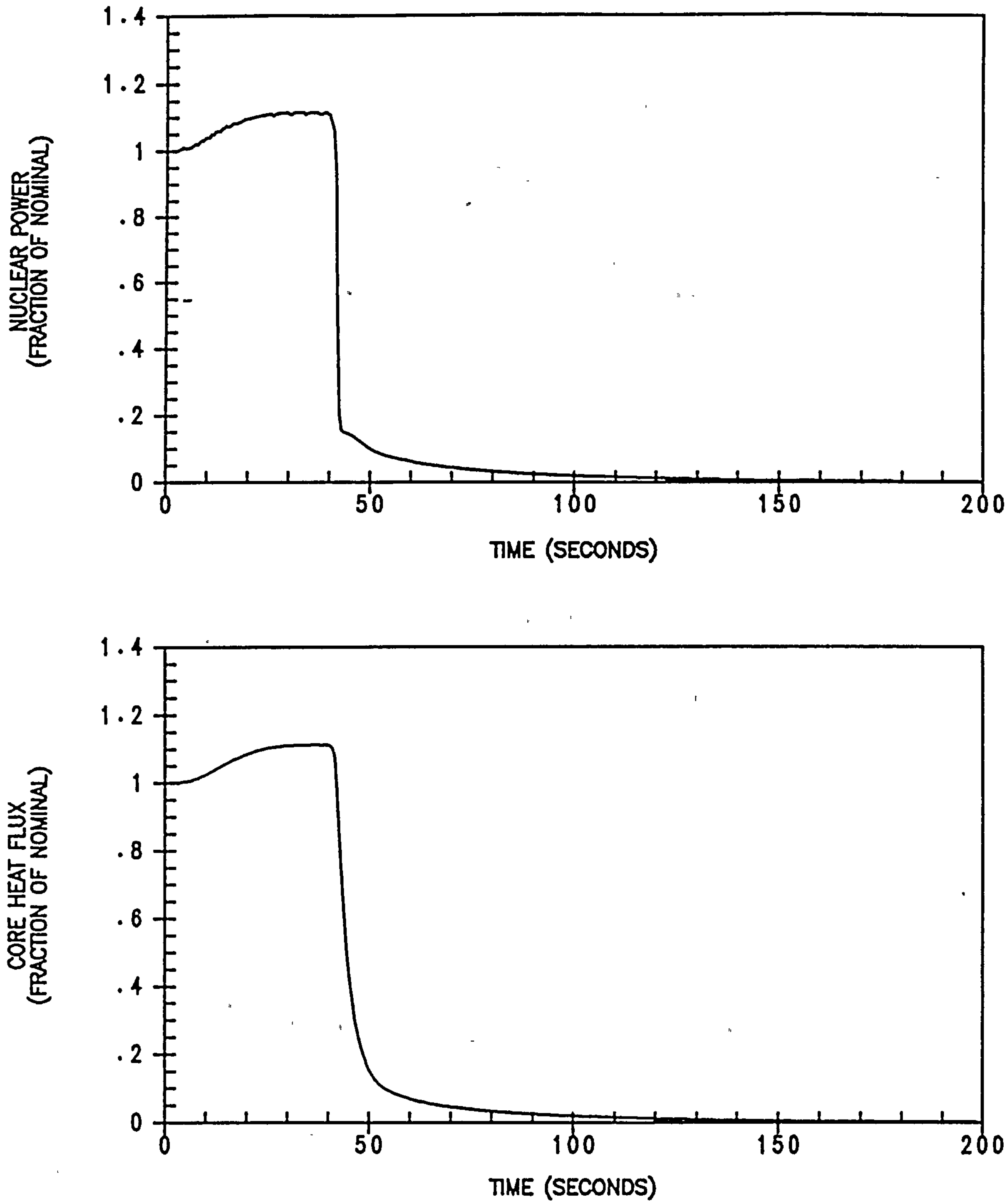
1. Westinghouse WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-proprietary), Burnet, T. W. T., et. al.,"LOFTRAN Code Description," dated April 1984.

2. Westinghouse WCAP-11397-P-A, A. J. Friedland and S. Ray,"Revised Thermal Design Procedure," dated April 1989.

TABLE 14.1.7-1

TIME SEQUENCE OF EVENTS
FOR EXCESSIVE FEEDWATER FLOW AT FULL POWER EVENT
WITH AUTOMATIC ROD CONTROL

Event	Time (seconds)
One main feedwater control valve fails fully open	0.0
High-High Steam Generator water level signal generated	35.0
Minimum DNBR occurs	37.0
Turbine trip occurs due to High-High Steam Generator water level signal	37.5
Reactor trip on turbine trip occurs	39.5
Feedwater isolation valves close due to High-High Steam Generator water level signal	44.0

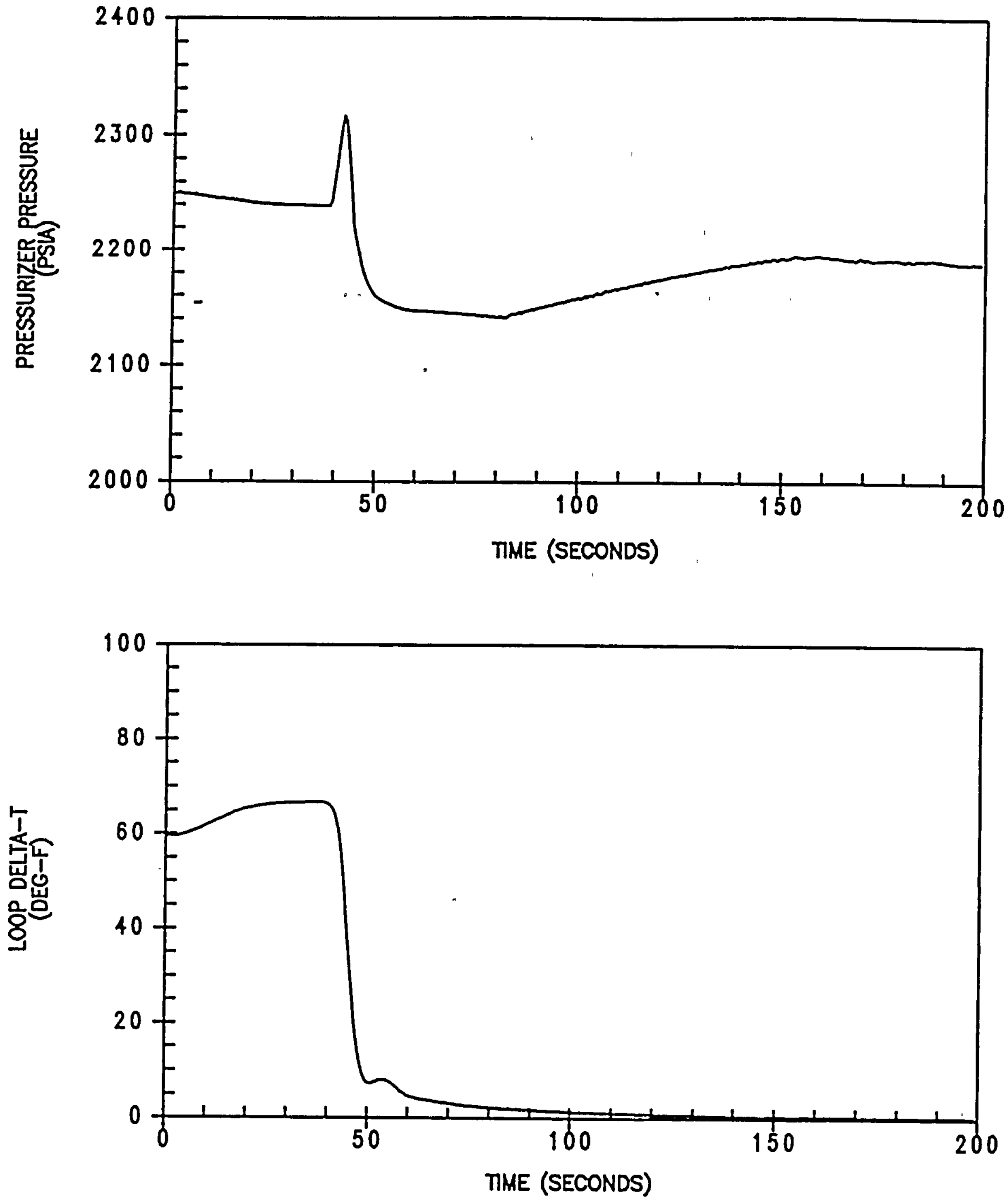


REV. 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

FEEDWATER CONTROL VALVE MALFUNCTION - NUCLEAR POWER AND CORE HEAT FLUX VERSUS TIME

FIGURE 14.1.7-1



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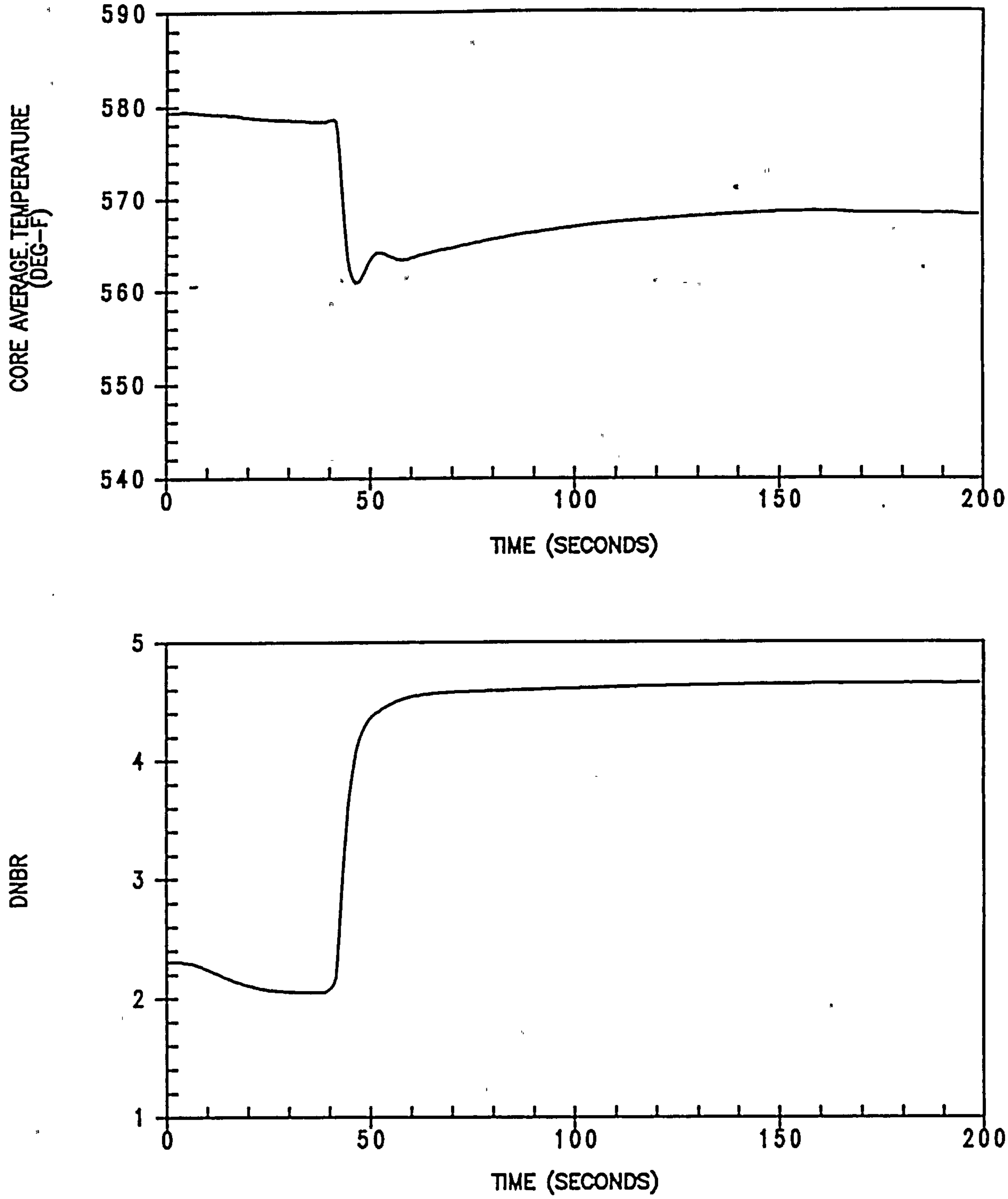
TURKEY POINT PLANT UNITS 3 & 4

FEEDWATER CONTROL VALVE MALFUNCTION - PRESSURIZER PRESSURE AND LOOP ΔT VERSUS TIME

FIGURE 14.1.7-2



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FEEDWATER CONTROL VALVE MALFUNCTION - CORE AVERAGE TEMPERATURE AND DNBR VS TIME

FIGURE 14.1.7-3

14.1.8 EXCESSIVE LOAD INCREASE INCIDENT

An excessive load increase incident is defined as a rapid increase in steam generator steam flow causing a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a 10 percent step load increase and a 5 percent per minute ramp load increase without a reactor trip in the range of 15 to 100 percent full power. Any loading rate in excess of these values may cause a reactor trip actuated by the protection system. If the load increase exceeds the capability of the reactor control system, the transient is terminated in sufficient time to prevent DNBR from going below the limit value since the core is protected by a combination of the nuclear overpower trip and the overpower-overtemperature trips, as discussed in Section 7. An excessive load increase incident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction such as steam bypass control or turbine speed control.

The load demand is limited to 100% load by the turbine load limiter.

During power operation, steam bypass to the condenser is controlled by signals of reactor coolant conditions, i.e., abnormally high reactor coolant temperature indicates a need for steam bypass. A single controller malfunction does not cause steam bypass because an interlock is provided which blocks the control signal to the valves unless a sudden large turbine load decrease has occurred. In addition, the reference temperature and loss of load signals are developed by independent sensors.

Regardless of the rate of load increase, the reactor protection system will trip the reactor in time to prevent DNBR from going below the limit value. Increases in steam load to more than design flow are analyzed as steam line ruptures in Section 14.2.5.

Protection against an excessive load increase accident is provided by the following reactor protection system signals.

a. Overtemperature ΔT
b. Power range high neutron flux
c. Low pressurizer pressure

Method of Analysis

This accident is analyzed using the LOFTRAN Code (Reference 1). The code simulates the neutron kinetics, reactor coolant system including natural circulation, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, steam generator main steam safety valves, and auxiliary feedwater system. The code computes pertinent plant variables including DNBR, temperatures, pressures, and power level.

Four cases are analyzed to demonstrate plant behavior following a 10-percent step load increase from rated load. These cases are as follows:

1. Reactor control in manual with minimum moderator reactivity feedback (BOL).

2. Reactor control in manual with maximum moderator reactivity feedback (EOL).

3. Reactor control in automatic with minimum moderator reactivity feedback (BOL).

4. Reactor control in automatic with maximum moderator reactivity feedback (EOL).

For the minimum moderator feedback cases (BOL), the core has the least negative moderator temperature coefficient of reactivity and the least-negative Doppler only power coefficient curve; therefore, reductions in coolant temperature will have the least impact on core power. Since a positive moderator temperature coefficient would provide a transient benefit, a zero moderator temperature coefficient was assumed in the minimum feedback cases. For the (EOL) maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its highest absolute value and the most negative Doppler only power coefficient curve. This results in the largest amount of reactivity feedback due to changes in coolant temperature.

A 10-percent step increase in steam demand is assumed, and all cases are studied without credit being taken for pressurizer heaters.

Normal reactor control systems and engineered safety systems are not required to function. The reactor protection system is assumed to be operable; however, reactor trip is not encountered for the cases analyzed. No single active failure will prevent the reactor protection system from performing its intended function.

Results

Figures 14.1.8-1 through 14.1.8-4 illustrate the transient with the reactor in the manual control mode. As expected, for the (BOL) minimum moderator feedback case there is a slight power increase, and the average core temperature shows a decrease. This results in a departure from nucleate boiling ratio (DNBR) which increases (after a slight decrease) above its initial value. For the (EOL) maximum moderator feedback, manually controlled case, there is a larger increase in reactor power due to the moderator feedback. A reduction in DNBR is experienced, but DNBR remains above the limit value.

Figures 14.1.8-5 through 14.1.8-8 illustrate the transient assuming the reactor is in the automatic rod control mode and no reactor trip signals occur. Both the BOL and EOL cases show that core power increases. The BOL case shows the core average temperature stabilizes, due to the action of the control rod system, at a slightly higher value from the initial temperature. The EOL case shows that after a slight increase the core average temperature stabilizes, again due to the action of the rod control system, at a value approximately equal to the initial temperature. For both of these cases, the minimum DNBR remains above the limit value.

The calculated sequence of events for the excessive load increase incident is shown in Table 14.1.8-1. Note that a reactor trip signal was not generated for any of the four cases.

Conclusions

The analysis presented above shows that for a 10-percent step load increase, the DNBR remains above the limit value. The plant rapidly reaches a stabilized condition following the load increase.

REFERENCES

1. Westinghouse WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-proprietary), Burnett, T W T, et al.,"LOFTRAN Code Description," dated April 1984.

2. Westinghouse WCAP-11397-P-A, Friedland, A. J., and S. Ray,"Revised Thermal Design Procedure," dated April 1989.

Evaluation of DNB in the Core During the Accident

For this accident, DNB is assumed to occur in the core and therefore, an evaluation of the consequences with respect to fuel rod thermal transients is performed. Results obtained from analysis of this "hot spot" condition represent the upper limit with respect to clad temperature and zirconium-water reaction. In the evaluation, the rod power at the hot spot is assumed to be 2.5 times the value at the initial core power level.

Film Boiling Coefficient

The film boiling coefficient is calculated in the FACTRAN code using the Bishop-Sandberg-Tong film boiling correlation (Reference 2). The fluid properties are evaluated at the film temperature (average between the wall and bulk temperatures). The program calculates the film coefficient at every time step based upon the actual heat transfer conditions at the time. The neutron flux, system pressure, bulk density, and mass flow rate as a function of time are used as program input.

For this analysis, the initial values of the pressure and the bulk density are used throughout the transient, since they are the most conservative with respect to the clad temperature response. As indicated earlier, DNB was assumed to start at the beginning of the accident.

Film Clad Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and clad (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between pellet and clad.

For the initial portion of the transient, a high gap coefficient produces higher clad temperatures, since the heat stored and generated in the fuel redistributes itself in the cooler cladding. This effect is reversed when the clad temperature exceeds the pellet temperature in cases where a zirconium-steam reaction is present. Based on investigations on the effect of the gap coefficient upon the maximum clad temperature during the transient, the gap coefficient was assumed to increase from a steady-state value consistent with initial fuel temperatures to 10,000 Btu/hr-ft^2-°F at the initiation of the transient. Thus, the large amount of energy stored in the fuel is released to the clad at the initiation of the transient.

Zirconium Steam Reaction

The zirconium-steam reaction can become significant above 1800°F (clad temperature). The Baker-Just parabolic rate equation (Reference 2) shown below is used to define the rate of the zirconium-steam reaction.

$$\frac{dw^2}{dt} = 33.3 \times 10^6 \exp^{(-45,500/1.986T)}$$

where,

w = amount reacted, mg/cm^2
t = time, sec
T = temperature, °K
The reaction heat is about 1510 cal/gm

The effect of zirconium-steam reaction is included in the calculation of the "hot spot" clad temperature transient.

Results

The calculated sequence of events is shown in Table 14.1.9-1. The transient results are shown in Figures 14.1.9-9 through 14.1.9-12. The peak Reactor Coolant System pressure reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits. Also, the peak clad surface temperature is considerably less than 2700°F. It should be noted that the clad temperature was conservatively calculated assuming that DNB occurs at the initiation of the transient. The results of these calculations (peak pressure, peak clad temperature, and zirconium-steam reaction) are also summarized in Table 14.1.9-2. The rods-in DNB design criteria of less than 10% has been met.

Dose Evaluation

For the analysis of offsite doses following a locked rotor, the doses are determined assuming a pre-accident spike that has raised the RCS iodine concentration to 60 μCi/gm of dose equivalent (DE) I-131.

The noble gas activity concentration in the RCS at the time the accident occurs is based on a fuel defect of 1.0%. The iodine activity of the secondary coolant at the time the locked rotor occurs is assumed to be the equivalent to the Technical Specification limit of 0.10 μCi/gm of DE I-131.

As a result of the locked rotor event, less than 10% of the fuel rods undergo DNB. However, it is conservatively assumed that 10% of the fuel rods fail and that all of the fuel rod gap activity is released to the RCS. The gap activity is assumed to be 10% of the total core activity for both iodines and noble gases.

The total primary to secondary SG tube leak rate used in the analysis is the Technical Specification limit of 1.0 gpm. No credit for iodine removal is taken for any steam released to the condenser prior to the reactor trip and concurrent loss of offsite power. An iodine partition factor in the SGs of 0.01 (Ci I/gm steam)/(Ci I/gm water) is used. All noble gas activity carried over to the secondary side through SG tube leakage is assumed to be immediately released to the outside atmosphere.

At 24 hours after the accident the RHR System is assumed to be placed in service for heat removal and there are no further steam releases to the atmosphere from the secondary system.

The major assumptions and parameters used in the analysis are itemized in Table 14.1.9-3. The thyroid dose conversion factors, breathing rates, and atmospheric dispersion factors used in the dose calculations are given in Table 14.3.5-4.

The dose limits for a locked rotor are a small fraction of the 10 CFR 100 guideline values of 30 REM thyroid 2.5 REM whole body. The offsite thyroid and whole body doses due to the locked rotor are given in Table 14.1.9-4. The offsite doses due to the locked rotor are within the acceptance criteria.

Conclusions

The analysis has shown the following:

a. Since the peak RCS pressure reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits, the integrity of the primary coolant system is not endangered.

b. Since the peak clad surface temperature calculated for the hot spot during the worst transient remains considerably less than 2700°F, the core will remain in place and intact with no loss of core cooling capability.

REFERENCES

1. Westinghouse WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-proprietary), Burnett, T. W. T., et al.,"LOFTRAN Code Description," dated April 1984.

2. Westinghouse WCAP-7908-A, Hargrove, W. G.,"FACTRAN - A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," dated December 1989.

3. Westinghouse WCAP-11397-P-A, Friedland, A. J., and S. Ray,"Revised Thermal Design Procedure," dated April 1989.

4. Westinghouse WCAP-12910, Barret, G. O., et at.,"Pressurizer Safety Valve Set Pressure Shift," dated March 1991.

14.1.10 LOSS OF EXTERNAL ELECTRICAL LOAD

The loss of external electrical load may result from an abnormal increase in network frequency, or an accidental opening of the main breaker from the generator which fails to cause a turbine trip but causes a rapid large load reduction by the action of the turbine control. For either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps. The case of loss of all non-emergency AC power is presented in Section 14.1.12.

The unit is designed to accept a 50 percent step loss of load without actuating a reactor trip with all NSSS control systems in automatic (reactor control system, pressurizer pressure and level, steam generator water level control, and steam dumps). The automatic turbine bypass system with 27 percent design flow to the condenser is able to accommodate this abnormal load rejection by reducing the transient imposed upon the reactor coolant system. The reactor power is reduced to the new equilibrium power level at a rate consistent with the capability of the rod control system. The pressurizer power-operated relief valves may be actuated, but the pressurizer safety valves and the steam generator safety valves do not lift in this case.

A loss of external load would normally trip the reactor directly from a signal derived from the turbine autostop oil pressure (a two out of three signal). Reactor coolant temperatures and pressure do not significantly increase if the steam dump system and pressurizer pressure control system are functioning properly.

In the event the turbine bypass valves fail to open following a large load loss, the main steam safety valves lift and the reactor may be tripped by the high pressurizer pressure signal or high pressurizer level signal or the overtemperature ΔT signal. In the event of feedwater flow also being lost, the reactor may also be tripped by a steam generator low-low water level signal. The steam generator shell side pressure and reactor coolant temperatures increase rapidly. The pressurizer safety valves are sized to protect the reactor coolant system against overpressure without taking credit for the turbine bypass system, pressurizer spray, pressurizer power-operated relief valves, automatic RCCA control, or the direct reactor trip on turbine trip.

The pressurizer safety valve capacity is sized based on a complete loss of heat sink with the plant initially operating at the maximum calculated turbine load along with operation of the main steam safety valves. The pressurizer and main steam safety valves are then able to maintain the RCS and Main Steam System pressures within 110% of the corresponding design pressure without a direct reactor trip on turbine trip action.

The Turkey Point Units 3 and 4 Reactor Protection System and primary and secondary system designs preclude overpressurization without requiring the automatic rod control, pressurizer pressure control and/or turbine bypass control system.

Method of Analysis

In this analysis, the behavior of the unit is evaluated for a complete loss of steam load from full power, without direct reactor trip, primarily to show the adequacy of the pressure-relieving devices, and also to demonstrate core protection margins; i.e., the turbine is assumed to trip without actuating all the sensors for reactor trip on the turbine stop valves. This assumption delays reactor trip until conditions in the reactor coolant system (RCS) result in a trip due to other signals. Thus, the analysis assumes a worst transient. In addition, no credit is taken for the turbine bypass system. Main feedwater flow is terminated at the time of turbine trip, with no credit taken for auxiliary feedwater (except for long-term recovery) to mitigate the consequences of the transient.

The turbine trip transients are analyzed by employing the detailed digital computer program LOFTRAN (Reference 1). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and main steam safety valves. The program computes pertinent plant variables, including temperatures, pressures, DNBR, and power level.

Four cases are analyzed for a total loss of load from full power conditions.

1. Minimum reactivity feedback with pressure control;
2. Maximum reactivity feedback with pressure control;
3. Minimum reactivity feedback without pressure control; and
4. Maximum reactivity feedback without pressure control.

The primary concern for the cases analyzed with pressure control is minimum DNBR, whereas the primary concern for those cases analyzed without pressure control is maintaining reactor coolant and main steam system pressure below 100% of design pressure.

The major assumptions used in these analyses are summarized below:

A. Initial Operating Conditions

The automatic pressure control cases are analyzed using the Revised Thermal Design Procedure (Reference 2). The initial reactor power and RCS temperatures are assumed at their nominal values consistent with steady-state, full-power operation. Uncertainties in initial conditions are included in the departure from nucleate boiling ratio (DNBR) limit as described in WCAP-11397 (Reference 2). The RCS total flow rate assumed is the value of the minimum measured flow consistent with 20% steam generator tube plugging.

The cases without pressure control are analyzed using the Standard Thermal Design Procedure. Initial uncertainties on core power, reactor coolant temperature, and pressure are applied in the most conservative direction to obtain the initial plant conditions for the beginning of the transient. The RCS total flow rate assumed is the value of the thermal design flow consistent with 20% steam generator tube plugging.

B. Reactivity Coefficients

The total loss of load transient is analyzed with both maximum and minimum reactivity feedback. The maximum feedback (EOL) cases assume a large (absolute value) negative moderator temperature coefficient and the most-negative Doppler only power coefficient. The minimum feedback (BOL) cases assume a positive moderator temperature coefficient and the least-negative Doppler only coefficient.

C. Reactor Control

From the standpoint of the maximum pressures attained, it is conservative to assume that the reactor is in manual rod control. If the reactor were in automatic rod control, the control rod banks would move prior to trip and reduce the severity of the transient.

D. Pressurizer Spray and Power-Operated Relief Valves

The loss of load event is analyzed both with and without pressurizer pressure control (for both minimum and maximum reactivity feedback). The pressurizer PORVs and sprays are assumed operable for the cases with pressure control. The cases with pressure control conservatively minimize the increase in primary pressure which is more limiting for the DNBR transient. The cases without pressure control conservatively maximize the pressure increase which is more limiting for the RCS overpressurization criterion. In all cases the main steam and pressurizer safety valves are operable.

The pressurizer safety valve modeling includes the effects of the pressurizer safety valve loop seals. For those cases which are analyzed primarily for DNBR (pressurizer control cases), a -3% uncertainty was applied to reduce the setpoint. For those cases which are analyzed primarily for peak RCS pressure, a +2% uncertainty and a +1% set pressure shift were applied to increase the set point pressure by a total of 3%, such that, the pressurizer safety valves begins to open at 2575 psia. Additionally, no steam flow is assumed until the valve loop seals are purged.

E. Feedwater Flow

Main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow, however, the auxiliary feedwater pumps would be expected to start on a trip of the main feedwater pumps. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

F. Reactor Trip

Only the overtemperature ΔT, high pressurizer pressure, and low-low steam generator water level reactor trips are assumed operable for the purposes of this analysis. No credit is taken for a reactor trip on high pressurizer level or the direct reactor trip on turbine trip.

G. Steam Release

No credit is taken for the operation of the steam dump to condenser or atmosphere. This assumption maximizes both primary and secondary pressure. The main steam safety valves are assumed to lift and be full open at 6% above their design setpoints. This 6% includes 3% for safety valve setpoint uncertainty and 3% for accumulation.

Results

The transient responses for a total loss of load from 100 percent of full-power operation are shown for four cases. The calculated sequence of events for the accident is shown in Table 14.1.10-1.

Case 1:

Figures 14.1.10-1 through 14.1.10-3 show the transient response for the total loss of steam load event under BOL conditions, including a positive moderator temperature coefficient, with pressure control. The reactor is tripped on overtemperature ΔT. The neutron flux increases until the reactor is tripped, and although the DNBR value decreases below the initial value, it remains well above the safety analysis limit throughout the entire transient. The pressurizer relief valves and sprays maintain primary pressure below 110% of the design value. The main steam safety valves are also actuated and maintain secondary pressure below 110% of the design value.

Case 2:

Figures 14.1.10-4 through 14.1.10-6 show the transient response for the total loss of steam load event under EOL conditions, assuming a conservatively large positive moderator density coefficient of 0.5 Δk/gm/cc (corresponding to a large negative moderator temperature coefficient) and a most-negative Doppler only power coefficient, with pressure control. The reactor does not trip under these conditions. The plant stabilizes at a power level established by the relief valve capacity of the main steam safety valves. Without operator intervention, the reactor would eventually reach a low-low steam generator water level reactor trip condition as the secondary system inventory decreases. The DNBR increases throughout the transient and never drops below the initial value. The pressurizer relief valves and sprays maintain primary pressure below 110% of the design value. The pressurizer pressure remains below the safety valve setpoint during the transient. The main steam safety valves are also actuated and maintain secondary pressure below 110% of the design value.

Case 3:

Figures 14.1.10-7 through 14.1.10-9 show the transient response for the total loss of steam load event under BOL conditions, including a positive moderator temperature coefficient, without pressure control. The reactor is tripped on high pressurizer pressure. The neutron flux remains essentially constant at full power until the reactor is tripped, and the DNBR remains above the initial value for the duration of the transient. The pressurizer safety valves are actuated and maintain primary pressure below 110% of the design value. The main steam safety valves are also actuated and maintain secondary pressure below 110% of the design value.

Case 4:

Figures 14.1.10-10 through 14.1.10-12 show the transient response for the total loss of steam load event under EOL conditions, assuming a conservatively large positive moderator density coefficient of 0.5 Δk/gm/cc (corresponding to a large negative moderator temperature coefficient) and a most-negative Doppler only power coefficient, without pressure control. The reactor is tripped on high pressurizer pressure. The DNBR increases throughout the transient and never drops below the initial value. The pressurizer safety valves are actuated and maintain primary pressure below 110% of the design value. The main steam safety valves are also actuated and maintain secondary pressure below 110% of the design value.

Conclusions

The analysis indicates that a total loss of load without a direct or immediate reactor trip presents no hazard to the integrity of the Reactor Coolant System and the Steam System. All of the applicable acceptance criteria are met. The minimum DNBR for each case is greater than the safety analysis limit value. The peak primary and secondary pressures remain below 110% of design at all times.

REFERENCES

1. Westinghouse WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-proprietary), Burnett, T. W. T., et al.,"LOFTRAN Code Description," dated April 1984.

2. Westinghouse WCAP-11397 (Proprietary), Friedland, A. J., and Ray, S., "Revised Thermal Design Procedure," dated April 1989.

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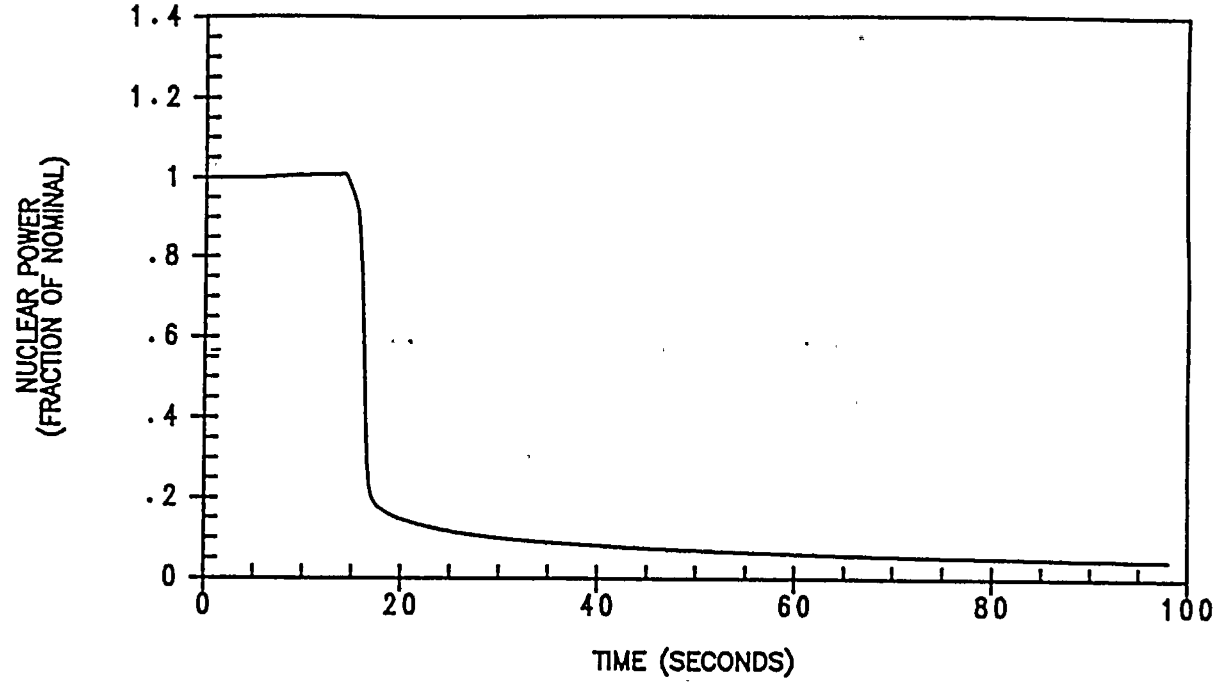
TABLE 14.1.10-1

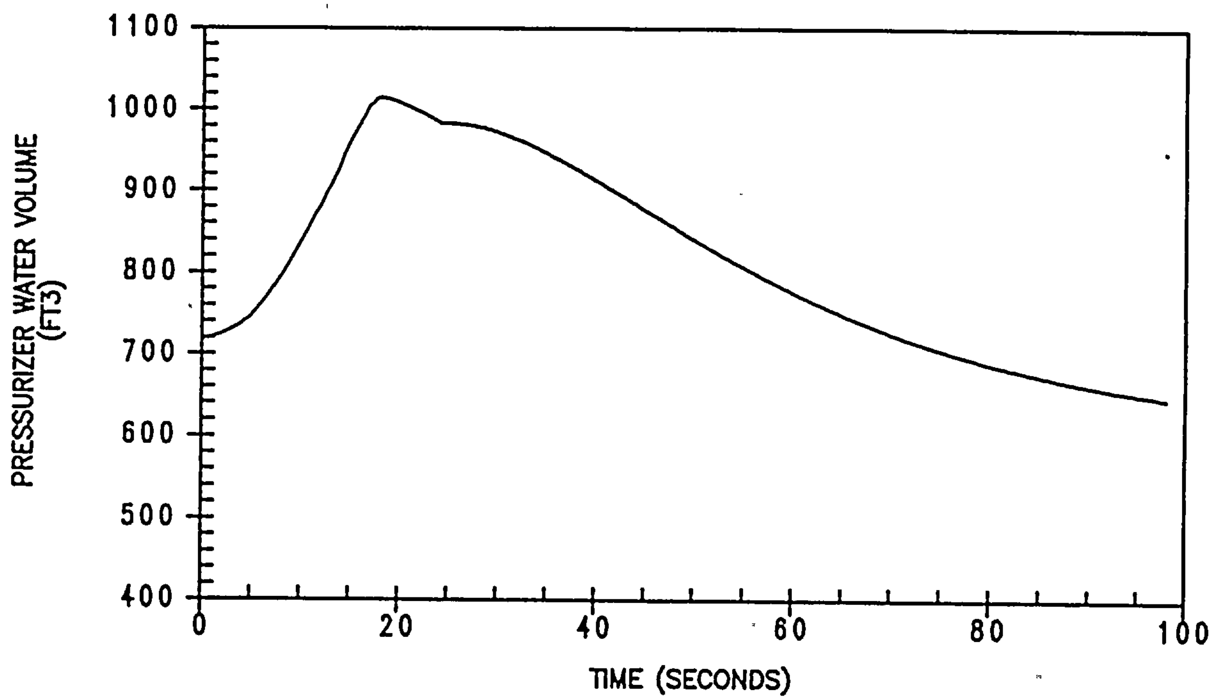
SEQUENCE OF EVENTS - LOSS OF LOAD/TURBINE TRIP ACCIDENTS

Case	Event	Time (sec)
With pressurizer pressure control (minimum reactivity feedback)	Turbine Trip	0.0
	Overtemperature ΔT setpoint reached	12.0
	Rods begin to drop	13.8
	Peak RCS pressure occurs	14.0
	Minimum DNBR occurs	15.2
With pressurizer pressure control (maximum reactivity feedback) (See Note 2)	Turbine Trip	0.0
	Peak RCS pressure occurs	7.6
	Peak Main Steam System pressure occurs	21.8
	Minimum DNBR occurs	(Note 1)
Without pressurizer pressure control (minimum reactivity feedback)	Turbine Trip	0.0
	High Pressurizer pressure setpoint reached	7.2
	Rods begin to drop	9.2
	Peak RCS pressure occurs	10.2
	Peak Main Steam System pressure occurs	15.4
	Minimum DNBR occurs	(Note 1)
Without pressurizer pressure control (maximum reactivity feedback)	Turbine Trip	0.0
	High Pressurizer pressure setpoint reached	7.4
	Rods begin to drop	9.4
	Peak RCS pressure occurs	10.6
	Peak Main Steam System pressure occurs	15.0
	Minimum DNBR occurs	(Note 1)

Notes:

1. Never falls below the initial value.
2. A reactor trip condition is never reached in the analysis. The reactor stabilizes at a power level established by the relief capacity of the MSSVs. Eventually, a low-low steam generator water level reactor trip would occur.





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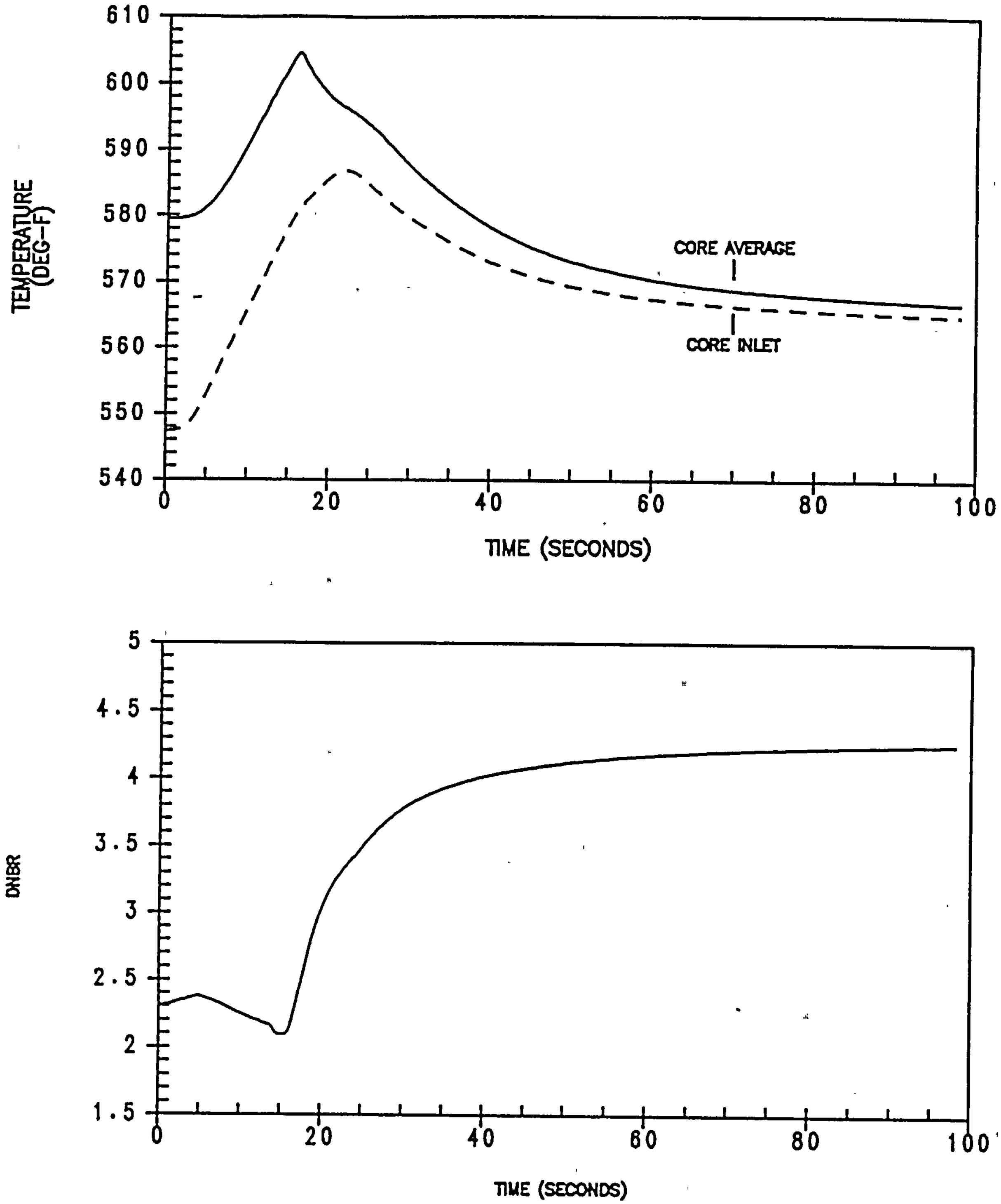
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITH PRESSURE CONTROL, MINIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-1



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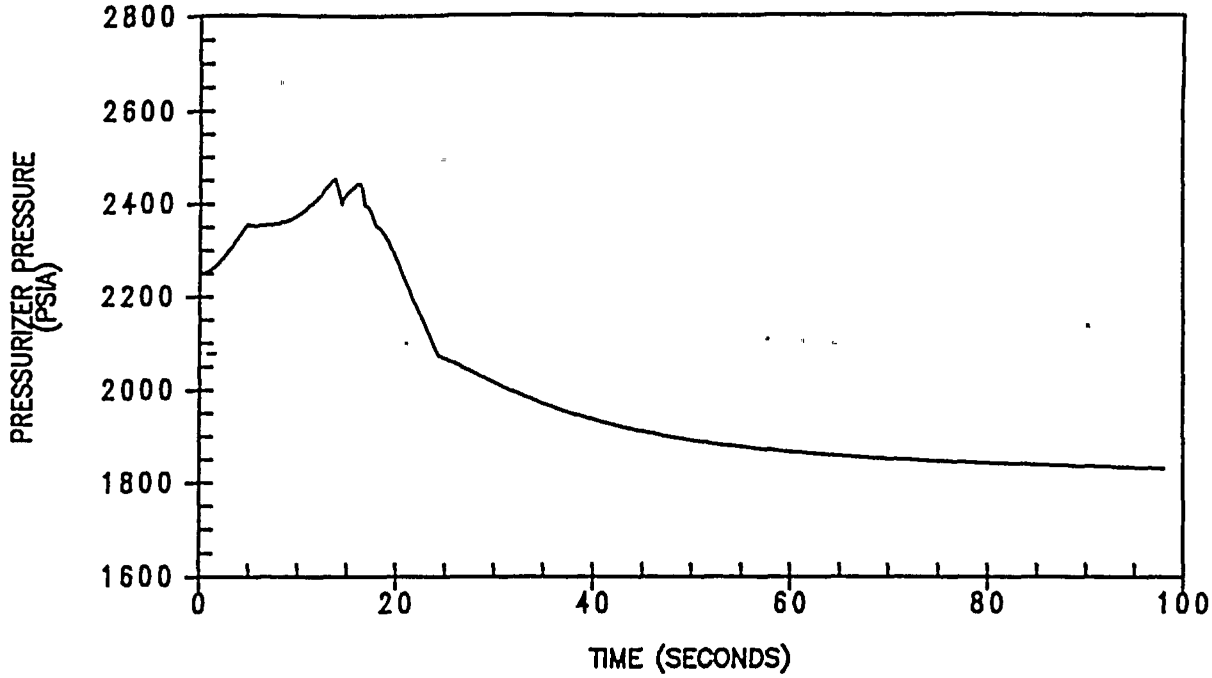
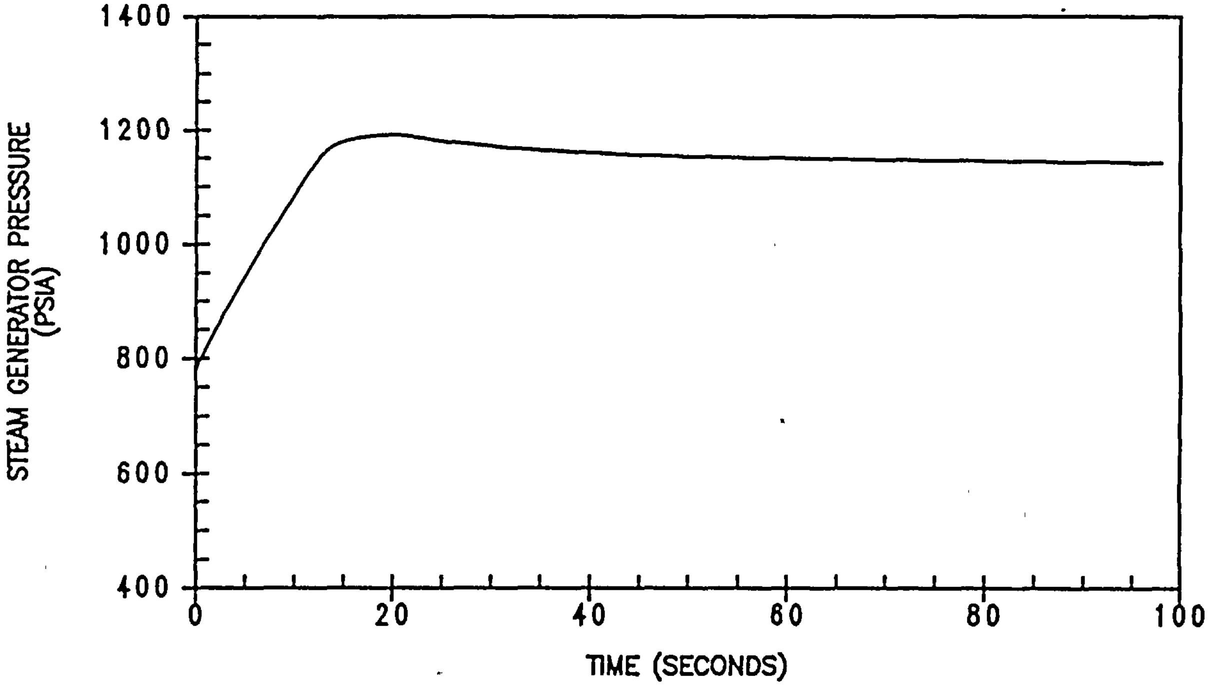
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITH PRESSURE CONTROL, MINIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-2





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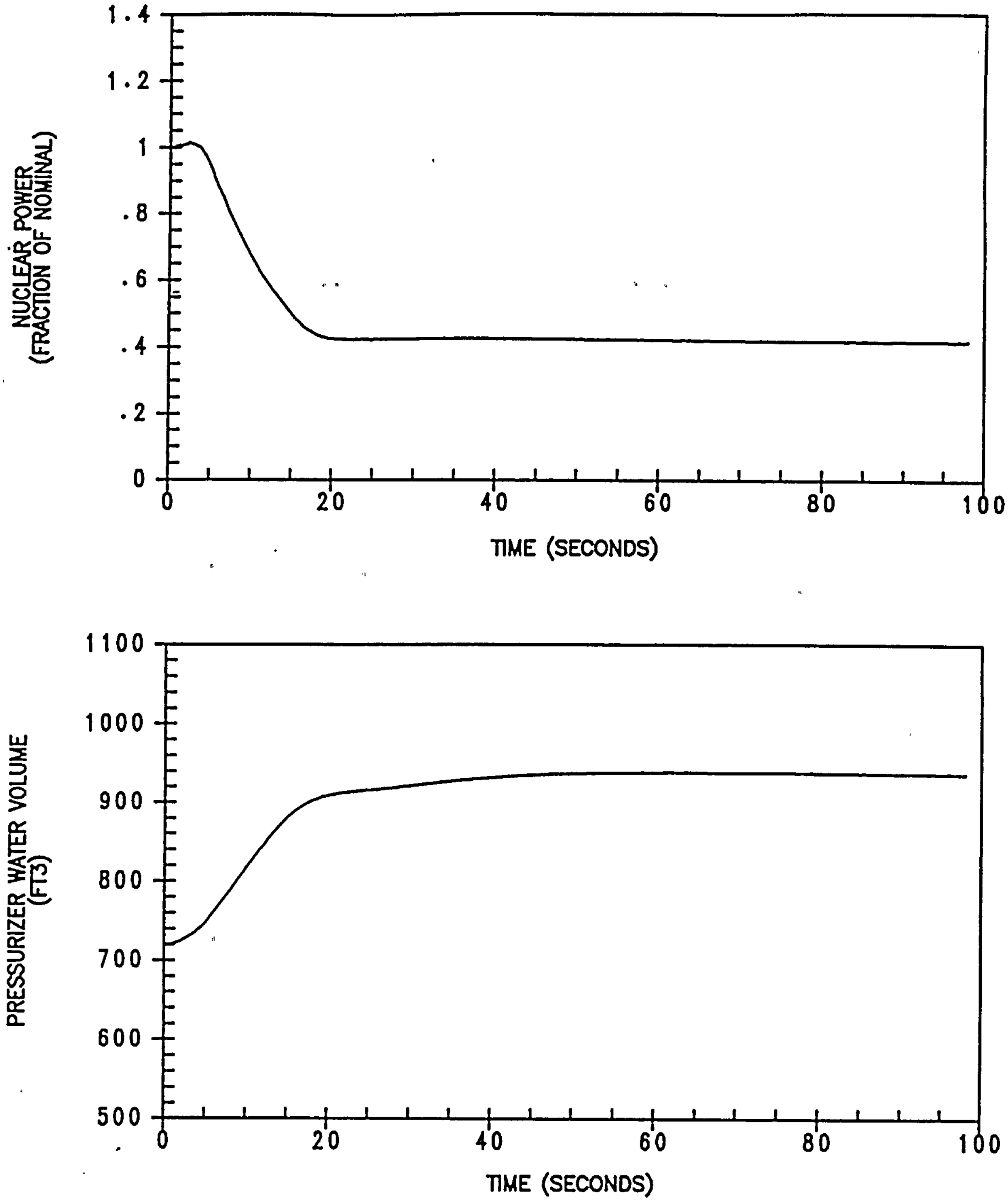
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITH PRESSURE CONTROL, MINIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-3



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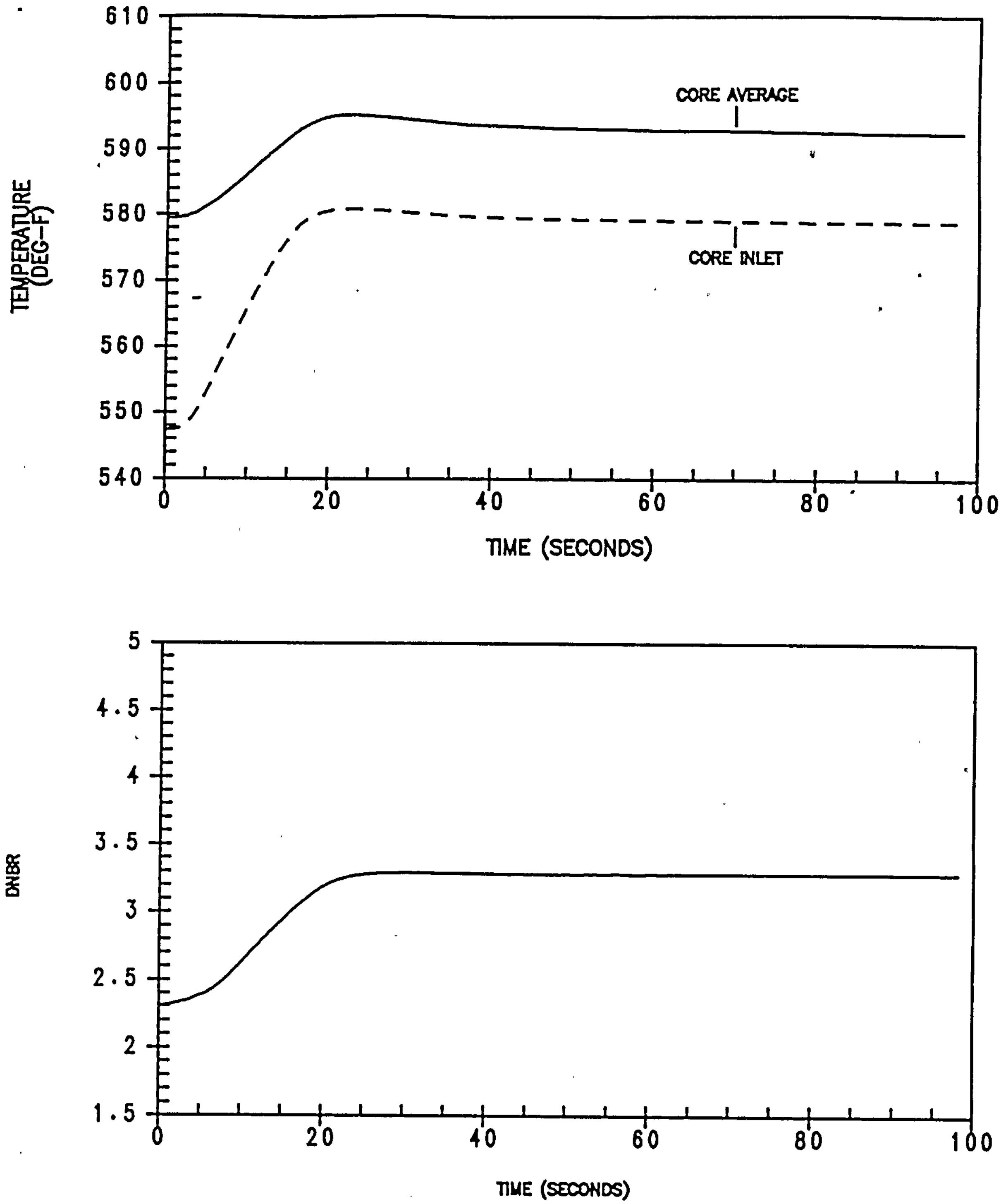
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITH PRESSURE CONTROL, MAXIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-4



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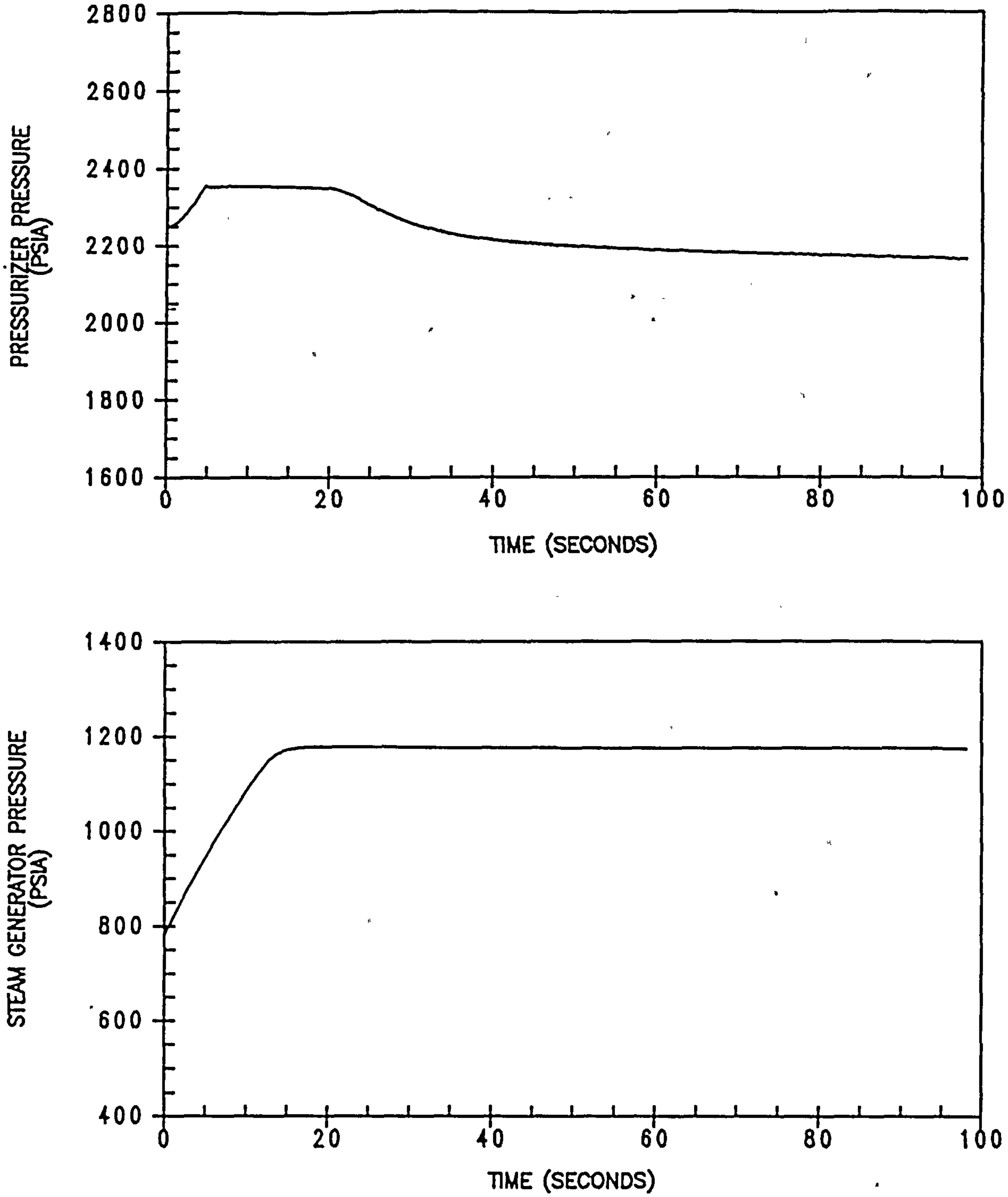
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITH PRESSURE CONTROL, MAXIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-5



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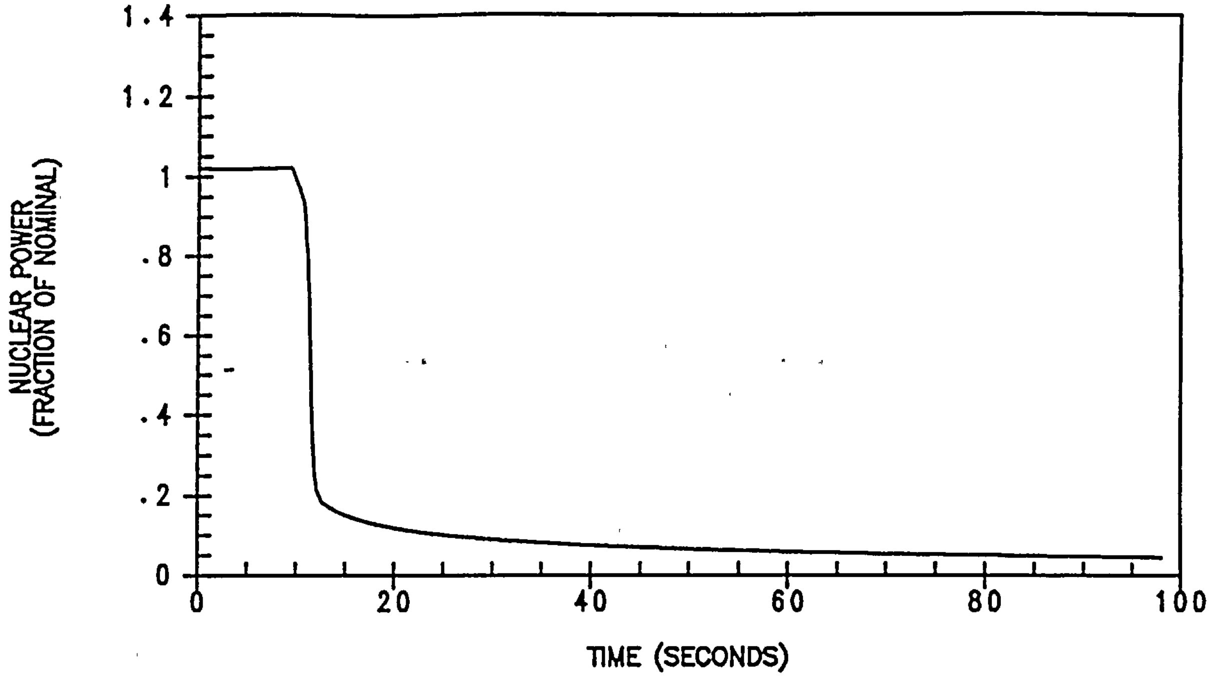
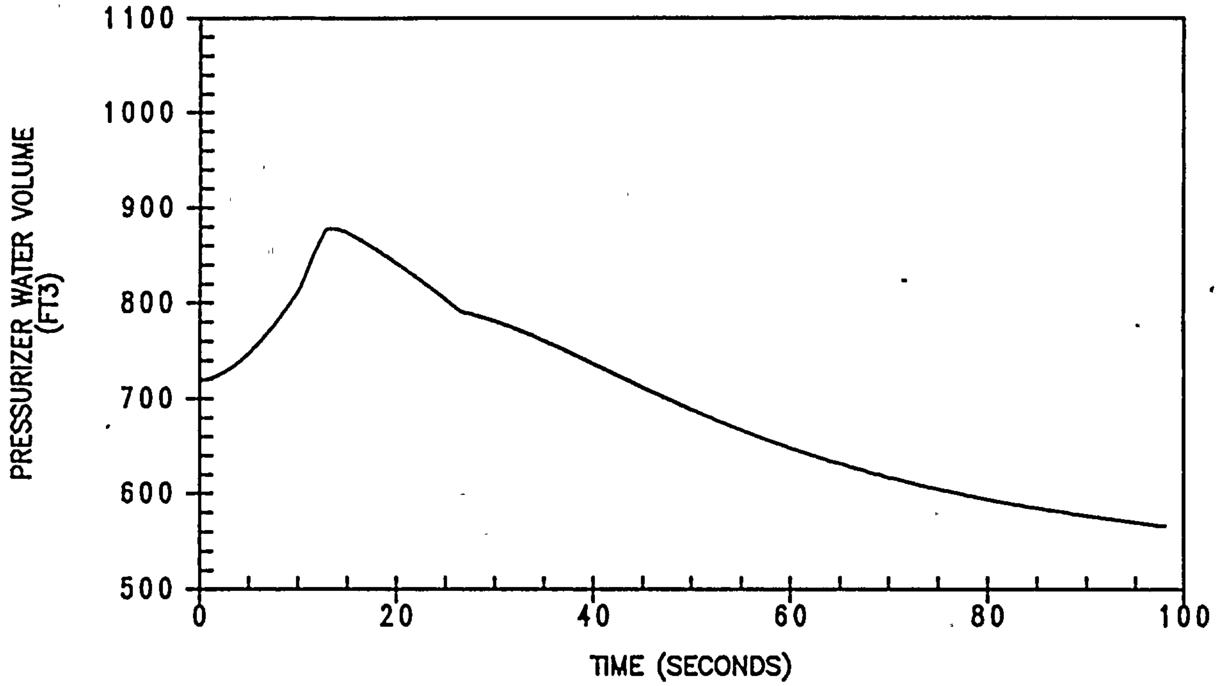
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITH PRESSURE CONTROL, MAXIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-6





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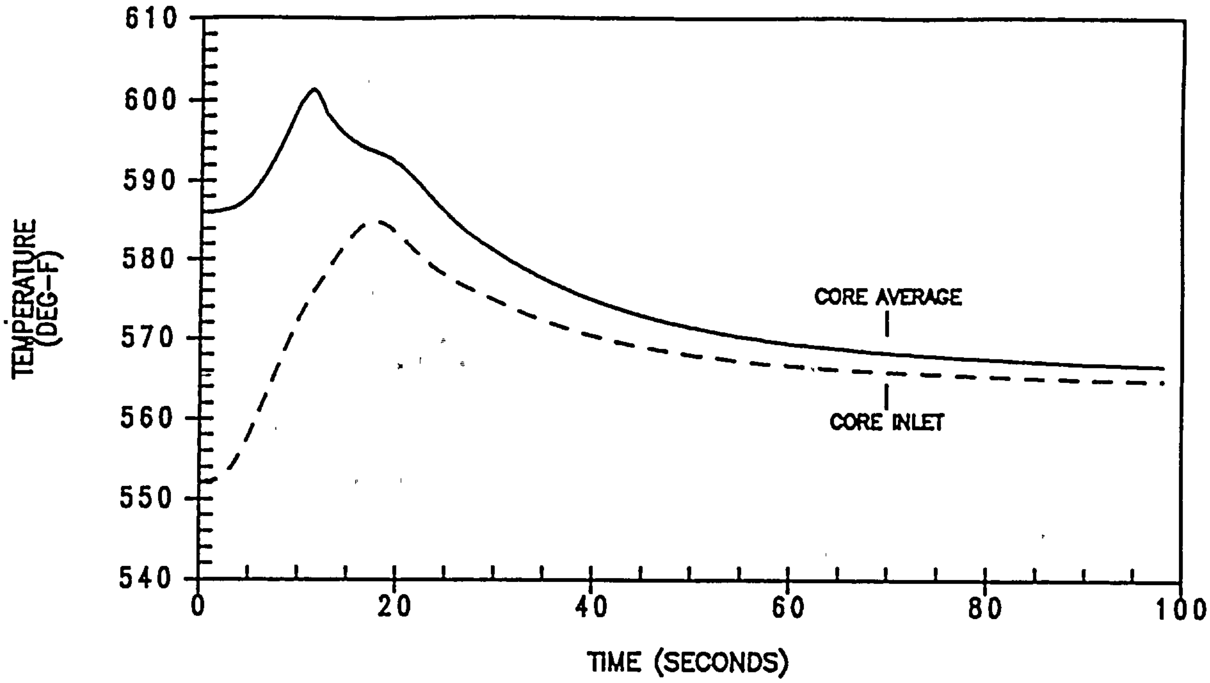
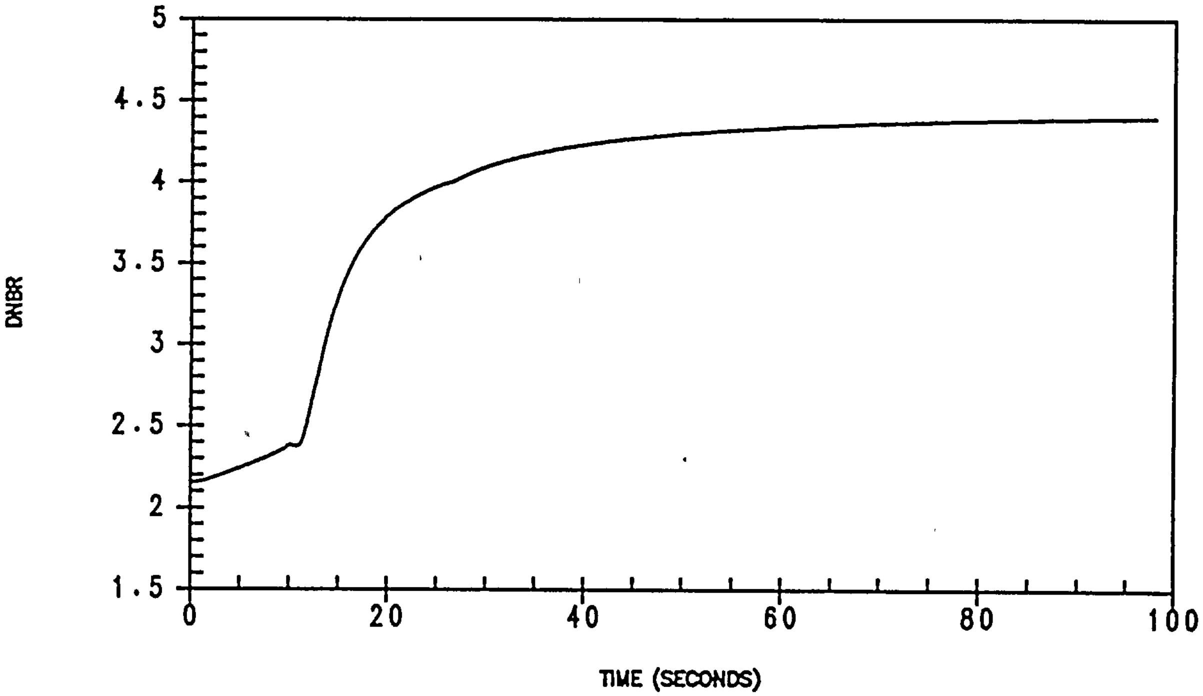
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITHOUT PRESSURE CONTROL, MINIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-7





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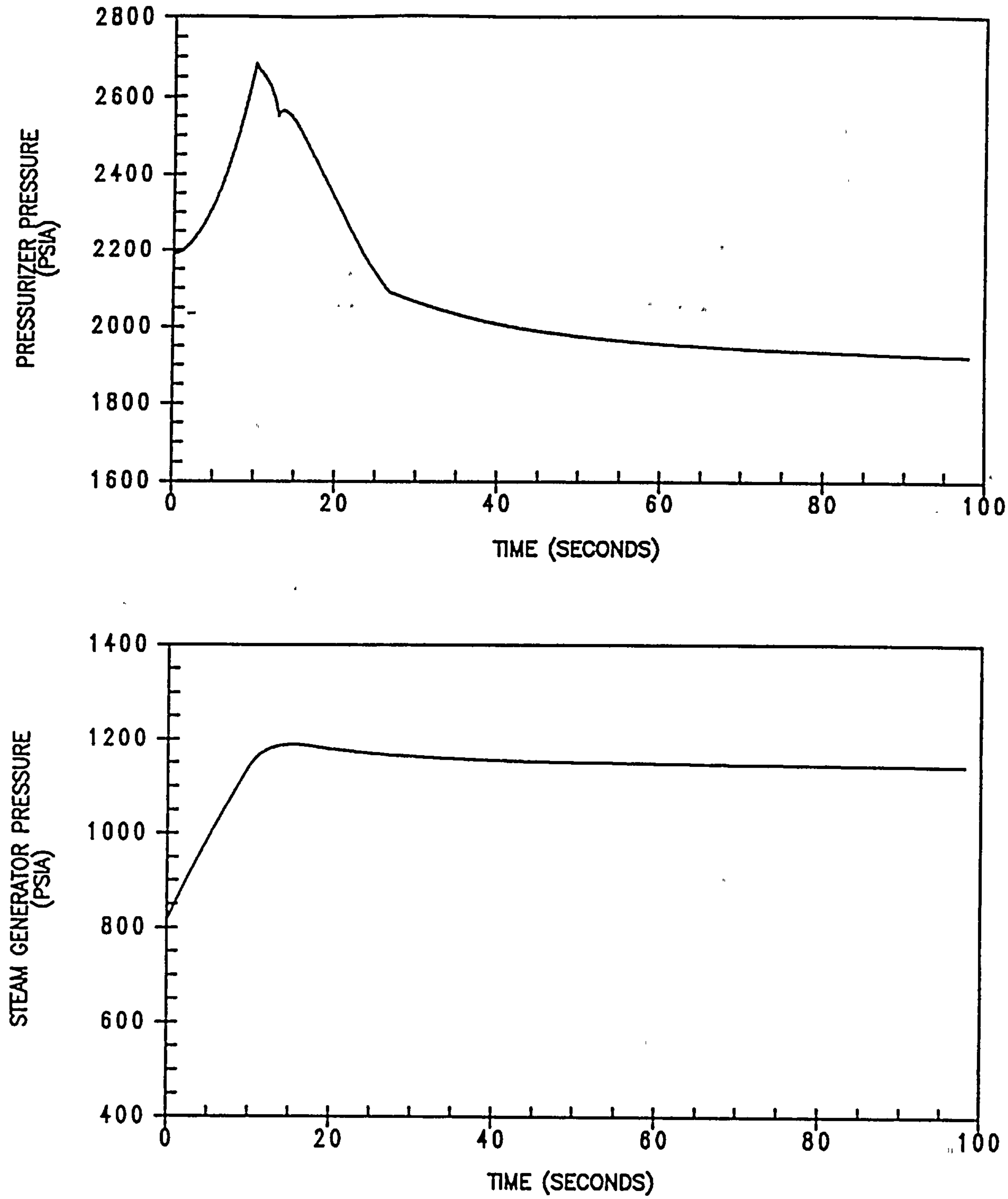
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITHOUT PRESSURE CONTROL, MINIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-8



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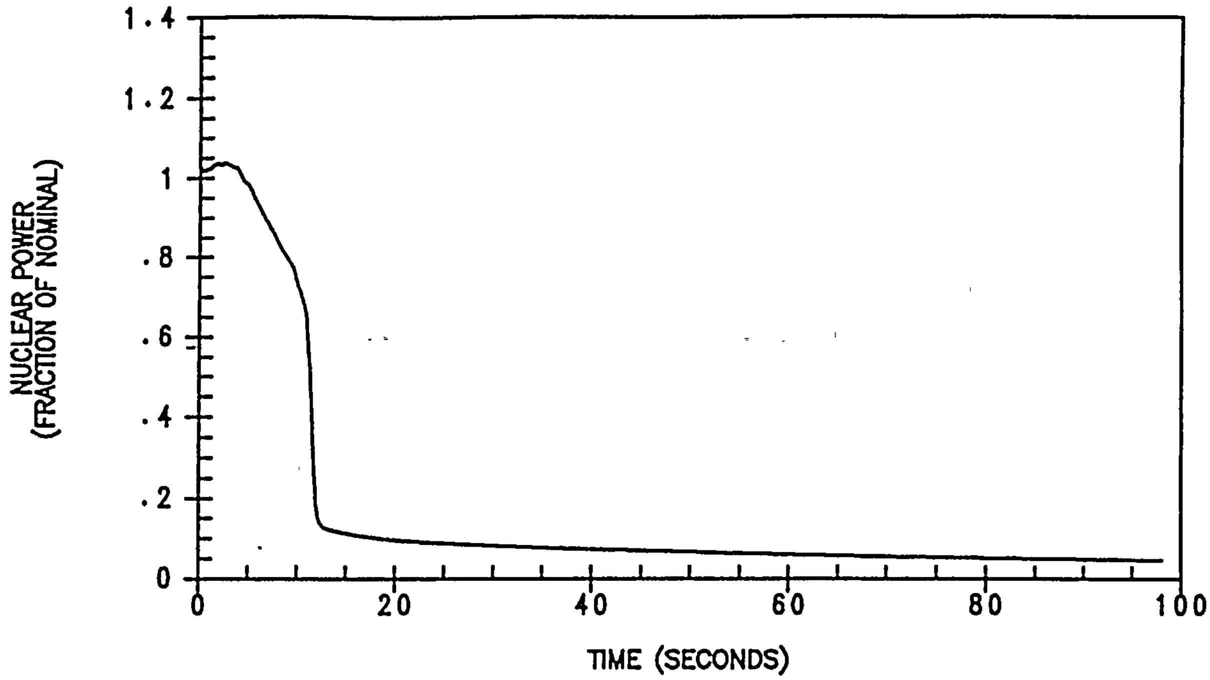
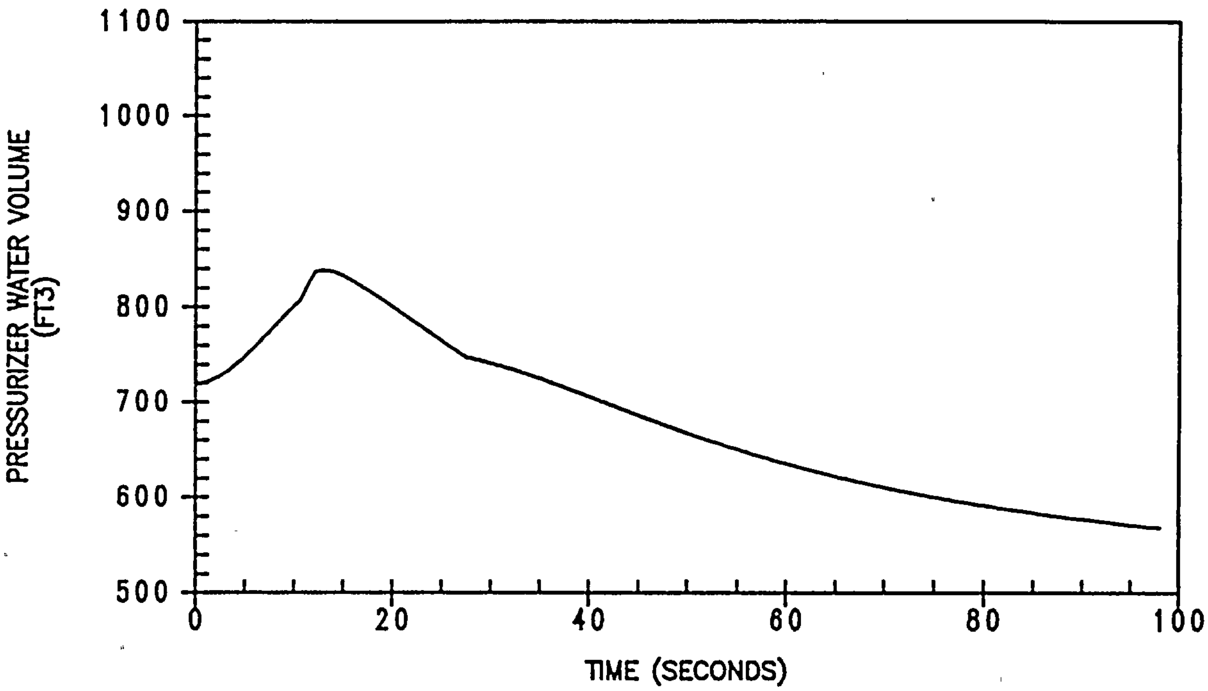
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITHOUT PRESSURE CONTROL, MINIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-9





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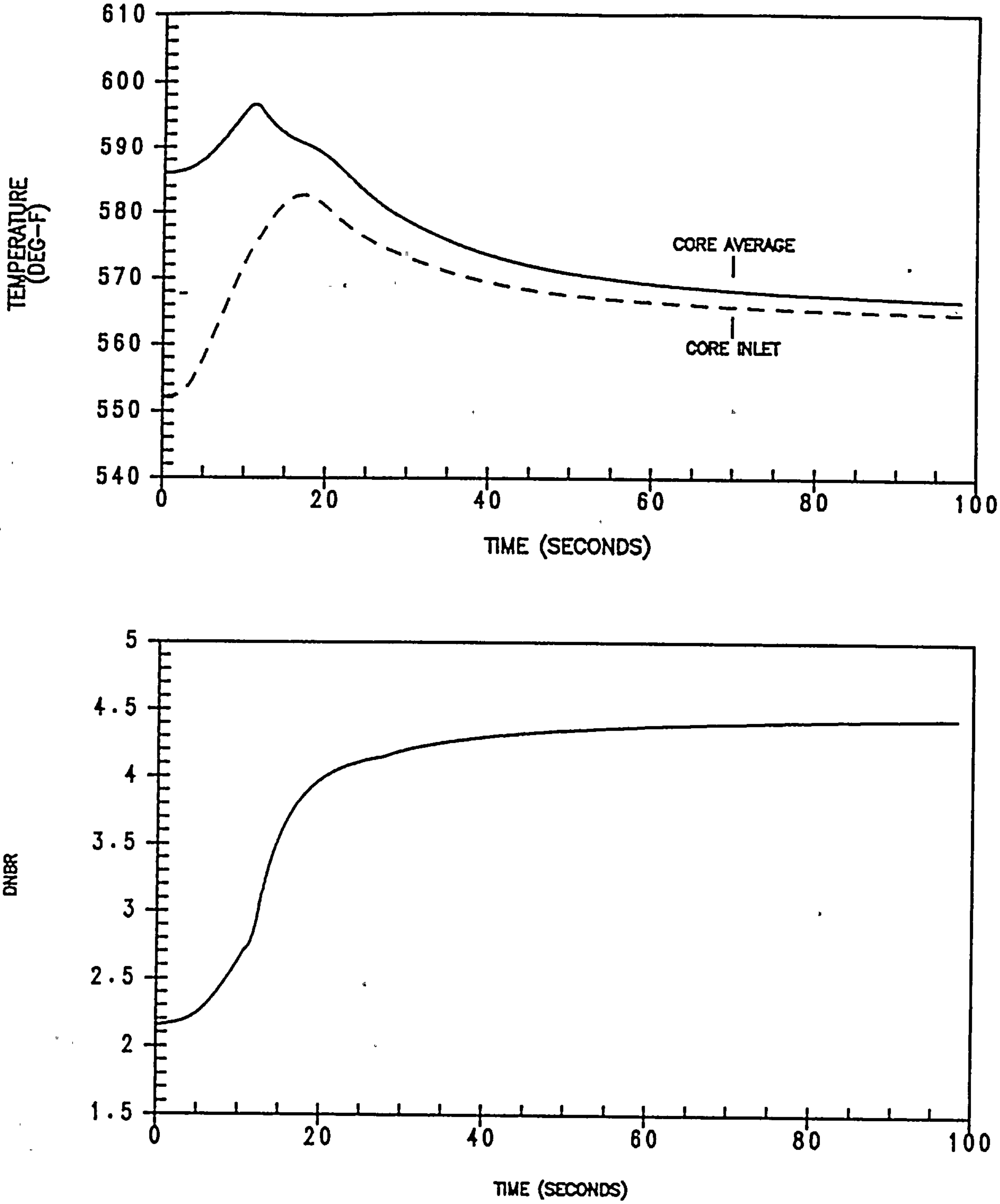
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITHOUT PRESSURE CONTROL, MAXIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-10



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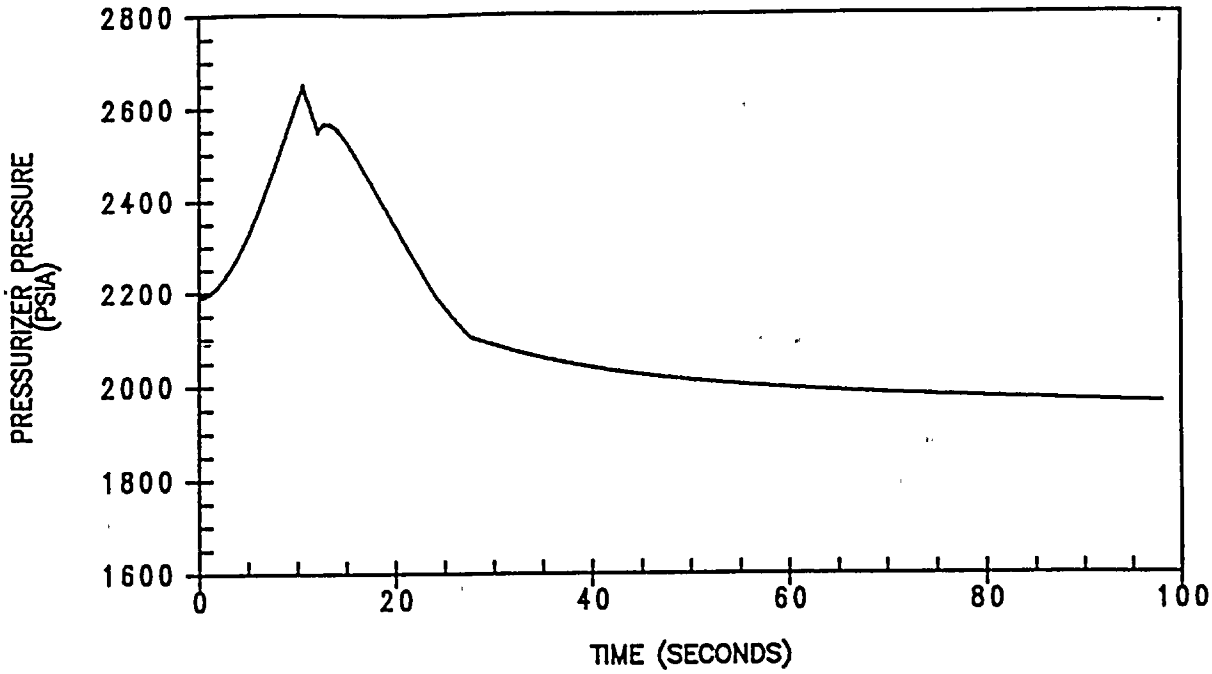
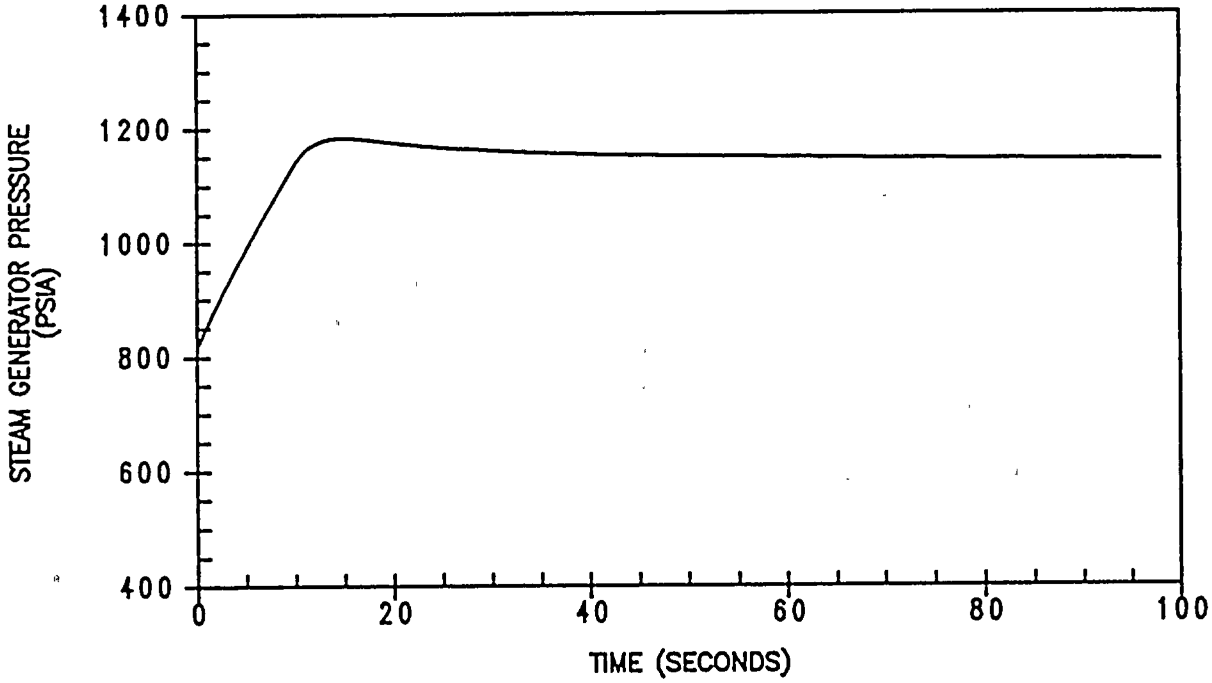
TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITHOUT PRESSURE CONTROL, MAXIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-11





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TURKEY POINT PLANT UNITS 3 & 4

TOTAL LOSS OF EXTERNAL ELECTRICAL LOAD WITHOUT PRESSURE CONTROL, MAXIMUM REACTIVITY FEEDBACK

FIGURE 14.1.10-12

2. The initial reactor coolant average temperature is 6.0°F higher than the nominal value which is comprised of the uncertainty on nominal temperature. The initial pressurizer pressure uncertainty is 60 psi.

3. Reactor trip occurs on steam generator low-low water level at 4.0% of narrow range span, including an incremental reduction of 10% in the steam generator water mass to account for modeling uncertainties.

4. The worst single failure is assumed to occur in the auxiliary feedwater system. This results in the availability of only one auxiliary feedwater pump supplying a minimum of 310 gpm to three steam generators, 120 seconds following a low-low steam generator water level signal.

5. The pressurizer sprays and PORVs are assumed operable. This maximizes the peak transient pressurizer water volume. If these control systems did not operate, the pressurizer safety valves would maintain peak RCS pressure at or below the actuation setpoint (2500 psia) throughout the transient.

6. Secondary system steam relief is achieved through the self-actuated main steam safety valves. Note that steam relief will, in fact, be through the atmospheric dump valves or condenser dump valves for most cases of loss of normal feedwater. However, for the sake of analysis, these have been assumed unavailable.

7. The main steam safety valves are assumed to lift and be full open at 6% above the steam generator design pressure. This 6% includes 3% each for safety valve setpoint uncertainty and accumulation.

8. The AFW line purge volume is conservatively assumed to be the average value for Unit 3 which is 129.7 ft^3. The average purge volume for Unit 4 is 127 ft^3. An inital maximum AFW enthalpy of 73.0 Btu/lbm is assumed.

9. Core residual heat generation is based on the 1979 version of ANS 5.1 (Reference 2). ANSI/ANS-5.1-1979 is a conservative representation of the decay energy release rates. Long-term operation at the initial power level preceding the trip is assumed.

Results

Figures 14.1.11-1 and 14.1.11-2 show the significant plant parameters following a loss of normal feedwater with the assumptions listed in the previous subsection.

The calculated sequence of events for this accident is listed in Table 14.1.11-1. Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to the reduction of steam generator void fraction, and because steam flow through the safety valves continues to dissipate the stored and generated heat. Two minutes following the initiation of the low-low water level trip, the auxiliary feedwater pump starts, consequently reducing the rate of water level decrease in the steam generators.

The capacity of one auxiliary feedwater pump is such that the water level in the steam generators does not recede below the level at which sufficient heat transfer area is available to dissipate core residual heat and reactor coolant pump heat without water relief from the RCS pressurizer relief or safety valves. Figure 14.1.11-1 shows that at no time is there water relief from the pressurizer. If the auxiliary feedwater delivered is greater than that of one AFW pump, or the initial reactor power is less than 102% of the NSSS power, or the steam generator water level in one or more steam generators is above the conservatively low 4% narrow range span level assumed for the low-low steam generator setpoint, the results for this transient will be bounded by the analysis presented.

14.1.11.3 CONCLUSIONS

Results of the analysis show that a loss of normal feedwater does not adversely affect the core, the RCS, or the main steam system, since the auxiliary feedwater capacity is such that all applicable acceptance criteria are met.

14.1.11.4 REFERENCES

1. Westinghouse WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), Burnett, T. W. T., et al,"LOFTRAN Code Description," dated April 1984.

2. ANSI/ANS-5.1-1979, "American National Standard for Decay Heat Power in Light Water Reactors," dated August 1979.

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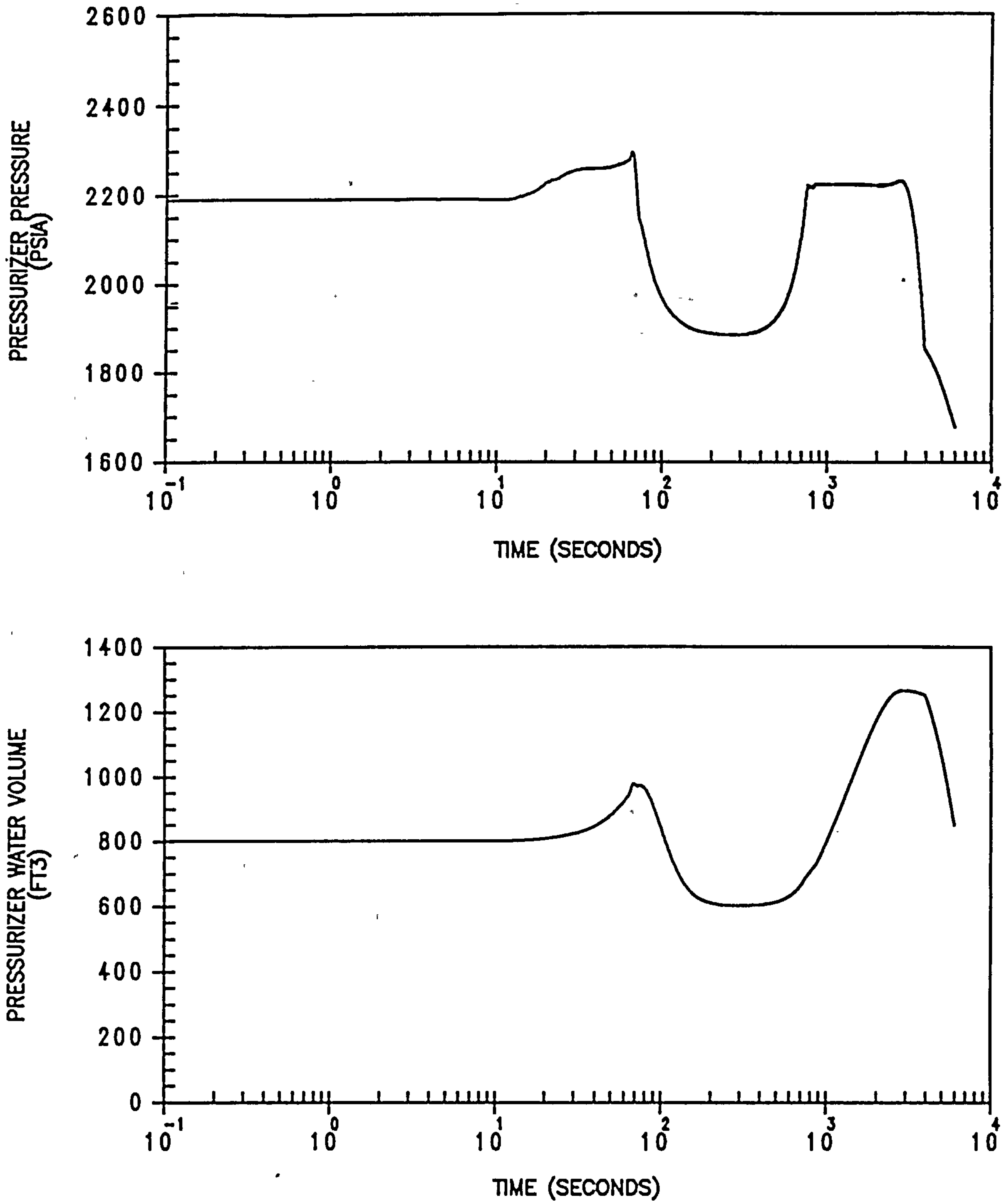
TABLE 14.1.11-1

SEQUENCE OF EVENTS FOR LOSS OF NORMAL FEEDWATER FLOW

Event	Time (sec)
Main feedwater flow stops	10
Low-low steam generator water level trip	62.4
Rods begin to drop	64.4
Flow from one turbine driven auxiliary feedwater pump is started	182.4
Feedwater lines are purged and cold auxiliary feedwater is delivered to three steam generators	746.0
Peak water level in pressurizer occurs (post trip)	2956.0
Core decay and reactor coolant pump heat decreases to auxiliary feedwater heat removal capacity	3000



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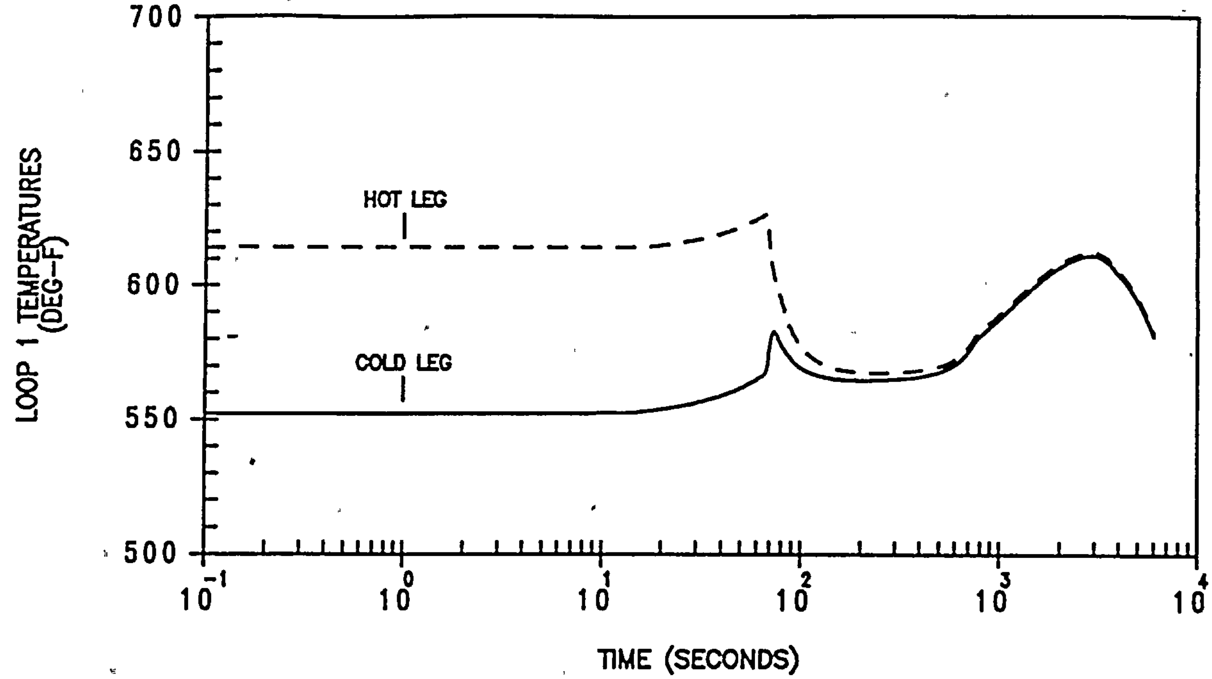
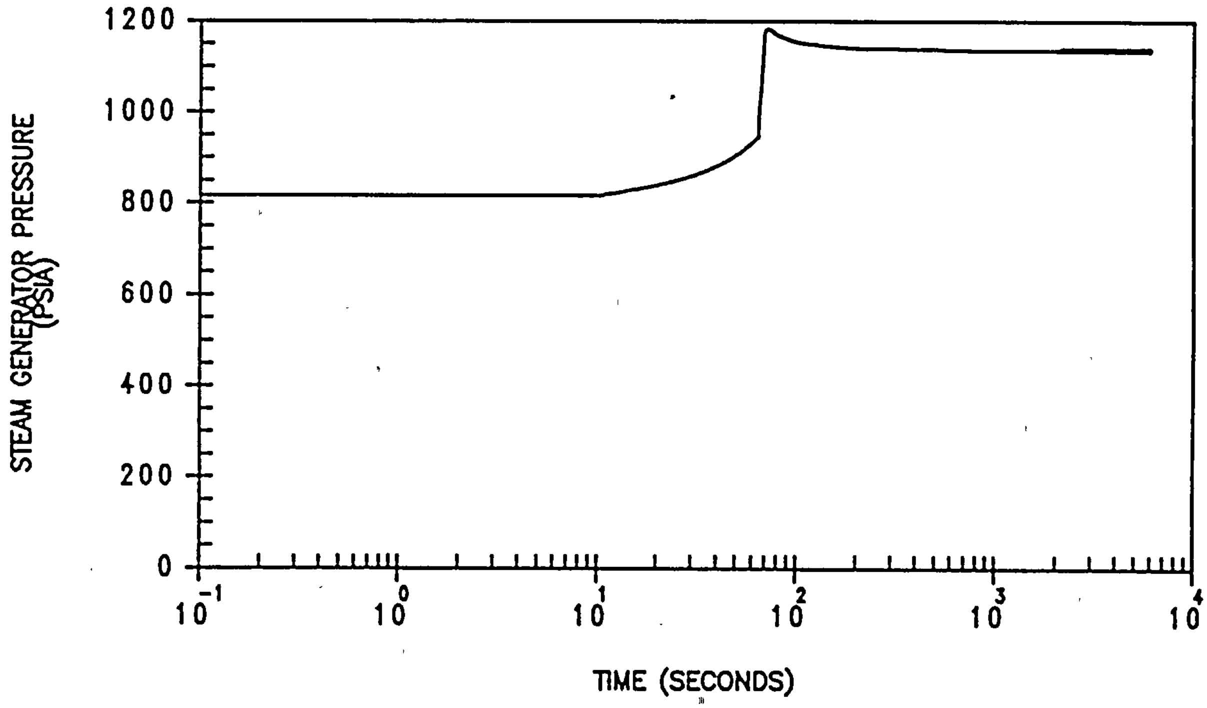
PRESSURIZER PRESSURE AND WATER VOLUME TRANSIENTS FOR LOSS OF NORMAL FEEDWATER

FIGURE 14.1.11-1





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FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LOOP TEMPERATURES AND STEAM GENERATOR PRESSURE FOR LOSS OF NORMAL FEEDWATER

FIGURE 14.1.11-2

removing the stored and residual heat; consequently, preventing overpressurization of the RCS, overpressurization of the secondary side, or water relief from the pressurizer and uncovering of the reactor core. The plant is, therefore, able to return to a safe condition.

Turkey Point Units 3 and 4 share common auxiliary feedwater systems. Thus, a loss of non-emergency AC power to the plant auxiliaries could simultaneously affect both units. The auxiliary feedwater system would then be required to provide flow to both units.

The worst single failure in the auxiliary feedwater system could result in availability of only one of the three auxiliary feedwater pumps. Flow from this pump could be as low as 233.4 gpm to one of the units until the operator takes action from the control board to realign the flow split to the units.

The analysis is performed for one unit, representing the worst case of the two units.

14.1.12.2 ANALYSIS OF EFFECTS AND CONSEQUENCES

Method of Analysis

A detailed analysis using the LOFTRAN Code (Reference 1) is performed to obtain the plant transient following a loss of all AC power. The analysis addresses the plant thermal kinetics, RCS including the natural circulation, pressurizer, pressurizer PORVs and sprays, steam generators, main steam safety valves, and the auxiliary feedwater system. The digital program computes pertinent variables including the pressurizer pressure, pressurizer water level, steam generator mass, and reactor coolant average temperature.

The major assumptions used in this analysis are identical to those used in the loss of normal feedwater analysis (Subsection 14.1.11) with the following exceptions.

1. Loss of AC power occurs at reactor trip on low-low SG water level. No credit is taken for the immediate insertion of the control rods as a result of the loss of AC power to the station auxiliaries.

2. Power is assumed to be lost to the RCPs following the start of rod motion. This assumption results in the maximum amount of stored energy in the RCS.

3. A heat transfer coefficient in the steam generators associated with RCS natural circulation is assumed following the RCP coastdown.

4. The RCS flow coastdown is based on a momentum balance around each reactor coolant loop and across the reactor core. This momentum balance is combined with the continuity equation, a pump momentum balance, the as-built pump characteristics and conservative estimates of system pressure losses.

5. The worst single failure assumed to occur is in the AFW system. This results in the availability of only one AFW pump supplying 233.4 gpm to three steam generators 95 seconds following a start signal on low-low steam generator water level. This AFW flow is less than that assumed for a loss of normal feedwater, because Turkey Point Units 3 and 4 have a shared AFW system and a loss of AC power may occur simultaneously at both Units.

Results

The transient response of the RCS following a loss of AC power is shown in Figures 14.1.12-1 and 14.1.12-2. The calculated sequence of events for this accident is listed in Table 14.1.12-1.

The first few seconds after the loss of power to the reactor coolant pumps will closely resemble a simulation of the complete loss of flow incident, i.e., core damage due to rapidly increasing core temperatures is prevented by the reactor trip on the low-low steam generator water level signal.

After the reactor trip, stored and residual heat must be removed to prevent damage to the core and the reactor coolant and main steam systems. The LOFTRAN code results show that the natural circulation and AFW flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown.

The capacity of the turbine-driven AFW pump is such that the water level in the steam generators does not recede below the lowest level at which sufficient heat transfer area is available to establish enough natural circulation flow in order to dissipate core residual heat without water release through the RCS relief or safety valves. From Figure 14.1.12-1, it can be seen that at no time is there water relief from the pressurizer.

The calculated sequence of events for this accident is listed in Table 14.1.12-1. As shown in Figures 14.1.12-1 and 14.1.12-2, the plant approaches a stabilized condition following reactor trip, pump coastdown, and auxiliary feedwater initiation.

14.1.12.3 CONCLUSIONS

Results of the analysis show that, for the loss of offsite power to the station auxiliaries event, all safety criteria are met. The DNBR transient is bounded by the complete loss of flow event (Section 14.1.9) and remains above the safety analysis limit value. AFW capacity is sufficient to prevent water relief through the pressurizer relief and safety valves; this assures that the RCS is not overpressurized.

Analysis of the natural circulation capability of the Reactor Coolant System has demonstrated that sufficient heat removal capability exists following RCP coastdown to prevent fuel or clad damage.

14.1.12.4 REFERENCES

1. Westinghouse WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), Burnett, T. W. T. et al, "LOFTRAN Code Description," dated April 1984.

2. ANSI/ANS-5.1-1979, "American National Standard for Decay Heat Power in Light Water Reactors," dated August 1979.

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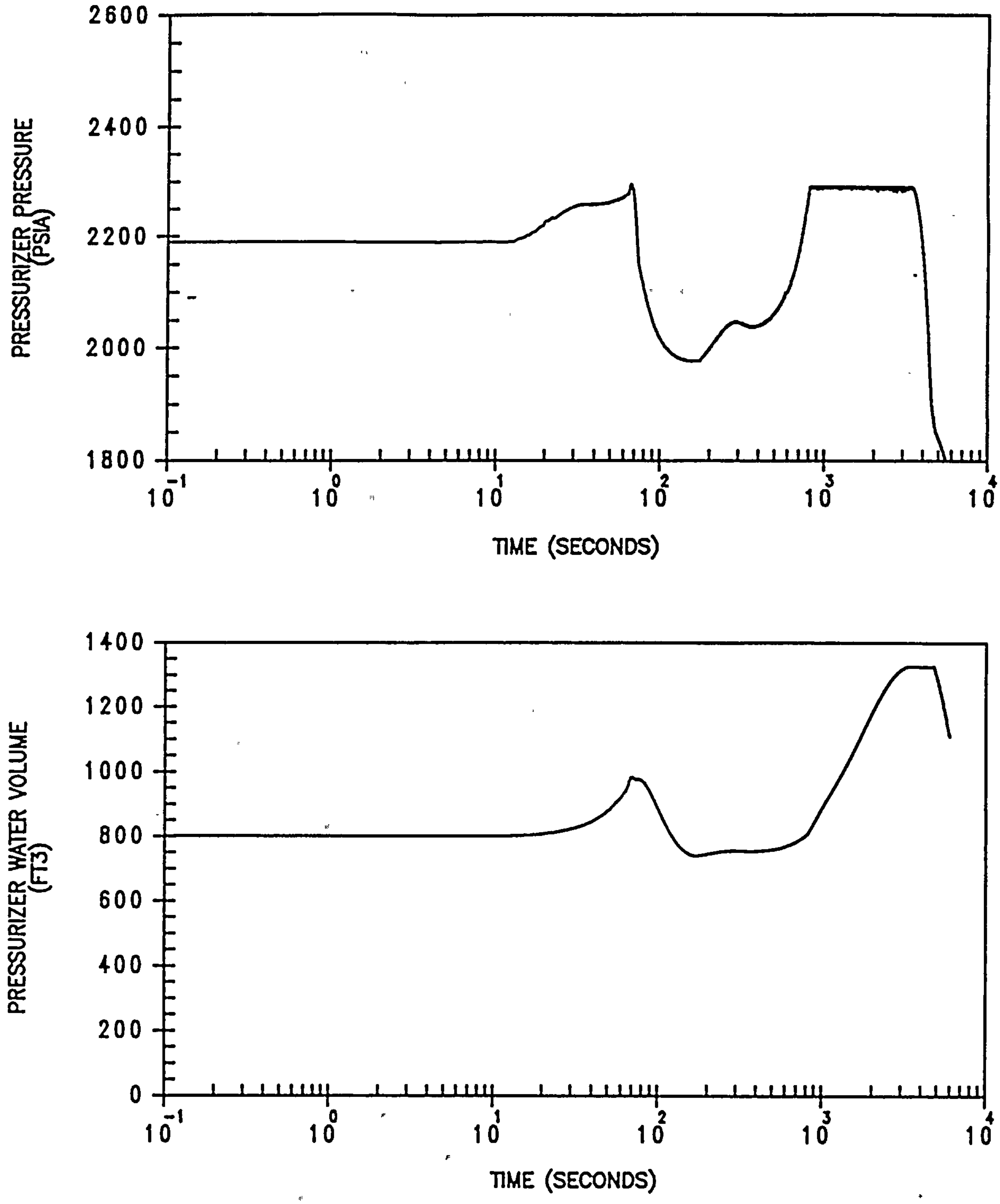
TABLE 14.1.12-1

SEQUENCE OF EVENTS
FOR
LOSS OF NON-EMERGENCY AC POWER

Event	Time (sec)
Main feedwater flow stops	10
Low-low steam generator water level trip	62.4
Rods begin to drop	64.4
Reactor coolant pumps begin to coastdown	66.4
Flow from one turbine driven auxiliary feedwater pump is started	157.4
Feedwater lines are purged and cold auxiliary feedwater is delivered to three steam generators	906.0
Core decay heat decreases to auxiliary feedwater heat removal capacity	3500
Peak water level in pressurizer occur	3596.0



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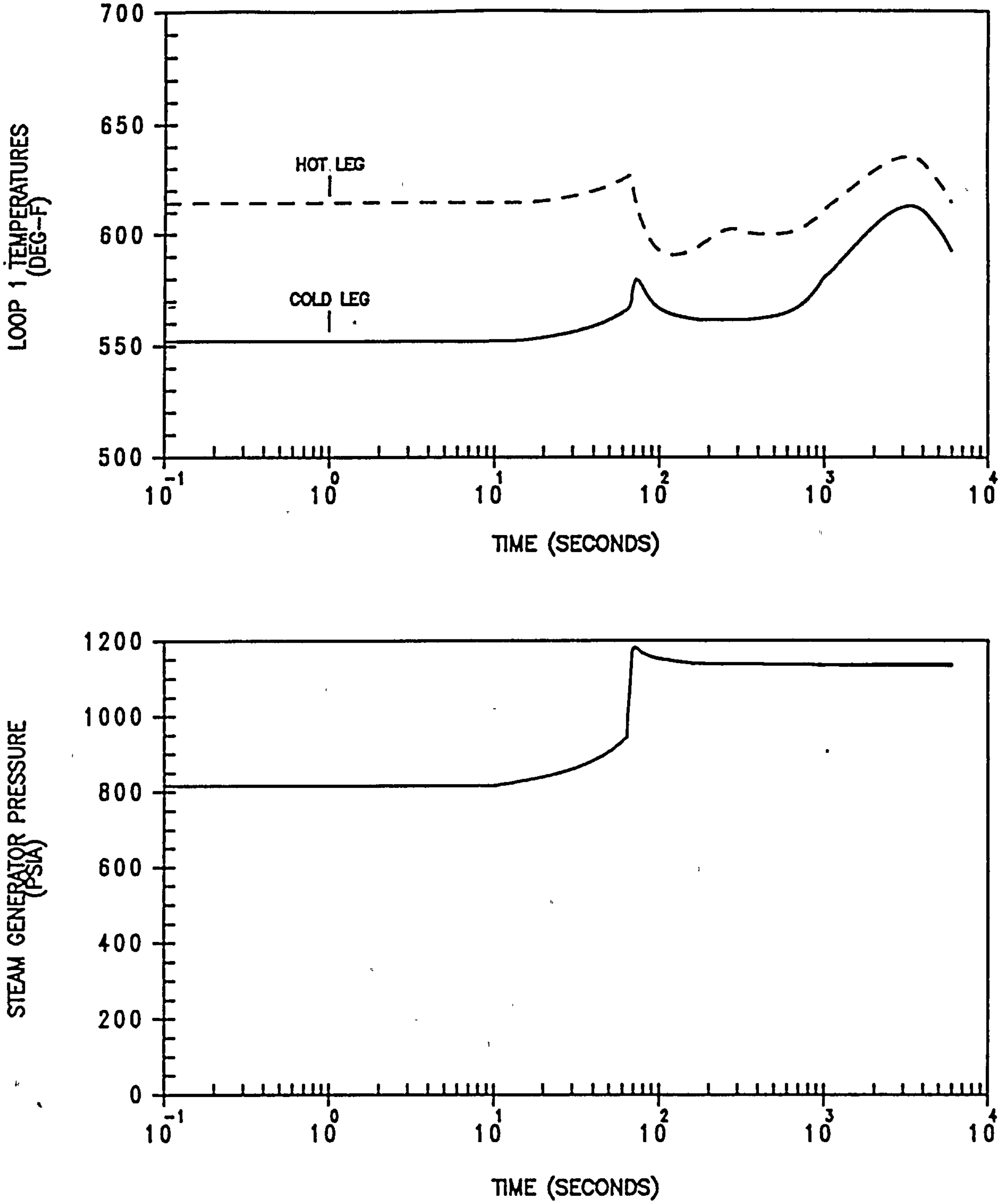
TURKEY POINT PLANT UNITS 3 & 4

PRESSURIZER PRESSURE AND WATER
VOLUME TRANSIENTS FOR
LOSS OF OFFSITE POWER

FIGURE 14.1.12-1



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TURKEY POINT PLANT UNITS 3 & 4

LOOP TEMPERATURES AND STEAM GENERATOR PRESSURE FOR LOSS OF OFFSITE POWER

FIGURE 14.1.12-2

If during handling the fuel assembly strikes against a flat surface, the loads would be distributed across the fuel assemblies and grid clips and essentially no damage would be expected in any fuel rods.

If the fuel assembly were to strike a sharp object, it is possible that the sharp object might damage the fuel rods with which it comes in contact but breaching of the cladding is not expected. It is on this basis that the assumption of the failure of an entire row of fuel rods (15) is a conservative upper limit.

Analyses have been made assuming the extremely remote situations where a fuel assembly is dropped and strikes a flat surface, where one assembly is dropped on another, and where one assembly strikes a sharp object. The analysis of a fuel assembly assumed to be dropped and strikes a flat surface considered the stresses the fuel cladding was subjected to and any possible buckling of the fuel rods between the grip clip supports. The results show that the buckling load at the bottom section of the fuel rod, which would receive the highest loading, is below the critical buckling load and the stresses were relatively low and below the yield stress. For the case where one assembly is dropped on top of another fuel assembly, the loads will be transmitted through the end plates and the RCCA guide tubes of the stuck assembly before any of the loads reach the fuel rods.

The end plates and guide thimbles absorb a large portion of the kinetic energy as a result of bending in the lower plate of the falling assembly. Also, energy is absorbed in the struck assembly top end plate before any load can be transmitted to the fuel rods. The results of this analysis indicated that the buckling load on the fuel rods was below the critical buckling loads and the stresses in the cladding were relatively low and below yield.

The refueling operation experience that has been obtained with Westinghouse reactors has verified the fact that no fuel cladding integrity failures are expected to occur during any fuel handling operations.

Although rupture of one complete outer row of fuel rods is considered to be a conservative assumption, a reanalysis of the offsite radiological consequences of a dropped fuel assembly (Section 14.2.1.1) assumed both a case where a single outer row is damaged and an additional case in which all the fuel rods in a single assembly are damaged. The original FSAR assessment of the postulated accidents which evaluated the containment and spent fuel pool area radiological doses (Section 14.2.1.2) only assumed the case where a single outer row of fuel rods was damaged.

14.2.1.1 DOSE EVALUATION

A fuel assembly is assumed to be dropped and damaged during refueling. Analysis of the accident is performed for the accident occurring both inside containment and in the spent fuel pit. Activity released from the damaged assembly is released to the outside atmosphere through either the containment purge system or the spent fuel pit area ventilation systems.

The offsite doses following a fuel handling accident (FHA) reflect the uprated power level of 2346 MWt. Also addressed is a 20% increase in the I-131 gap fraction for high burnup fuel. The gap fractions applied to the remaining iodine and noble gas isotopes are 0.10 for these iodine and noble gas isotopes with the exception of 0.30 for Kr-85.

Two cases are analyzed with respect to the amount of damage suffered by the dropped assembly. For the first case, it is assumed that all of the fuel rods in the equivalent of one assembly are damaged to the extent that all their gap activity is released. In the second case, only the fuel rods in one row of the assembly (i.e., 15 fuel rods) are damaged sufficiently to cause their gap activity to be released.

Since, per Technical Specifications, the reactor has to be subcritical for 100 hours before fuel is moved, 100 hours of radioactive decay is assumed in the analysis. Also in accordance with Technical Specifications, it is assumed that there is a minimum of 23 feet of water above the vessel flange. With this water depth, decontamination factors (DF) of 133 for elemental iodine and 1 for methyl iodine are used for pool scrubbing. The iodine activity in the fuel rod gap is assumed to be 99.75% elemental and 0.25% methyl. The resulting overall pool scrubbing DF for iodine is 100.

TABLE 14.2.1-1

ASSUMPTIONS USED
FOR
FUEL HANDLING ACCIDENT DOSE ANALYSIS

Power	2346 MWt
Radial Peaking Factor	1.7
Damaged Fuel:	
Case 1	1 Fuel Assembly
Case 2	15 Rods
Fuel Rod Gap Fractions	0.10 for iodines and noble gases, except 0.12 for I-131 and 0.30 for Kr-85
Percent of Gap Activity Released	100%
Pool Decontamination Factors:	
Elemental Iodine	133
Methyl Iodine	1
Noble Gas	1
Iodine Species in Fuel Rod Gap:	
Elemental Iodine	99.75%
Methyl Iodine	0.25%
Minimum Water Depth Above Vessel Flange	23 feet
Filter Efficiency	No filtration assumed
Containment Isolation	No containment isolation assumed

TABLE 14.2.1-4

ASSUMPTIONS USED
FOR
DROPPED CASK DOSE ANALYSIS

Power	2346 MWt
Radial Peaking Factor	1.0
Damaged Fuel (Base Case)	157 Fuel Assemblies
Fuel Rod Gap Fractions	0.10 for iodines and noble gases, except 0.12 for I-131 and 0.30 for Kr-85
Percent of Gap Activity Released	100%
Pool Decontamination Factors:	
Elemental Iodine	133
Methyl Iodine	1
Noble Gas	1
Iodine Species in Fuel Rod Gap:	
Elemental Iodine	99.75%
Methyl Iodine	0.25%
Minimum Water Depth Above Damaged Assembly	23 feet
Filter Efficiency	No filtration assumed

14.2.5 RUPTURE OF A STEAM PIPE

A rupture of a steam pipe is assumed to include any accident which results in an uncontrolled steam release from a steam generator. The release can occur due to a break in pipe line or due to a valve malfunction. The steam release results in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the Reactor Coolant System causes a reduction of coolant temperature and pressure. With a negative moderator temperature coefficient, the cooldown results in a reduction of core shutdown margin. If the most reactive control rod is assumed stuck in its fully withdrawn position, there is a possibility that the core will become critical and return to power even with the remaining control rods inserted. A return to power following a steam pipe rupture is a potential problem only because of the high hot channel factors which may exist when the most reactive rod is assumed stuck in its fully withdrawn position. Assuming the most pessimistic combination of circumstances which could lead to power generation following a steam line break, the core is ultimately shut down by the boric acid in the refueling water storage tank.

14.2.5.1 INADVERTENT OPENING OF A STEAM GENERATOR RELIEF OR SAFETY VALVE

14.2.5.1.1 IDENTIFICATION OF CAUSES AND ACCIDENT DESCRIPTION

The most severe core conditions for an accidental depressurization of the main steam system result from an inadvertent opening of a single steam dump, relief, or safety valve. The analyses performed assuming a rupture of a main steam line are given in Subsection 14.2.5.2.

The steam release as a consequence of this accident results in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity.

The analysis is performed to demonstrate that the following criterion is satisfied: Assuming a stuck rod cluster control assembly (RCCA), with offsite power available, and assuming a single failure in the Engineered Safety Features (ESF) there will be no consequential damage to the core or reactor coolant system after reactor trip for a steam release equivalent to the spurious opening, with failure to close, of the largest of any single steam dump, relief or safety valve.

The following systems provide protection against an accidental depressurization of the main steam system:

A) Safety Injection System actuation from any of the following:

   1) Two out of three Low pressurizer pressure signals

   2) Two out of three High containment pressure signals

   3) Two out of three High differential pressure signals between any steam line and the main steam header

   4) High steam flow in two out of three lines (one out of two per line) coincident with either:

      a) Two out of three Low reactor coolant system average temperature signals, or

      b) Two out of three Low steam line pressure signals

B) The overpower reactor trips (neutron flux and ΔT) and the reactor trip occurring in conjunction with receipt of the Safety Injection Signal.

C) Redundant isolation of the main feedwater lines: Sustained high feedwater flow would cause additional cooldown. Therefore, in addition to the normal control action which will close the main feedwater valves following reactor trip, any SI signal will rapidly close all feedwater control valves, trip the main feedwater pumps, and indirectly close the feedwater pumps discharge valves.

D) Trip of the Main Steam Isolation Valves (MSIVs), designed to close in less than 5 seconds with no flow (analysis assumes 15 second closure time from receipt of signal), on:

1) Two out of three High-High containment pressure signals coincident with two out of three High containment pressure signals

2) High steam flow in two out of three lines (one out of two per line) coincident with either:

a) Two out of three Low reactor coolant system average temperature signals, or

b) Two out of three Low steam line pressure signals

14.2.5.1.2 ANALYSIS OF EFFECTS AND CONSEQUENCES

Method of Analysis

The following analyses of a secondary system steam release are performed for this section:

A) A full plant digital computer simulation using the LOFTRAN code (Reference 1) to determine RCS temperature and pressure during cooldown. and the effect of safety injection.

B) Analyses to determine that there is no damage to the core or reactor coolant system.

The following conditions are assumed to exist at the time of a secondary steam system release:

A) End-of-life shutdown margin at no load, equilibrium xenon conditions, and with the most reactive rod cluster control assembly (RCCA) stuck in its fully withdrawn position. Operation of RCCA banks during core burnup is restricted in such a way that addition of positive reactivity in a secondary system steam release accident will not lead to a more adverse condition than the case analyzed.

B) A negative moderator coefficient corresponding to the end-of-life rodded core with the most reactive RCCA in the fully withdrawn position. The variation of the coefficient with temperature and pressure is included in the LOFTRAN calculations. The k_{eff} versus temperature at 1050 psia corresponding to the negative moderator temperature coefficient used is shown in Figure 14.2.5-1.

C) Minimum capability for injection of high concentration boric acid solution corresponding to one safety injection pump delivering full flow to the cold leg header. No credit is taken for the low concentration boric acid which must be swept from the safety injection lines downstream of the Refueling Water Storage Tank (RWST) prior to the delivery of boric acid (1950 ppm) to the reactor coolant loops. The Boron Injection Tank (BIT) boron concentration is assumed to be 0 ppm.

D) The case studied is a steam flow of 280 lbs/sec at 1100 psia from one steam generator with offsite power available. This is the maximum capacity of any single steam dump, relief or safety valve. Hot standby conditions with minimum required shutdown margin at the no-load T-avg at time zero are assumed since this represents the most conservative initial condition.

Should the reactor be just critical or operating at power at the time of a steam release, the reactor will be tripped by the normal overpower protection when the power level reaches a trip point. Following a trip at power, the RCS contains more stored energy than at no-load, the average coolant temperature is higher than at no-load and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steam release before the no-load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis which assumes no-load condition at time zero. However, since the initial steam generator water inventory is greatest at no-load, the magnitude and duration of the RCS cooldown are less for steam line releases occurring at power.

E) In computing the steam flow, the Moody curve (Reference 2) for fL/D = 0 is used.

F) Perfect moisture separation in the steam generator is assumed.

Results

The calculated time sequence of events for this accident is listed in Table 14.2.5-1.

The results presented are a conservative indication of the events which would occur assuming a secondary system steam release since it is postulated that all of the conditions described above occur simultaneously.

Figures 14.2.5-2 and 14.2.5-3 show the transient results for a steam flow of 280 lbs/sec at 1100 psia. The assumed steam release is typical of the capacity of any single steam dump, relief or safety valve.

Safety injection is initiated automatically by low pressurizer pressure. Minimum safety injection capability corresponding to one out of four safety injection pumps in operation is assumed. Safety injection flow used in the analysis is shown in Figure 14.2.5-13.

Boron solution at 1950 ppm enters the RCS providing sufficient negative reactivity to prevent core damage. The calculated transient is quite conservative with respect to cooldown, since no credit is taken for this energy stored in the system metal other than that of the fuel elements or the energy stored in the other steam generators. Since the transient occurs over a period of about ten minutes, the neglected stored energy is likely to have a significant effect in slowing the cooldown.

Conclusions

The analysis shows that the criteria stated earlier in this section are satisfied. For an accidental depressurization of the main steam system, the minimum DNBR stays above the limiting value and no system design limits are exceeded.

14.2.5.2 STEAM SYSTEM PIPING FAILURE

14.2.5.2.1 IDENTIFICATION OF CAUSES AND ACCIDENT DESCRIPTION

The steam release arising from a rupture of a main steam line would result in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the RCS causes a reduction of coolant temperature and pressure. In the presence of a negative moderator temperature coefficient, the cooldown results in an insertion of positive reactivity. If the most reactive RCCA is assumed stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid delivered by the safety injection system.

The analysis of a main steam line rupture is performed to demonstrate that the following criteria are satisfied:

A) Assuming a stuck RCCA with or without offsite power, and assuming a single failure in the Engineered Safety Features, the core remains in place and intact. Radiation doses do not exceed the guidelines of 10CFR100.

reactivity feedback calculation. Further, it was conservatively assumed that the core power distribution was uniform. These two conditions cause underprediction of the reactivity feedback in the high power region near the stuck rod. The reactivity, as well as the power distribution, was checked for the limiting conditions for the cases analyzed. This core analysis considered the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high water enthalpy near the stuck RCCA, power redistribution and non-uniform core inlet temperature effects. For cases in which steam generation occurs in the high flux regions of the core, the effect of void formation was also included.

C) Minimum capability for injection of boric acid (1950 ppm) solution corresponding to the most restrictive single failure in the safety injection portion of the Emergency Core Cooling System (ECCS). The ECCS consists of three systems: (1) the passive accumulators; (2) the low head safety injection (residual heat removal) system; and (3) the high head safety injection system. Only the high head safety injection system and the passive accumulators are modeled for the steam line break accident analysis.

The modeling of the safety injection system in LOFTRAN is described in Reference 1. The flow corresponds to that delivered by one SI pump delivering full flow to the cold leg header. No credit has been taken for the low concentration borated water which must be swept from the lines downstream of the RWST prior to the delivery of boric acid to the reactor coolant loops.

The calculation assumes the boric acid is mixed with and diluted by the water flowing in the RCS prior to entering the reactor core. The concentration after mixing depends upon the relative flow rates in the RCS and in the safety injection system. The variation of mass flow rate in the RCS due to water density changes is included in the calculation as is the variation of flow rate in the SI system due to changes in the

RCS pressure. The SI system flow calculation includes the line losses in the system as well as the SI pump head curve. Figure 14.2.5-13 provides the relationship between SI flow and RCS pressure.

For the cases where offsite power is assumed, the sequence of events in the safety injection system is the following: After the generation of the safety injection signal (appropriate delays for instrumentation, logic, and signal transport included), the appropriate valves begin to operate and one SI pump starts. In 23 seconds, the valves are assumed to be in their final position and the pump is assumed to be at full speed. The volume containing the low concentration borated water is swept into core before the 1950 ppm borated water reaches the core. This delay, described above, is inherently included in the modeling.

In cases where offsite power is not available, an additional 22 second delay is assumed to start the diesel generators and to commence loading the necessary safety injection equipment onto them.

D) Design value of the steam generator heat transfer coefficient.

E) Since the steam generators are provided with integral flow restrictors with a 1.4 ft^2 throat area, any rupture with a break area greater than 1.4 ft^2, regardless of location, would have the same effect on the NSSS as the 1.4 ft^2 break. The following cases have been considered in determining the core power and RCS transients:

1) Complete severance of a pipe, with the plant initially at no-load conditions, full reactor coolant flow with offsite power available.

2) Case (1) with loss of offsite power simultaneous with the steam line break and initiation of the SI signal. Loss of offsite power results in reactor coolant pump coastdown.

F) Power peaking factors corresponding to one stuck RCCA and nonuniform core inlet coolant temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control rod assembly during the return to power phase following the steam line break. This void in conjunction with the large negative moderator coefficient partially offsets the effect of the stuck RCCA. The power peaking factors depend upon the core power, temperature, pressure, and flow, and thus are different for each case studied.

The core parameters used for each of the two cases correspond to values determined from the respective transient analysis.

Both the cases above assume initial hot shutdown conditions at time zero since this represents the most pessimistic initial condition. Should the reactor be just critical or operating at power at the time of a steam line break, the reactor will be tripped by the normal overpower protection system when power level reaches a trip point. Following a trip at power, the reactor coolant system contains more stored energy than at no-load, the average coolant temperature is higher than at no-load, and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steam release before the no-load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis which assumes no-load condition at time zero.

In addition, since the initial steam generator water inventory is greatest at no-load, the magnitude and duration of RCS cooldown are more severe than for the steam line breaks occurring at power.

G) In computing the steam flow during a steam line break, the Moody curve (Reference 2) for $fL/D = 0$ is used.

H) Feedwater addition aggravates cooldown accidents like the steam line rupture. Therefore, the maximum feedwater flow is assumed. All the main and auxiliary feedwater pumps are assumed to be operating at full capacity when the rupture occurs, even though the plant is assumed to be in a hot standby condition. The maximum auxiliary feedwater flow to the faulted loop is assumed to be 800 gpm.

The sensitivity of the core anaysis to plant operation at zero power using the standby steam generator feedwater pumps was considered. The maximum main feedwater flow assumed bounds the case for a zero power MSLB with a bypass feedwater control valve failing open and continued standby feedwater at 1350 gpm to the faulted generator to ten minutes.

When a Safety Injection signal actuation occurs, the main feedwater pumps trip, the feedwater control valves (FCVs) close, and the main feedwater pump discharge valves start to close (90 second closure). In the analysis, the FCV in the faulted loop is assumed to fail open, such that the faulted steam generator continues to be fed by the condensate pumps (which do not trip on SI signal actuation) until the main feedwater pump discharge valves close. A conservatively high flow rate to the depressurizing steam generator is assumed prior to isolation.

I) The effect of the heat transferred from thick metal in the pressurizer and reactor vessel upper head is not included in the cases analyzed. Studies previously performed have shown that the heat transferred to the coolant from these latent sources is a net benefit in DNB and RCS energy when the effect of the extra heat on reactivity and peak power is considered.

<u>Results</u>

The calculated sequence of events for the cases analyzed is shown in Tables 14.2.5-2 and 14.2.5-3.

The results presented are a conservative indication of the events which would occur assuming a steam line rupture since it is postulated that all of the conditions described above occur simultaneously.

Core Power and Reactor Coolant System Transient

Figures 14.2.5-5 through 14.2.5-8 show the RCS transient and core heat flux following a main steam line rupture (complete severance of a pipe) downstream of the MSIVA at initial no-load condition (Case A). Offsite power is assumed available so that full reactor coolant flow exists. The transient shown assumes an uncontrolled steam release from only one steam generator. Should the core be critical at near zero power when the rupture occurs, the initiation of safety injection by high steam flow coincident with low steam line pressure or low T-avg will trip the reactor. Steam release from more than one steam generator will be prevented by automatic closure of the MSIVs in the steam lines, by high containment pressure signals, or by high steam flow coincident with low steam line pressure. (For a break upstream of the MSIVA, MSIV closure is not required due to the presence of the MSCVs, which prevent blowdown of the unfaulted steam generators. In this case, SI actuation would occur immediately from high differential steam pressure between the faulted steam line and the main steam header. The results would be less severe than those for the cases presented.)

As shown in Figure 14.2.5-8. the core attains criticality with the RCCAs inserted (with the design shutdown assuming one stuck RCCA) before boron solution at 1950 ppm enters the RCS. A peak core power well below the nominal full power value is attained.

Figures 14.2.5-9 through 14.2.5-12 show the response of the salient parameters for Case B. which corresponds to the case discussed above with additional loss of offsite power at the time the SI signal is generated. The SI system delay time includes 22 seconds to start the diesel generator and load the necessary equipment and 23 seconds to start the SI pump and open the valves. Criticality is achieved later and the core power increase is slower than in Case A. The ability of the emptying steam generator to extract heat from the RCS is reduced by the decreased flow in the RCS.

It should be noted that following a steam line break, only one steam generator blows down completely. Thus, the remaining steam generators are still available for dissipation of decay heat after the initial transients is over. In the case of loss of offsite power, this heat is removed to the atmosphere via the steam line safety valves.

Margin to Critical Heat Flux

A DNB analysis was performed for the limiting case. It was found that the minimum DNBR is greater than the limit value.

Conclusions

The analysis has shown that the criteria stated earlier are satisfied. Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable and not precluded by the criteria, the above analysis, in fact, shows that the minimum DNBR remains above the limit value for any rupture assuming the most reactive RCCA stuck in its fully withdrawn position.

14.2.5.3 CONTAINMENT PRESSURE RESPONSE TO STEAMLINE BREAK

Analyses have been performed for the Main Steam Line Break (MSLB) containment response considering a spectrum of break sizes, power levels, and different single failures for the original licensed power level of 2200 Mwt (Reference 5). In developing these analyses, consideration was given to the potential for continued feedwater addition as described in IE Bulletin 80-04 (Reference 3).

The mass/energy release portion of the transients evaluated were calculated using the LOFTRAN code. LOFTRAN has been used for accident analyses in numerous safety analysis reports. The containment pressure transients are calculated using the COCO code. COCO was used and found acceptable to calculate the containment pressure transients for the H. B. Robinson and Zion plants.

Steam generator masses assume nominal level with appropriate conservatism to account for mass and instrument uncertainties. Dry steam blowdown is assumed, i.e., no credit was taken for liquid entrainment in the mass/energy releases. Credit was taken for integral flow restrictors (1.4 ft^2) in the steam generator outlet nozzles. Conservatively high main feedwater flow was assumed prior to feedline isolation. Auxiliary feedwater was assumed to be available from both trains at conservatively high flows with no delay. Credit was taken for operator action at 10 minutes to isolate auxiliary feed flow to the faulted steam generator.

For the containment pressure transient calculations, containment heat sinks, containment fan coolers, and containment sprays were modeled. Conservative values for fan cooler heat removal and containment spray pump performance were assumed.

Based on the spectrum of break sizes and power levels evaluated (Reference 5), the limiting break was determined to be a double-ended break of a main steamline at zero power. Availability of offsite power permits operation of the reactor coolant pumps (RCPs); operation of the reactor coolant pumps improves primary to secondary heat transfer and, thus, increases the severity of a Main Steam Line Break event.

Various single failures were considered, including a main steam check valve failure, a main feedwater flow control valve (FCV) failing in the open position, and an Emergency Diesel Generator (EDG) failure (for offsite power not available cases). The most limiting single failure was found to be a failure of the main steam check valve (MSCV) on the faulted loop, with offsite power available. This failure is limiting because of the large mass input from the intact steam generators that feeds the break until main steam isolation is achieved. This break was analyzed in detail for the uprated power level of 2300 MWt (Reference 6), with the results indicating a peak pressure of 48.1 psig. Additional details of the analysis, accompanied by a presentation of the results regarding this limiting case, are presented in Section 14.3.4.3.3.2.

14.2.5.4 DOSE EVALUATION

An evaluation of the offsite doses following a steamline break was completed to determine both a pre-accident iodine spike and an accident initiated iodine spike.

For the pre-accident iodine spike it is assumed that a reactor transient has occurred prior to the SGTR and has raised the RCS iodine concentration to 60 μCi/gm of dose equivalent (DE) I-131. For the accident initiated iodine spike the reactor trip associated with the steamline break (SLB) creates an iodine spike in the RCS which increases the iodine release rate from the fuel to the RCS to a value 500 times greater than the release rate corresponding to the maximum equilibrium RCS Technical Specification concentration of 1.0 μCi/gm of DE I-131. The duration of the accident initiated iodine spike is 1.6 hours.

The noble gas activity concentration in the RCS at the time the accident occurs is based on a fuel defect of 1.0%. The iodine activity concentration of the secondary coolant at the time the steamline break occurs is assumed to be equivalent to the Technical Specification limit of 0.10 μCi/gm of DE I-131.

The amount of primary to secondary SG tube leakage in each of the three SGs is assumed to be equal to the Technical Specification limit for a single SG of 500 gallons/day. No credit for iodine removal is taken for any steam released to the condenser prior to reactor trip and concurrent loss of offsite power.

The SG connected to the broken steamline is assumed to boil dry within the initial two hours following the steamline break. The entire liquid inventory of this SG is assumed to be steamed off and all of the iodine initially in this SG is released to the environment. Also, iodine carried over to the faulted SG by SG tube leaks is assumed to be released directly to the environment.

An iodine partition factor in the intact SG of 0.01 (curies l/gm steam) (curies l/gm water) is used. All noble gas activity carried over to the secondary through SG tube leakage is assumed to be immediately released to the outside atmosphere from the secondary system.

At 24 hours after the accident the RHR System is assumed to be placed into service for heat removal, and there are no further steam releases to atmosphere from the secondary system.

The major assumptions and parameters used in the analysis are itemized in Table 14.2.5-5. The thyroid dose conversion factors, breathing rates, and atmospheric dispersion factors used in the does calculations are given in Table 14.3.5-4.

The offsite dose limits for a steamline break with a pre-accident iodine spike are the guideline values of 10 CFR 100. These guideline values are 300 rem thyroid and 25 rem whole body. For a SLB with an accident initiated iodine spike the acceptance criteria are a "small fraction of" the 10 CFR 100 guideline values, 30 rem thyroid and 2.5 rem whole body. The offsite thyroid and whole body doses due to the steamline break given in Table 14.2.5-6. The offsite doses due to the steamline break are within the acceptance criteria.

14.2.5.5 REFERENCES

1. Burnett T. W. T. et al., "LOFTRAN Code Description," WCAP-7907-P-A (Proprietary) and WCAP-7907-A (Non-Proprietary), dated April 1984.

2. Moody, F. J., "Transaction of the ASME, Journal of Heat Transfer," page 134, February 1965.

3. Letter, L-81-211, R. E. Uhrig (FPL) to D. G. Eisenhut (NRC), "NRC IE Bulletin 80-04," dated May 19, 1981.

4. Westinghouse letter to FPL, FPL-91-651, dated October 21, 1991, Safety Evaluation for Diesel Loading Scheme - Revision 3. Refer to FPL Safety Evaluation JPN-PTN-SEMJ-91-035, Revision 0; transmitted by letter JPN-PTN-91-0784, dated November 5, 1991.

5. Westinghouse WCAP-12262, "Analysis of Containment Response Following a Main Steam Line Break for Turkey Point Units 3 and 4," dated August, 1989.

6. Westinghouse WCAP-14276,"Florida Power and Light Company Turkey Point Units 3 and 4 Uprating Licensing Report," Revision 1, dated December 1995.

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TABLE 14.2.5-4

MAIN STEAM LINE BREAK CONTAINMENT ANALYSIS ASSUMPTIONS
FOR ZERO POWER BREAK WITH OFFSITE POWER AVAILABLE
AND FAILURE OF AN MSCV

Initial Conditions

Power Level	0%
RCP Heat Input	15 MW_{th}
RCS Pressure, psia	2250
RCS Average Temperature, °F	547
Pressurizer Water Level	22.2% of level span
Steam Generator Water Level	
Intact Steam Generator	Nominal - 5% NRS + 5% SG Mass
Faulted Steam Generator	Nominal + 5% NRS + 5% SG Mass
Feedwater Enthalpy, BTU/lbm	70.6
Feedwater Flow	
Main Feedwater	Refer to Figure 14.2.5-16
Auxiliary Feedwater	300 gpm per SG initiated with no delay on SI (150 gpm/SG/ train)
Containment Conditions	
Containment Free Volume, ft^3	1.55×10^6
Initial Pressure, psig	+0.3
Initial Air Temperature, °F	130
Relative Humidity, %	20
Emergency Containment Coolers	
Number Operating	2
Delay time for actuation	18 seconds after SI
Containment Spray Pumps	
Number Operating	2
Delay time for actuation	14 seconds after SI with Hi-Hi containment pressure present + 30 second header fill time = 44 seconds; otherwise anytime greater than 45 seconds after SI with Hi-Hi containment pressure present + 30 second header fill time.
CS Pump Performance	20% degraded, see below

Containment Pressure (psig)	Spray Flow (gpm)
0.0	2819.1
20.0	2644.4
40.0	2452.8
60.0	2253.5

The rod ejection accident is similar to a 2 inch diameter LOCA. Analysis of the 2-inch LOCA at Turkey Point shows that the high containment pressure SI signal of 4.0 psig would be reached at approximately 100 seconds. The safety analysis limit for high containment pressure SI signal of 6.0 psig would be reached at approximately 150 seconds. The SI signal would start the emergency containment filtration (ECF) system filter fans. To account for time to allow the fans to reach operating speed and to add conservatism, credit for the ECF system filters is not taken in the initial 300 seconds following the rod ejection accident. After 2 hours following the accident, no further iodine removal is assumed by the ECF system filters.

The major assumption and parameters used in the analysis are itemized in Table 14.2.6-3. The thyroid dose conversion factors, breathing rates, and atmospheric dispersion factors used in the dose calculations are given in Table 14.3.5-4.

The dose limits for a rod ejection accident are "well within" the 10 CFR 100 guideline values, or 75 REM thyroid and 6 REM whole body.

The offsite thyroid and whole body doses due to the rod ejection accident are given in Table 14.2.6-4. The offsite doses due to the rod ejection accident do not exceed the acceptance criteria.

14.2.6.5 CONCLUSIONS

Despite the conservative assumptions, the analyses indicate that the described fuel and clad limits are not exceeded. It is concluded that there is no danger of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no danger of further consequential damage to the RCS. The analyses demonstrate that the fission product release as a result of fuel rods entering DNB is limited to less than 10 percent of the fuel rods in the core.

14.2.6.6 REFERENCES

1. Risher, D. H., "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors using Special Kinetics Methods" WCAP-7588, January 1975.

2. Taxebius, T. G., ed., "Annual Report - Spert Project, October 1968 - September 1969," IN-1370 Idaho Nuclear Corporation, June 1970.

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4. Letter from W. J. Johnson of Westinghouse Electric Corporation to Mr. R. C. Jones of the Nuclear Regulatory Commission, Letter Number NS-NRC-89-3466, "Use of 2700°F PCT Acceptance Limit in Non-LOCA Accidents," October 23, 1989.

5. Risher, D. H., Jr. and Barry, R. F., "TWINKLE, A Multi-dimensional Neutron Kinetics Computer Code", WCAP-7979-P-A, January 1975 (Proprietary) and WCAP-8028-A, January 1975 (Non-Proprietary).

6. Hargrove, H. G., "FACTRAN, a FORTRAN IV Code for Thermal Transients in a UO_2 Fuel Rod" WCAP-7908-A, December 1989.

7. Bishop. A. A., Sandberg. R. O. and Tong, L. S., "Forced Convection Heat Transfer at High Pressure After the Critical Heat Flux", ASME 65-HT-31, August 1965.

8. "Fuel Densification Turkey Point Unit No 3, WCAP-8074, February 1973.

14.3.2 THERMAL ANALYSIS

The analysis specified by 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Power Reactors," (Reference 1) is presented in this section. The results of the loss of coolant accident analyses are summarized in Tables 14.3.2.1-3 and 14.3.2.2-4 and show compliance with the Acceptance Criteria. The highest cladding temperature was for the double ended cold leg guillotine (DECLG) break at the low vessel average temperature (T_{AVG}=562.7°F) assuming an 8.5 ft top-skewed axial power shape with a Moody discharge coefficient (C_D) of 0.4.

The potential for adverse boric acid concentration occurring in the reactor vessel during the long term recirculation phase following LOCA has been analyzed. The analysis showed that there is no problem in maintaining long term core cooling.

The boundary considered for loss of coolant accidents as related to connecting piping is defined in Section 4.1.

The method of analysis to determine peak cladding temperature is divided into two types of analysis: (1) large break LOCA; and (2) small break LOCA. The method of analysis for large and small break LOCA is described below and results are given.

14.3.2.1 LARGE BREAK LOCA

14.3.2.1.1 LARGE BREAK LOCA ANALYSIS

Past licensing studies for break type and location were performed for a double-ended cold leg guillotine (DECLG) break with various values of discharge coefficient (C_D), double-ended hot leg guillotine (DEHLG), double-ended pump suction guillotine (DEPSG), and a range of split-type break sizes ranging from a 1.0 ft^2 area to a full double-ended area of the cold leg. This study determined that the DECLG type break was both the most limiting type and location. Furthermore, the previous licensing basis analysis for Turkey Point has shown that the limiting discharge coefficient, C_D=0.4, is much more limiting than the non-limiting discharge coefficients, C_D=0.6 and C_D=0.8. Therefore, only the limiting Moody discharge coefficient, C_D=0.4, was reperformed utilizing the BASH Evaluation Model (EM). Sensitivity studies were performed to the RCS vessel average temperature and also to top-skewed power shapes.

The limiting single active failure used in the large break LOCA analysis is dependent upon the maximum and minimum emergency core cooling system (ECCS) scenarios. For the case of minimum ECCS, the limiting single failure is the loss of the residual heat removal (RHR) pump. Failure of the diesel generator is not limiting for large break LOCA, because it also results in the loss of a containment spray pump. Operation of all containment pressure reducing equipment is required by 10 CFR 50 Appendix K, since this results in a minimum containment pressure transient. In addition to the loss of an RHR pump, the large break LOCA analysis conservatively assumed failure of one high head safety injection (HHSI) pump, but still modeled both containment spray pumps. The approval of the BASH EM (Reference 2) specifically requires consideration of the maximum ECCS scenario. The maximum ECCS analysis assumes no single failure within the ECCS. The limiting single failure assumed in the maximum ECCS analysis is the loss of an auxiliary feedwater pump. The maximum ECCS analysis requirement is dependent upon a full downcomer at the start of the reflood phase. Because Turkey Point does not have a full downcomer at the beginning of reflood, the maximum ECCS analysis is unnecessary. Additional ECCS injection during the maximum ECCS analysis will only contribute to filling the downcomer and increasing the reflood rate.

The limiting time for fuel burnup in the large break LOCA analysis is at the beginning of life where maximum pellet temperatures occur. The beginning of life analysis will bound burnup conditions up to 62,000 MWD/MTU.

Prior to break initiation, the plant is assumed to be in a full power (102%) equilibrium condition, i.e., the heat generated in the core is being removed via the secondary system. Other initial plant conditions assumed in the analysis are given in Table 14.3.2.1-1. Subsequent to the break opening, a period of reactor coolant system blowdown ensues in which the heat from fission product decay, the hot reactor internals, and the reactor vessel continues to be transferred to the RCS fluid.

Loss of Offsite Power (LOOP) is assumed to occur coincident with initiation of the large break LOCA. If a large break LOCA occurs, depressurization of the RCS results in a pressure and level decrease in the pressurizer. The reactor trip signal subsequently occurs when the pressurizer low-pressure reactor trip setpoint, conservatively modeled as 1805 psia, is reached. A safety injection signal is generated when the pressurizer low-pressure safety injection setpoint, conservatively modeled as 1615 psia, is reached. The safety injection signal may also result from the containment high pressure signal. Both signals are modeled in the large break LOCA analysis and the fastest initiation of safety injection is used. Safety injection is delayed 35 seconds after the occurrence of the signal. This delay accounts for signal initiation, diesel generator start up and emergency power bus loading, as well as the time involved in aligning the valves and bringing the RHR and HHSI pumps up to full speed. Finally, the RCS depressurizes to below 615 psia and the accumulators begin to inject borated water. These counter-measures limit the consequences of the accident in two ways:

1. Reactor trip and borated water injection supplement void formation in causing a rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay. No credit is taken in the large break LOCA analysis for the boron content of the injection water. However, an average RCS/sump mixed boron concentration is calculated to ensure that the post-LOCA core remains subcritical. No credit is taken for control rod insertion. The core is shutdown on void formation alone during the depressurization phase.

2. Injection of borated water ensures sufficient flooding of the core to prevent excessive cladding temperatures.

The core heat removal mechanisms associated with the large break transient include the break itself and the injected ECCS water.

14.3.2.1.2 LARGE BREAK LOCA ANALYTICAL MODEL

The LOCA analysis presented here was performed with the BASH Westinghouse ECCS Evaluation Model (References 2 and 3). This version includes the BART (Reference 4) computer code which is a mechanistic core heat transfer model, and BASH which is a mechanistic reflood model.

The large break LOCA transient can be conveniently divided into three periods: blowdown, refill, and reflood. Also, three physical parts of the transient are analyzed for each period: the thermal-hydraulic transient in the reactor coolant system, the containment pressure and temperature, and the fuel and clad temperatures of the hottest rod. These considerations lead to the use of a system of computer codes designed to model the large break LOCA transient.

The SATAN-VI (Reference 5) code evaluates the thermal-hydraulic transient during blowdown. The REFILL (References 3 and 6) code computes, using output from the SATAN-VI code. the time to bottom of core recovery (BOCREC) and RCS conditions at BOCREC. Since the mass flow rate to the containment depends upon the local RCS and containment conditions, the REFILL and COCO codes are interactively linked. The COCO (Reference 7) code is used to model the containment pressure transient. The containment parameters used by COCO to determine the ECCS backpressure were reviewed by FPL prior to use in the LOCA reanalysis and are summarized in Table 14.3.2.1-2. The BOCREC conditions calculated by REFILL are used as input to the BASH code. Data from both the SATAN-VI code and the REFILL code out to BOCREC are input to the LOCBART (Reference 4) code. which calculates core average conditions at BOCREC for use by the BASH code.

BASH provides a thermal-hydraulic response of the reactor core and RCS during the reflood phase of a large break LOCA. Instantaneous values of the accumulator conditions and safety injection flow at the time of completion of lower plenum refill are provided to BASH by REFILL. A more detailed description of the BASH code is available in Reference 2. The BASH code provides a sophisticated treatment of steam/water flow phenomena in the reactor coolant system during core reflood. A dynamic interaction between core thermal-hydraulics and system behavior is expected, and experiments have shown this behavior. The BART code has been coupled with a loop model to form the BASH code and BART provides the entrainment rate for a given flooding rate. The loop model determines the loop flows and pressure drops in response to the calculated core exit flow determined by BART. The updated inlet flow is used by BART to calculate a new entrainment rate fed back to the loop code. This process of transferring data between BART, the loop code and back to BART forms the calculational process for analyzing the reflood transient. This coupling of the BART code with a loop code produces a more dynamic flooding transient, which reflects the close coupling between core thermal-hydraulics and loop behavior. The BASH code is also interactively linked with COCO to utilize the local conditions at each time step to calculate the containment response.

In the BASH EM, the cladding heat-up transient is calculated by LOCBART which is a combination of the LOCTA (Reference 8) code with BART (Reference 4). A more detailed description of the LOCBART code can be found in Reference 2. The LOCBART code is used throughout the transient to compute fuel and clad temperatures in the hottest rod. During reflood, the LOCBART code provides a significant improvement in the prediction of fuel rod behavior. In LOCBART the empirical FLECHT correlation has been replaced by the BART code. BART employs rigorous mechanistic models to generate heat transfer coefficients appropriate to the actual flow and heat transfer regimes experienced by the fuel rods.

Figure 14.3.2.1-2 shows the interaction of the BASH large break model and the relationship of the computer codes to the LOCA sequence of events.

14.3.2.1.3 RESULTS OF LARGE BREAK LOCA ANALYSIS

In order to determine the conditions that produced the most limiting large break LOCA case (as determined by the highest calculated peak cladding temperature), two cases were examined. These cases included the limiting discharge coefficient, C_D=0.4, for high and low RCS T_{AVG} operation. The limiting condition for the Turkey Point Units was found to be low RCS T_{AVG} operation. The PCT attained during the low RCS T_{AVG} transient was 2103°F, while the PCT for the high RCS T_{AVG} transient was 2082°F (refer to Table 14.3.2.1-3). Table 14.3.2.1-4 provides the key transient event times.

Limiting Temperature Conditions

Reduced operating temperature sometimes results in a PCT benefit for the large break LOCA. However, due to competing effects and the complex nature of large break LOCA transients, there have been some instances where more limiting results have been observed for the reduced operating temperature case. For this reason, a large break LOCA transient based on both a lower and upper bound RCS vessel average temperature was performed, and the lower bound was found to be more limiting. The lower bound RCS vessel temperature has a higher initial RCS mass which could prolong the blowdown period and decrease the water left in the accumulator at the end of blowdown.

The temperature window analyzed was based on a nominal vessel average temperature of 574.2°F, with ± 3°F for an operating window and ± 8.5°F to bound uncertainties. The upper bound vessel average temperature is 585.7°F, while the lower bound vessel average temperature is 562.7°F.

A summary of the transient responses of key parameters for the limiting low T_{AVG} C_D=0.4 break case are shown in Figures 14.3.2.1-3 through 18. Plots of important parameters for high T_{AVG} conditions are shown in Figures 14.3.2.1-19 through 28.

Skewed Power Shapes

Large Break LOCA analyses have traditionally been performed using a symmetric, chopped cosine, core axial power shape. Under certain conditions, calculations have shown that there is a potential for top-skewed power distributions to result in PCTs greater than those calculated with a chopped cosine axial power distribution. Explicit analyses were performed in which power distributions were skewed to peak power at the 8.5, 9.5, and 10.5 ft elevations. The analyses results demonstrated that the 9.5 and 10.5 ft skewed power shapes are bounded by the chopped cosine power shape, while a PCT increase of 14°F was calculated for the 8.5 ft skewed power shape. This resulted in a limiting case PCT of 2117°F.

Plots of important parameters are given in Figures 14.3.2.1-29 through 44 for the 8.5 ft top-skewed power shape.

Evaluations

The Turkey Point Units will have 48 and 54 inch diameter containment purge valves open for the initial seconds of the large break LOCA transient. The open valves will reduce the containment pressure response during the large break LOCA, which is an adverse effect upon the calculated PCT. The calculated PCT effect is an increase of 27°F.

The DRFA fuel stack height above the lower core plate was explicitly modeled for the various cases analyzed.

A 5°F full-power T_{AVG} coastdown was also evaluated for the Turkey Point Large Break LOCA analysis. Since lower vessel average temperature is more limiting for the Turkey Point units, the effect of the 5°F T_{AVG} coastdown was to increase the PCT by 7°F.

14.3.2.1.4 LARGE BREAK LOCA CONCLUSIONS

A limiting discharge coefficient, C_D=0.4, large break LOCA analysis supporting a range of vessel average temperature was performed. Peak cladding temperatures of 2103°F and 2082°F were calculated for the RCS low (562.7°F) and high (585.7°F) T_{AVG} conditions respectively. After assessing the PCT effect for top-skewed power shapes, containment purging and the 5°F T_{AVG} coastdown on the most limiting case, the resulting PCT is 2151°F.

The analyses presented in this section show that the Emergency Core Cooling System provides sufficient core heat removal capability to maintain the calculated peak cladding temperatures below the required limit of 10 CFR 50.46. That is:

1. The calculated peak fuel element cladding temperature does not exceed 2200°F,

2. The localized cladding oxidation limit of 17 percent is not exceeded during or after quenching,

3. The amount of fuel element cladding that reacts chemically with water or steam to generate hydrogen, does not exceed 1 percent of the total amount of fuel rod cladding,

4. The core remains amenable to cooling during and after the break, and

5. The core temperature is reduced and decay heat is removed for an extended period of time, as required by the long-lived radioactivity remaining in the core.

Hence, adequate protection is afforded by the emergency core cooling system in the event of a large break Loss-of-Coolant Accident.

14.3.2.2 SMALL BREAK LOCA (SMALL RUPTURED PIPES OR CRACKS IN LARGE PIPES) WHICH ACTUATE THE EMERGENCY CORE COOLING SYSTEM

This section presents the results of the 1995 small break loss-of-coolant accident (LOCA) analysis of record performed to support the Turkey Point Units 3 and 4 uprating in conformance with 10 CFR 50.46 (Reference 9) and Appendix K to 10 CFR 50.

14.3.2.2.1 IDENTIFICATION OF CAUSES AND ACCIDENT DESCRIPTION

A loss-of-coolant accident is defined as a rupture of the reactor coolant system (RCS) piping or of any line connected to that system. A small break, as considered in this section, is defined as a rupture of the RCS piping with a cross sectional area of less than 1.0 ft^2, in which the normally operating charging system flow is not sufficient to sustain pressurizer level and pressure.

The most limiting single active failure assumed for a small break LOCA is that of an emergency power train failure which results in the loss of one complete train of Emergency Core Cooling System (ECCS) components. In addition, a loss-of-offsite power (LOOP) is assumed to occur coincident with reactor trip. This means that credit may be taken for at most two high head safety injection (SI) pumps and one low head (RHR) pump. However, in the analysis of the small break LOCA presented here, only the minimum delivered ECCS flow from a single high head SI pump was assumed.

The small break LOCA analysis performed for the Turkey Point Units 3 and 4 uprating program utilizes the NRC-approved NOTRUMP Evaluation Model (References 10 and 11), with appropriate modifications to model pumped SI and accumulator injection in the broken loop as well as an improved condensation model (COSI) for the pumped SI into the broken and intact loops(Reference 12).

The most limiting broken loop injection scenario has been identified. Given that a break at the bottom of the RCS piping is the most limiting location, and the fact that Westinghouse ECCS designs have the SI penetrations above the RCS cold leg center line, a break of an SI branch line cannot be limiting for PCT calculations. Since the most limiting break location cannot be in the SI lines, it is not necessary to perform small break LOCA analyses with and without SI to the broken loop in order to isolate the most limiting condition. Therefore, the small break LOCA analysis performed for the Turkey Point uprating program assumes SI is delivered to both the intact and broken loops at the RCS backpressure. These countermeasures limit the consequences of the small break LOCA accident in two ways:

1. Control rod insertion and borated injection (SI) supplement void formation in causing a rapid reduction of nuclear power to a residual level corresponding to the delayed fission and fission product decay.

2. Injection of borated water ensures sufficient flooding of the core to prevent excessive clad temperatures.

Prior to break initiation, the plant is assumed to be in a full power (102%) equilibrium condition, i.e., the heat generated in the core is being removed via the secondary system. Other initial plant conditions assumed in the analysis are given in Table 14.3.2-3. Subsequent to the break opening, a period of reactor coolant system blowdown ensues in which the heat from fission product decay, the hot reactor internals, and the reactor vessel continues to be transferred to the RCS. The heat transfer between the RCS and the secondary system may be in either direction and is a function of the relative temperatures of the primary and secondary. In the case of continuous heat addition to the secondary during a period of quasi-equilibrium, an increase in the secondary system pressure results in steam relief via the steam generator safety valves.

During the earlier part of the small break transient (prior to the assumed loss-of-offsite power coincident with reactor trip), the loss of flow through the break is not sufficient enough to overcome the positive core flow maintained by the reactor coolant pumps. During this period, upward flow through the core is maintained. However, following the reactor coolant pump trip (due to a LOOP) and subsequent pump coastdown, a partial period of core uncovery occurs. Ultimately, the small break transient analysis is terminated when the ECCS flow provided to the RCS exceeds the break flow rate.

The core heat removal mechanisms associated with the small break transient include not only the break itself and the injected ECCS water, but also that heat transferred from the RCS to the steam generator secondary side. Main Feedwater (MFW) is assumed to be isolated coincident with the safety injection signal, and the MFW pumps coast down to 0% flow in 10 seconds. A continuous supply of makeup water is also provided to the secondary using the auxiliary feedwater (AFW) system. An AFW actuation signal occurs coincident with the safety injection signal, resulting in the assumed delivery of full AFW system flow of 125 gpm to the affected unit 120 seconds following the signal. The heat transferred to the secondary side of the steam generator aids in the reduction of the RCS pressure.

Should the RCS depressurize to approximately 600 psig, as in the case of the limiting 3-inch break and the 4-inch break, the cold leg accumulators begin to inject borated water into the reactor coolant loops. In the case of the 2-inch break however, the vessel mixture level is recovered without the aid of accumulator injection.

14.3.2.2.2 ANALYSIS OF EFFECTS AND CONSEQUENCES

Method of Analysis

For small breaks (less than 1.0 ft^2) the NOTRUMP (References 10 and 11) digital computer code was employed to calculate the transient depressurization of the Reactor Coolant System as well as to describe the mass and enthalpy of the fluid flow through the break. The NOTRUMP computer code is a state-of-the-art one-dimensional general network code incorporating a number of advanced features. Among these are calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flooding limitations, mixture level tracking logic in multiple-stacked fluid nodes and regime-dependent heat transfer correlations. The NOTRUMP small-break LOCA emergency core cooling system (ECCS) evaluation model was developed to determine the RCS response to design basis small break LOCAs, and to address NRC concerns expressed in NUREG-0611 (Reference 14).

The reactor coolant system model is nodalized into volumes interconnected by flow paths. The broken loop is modelled explicitly, while the two intact loops are lumped into a second "unbroken" loop. The transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum. The multinode capability of the program enables explicit, detailed spatial representation of various system components which, among other capabilities, provides a proper calculation of the behavior of the loop seal during a loss-of-coolant accident. The reactor core is represented as heated control volumes with associated phase separation models to permit transient mixture height calculations. A more detailed description of the NOTRUMP code, its models, and the associated small break evaluation model is provided in References 10 and 11.

After the small break LOCA is initiated, reactor trip is calculated to occur due to a low pressurizer pressure signal at 1805 psia (including uncertainties). Soon after the reactor trip signal is generated, the safety injection signal is calculated to actuate due to a low pressurizer pressure of 1615 psia (including uncertainties). Safety injection systems consist of accumulator tanks pressurized with Nitrogen gas and pumped injection systems. The small break LOCA analysis assumed an accumulator water volume of 892 ft^3

with a cover gas pressure of 600 psig. As stated earlier, a minimum emergency core cooling system capability (i.e., only one high head safety injection pump) was assumed for the analysis. The assumed pumped safety injection flow to the broken and intact loops of the RCS as a function of RCS pressure is shown in Figure 14.3.2-47 and in Table 14.3.2-9. The safety injection flow rates presented are based upon a single high head safety injection degraded pump performance curve without any branch line imbalances. The effect of flow from the RHR pumps was not considered in any of the Turkey Point small break LOCA analyses, since the shutoff head is much lower than the RCS pressure during the critical portion of the small break transient. The onset of full safety injection flow was assumed to be delayed 35 seconds following the occurrence of the injection signal to account for emergency diesel generator startup and emergency power bus loading in the case of a loss-of-offsite-power coincident with a LOCA. A rod drop time of 3.0 seconds was assumed in addition to a 2.0 second signal processing delay time, resulting in a total delay time of 5.0 seconds from the time of the reactor trip signal (1805 psia) to full rod insertion.

Peak clad temperature calculations were performed with the LOCTA-IV (Reference 15) code using the NOTRUMP calculated core pressure, fuel rod power history, uncovered core steam and mixture heights as boundary conditions. Figure 14.3.2.2-2 depicts the hot rod axial power shape used to perform the small break LOCA analysis. This shape was chosen, because it represents a distribution with power concentrated in the upper regions of the core. Such a distribution is limiting for small-break LOCAs, because it minimizes coolant level swell, while maximizing vapor superheating and fuel rod heat generation at the uncovered elevations. The small break LOCA analysis assumes full power operation of the core until the control rods are completely inserted. Figure 14.3.2.2-3 represents the code interface between LOCTA and NOTRUMP.

Results - Limiting Break Case

This section presents the results of the limiting small break LOCA analysis (as determined by the highest calculated peak clad temperature), and fulfills the requirements of NUREG-0737 (Reference 16), Section II.K.3.31, which requires a plant-specific small break LOCA analysis using an Evaluation Model revised per Section II.K.3.30. In accordance with NRC Generic Letter 83-35

(Reference 17), generic Westinghouse analyses using NOTRUMP (References 10 and 11) were performed and are presented in WCAP-11145 (Reference 18). The results of Reference 18 demonstrate that the cold leg break location is limiting with respect to postulated cold leg, hot leg and pump suction leg break locations. First, a break spectrum was performed at the high RCS vessel average temperature, as this condition is typically limiting. Based on these conditions, the limiting break for the Turkey Point Units was found to be a 3-inch diameter break in the cold leg with a peak cladding temperature attained during the transient of 1688°F (refer to Table 14.3.2.2-2). Inherent in the limiting small break analysis are several input assumptions, a summary of which is provided in Table 14.3.2.2-1, while Table 14.3.2-3 provides the key transient event times.

A summary of the transient response for the limiting two-inch break case is shown in Figures 14.3.2.2-4 through 14.3.2.2-12. These figures present the response of the following parameters:

1. RCS Pressure Transient.
2. Core Mixture Level.
3. Peak Clad Temperature.
4. Cold Leg Break Mass Flow Rate.
5. Safety Injection Mass Flow Rate.
6. Top Core Node Vapor Temperature.
7. Hot Spot Rod Surface Heat Transfer Coefficient.
8. Hot Spot Fluid Temperature.

During the initial period of the small-break transient, the effect of the break flow rate is not sufficient to overcome the flow rate maintained by the reactor coolant pumps as they coast down. As such, normal upward flow is maintained through the core and core heat is adequately removed. Following reactor trip, the removal of the heat generated, as a result of fission products decay, is accomplished via a two-phase mixture level covering the core. From the clad temperature transients for the 3-inch break calculations given in Figures 14.3.2.2-5 and 14.3.2.2-6, it is seen that the peak clad temperature occurs near the time when the core is most deeply uncovered and the top of the core is being cooled by steam. This time is characterized by the highest vapor superheating above the mixture level (refer to Figure

14.3.2.2-7). A comparison of the flow provided by the safety injection system (Figures 14.3.2.2-8 and 14.3.2.2-9) to the total break mass flow rate at the end of the transient (Figures 14.3.2.2-10), shows that at the time the transient was terminated, the safety injection flow rate that was delivered to the RCS exceeds the mass flow rate out the break (70.1 lbm/s versus 61.2 lbm/s). In addition, the inner vessel core mixture level has recovered the top of the core (Figure 14.3.2.2-5).

Figures 14.3.2.2-11 and 14.3.2.2-12 provide additional information on the hot rod surface heat transfer coefficient at the hot spot and fluid temperature at the hot spot, respectively.

Additional Break Cases

Studies documented in Reference 18 have determined that the limiting small-break transient occurs for breaks of less than 10 inches in diameter. To ensure that the 3-inch diameter break was indeed the most limiting, calculations were also performed with break equivalent diameters of 2 inches and 4 inches. The results of each of these cases are given in Tables 14.4.2.2-2 and 14.3.2.2-3.

Plots of the following parameters for each case are also given in Figures 14.3.2.2-13 through 14.3.2.2-15 for the 2-inch break case and Figures 14.3.2.2-16 through 14.3.2.2-18 for the 4-inch break.

1. RCS Pressure Transient.
2. Core Mixture Level.
3. Peak Clad Temperature.

As seen in Table 14.3.2.2-2, the peak clad temperature for each of these cases was calculated to be less than that for the 3-inch break case.

Limiting Temperature Conditions

Reduced operating temperature typically results in a PCT benefit for the small break LOCA. However, due to competing effects and the complex nature of small break LOCA transients, there have been some instances where more limiting results have been observed for the reduced operating temperature case.

For this reason, a small break LOCA transient based on a lower bound RCS vessel average temperature was performed.

The temperature window analyzed was based on a nominal vessel average temperature of 574.2°F, with ± 3°F for an operating window and ± 8.5°F to bound uncertainties. The break spectrum was performed at the high vessel average temperature (585.7°F), as this case was expected to yield limiting results. Then, a sensitivity analysis for the low vessel average temperature (562.7°F) was performed based on the limiting 3-inch break case from the break spectrum analyses previously described.

Plots of the following parameters are given in Figures 14.3.2.2-19 through 14.3.2.2-21 for the 3-inch break case at low T_{AVG} conditions:

1. RCS Pressure Transient,
2. Core Mixture Level, and
3. Peak Cladding Temperature.

The PCT for the 3-inch break case based on low vessel average temperature was 1619°F (see Table 14.3.2.2-2). Therefore, the PCT for this case was calculated to be less than that for the 3-inch break case with high vessel average temperature conditions.

Evaluations

Upon completion of the small break LOCA analysis, an evaluation was performed for automatic containment spray actuation during small break LOCA. This evaluation accounts for the fact that Turkey Point Units 3 and 4 may be subject to SI interruption for up to 2 minutes while switching over to cold leg recirculation. The evaluation for containment spray actuation in small break LOCA resulted in no PCT penalty assessment. The basis for this conclusion was that the SI interruption occurs late in the transient when cladding temperatures are shown to be sufficiently low. Therefore, a conservative adiabatic heatup due to SI interruption would not exceed calculated PCT.

The DRFA fuel stack height above the lower core plate was explicitly modeled for the various cases analyzed.

The 5°F full-power T_{AVG} coastdown does not impact the small break LOCA analysis since lower vessel average temperature is non-limiting for the Turkey Point small break LOCA analysis.

The analyses and evaluation presented in this section show that the high head safety injection subsystems of the Emergency Core Cooling System, together with the heat removal capability of the steam generator, provide sufficient core heat removal capability to maintain the calculated peak-clad temperatures below the required limit of 10 CFR 50.46. Hence, adequate protection is afforded by the emergency core cooling system in the event of a small break loss-of-coolant accident.

14.3.2.2.3 CONCLUSIONS - SMALL BREAK LOCA ANALYSIS

For small breaks in the reactor coolant system pipe up to a cross sectional area of less than 1.0 ft^2, the Emergency Core Cooling System will meet the Acceptance Criteria presented to 10 CFR 50.46. That is:

1. The calculated peak fuel cladding temperature provides for a substantial margin to the requirement of 2200°F.

2. The amount of fuel cladding that reacts chemically with the water or steam does not exceed 1% of the hypothetical amount that would be generated if all the zirconium metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

3. The localized cladding oxidation limit of 17% is not exceeded during or after quenching.

4. The core remains amenable to cooling during and after the LOCA.

5. The core temperature is reduced and decay heat is removed for an extended period of time. This is required to remove the heat produced by the long-lived radioactivity remaining in the core.

14.3.2.3 REFERENCES

1. "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Cooled Nuclear Power Reactors," 10 CFR 50.46 and Appendix K of 10 CFR 50, Federal Register, Volume 39, Number 3. January 1974, as amended in Federal Register, Volume 53. September 1988.

2. Kabadi, J. N., et al., "The 1981 Version of the Westinghouse ECCS Evaluation Model Using the BASH Code," WCAP-10266-P-A Rev. 2 (proprietary), WCAP-11524-NP-A Rev 2 (non-proprietary), March 1987; including Addendum 1-A 'Power Shape Sensitivity Studies' 12/87 and Addendum 2-A 'BASH Methodology Improvements and Reliability Enhancements' May, 1988.

3. "Change in Methodology for Execution of BASH Evaluation Model," NTD-NRC-94-4143, May 23, 1994.

4. Young, M., et al., "BART-1A: A Computer Code for the Best Estimate Analyzed Reflood Transients", WCAP-9561-P-A (proprietary), WCAP-9695-NP-A (non-proprietary), 1984; including Addendum 3 Rev 1, July, 1986.

5. Bordelon, F. M., et al., "SATAN-VI Program: Comprehensive Space-Time Dependent Analysis of Loss-of-Coolant", WCAP-8302-P (proprietary), WCAP-8306-NP (non-proprietary), June, 1974.

6. Kelly, R. D., "Calculational Model for Core Reflooding after a Loss-of-Coolant Accident (WReflood Code)", WCAP-8170-P (proprietary), WCAP-8171-NP (non-proprietary), et al., June 1974.

7. Bordelon, F. M., and E. T. Murphy, "Containment Pressure Analysis Code (COCO)", WCAP-8327-P (proprietary), WCAP-8326-NP (non-proprietary), June 1974.

8. Bordelon, F. M. et al., "LOCTA-IV Program: Loss-of-Coolant Transient Analysis", WCAP-8301 (proprietary) and WCAP-8305 (non-proprietary), June 1974.

9. "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" 10CFR50.46 and Appendix K of 10 CFR 50. Federal Register, Vol. 39, Number 3, January 4, 1974.

14.3.2.3 REFERENCES (Continued)

10. Meyer, P. E., "NOTRUMP - A Nodal Transient Small Break and General Network Code," WCAP-10079-P-A (proprietary) and WCAP-10080-NP-A (non-proprietary), August 1985.

11. Lee, N., et al., "Westinghouse Small Break ECCS Evaluation Model Using The NOTRUMP Code," WCAP-10054-P-A (proprietary) and WCAP-10081-NP-A (non-proprietary), August 1985.

12. Thompson, C. M., et al, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection in the Broken Loop and COSI Condensation Model", WCAP-10054-P, Addendum 2, Revision 1 (proprietary) and WCAP-10081-NP, Addendum 2, Revision 1, (non-proprietary), October, 1995.

13. Shimeck, D. J., "COSI SI/Steam Condensation Experiment Analysis", WCAP-11767-P (proprietary), March 1988.

14. "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse - Designed Operating Plants," NUREG-0611. January 1980.

15. Bordelon. F. M.. et al., "LOCTA-IV Program: Loss-of-Coolant Transient Analysis". WCAP-8301 (proprietary) and WCAP-8305 (non-proprietary), June 1974.

16. "Clarification of TMI Action Plan Requirements," NUREG-0737. November 1980.

17. NRC Generic Letter 83-35 from D. G. Eisenhut. "Clarification of TMI Action Plan Item II.K.3.31". November 2. 1983.

18. Rupprecht. S. D. et al.. "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code:" WCAP-11145-P-A (proprietary) and WCAP-11372-NP-A (non-proprietary). October 1986.

TABLE 14.3.2.1-1

INPUT PARAMETERS USED IN THE LARGE BREAK LOCA ANALYSIS

Parameter	High T_{AVG}	Low T_{AVG}
Reactor Core Rated Thermal Power, (MWt) [1]	2300	2300
Peak Linear Power, (kw/ft) [1]	14.0	14.0
Total Peaking Factor (F_Q^T) at peak	2.35	2.35
Power Shape	Chopped Cosine and Top-Skewed	Chopped Cosine and Top-Skewed
$F_{\Delta H}$	1.64	1.64
Fuel	15x15 DRFA	15x15 DRFA
Accumulator Water Volume, minimum (ft^3/acc.) [2]	865	865
Accumulator Tank Volume (ft^3/acc.) [2]	1200	1200
Accumulator Gas Pressure, minimum (psig)	600	600
Pumped Safety Injection Flow	See Figure 14.3.2.1-1	See Figure 14.3.2.1-1
Steam Generator Tube Plugging Level (%) [3,4]	5	5
Thermal Design Flow/Loop, (gpm) [5]	85,000	85,000
Vessel Average Temperature w/uncertainties, (°F)	585.7	562.7
Reactor Coolant Pressure w/uncertainties, (psia)	2320	2320

NOTES:

1. Two percent is added to this power to account for calorimetric error.

2. The analysis value assumed the Tech Spec minimum and credited additional accumulator line volume.

3. Maximum plugging level in any one or all steam generators.

4. The analysis was performed at a SGTP level of 10% to bound the combined LOCA + Safe Shutdown Earthquake tube crush issue.

5. Flowrates conservatively based on 20% steam generator tube plugging.

TABLE 14.3.2.1-2

LARGE BREAK LOCA
CONTAINMENT DATA FOR PCT CALCULATION

Net Free Volume	1,550,000 ft^3
Initial Conditions	
Pressure	12.7 psia
Temperature	90.0°F
RWST Temperature	35.0°F
Temperature Outside Containment	39.0°F
Initial Spray Temperature	39.0°F
Spray System	
Maximum Flow for one Spray Pump	1821.5 gpm
Number of Spray Pumps Operating	2
Post-Accident Spray System Initiation Delay	26 sec
Containment Fan Coolers	
Post-Accident Initiation Fan Coolers	26 sec
Number of Fan Coolers Operating	3

TABLE 14.3.2.1-3

LARGE BREAK LOCA
ANALYSIS FUEL CLADDING RESULTS

Moody Discharge Coefficient, C_D=0.4

	Low T_{AVG}	High T_{AVG}	8.5-ft Peak Power Shape [1]
Peak Clad Temperature (°F)	2103	2082	2117
Peak Clad Temperature Location (ft) [2]	8.00	8.00	8.50
Peak Clad Temperature Time (sec)	137.5	146.3	128.9
Local Zr/H_2O Reaction, Max (%)	9.32	7.34	6.48
Local Zr/H_2O Reaction Location (ft) [2]	6.00	6.00	8.50
Total Zr/H_2O Reaction (%)	< 1.0	< 1.0	< 1.0
Hot Rod Burst Time (sec)	44.5	41.6	49.3
Hot Rod Burst Location (ft) [2]	6.00	6.00	7.00

NOTES:

1. The 9.5-foot and 10.5-foot top-skewed shapes were shown to be non-limiting compared to the chopped cosine.

2. Height from bottom of active fuel.

TABLE 14.3.2.1-4

LARGE BREAK LOCA ANALYSIS
TIME SEQUENCE OF EVENTS

Moody Discharge Coefficient, C_D=0.4

	Low T_{AVG}	High T_{AVG}	8.5-ft Peak Power Shape
Start of LOCA with LOOP (sec)	0.00	0.00	0.00
Reactor Trip Setpoint Exceeded (sec)	0.546	0.654	0.546
Safety Injection Setpoint Exceeded (sec)[1]	1.9	1.7	1.9
Accumulator Injection Begins (sec)	14.4	15.4	14.3
End-of-Bypass (sec)	33.205	29.593	33.156
End-of-Blowdown (sec)	33.205	31.389	33.156
Pump Injection Begins (sec)	36.9	36.7	36.9
Bottom of Core Recovery (sec)	53.9	50.7	53.8
Accumulator Empty (sec)	62.83	62.02	61.70
PCT Time (sec)	137.5	146.3	128.9

NOTE:

1. Safety Injection signal actuated off of containment high pressure as opposed to low pressurizer pressure for Turkey Point.

TABLE 14.3.2.2-2

SMALL BREAK LOCA ANALYSIS
FUEL CLADDING RESULTS

Break Spectrum, (High T_{AVG})

	BREAK SIZE		
	2-inch	3-inch	4-inch
Peak Clad Temperature (°F)	1656	1688	1583
Peak Clad Temperature Location (ft)	11.75	11.75	11.50
Peak Clad Temperature Time (sec)	2627	1188	668
Local Zr/H_2O Reaction, Max (%)	2.0188	1.5535	0.6679
Local Zr/H_2O Reaction Location (ft)	11.75	11.50	11.25
Total Zr/H_2O Reaction (%)	< 1.0	< 1.0	< 1.0
Hot Rod Burst Time (sec)	No Burst	No Burst	No Burst
Hot Rod Burst Location (ft)	N/A	N/A	N/A

Results for the Limiting 3-inch Break Size

	High T_{AVG}	Low T_{AVG}
Peak Clad Temperature (°F)	1688	1619
Peak Clad Temperature Location (ft)	11.75	11.50
Peak Clad Temperature Time (sec)	1188	1229
Local Zr/H_2O Reaction, Max (%)	1.5535	1.1034
Local Zr/H_2O Reaction Location (ft)	11.50	11.50
Total Zr/H_2O Reaction (%)	< 1.0	< 1.0
Hot Rod Burst Time (sec)	No Burst	No Burst
Hot Rod Burst Location (ft)	N/A	N/A

TABLE 14.3.2.2-3

SMALL BREAK LOCA ANALYSIS
TIME SEQUENCE OF EVENTS

Break Spectrum, (High T_{AVG})

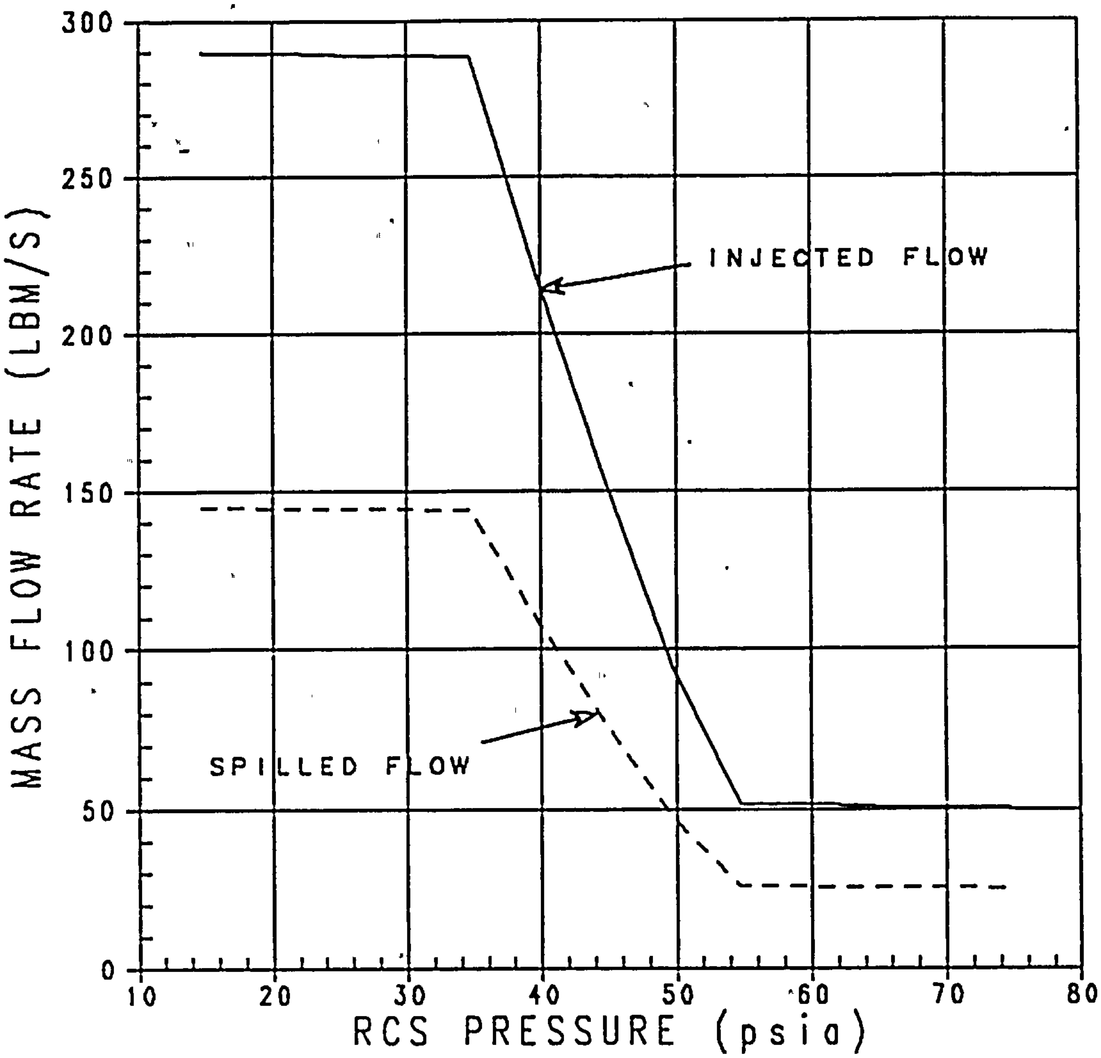
	BREAK SIZE		
	2-inch	3-inch	4-inch
Break Occurs (sec)	0.0	0.0	0.0
Reactor Trip Signal (sec)	40.6	17.0	10.4
Safety Injection Signal (sec)	58.9	30.4	21.4
Top Of Core Uncovered (sec)	1402	482	278[1]
Accumulator Injection Begins (sec)	N/A	1040	525
Peak Clad Temperature Occurs (sec)	2627	1188	668
Top Of Core Covered (sec)	4554	2363	965

Results for the Limiting 3-inch Break Size

	High T_{AVG}	Low T_{AVG}
Break Occurs (sec)	0.0	0.0
Reactor Trip Signal (sec)	17.0	14.4
Safety Injection Signal (sec)	30.4	21.8
Top Of Core Uncovered (sec)	482	526
Accumulator Injection Begins (sec)	1040	1086
Peak Cladding Temperature Occurs (sec)	1188	1229
Top Of Core Covered (sec)	2363	2343

NOTE:

1. Momentary core uncovery occurred at 213 seconds during prelude to loop seal clearing. The beginning of the subsequent extended core uncovery at 278 seconds is the time listed.



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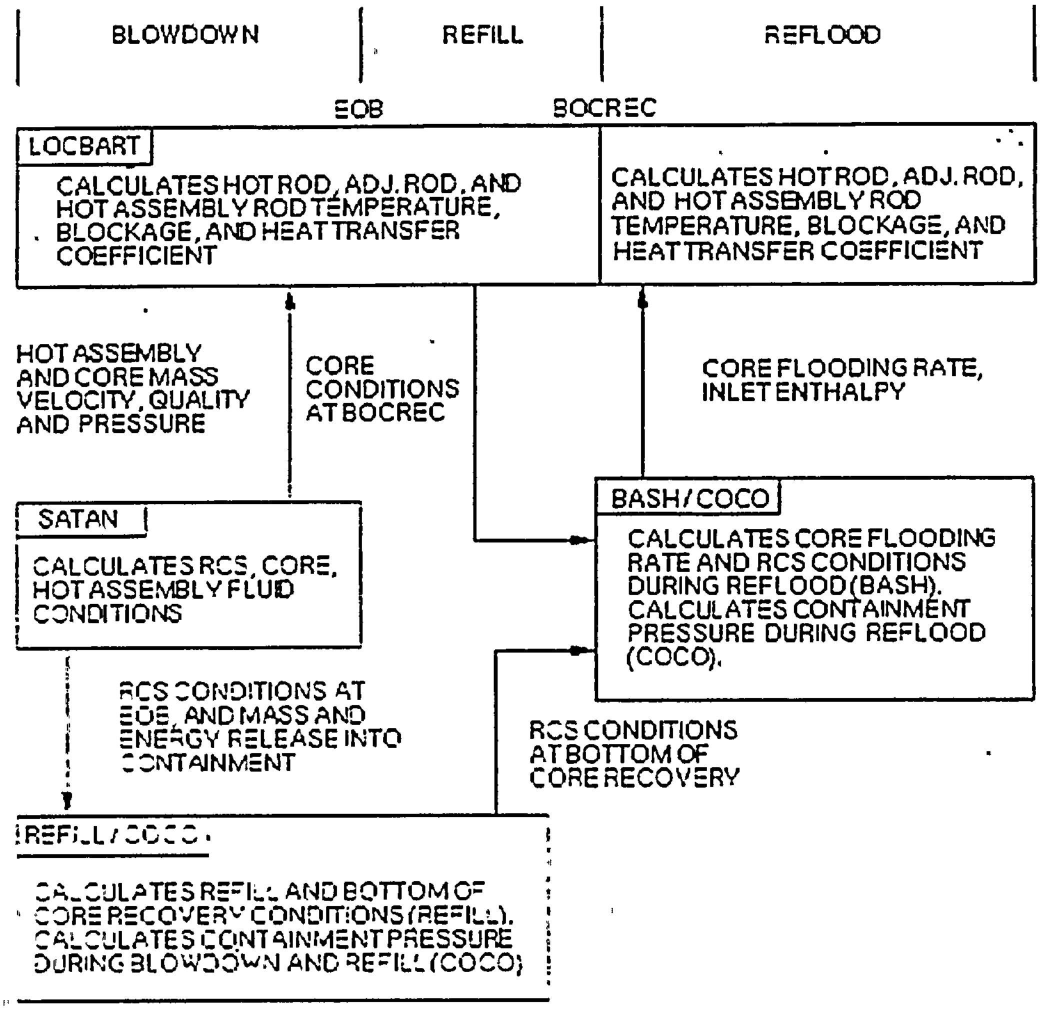
FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LARGE BREAK
PUMPED SAFETY INJECTION FLOW RATE
1 HHSI AND 1 RHR PUMP
FIGURE 14.3.2.1-1



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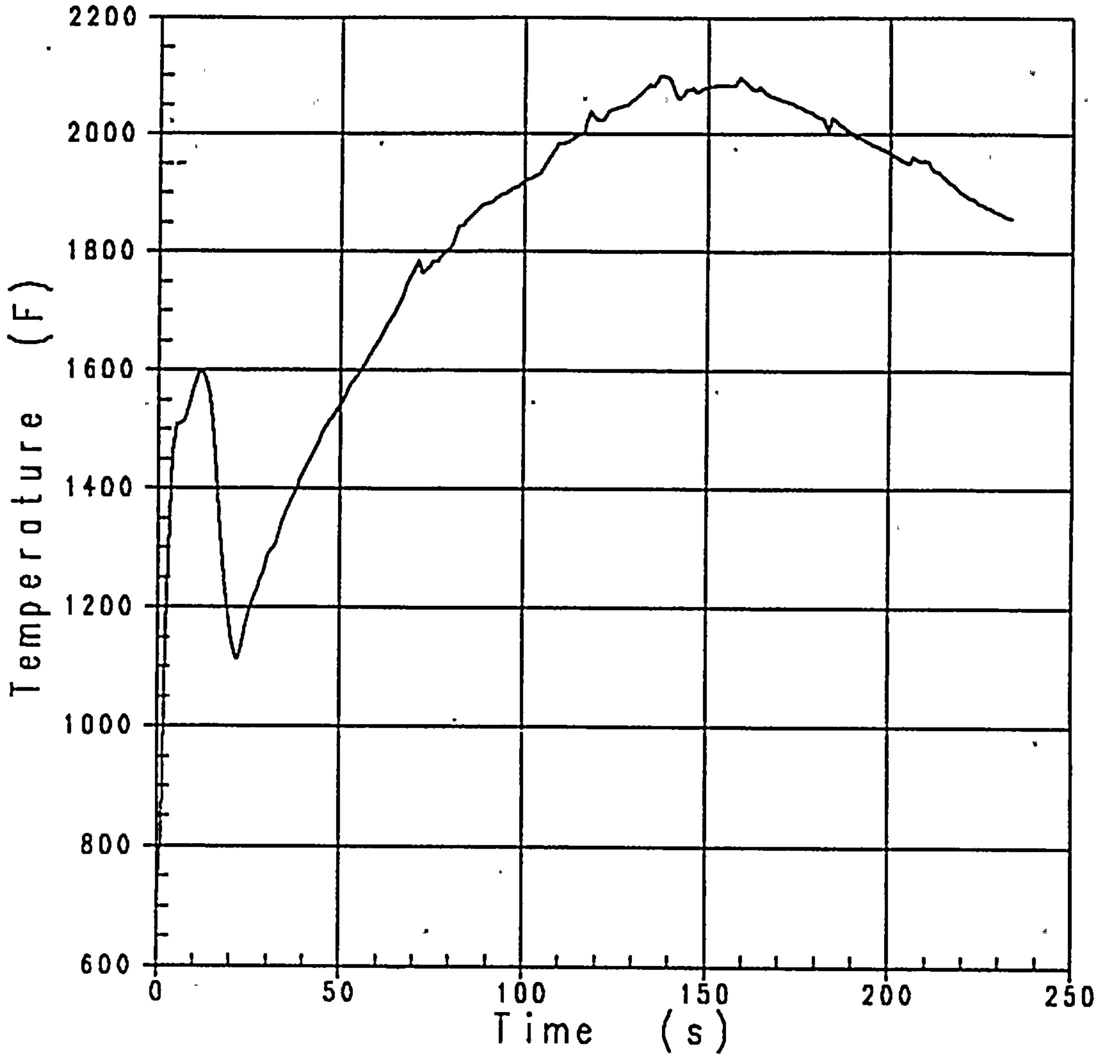
CODE INTERFACE DESCRIPTION FOR THE LARGE BREAK LOCA MODEL

FIGURE 14.3.2.1-2



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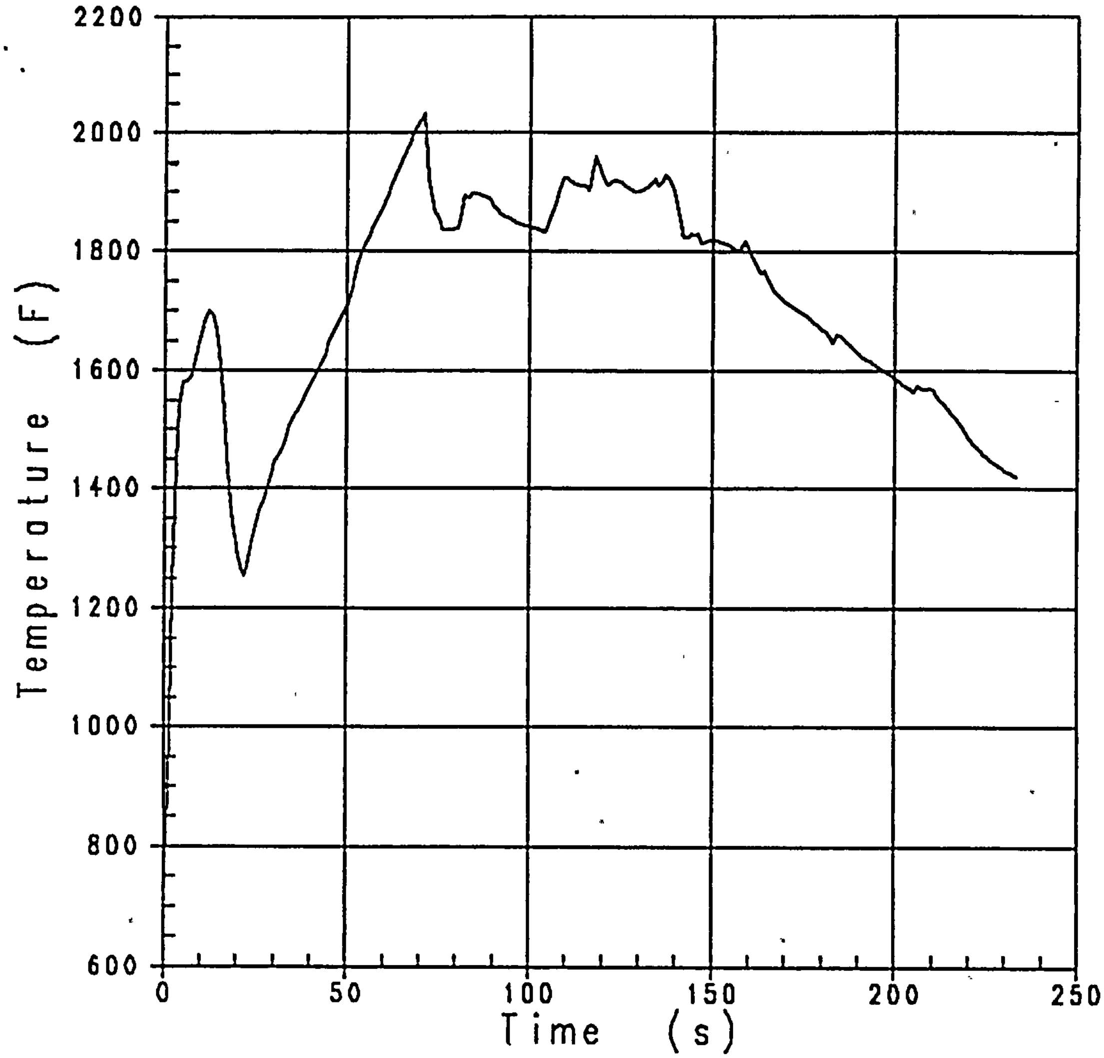
TURKEY POINT PLANT UNITS 3 & 4

PEAK CLADDING TEMPERATURE
FOR $C_0=0.4$, LOW T_{AVG}

FIGURE 14.3.2.1-3



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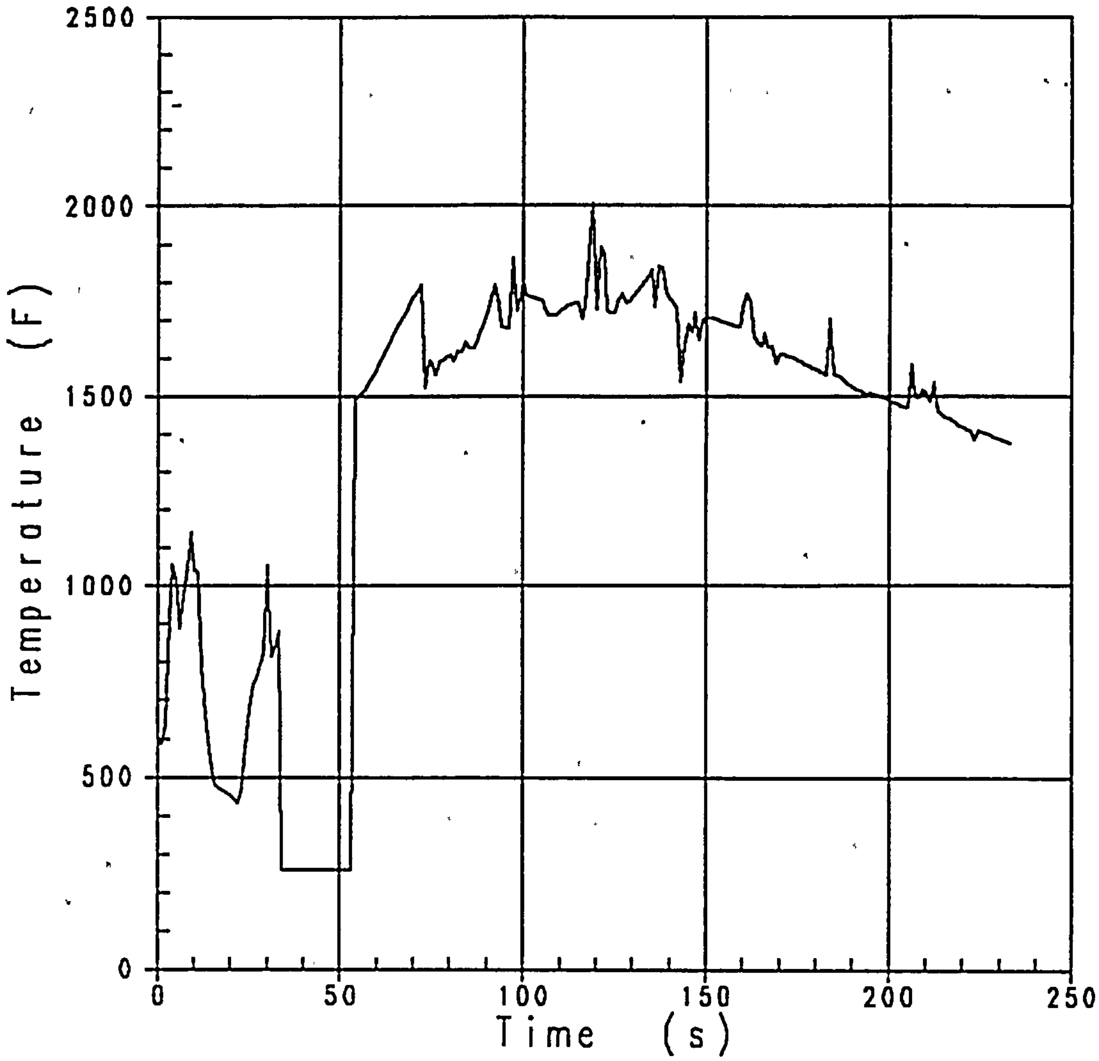
CLADDING TEMPERATURE
AT FUEL ROD BURST LOCATION
FOR C_D=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-4

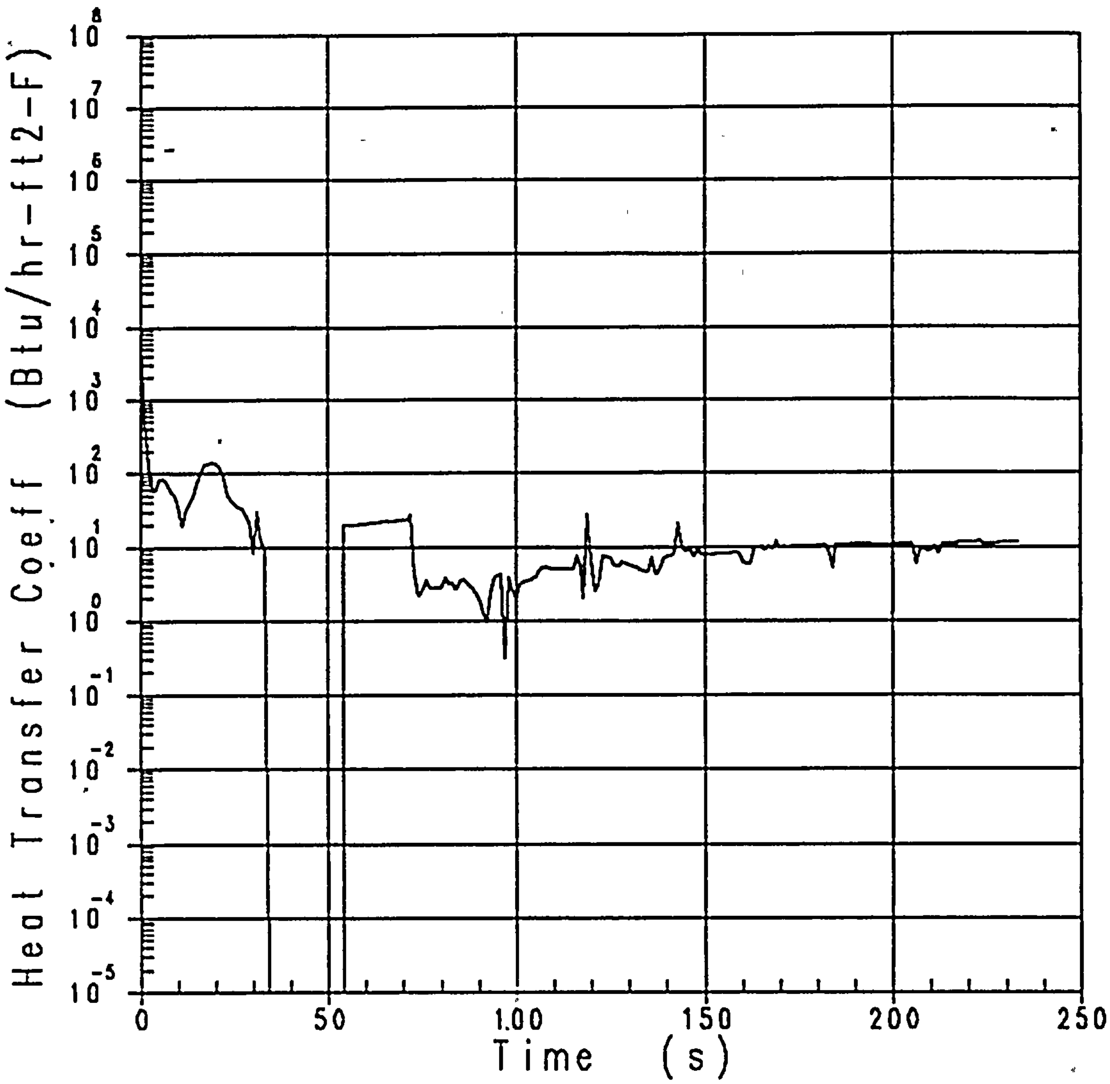


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LOCAL FLUID TEMPERATURE
AT PCT ELEVATION
FOR C_0=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-5



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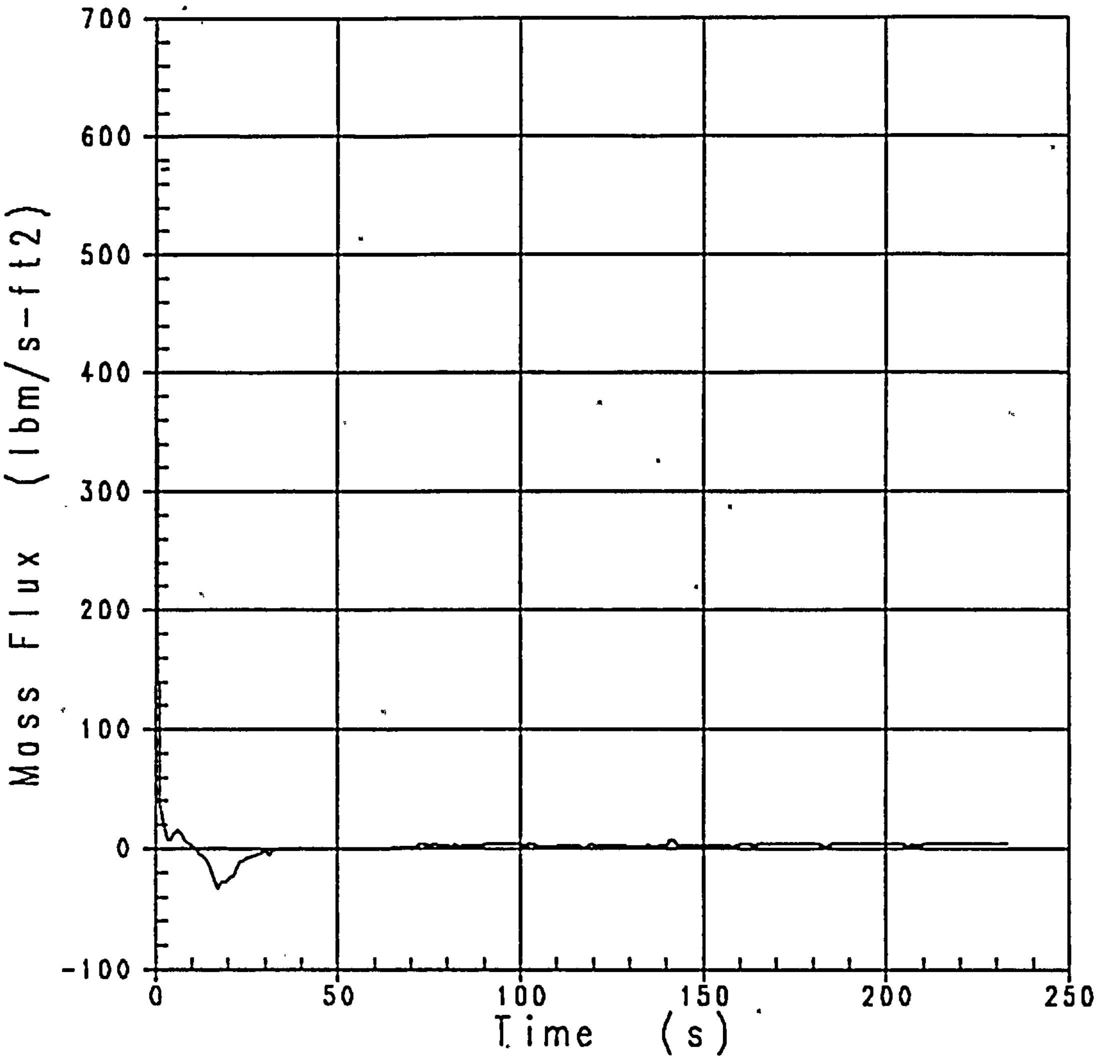
FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LOCAL HEAT TRANSFER COEFFICIENT
AT PCT ELEVATION
FOR C_D=0.4, LOW T_{AVG}
FIGURE 14.3.2.1-6



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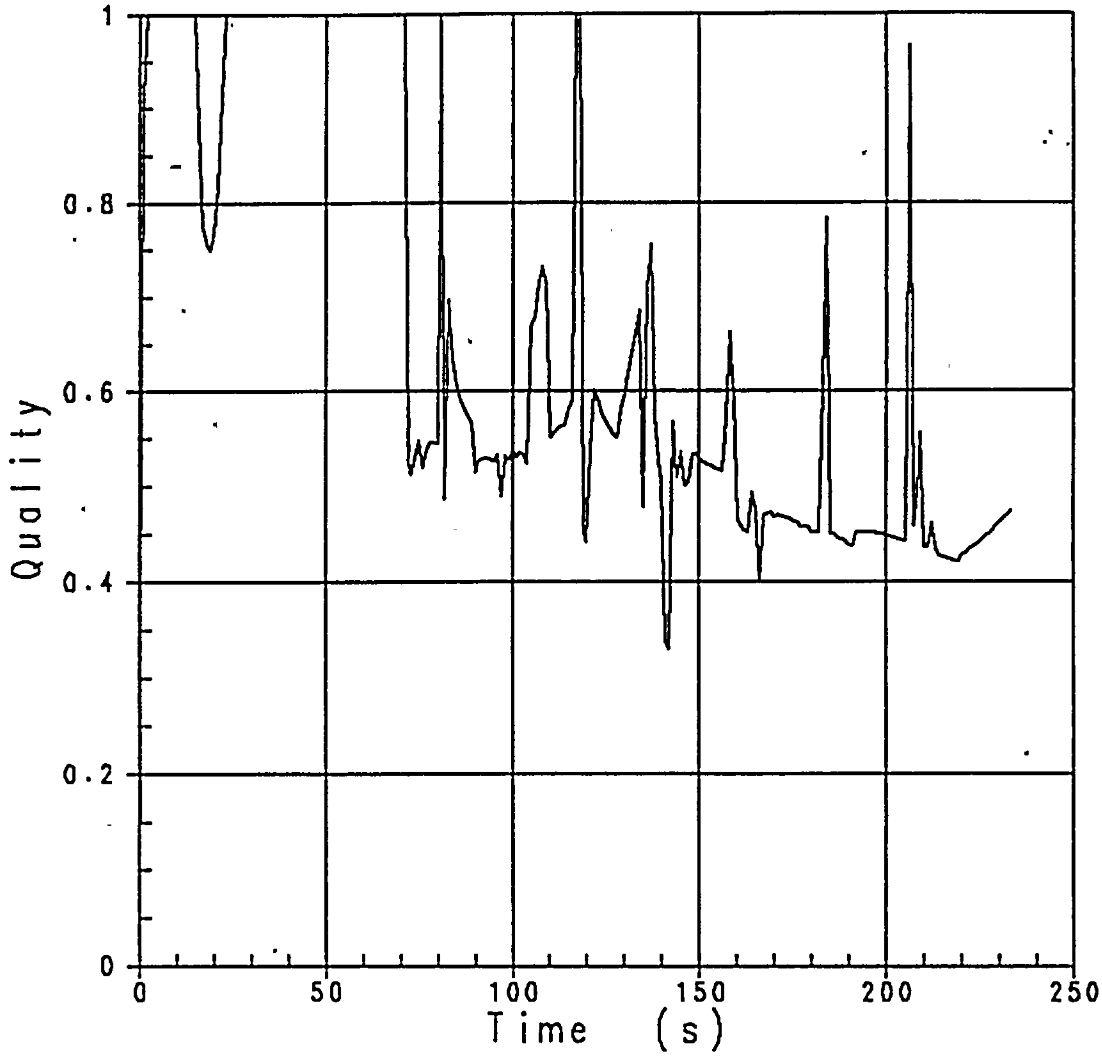
TURKEY POINT PLANT UNITS 3 & 4

LOCAL MASS FLUX
AT PCT ELEVATION
FOR C_D=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-7



REV 14 (2/97)

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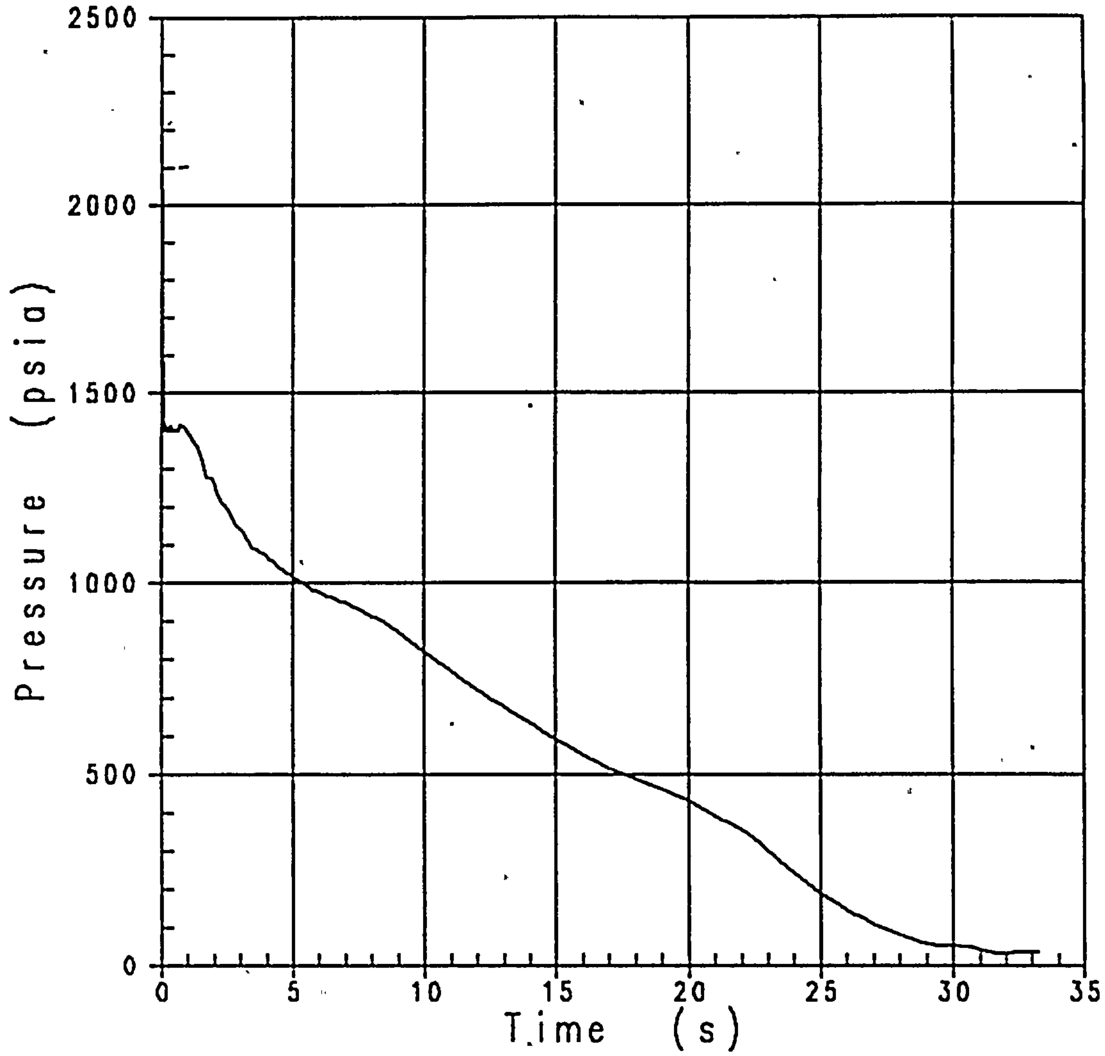
TURKEY POINT PLANT UNITS 3 & 4

LOCAL QUALITY
AT PCT ELEVATION
FOR C_D=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-8



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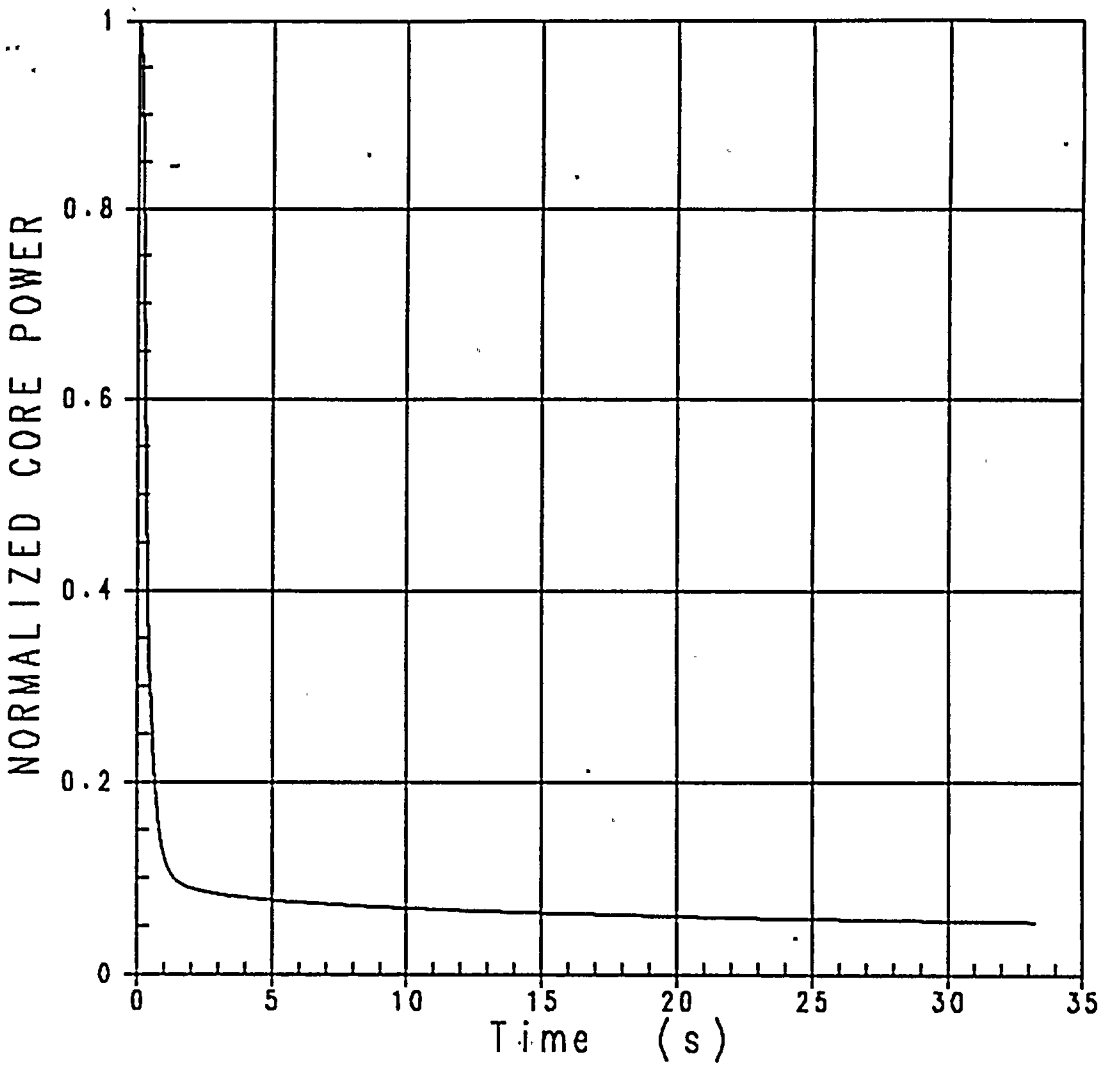
TURKEY POINT PLANT UNITS 3 & 4

RCS PRESSURE
DURING BLOWDOWN
FOR C_D=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-9



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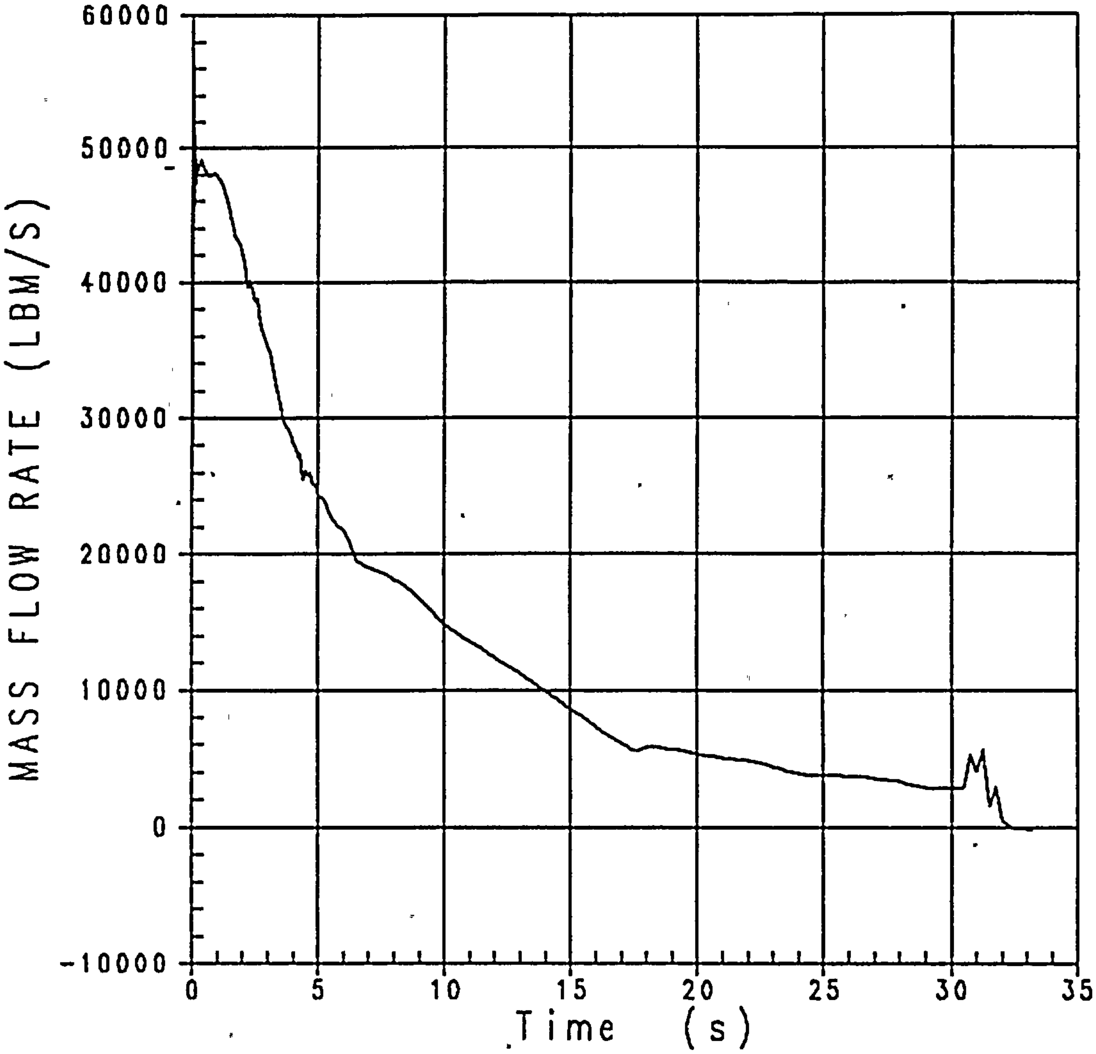
TURKEY POINT PLANT UNITS 3 & 4

DECAY HEAT
DURING BLOWDOWN
FOR C_D=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-10



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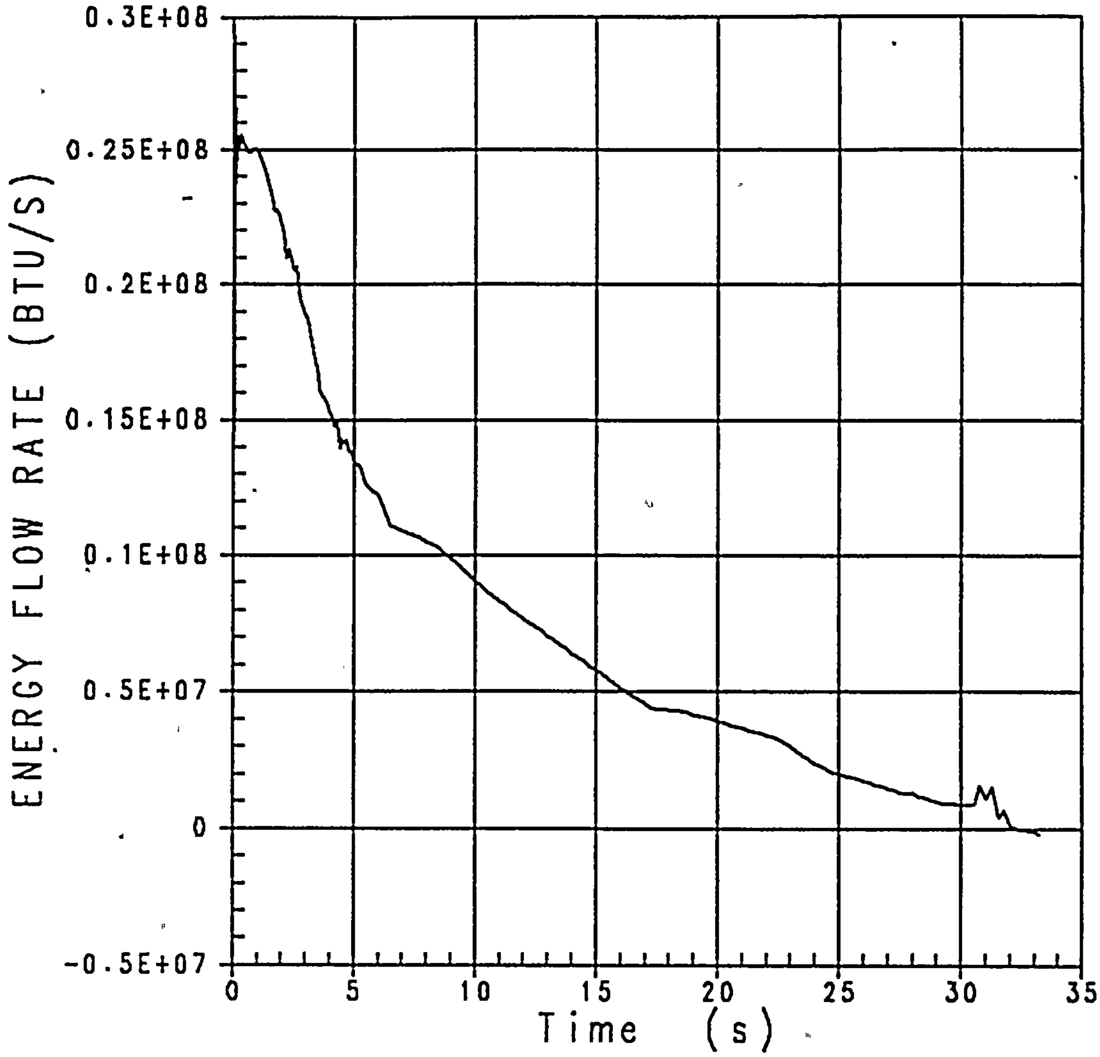
TURKEY POINT PLANT UNITS 3 & 4

BREAK MASS FLOW
DURING BLOWDOWN
FOR $C_D = 0.4$, LOW T_{AVG}

FIGURE 14.3.2.1-11



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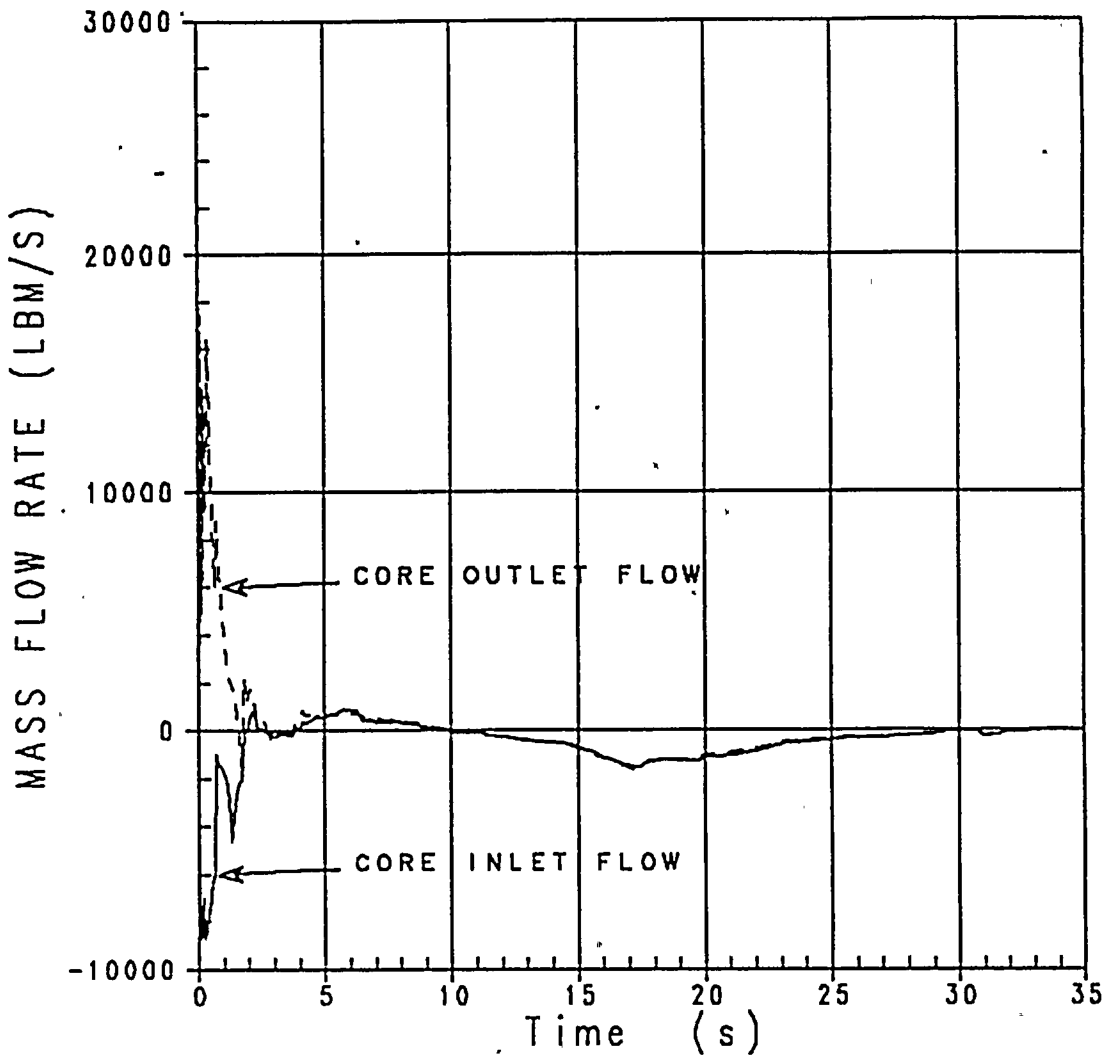
TURKEY POINT PLANT UNITS 3 & 4

BREAK ENERGY FLOW
DURING BLOWDOWN
FOR C_0=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-12



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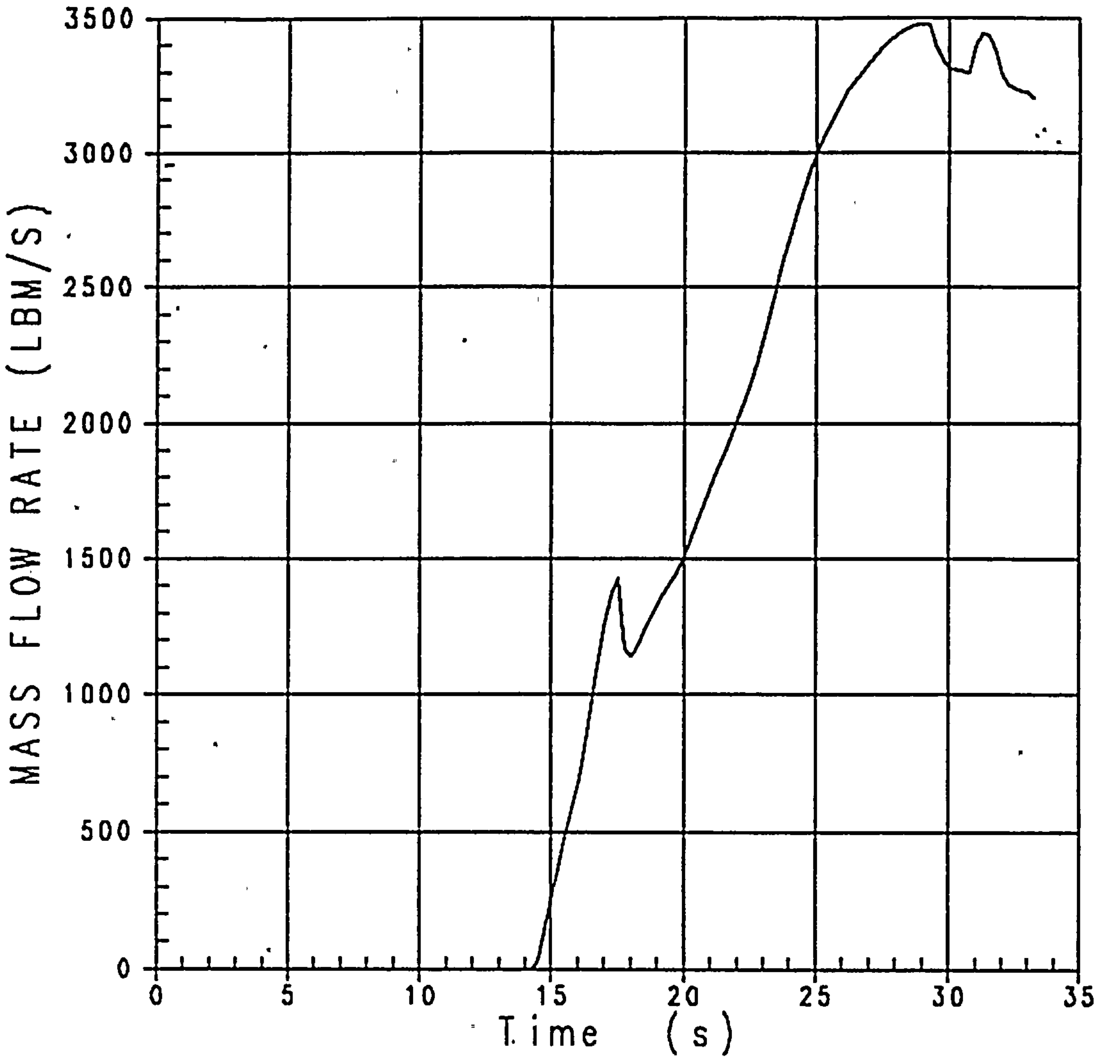
TURKEY POINT PLANT UNITS 3 & 4

CORE FLOW
DURING BLOWDOWN
FOR $C_D = 0.4$, LOW T_{AVG}
FIGURE 14.3.2.1-13

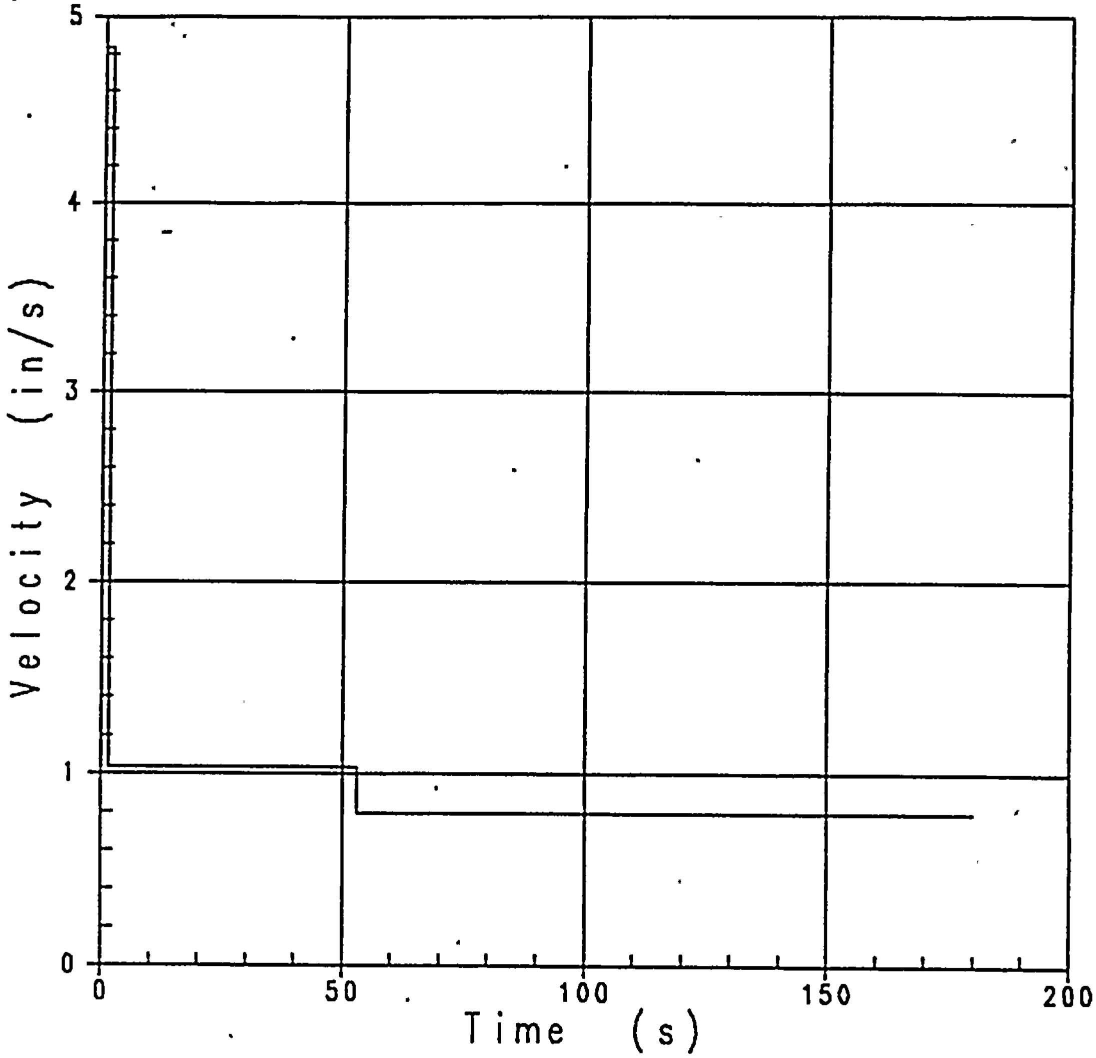


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

ACCUMULATOR FLOW
DURING BLOWDOWN
FOR C_D=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-14



NOTES

1 Time = 0.0 Seconds is Bottom of Core Recovery Time.

2 Time (from Event Initiation) = 53.9 Seconds After Break for C_D = 0.4, Low T_{AVG} Case.

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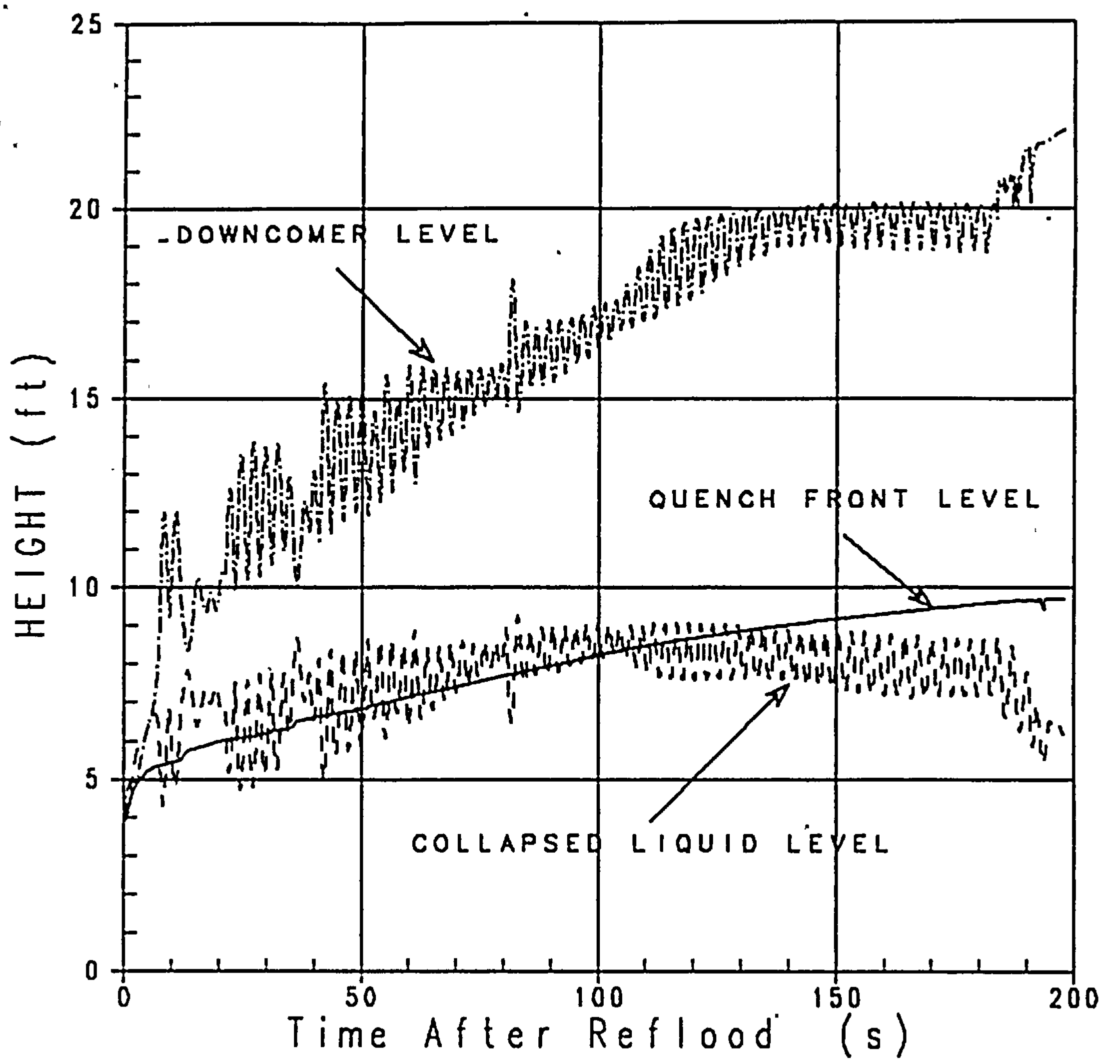
TURKEY POINT PLANT UNITS 3 & 4

CORE REFLOODING RATE
FOR C_D = 0.4, LOW T_{AVG}

FIGURE 14.3.2.1-15



NOTES

1 Time = 0.0 Seconds is Bottom of Core Recovery Time.

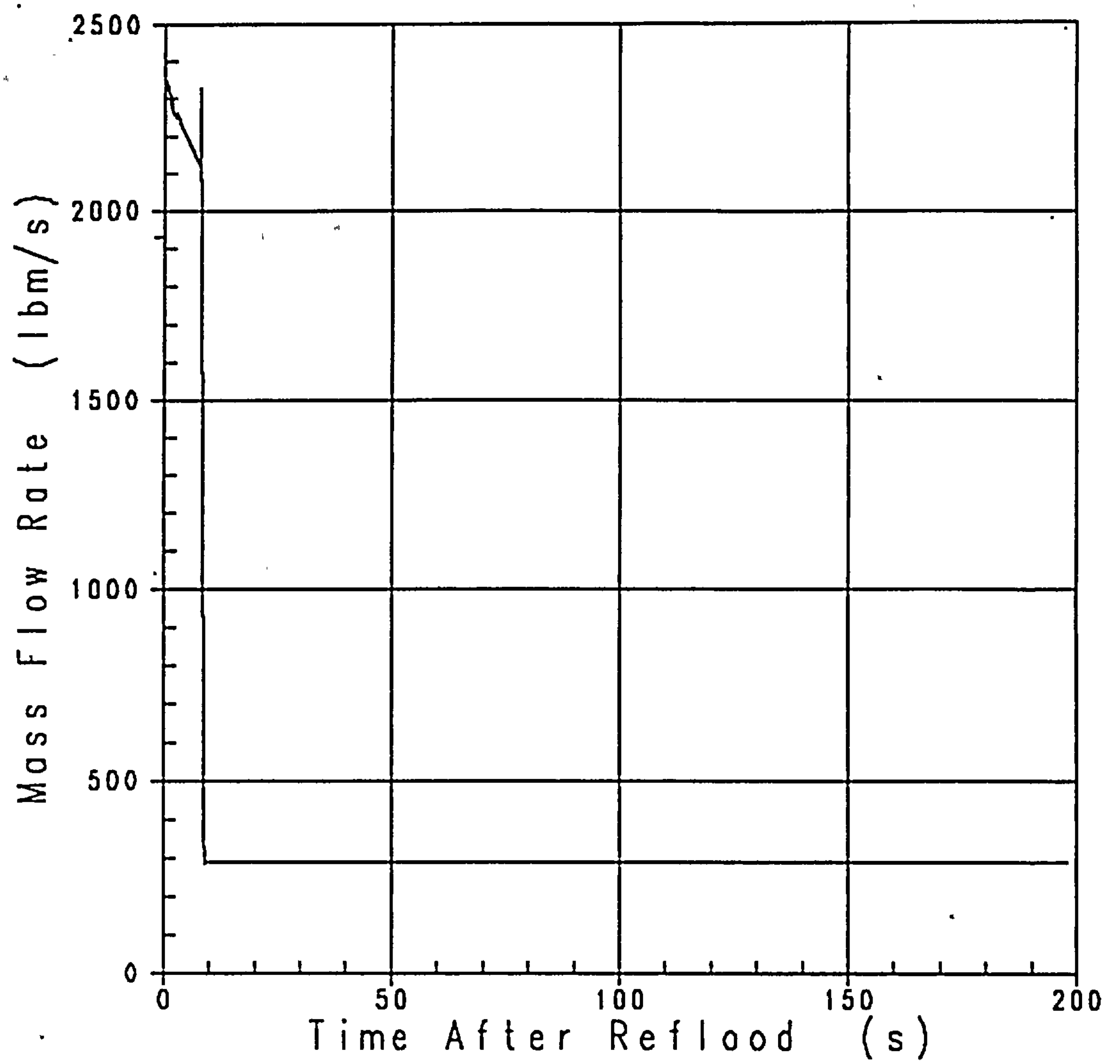
2 Time (from Event Initiation) = 53.9 Seconds After Break for C_D = 0.4, Low T_{AVG} Case.

REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

CORE AND DOWNCOMER MIXTURE LEVELS DURING REFLOOD FOR C_D=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-16



NOTES

1 Time = 0.0 Seconds is Bottom of Core Recovery Time.

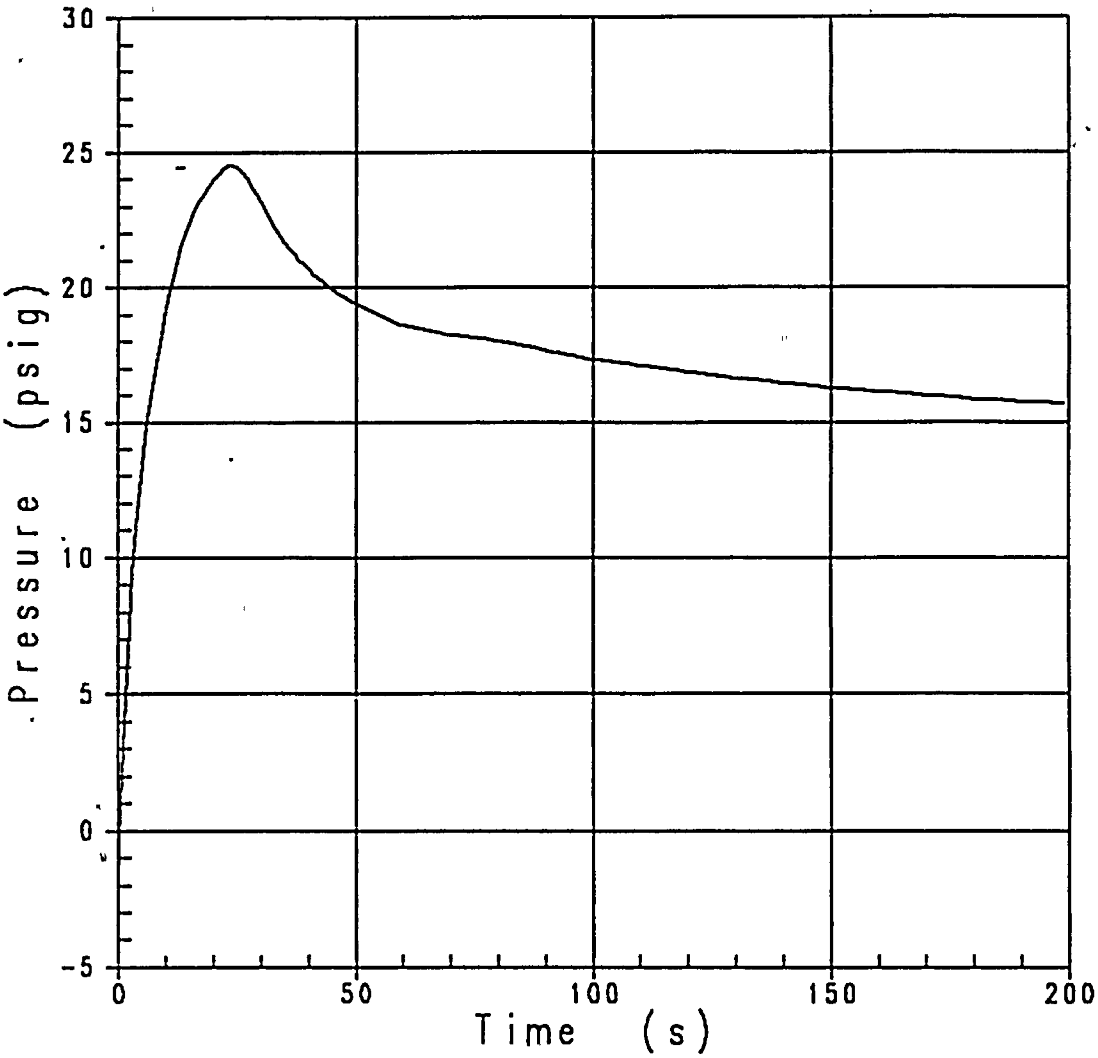
2 Time (from Event Initiation) = 53.9 Seconds After Break for C_0 = 0.4, Low T_{AVG} Case.

REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

ECCS FLOWS DURING REFLOOD
FOR C_0=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-17

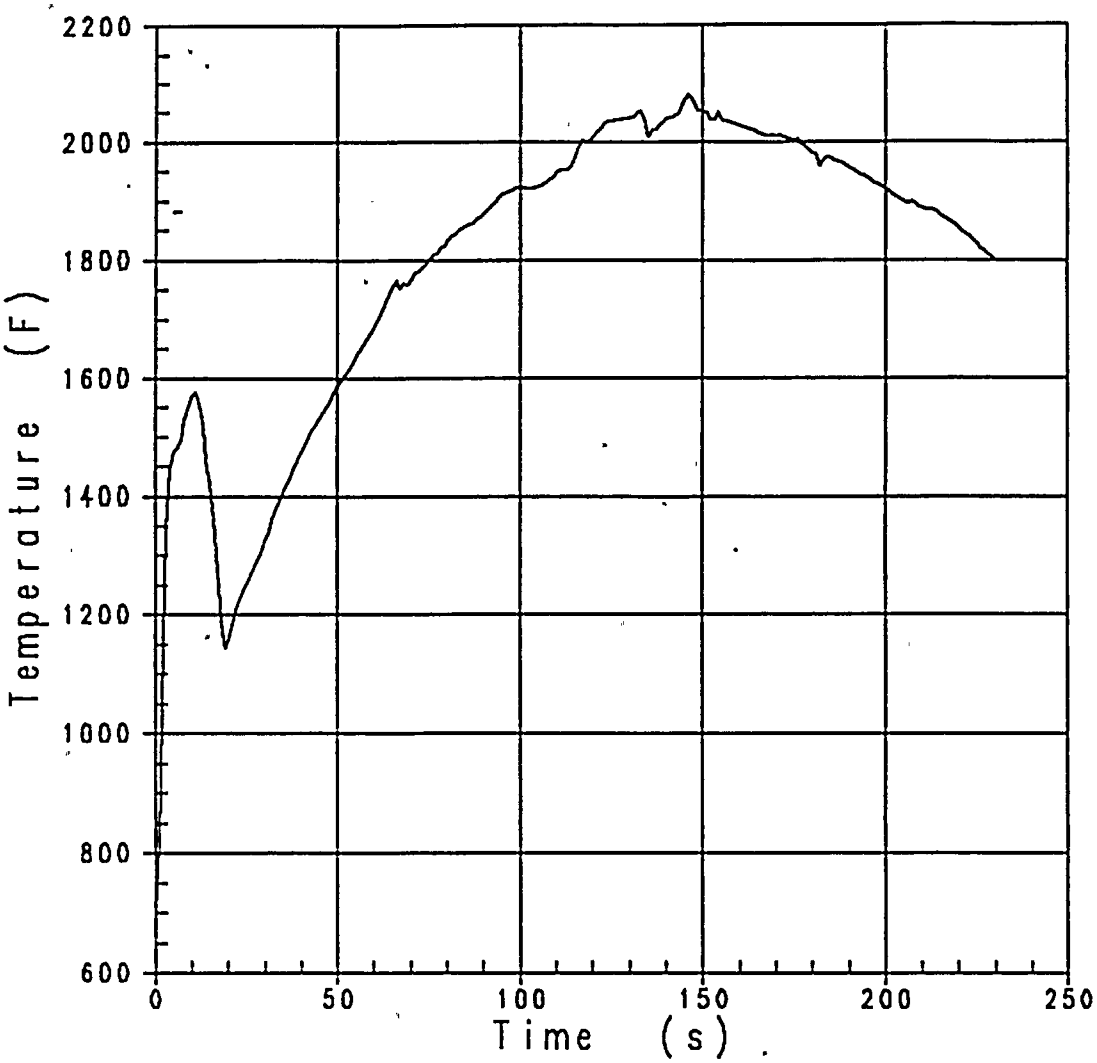


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

CONTAINMENT PRESSURE TRANSIENT
FOR $C_D = 0.4$, LOW T_{AVG}

FIGURE 14.3.2.1-18

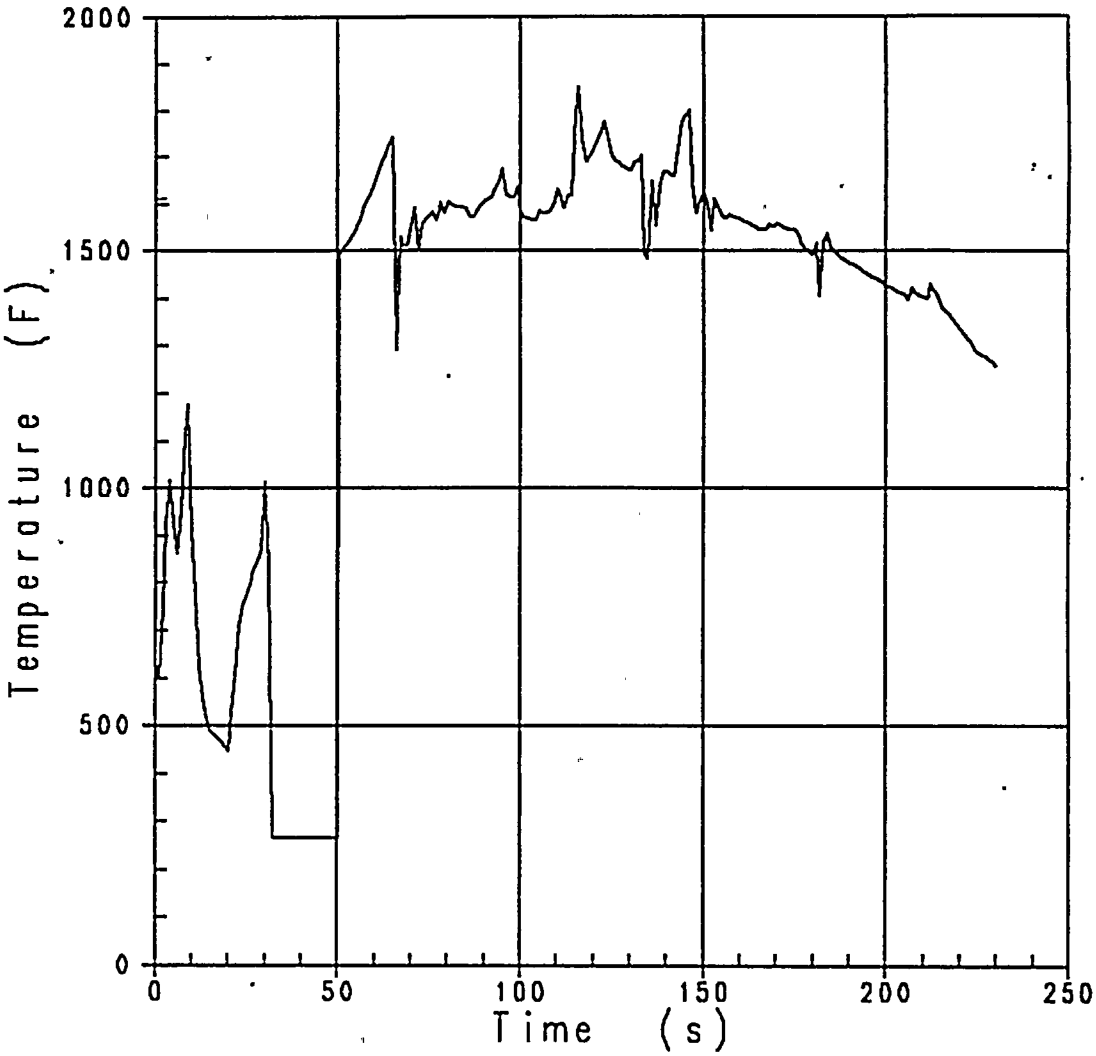


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

PEAK CLADDING TEMPERATURE
FOR $C_D = 0.4$, HIGH T_{AVG}

FIGURE 14.3.2.1-19

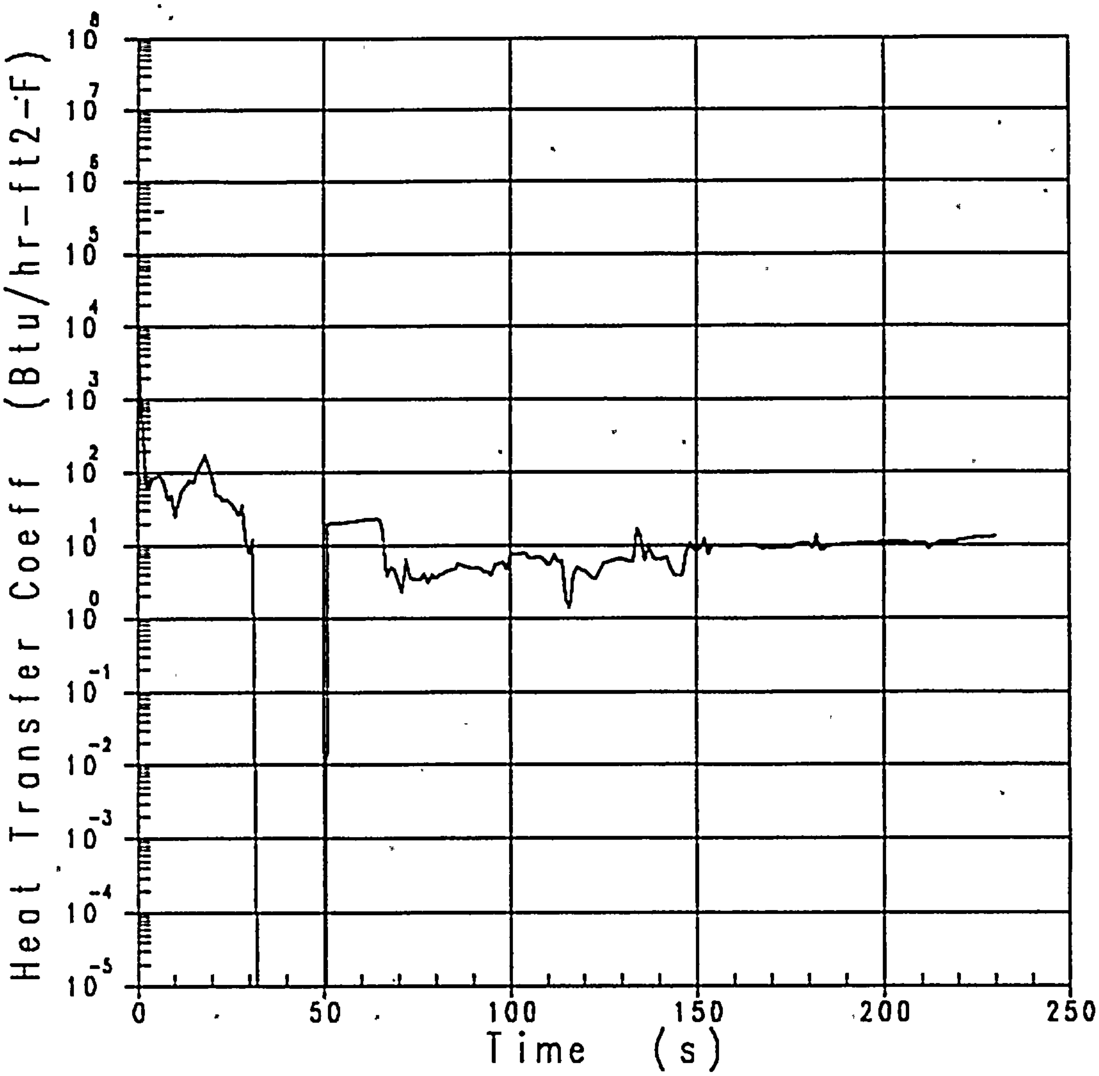


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LOCAL FLUID TEMPERATURE
AT PCT ELEVATION
FOR C_D=0.4, HIGH T_{AVG}

FIGURE 14.3.2.1-20

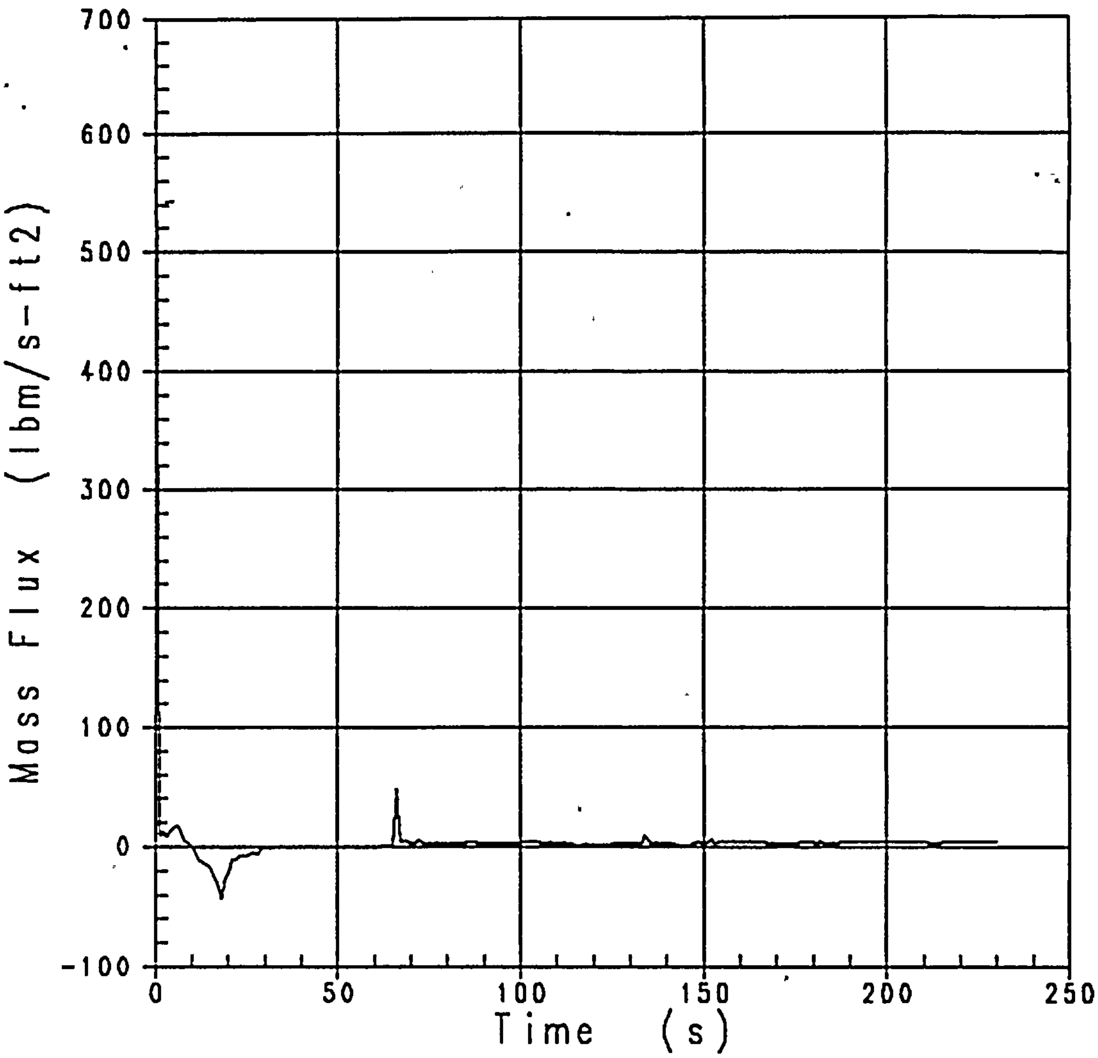


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LOCAL HEAT TRANSFER COEFFICIENT
AT PCT ELEVATION
FOR C_D=0.4, HIGH T_{AVG}

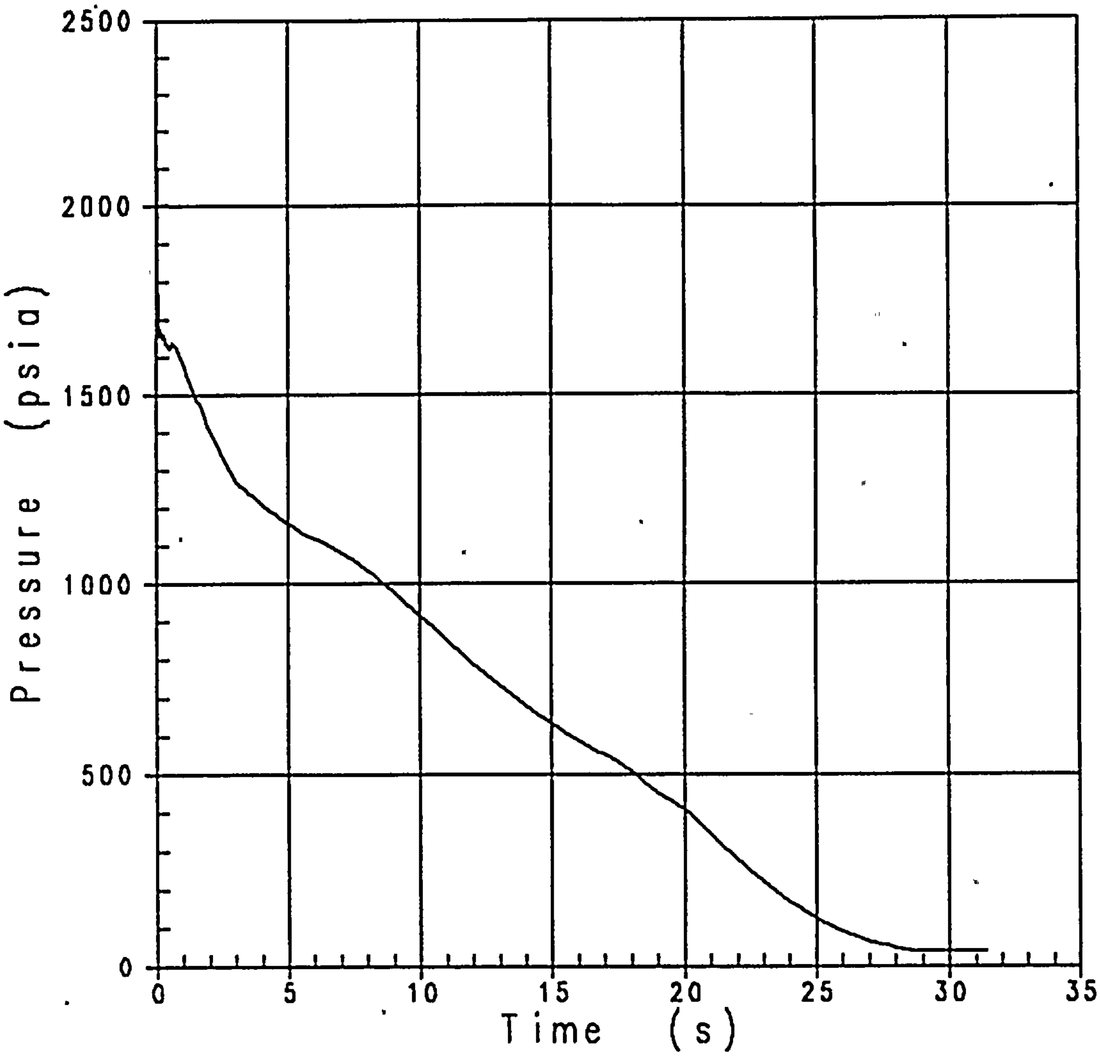
FIGURE 14.3.2.1-21



REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LOCAL MASS FLUX
AT PCT ELEVATION
FOR C_0=0.4, HIGH T_{AVG}
FIGURE 14.3.2.1-22

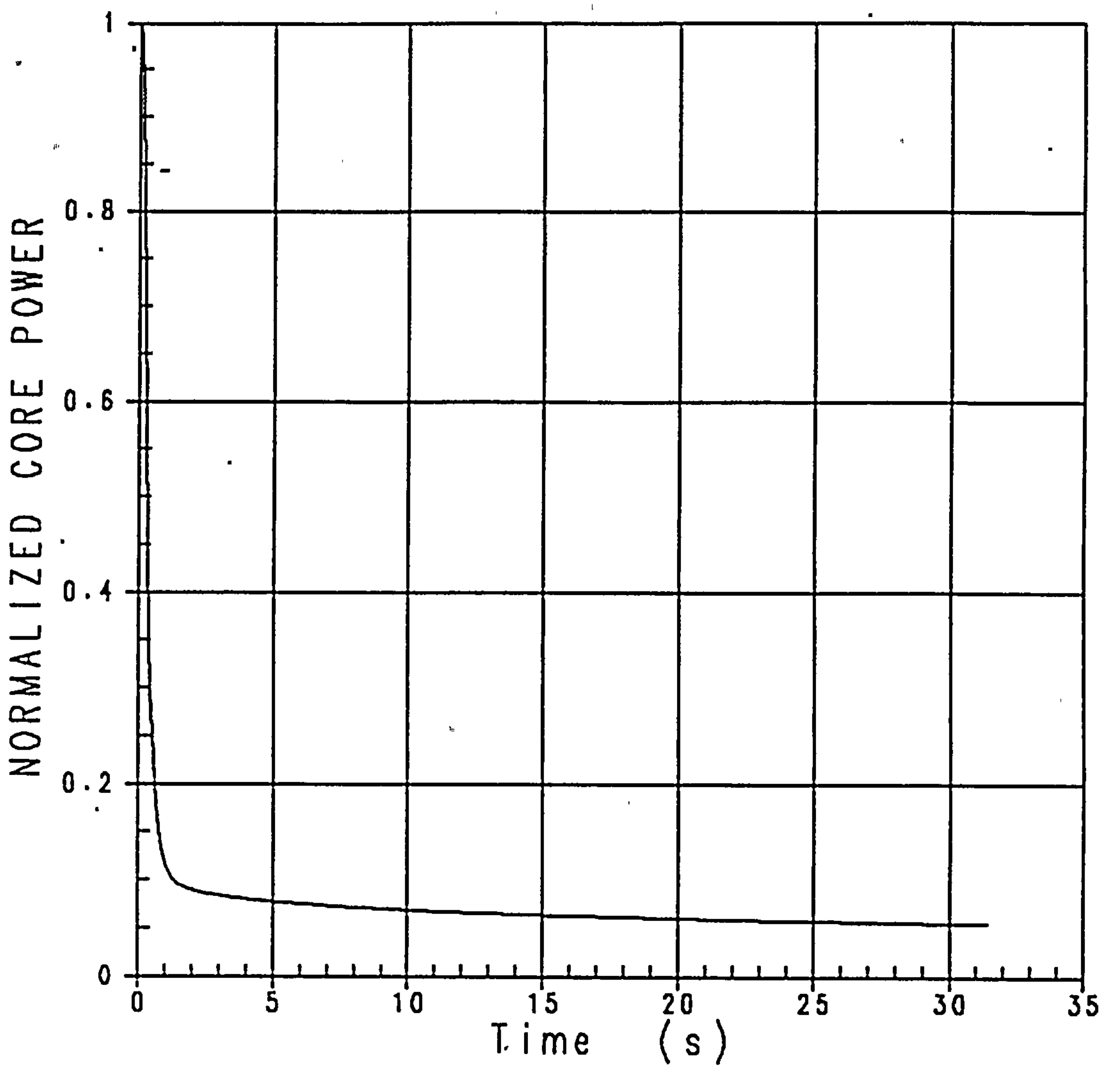


REV. 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

RCS PRESSURE
DURING BLOWDOWN
FOR $C_0=0.4$, HIGH T_{AVG}

FIGURE 14.3.2.1-23

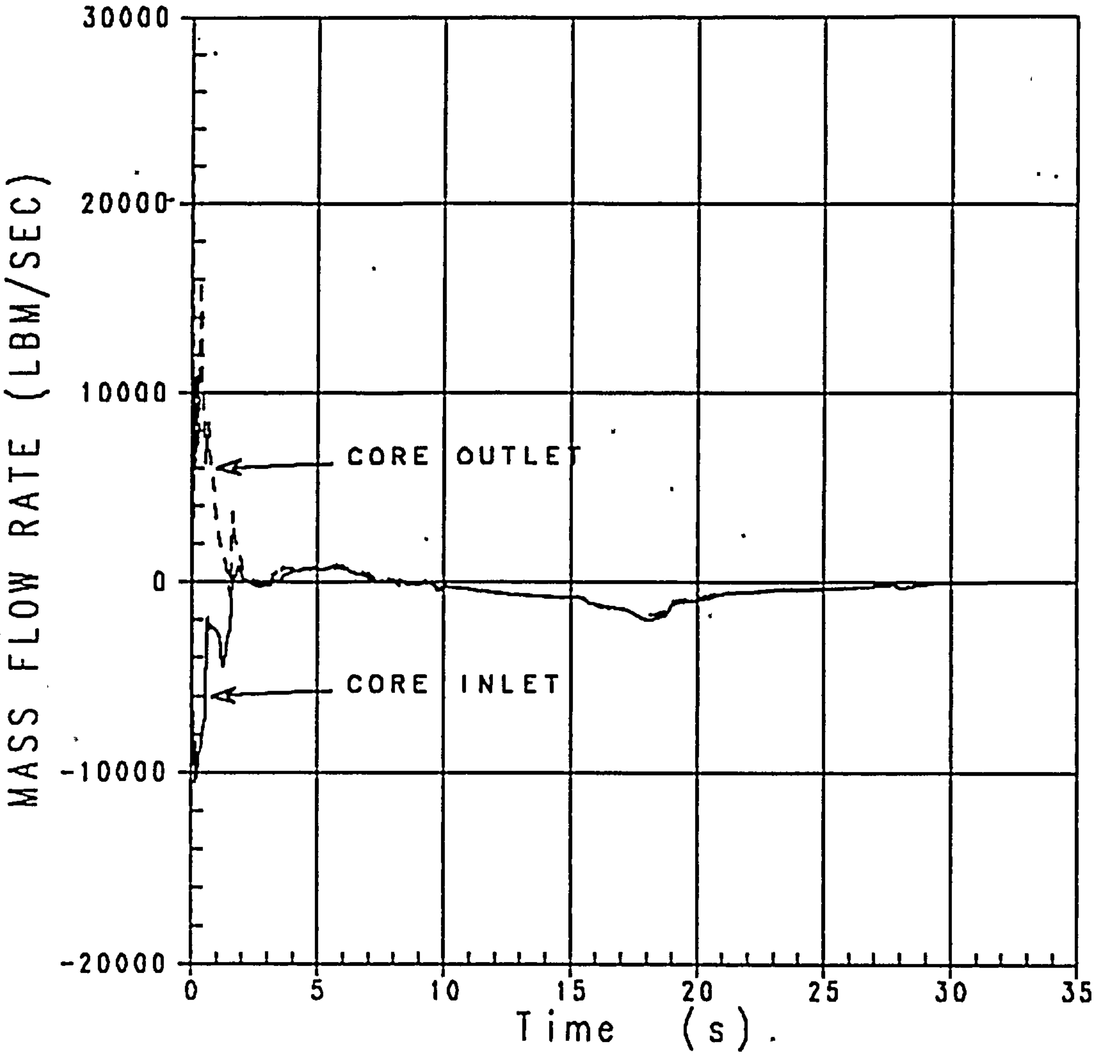


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

DECAY HEAT
DURING BLOWDOWN
FOR $C_D = 0.4$, HIGH T_{AVG}

FIGURE 14.3.2.1-24

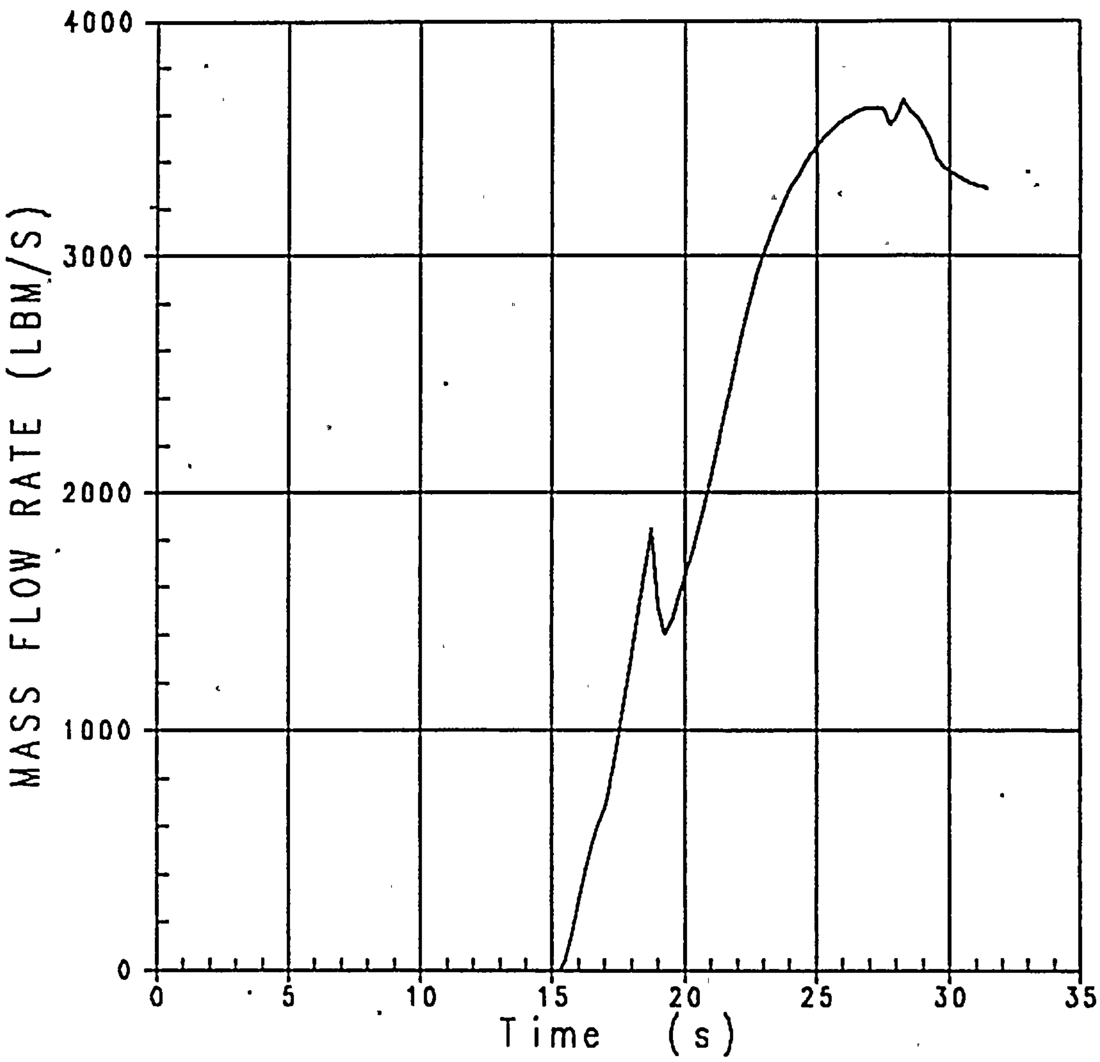


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

CORE FLOW
DURING BLOWDOWN
FOR C_D=0.4, HIGH T_{AVG}

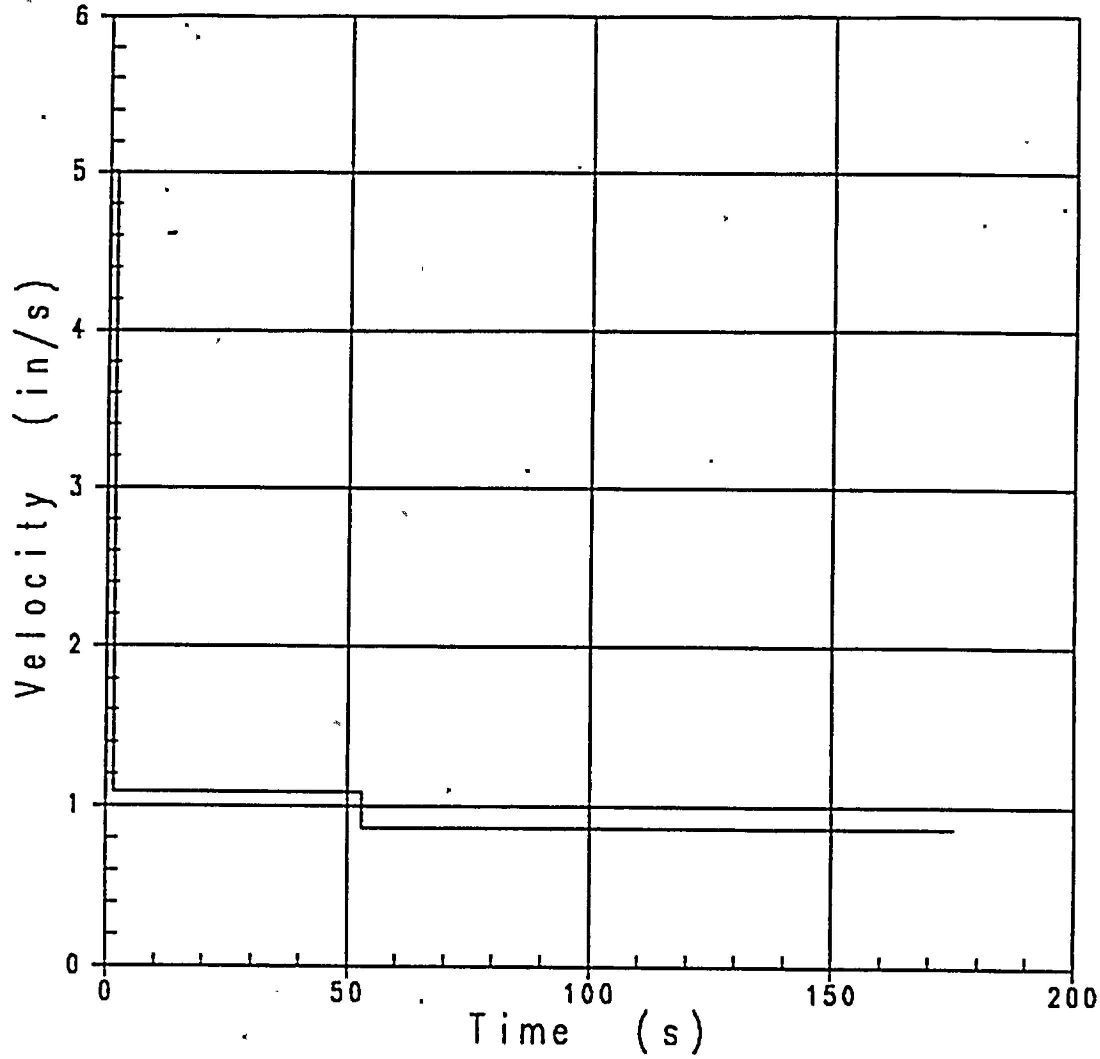
FIGURE 14.3.2.1-25



REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

ACCUMULATOR FLOW
DURING BLOWDOWN
FOR $C_D = 0.4$, HIGH T_{AVG}
FIGURE 14.3.2.1-26



NOTES:

1 Time = 0.0 Seconds is Bottom of Core Recovery Time.

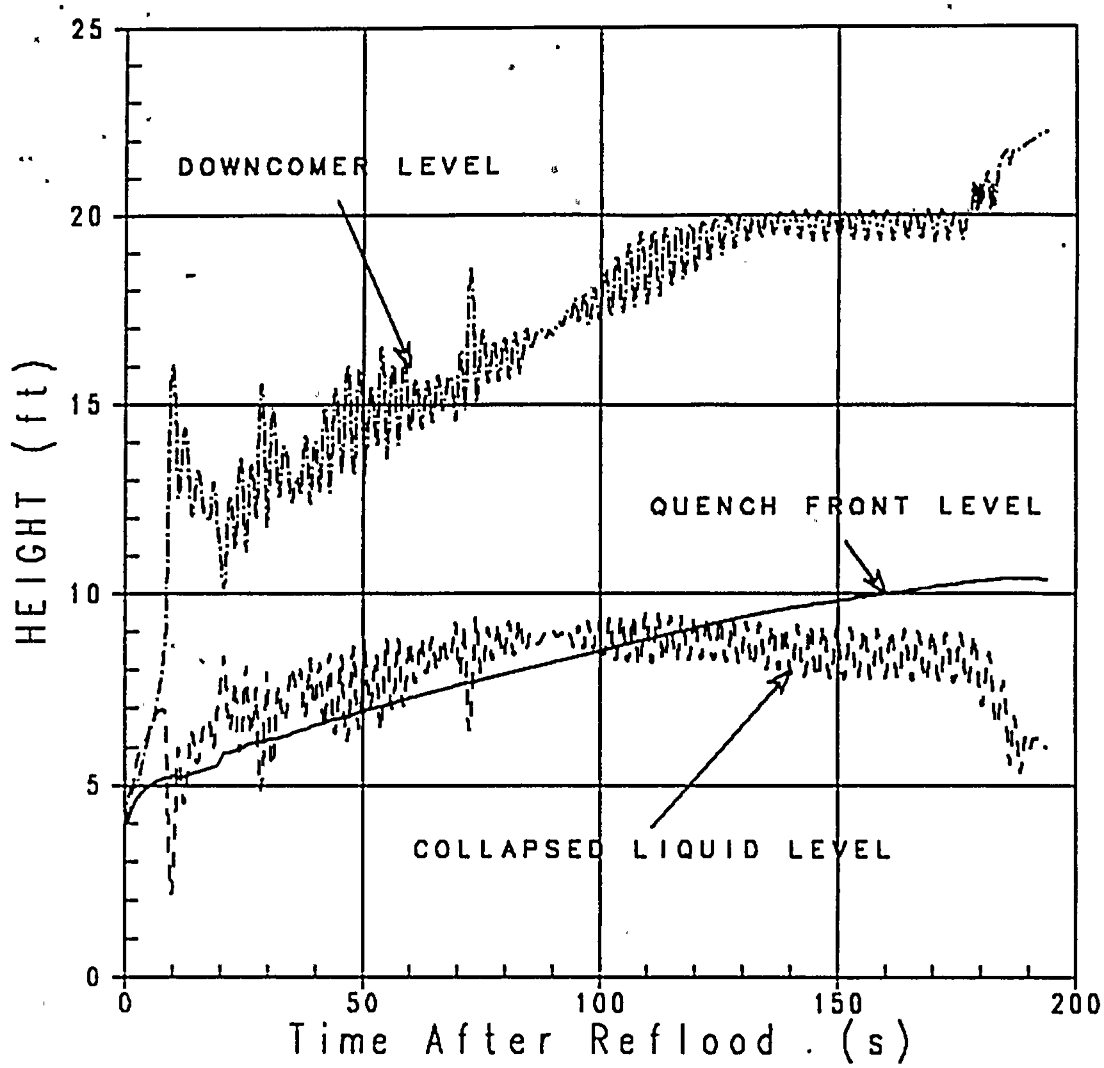
2 Time (from Event Initiation) = 50.7 Seconds After Break for C_D = 0.4, Low T_{AVG} Case.

REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

CORE REFLOODING RATE
FOR C_D=0.4, LOW T_{AVG}

FIGURE 14.3.2.1-27



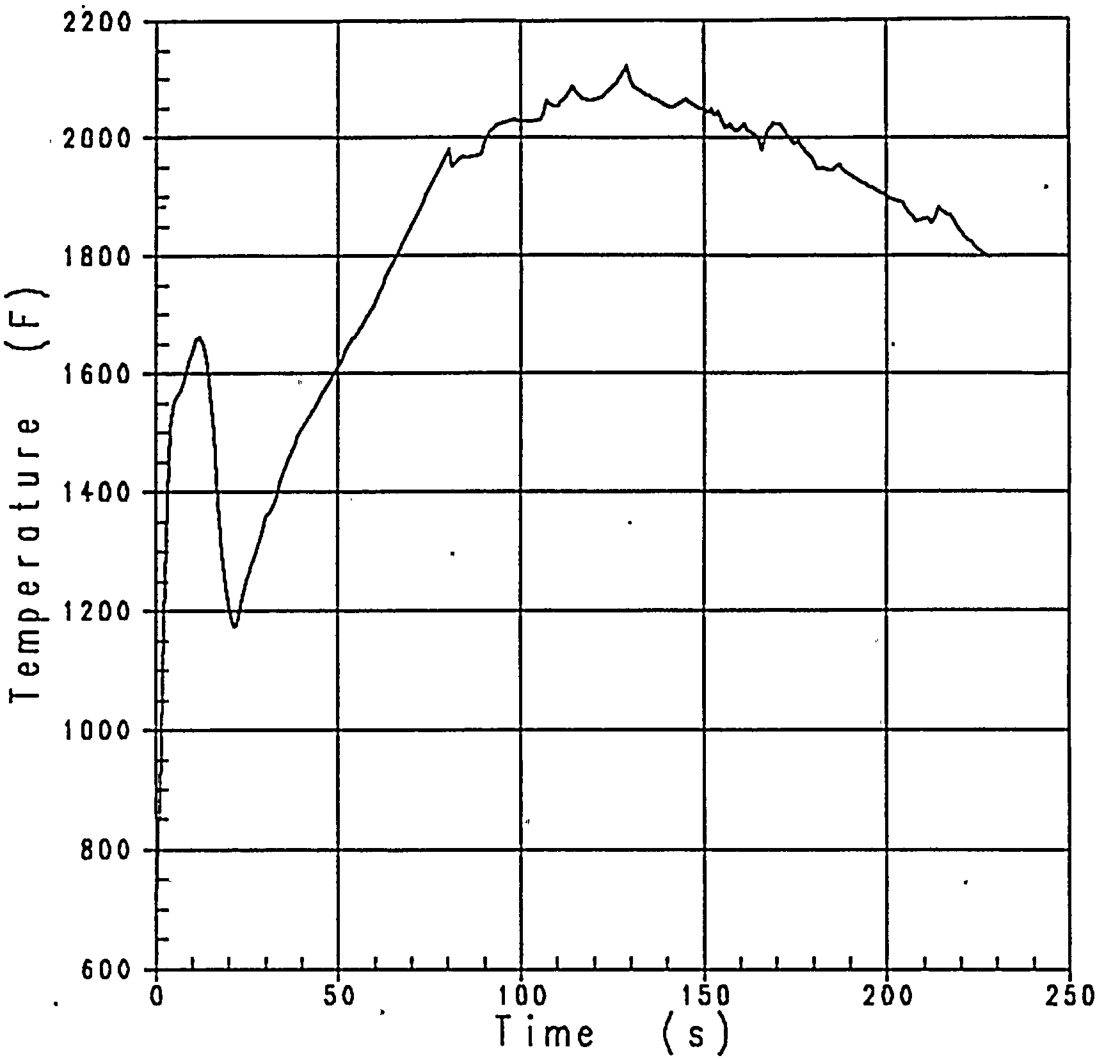
NOTES

1 Time - 0.0 Seconds is Bottom of Core Recovery Time.

2 Time (from Event Initiation) = 50.7 Seconds After Break for C_D = 0.4. Low T_{AVG} Case.

REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY TURKEY POINT PLANT UNITS 3 & 4
CORE AND DOWNCOMER MIXTURE LEVELS DURING REFLOOD FOR C_D=0.4. LOW T_{AVG} **FIGURE 14.3.2.1-28**

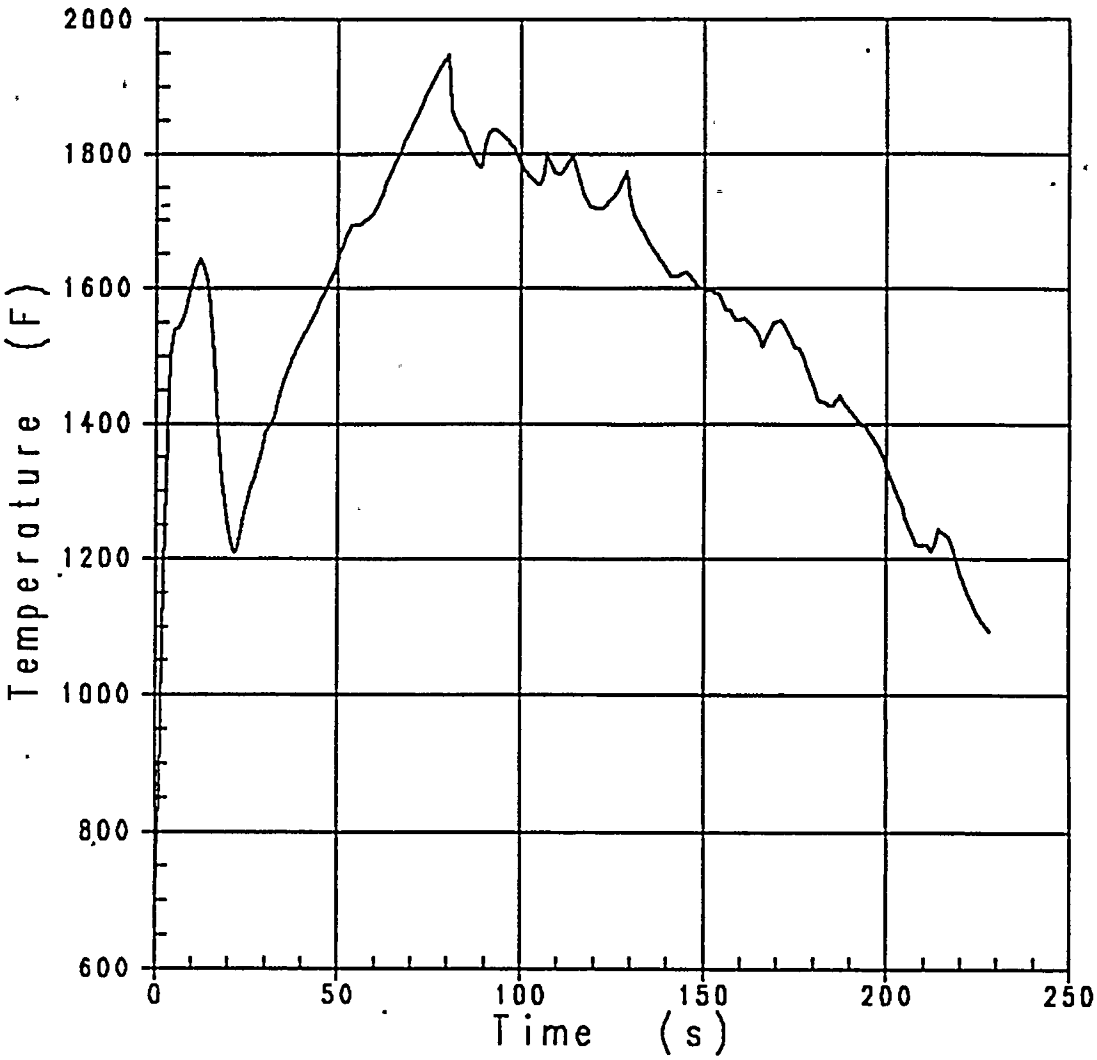


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

PEAK CLADDING TEMPERATURE
FOR C_D=0.4, LOW T_{AVG},
8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-29

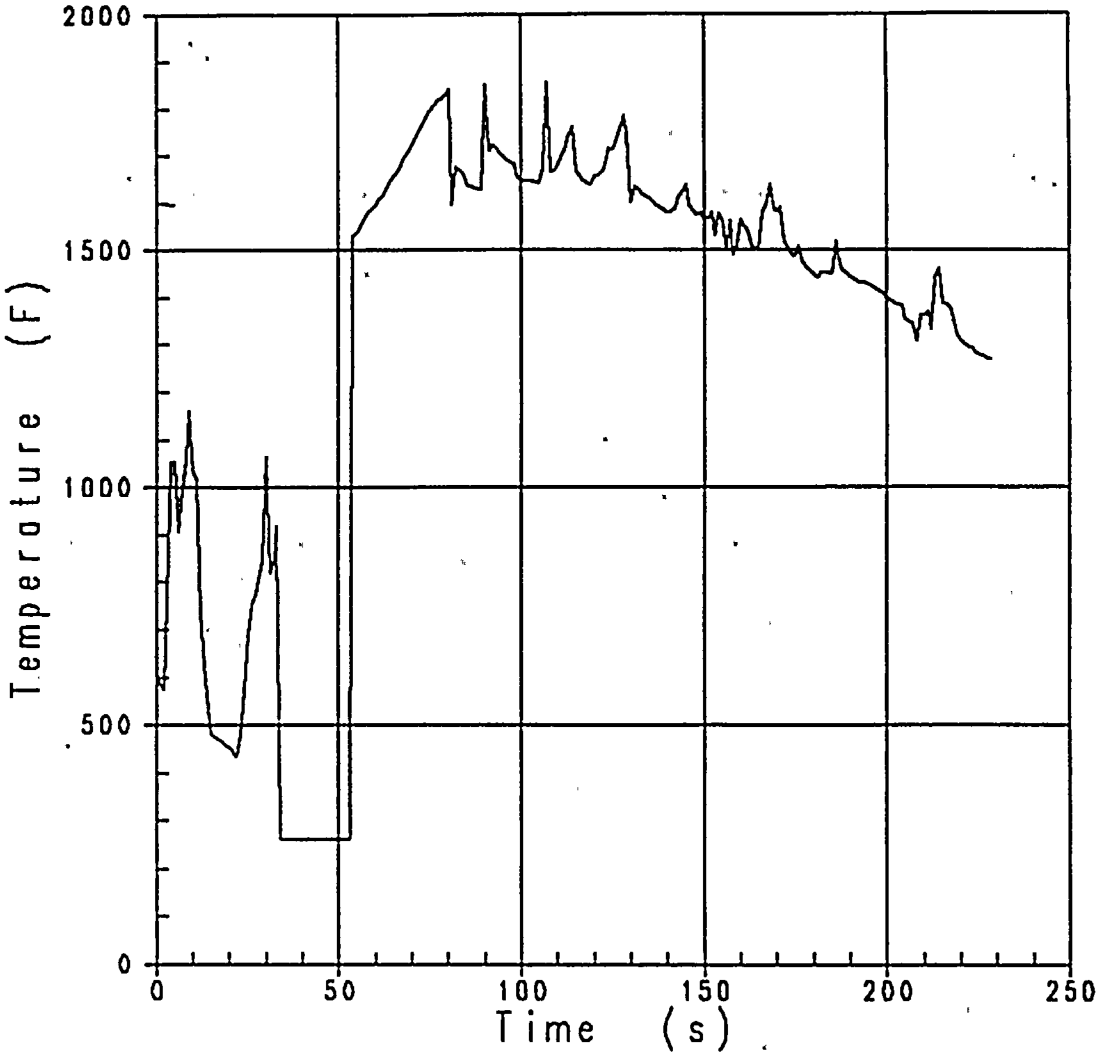


REV. 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

CLADDING TEMPERATURE AT FUEL BURST LOCATION FOR C_D=0.4, LOW T_{AVG}, 8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-30

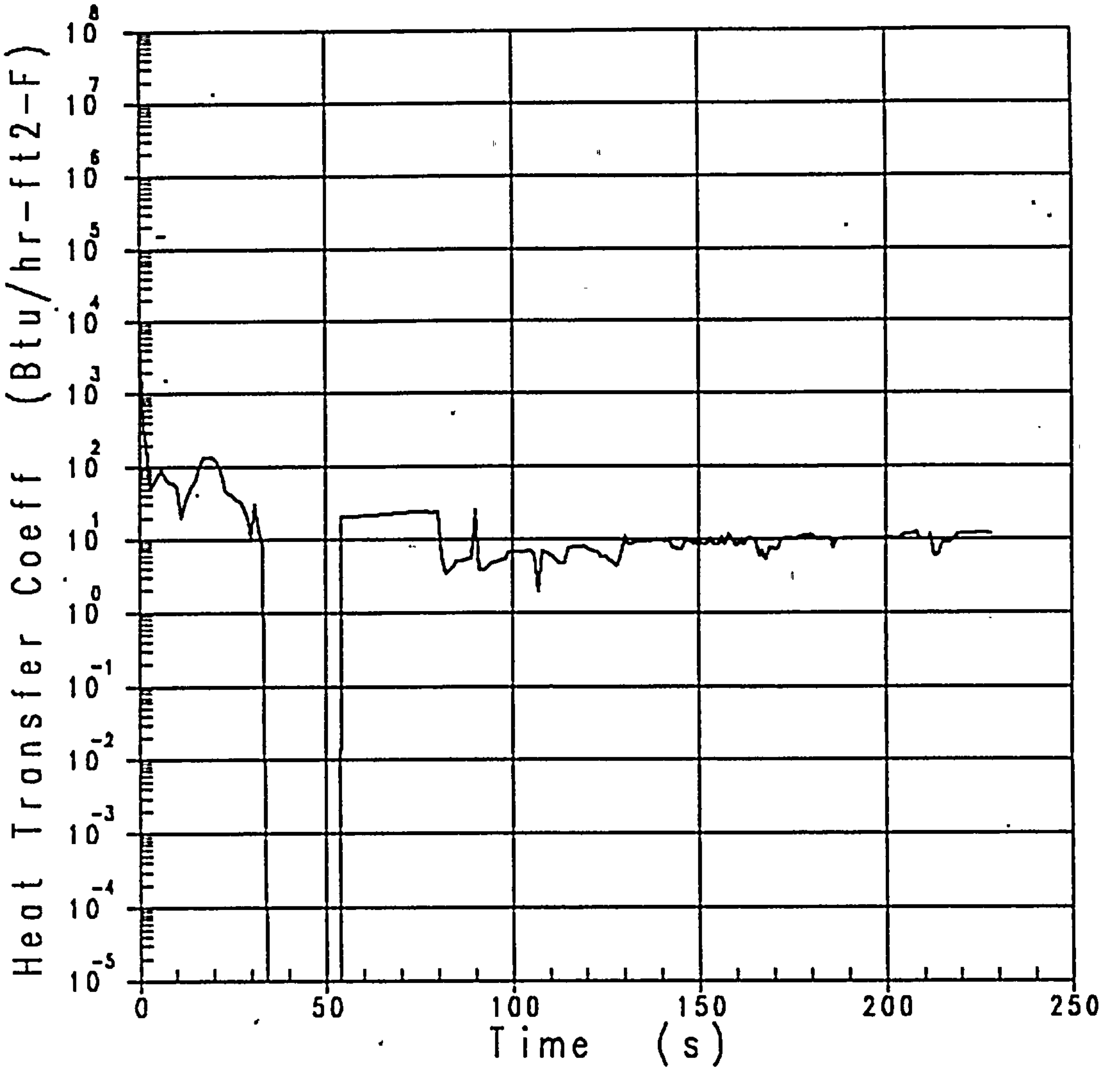


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LOCAL FLUID TEMPERATURE AT PCT ELEVATION FOR C_D=0.4, LOW T_{AVG}, 8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-31

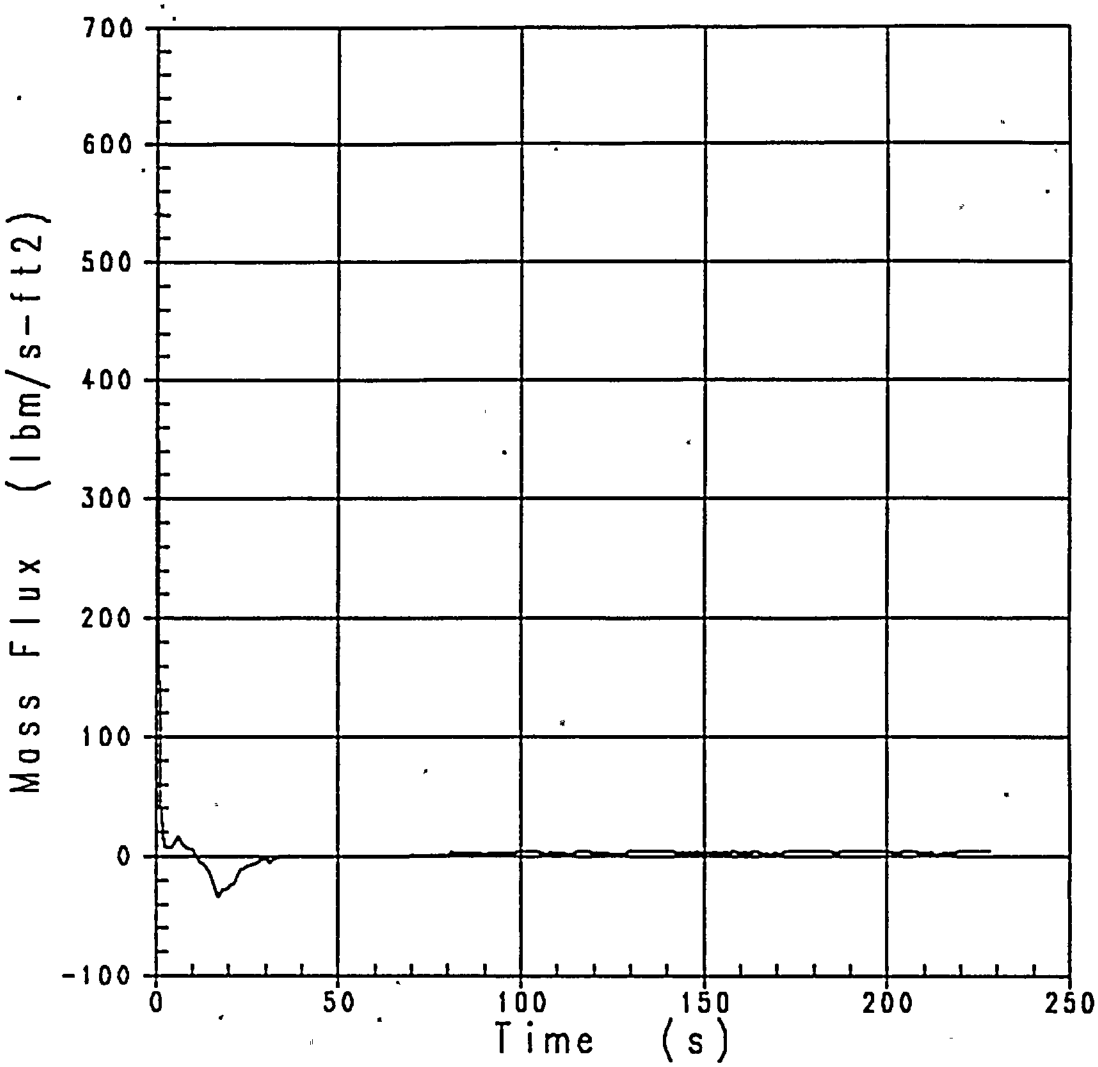


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LOCAL HEAT TRANSFER COEFFICIENT
AT PCT ELEVATION FOR C_D=0.4, LOW T_{AVG},
8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-32

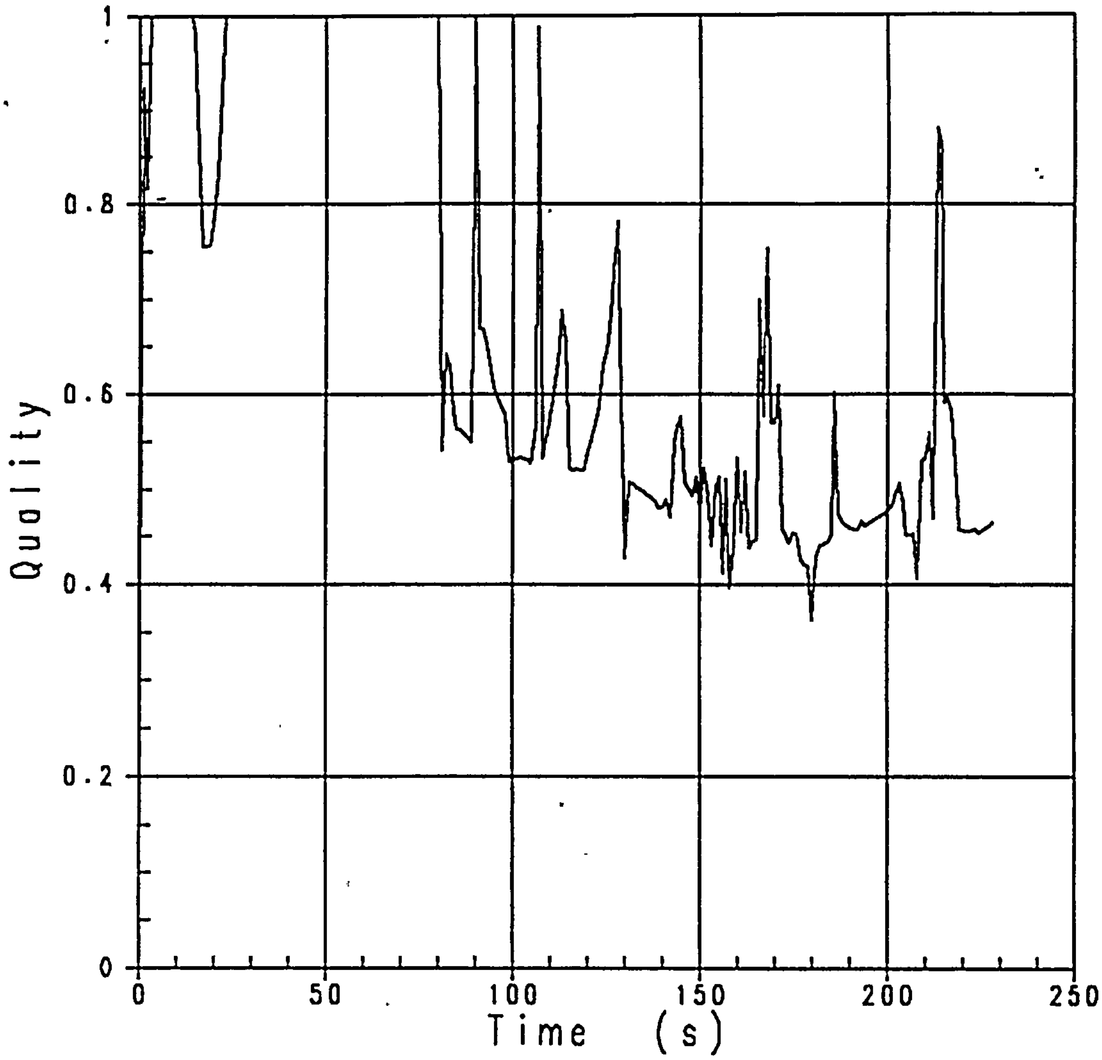


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LOCAL MASS FLUX
AT PCT ELEVATION FOR C_D=0.4, LOW T_{AVG},
8.5 FT SKEWED POWER SHAPE

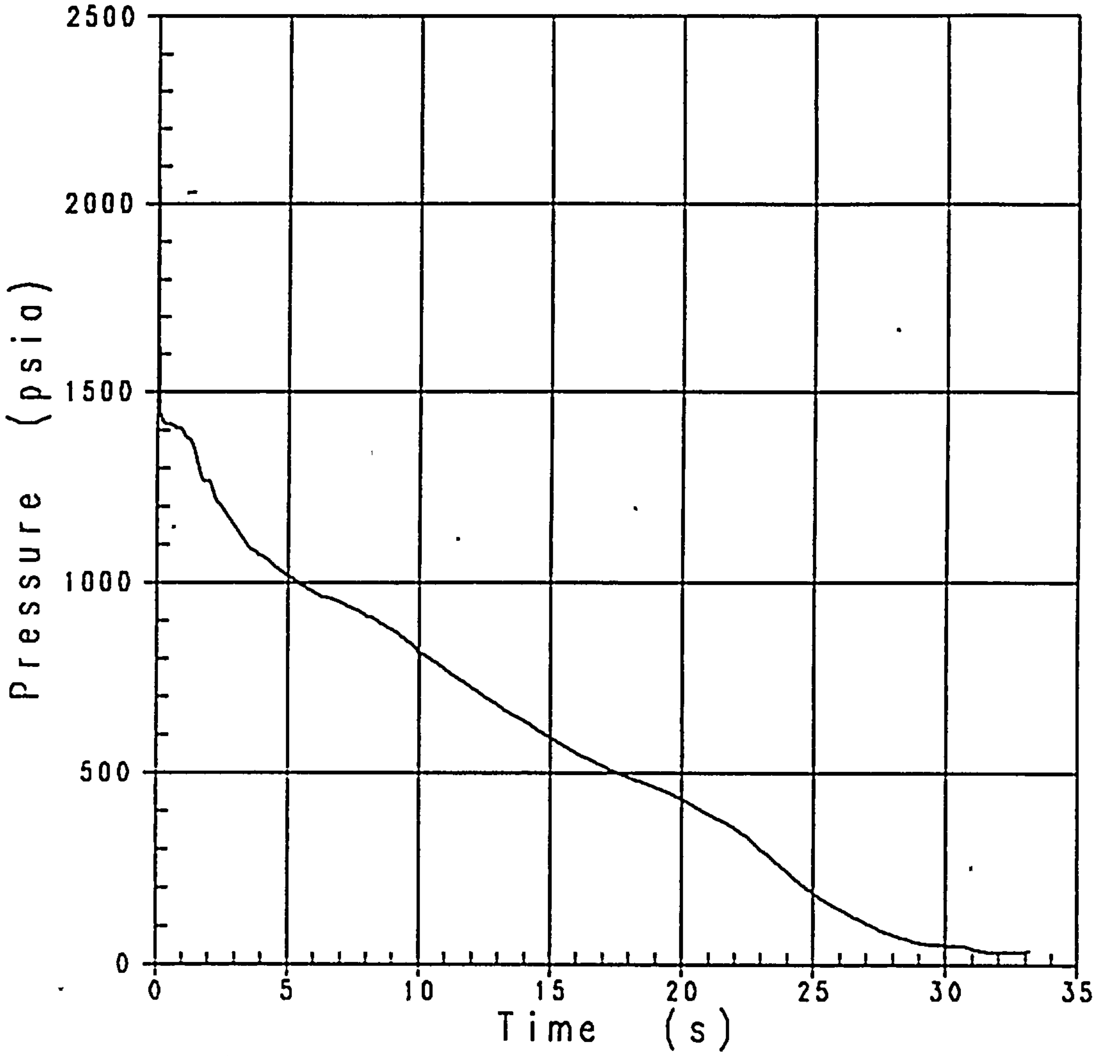
FIGURE 14.3.2.1-33



REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

LOCAL QUALITY
AT PCT ELEVATION FOR C_0=0.4, LOW T_{AVG},
8.5 FT SKEWED POWER SHAPE
FIGURE 14.3.2.1-34

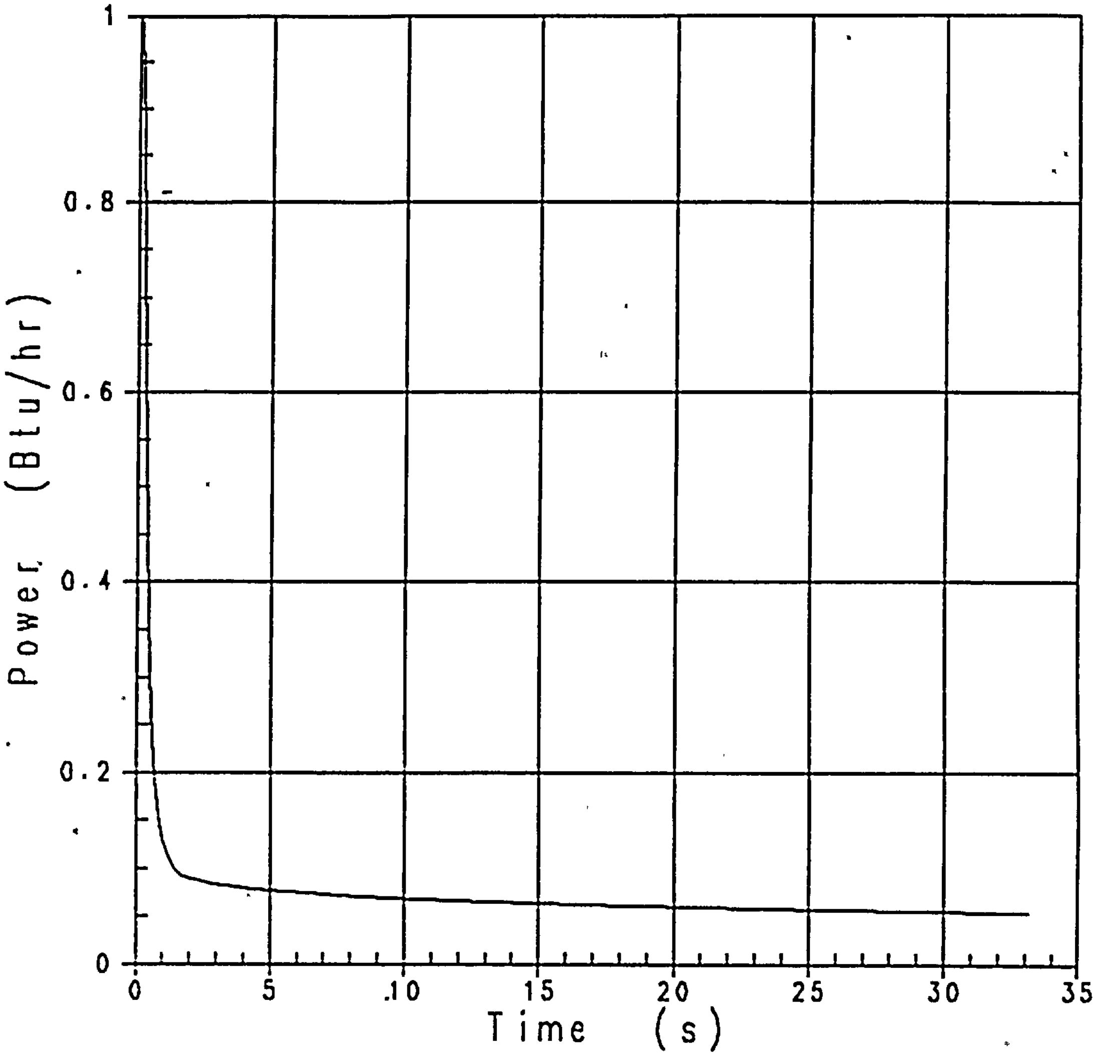


REV 14 (2 97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

RCS PRESSURE DURING REFLOOD
FOR $C_D = 0.4$, LOW T_{AVG},
8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-35

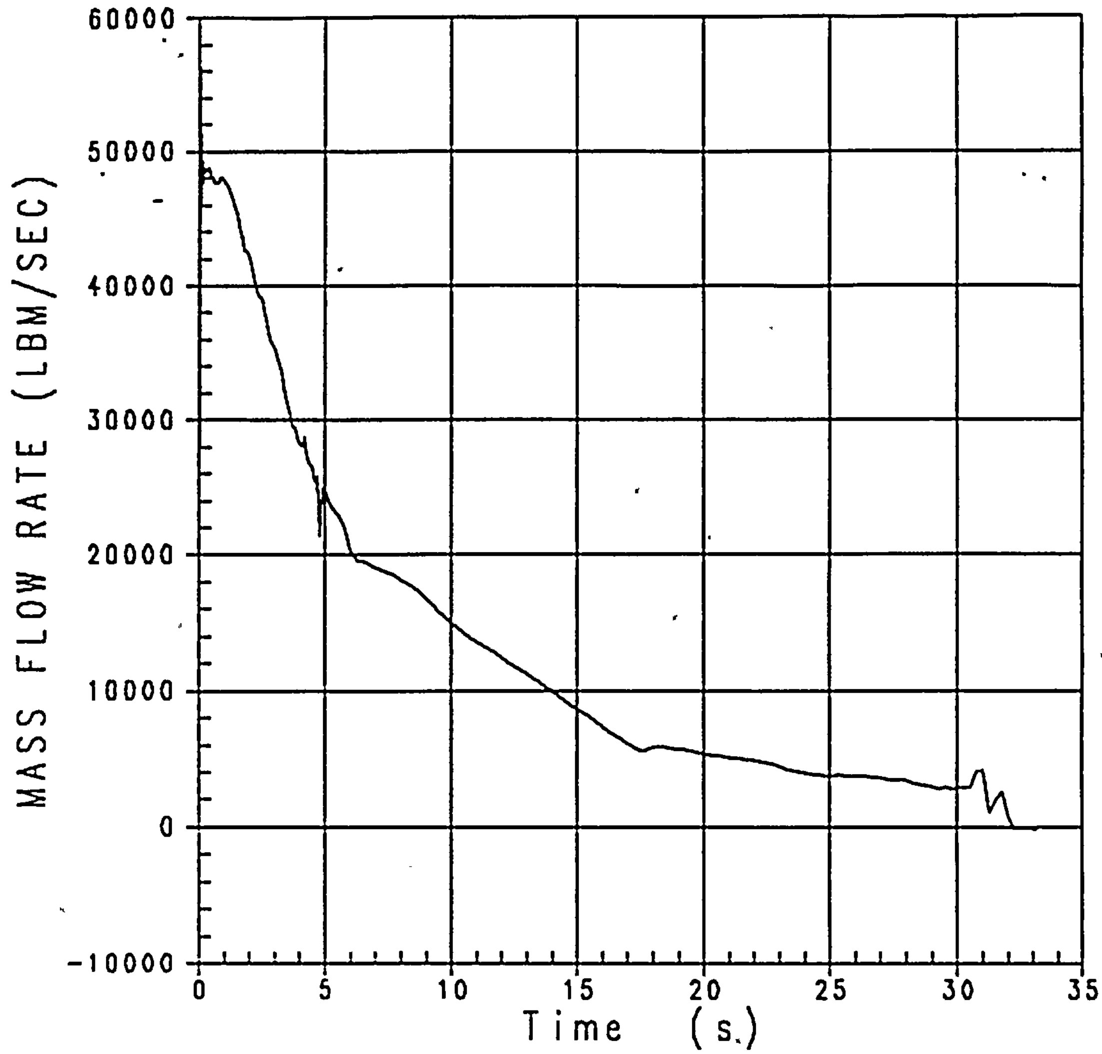


REV 14 (2'97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

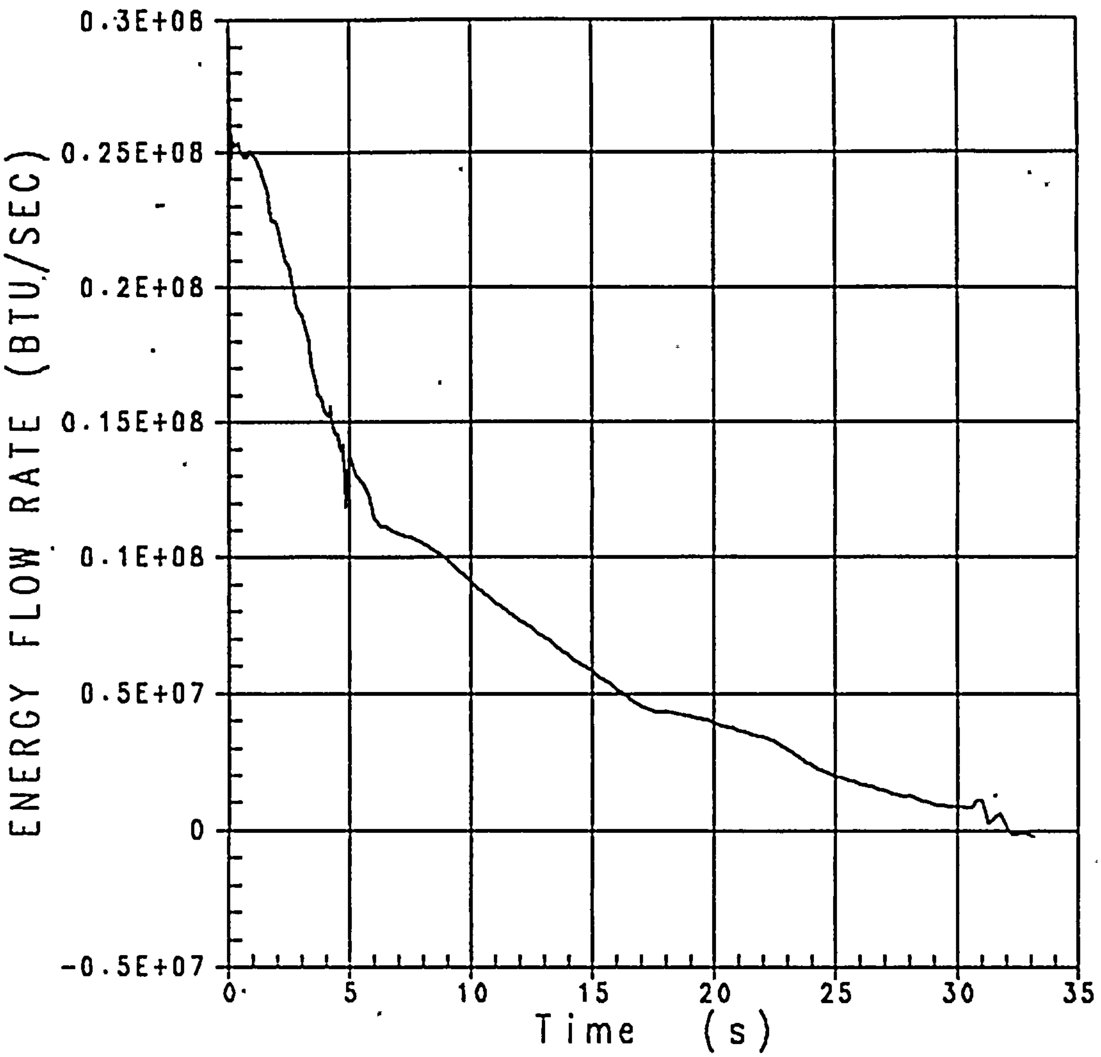
DECAY HEAT DURING REFLOOD
FOR $C_D = 0.4$, LOW T_{AVG},
8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-36



REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY TURKEY POINT PLANT UNITS 3 & 4
BREAK MASS FLOW DURING BLOWDOWN FOR $C_D = 0.4$, LOW T_{AVG}, 8.5 FT SKEWED POWER SHAPE **FIGURE 14.3.2.1-37**

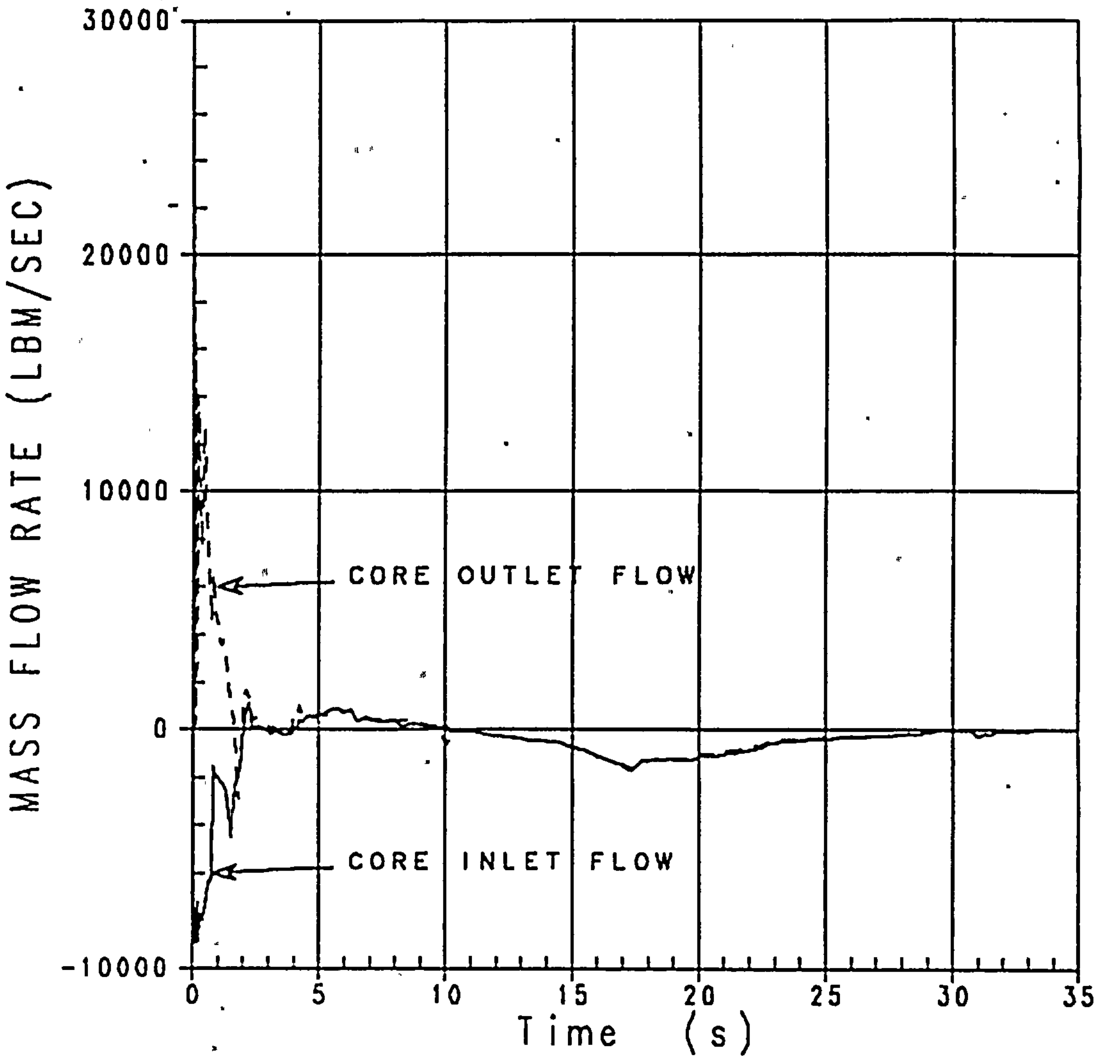


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

BREAK ENERGY FLOW DURING BLOWDOWN FOR C_D=0.4, LOW T_{AVG}, 8.5 SKEWED POWER SHAPE

FIGURE 14.3.2.1-38

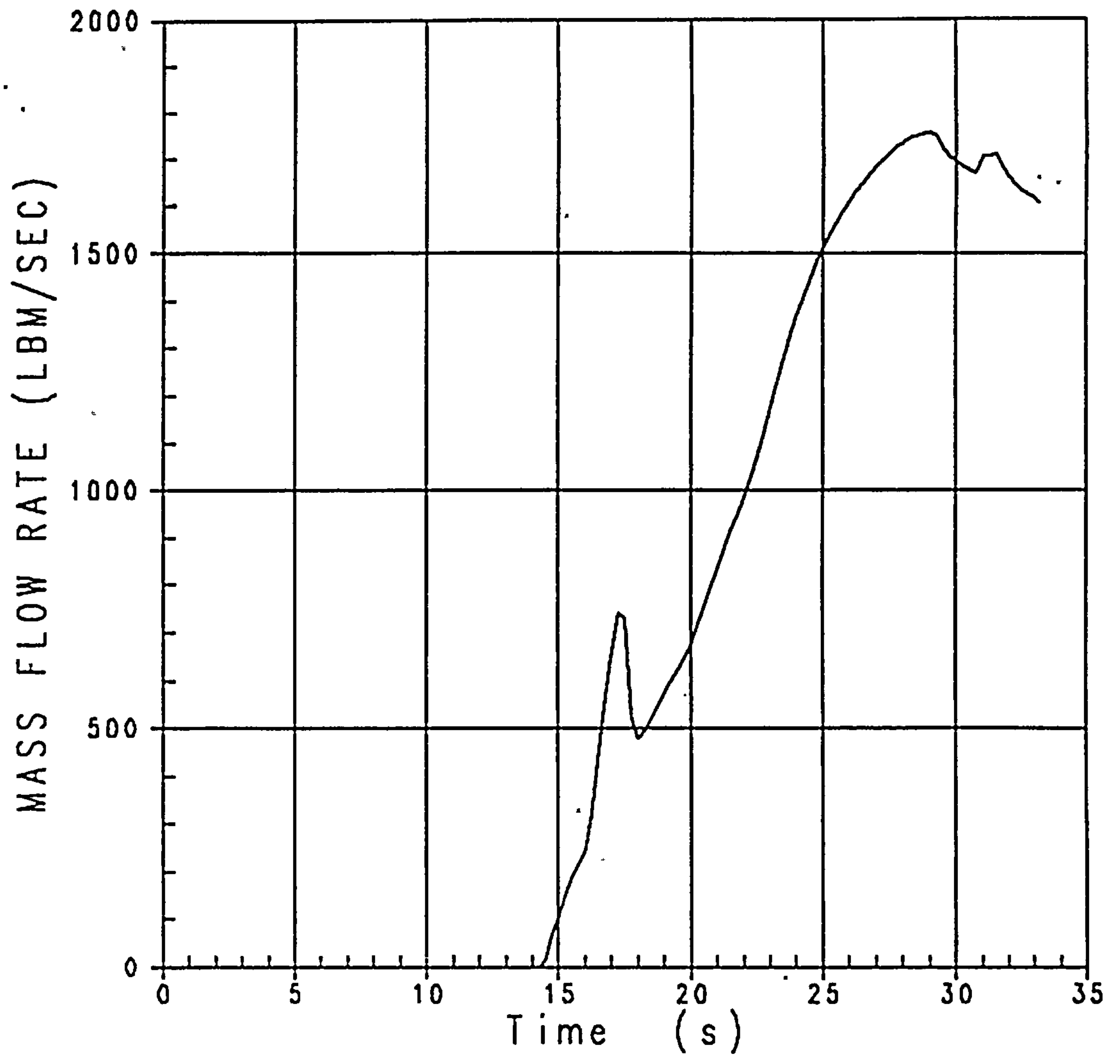


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

CORE FLOW DURING BLOWDOWN
FOR C_D=0.4, LOW T_{AVG},
8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-39

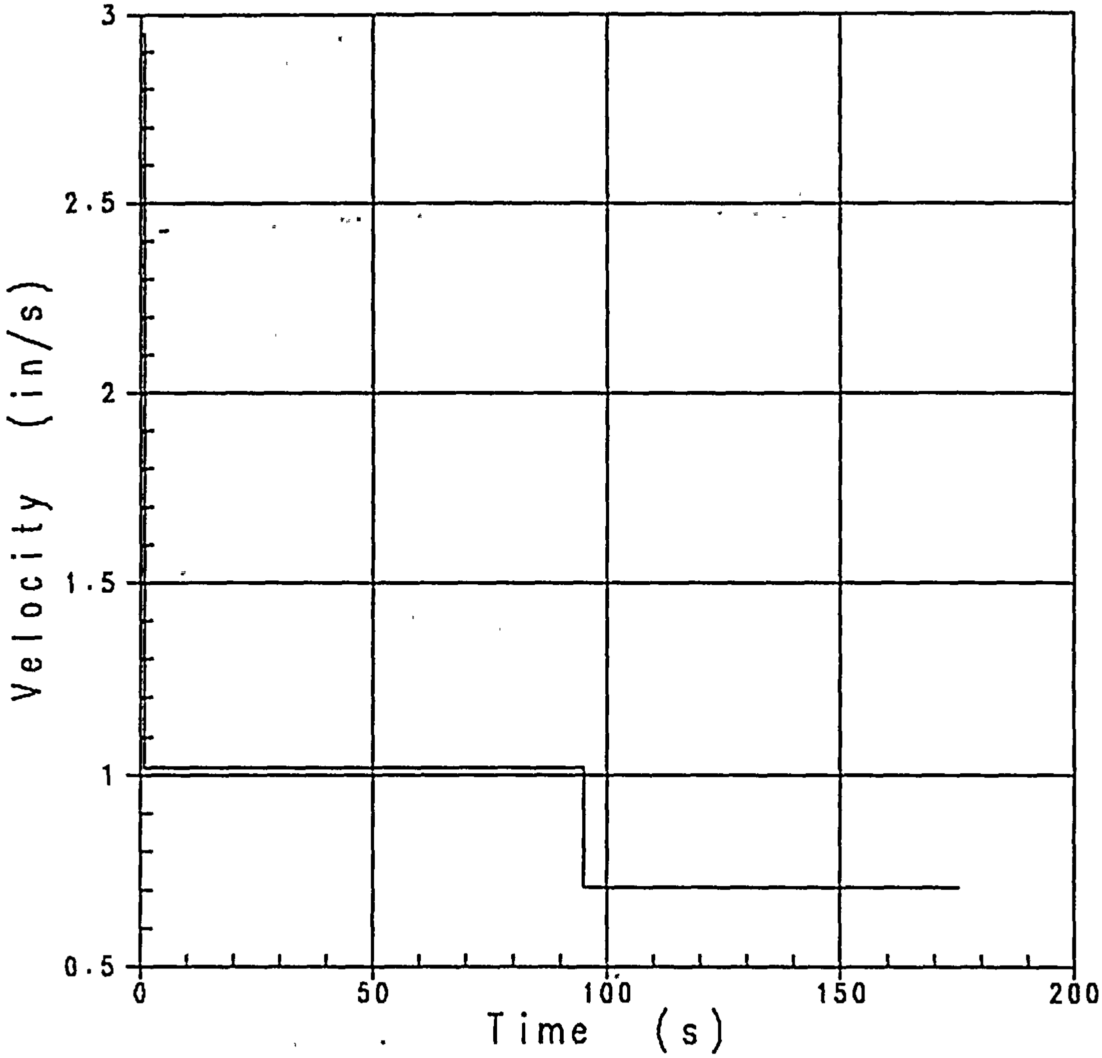


REV 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

ACCUMULATOR FLOW DURING BLOWDOWN FOR C_D=0.4, LOW T_{AVG}, 8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-40



NOTES:

1. Time = 0.0 Seconds is Bottom of Core Recovery Time.

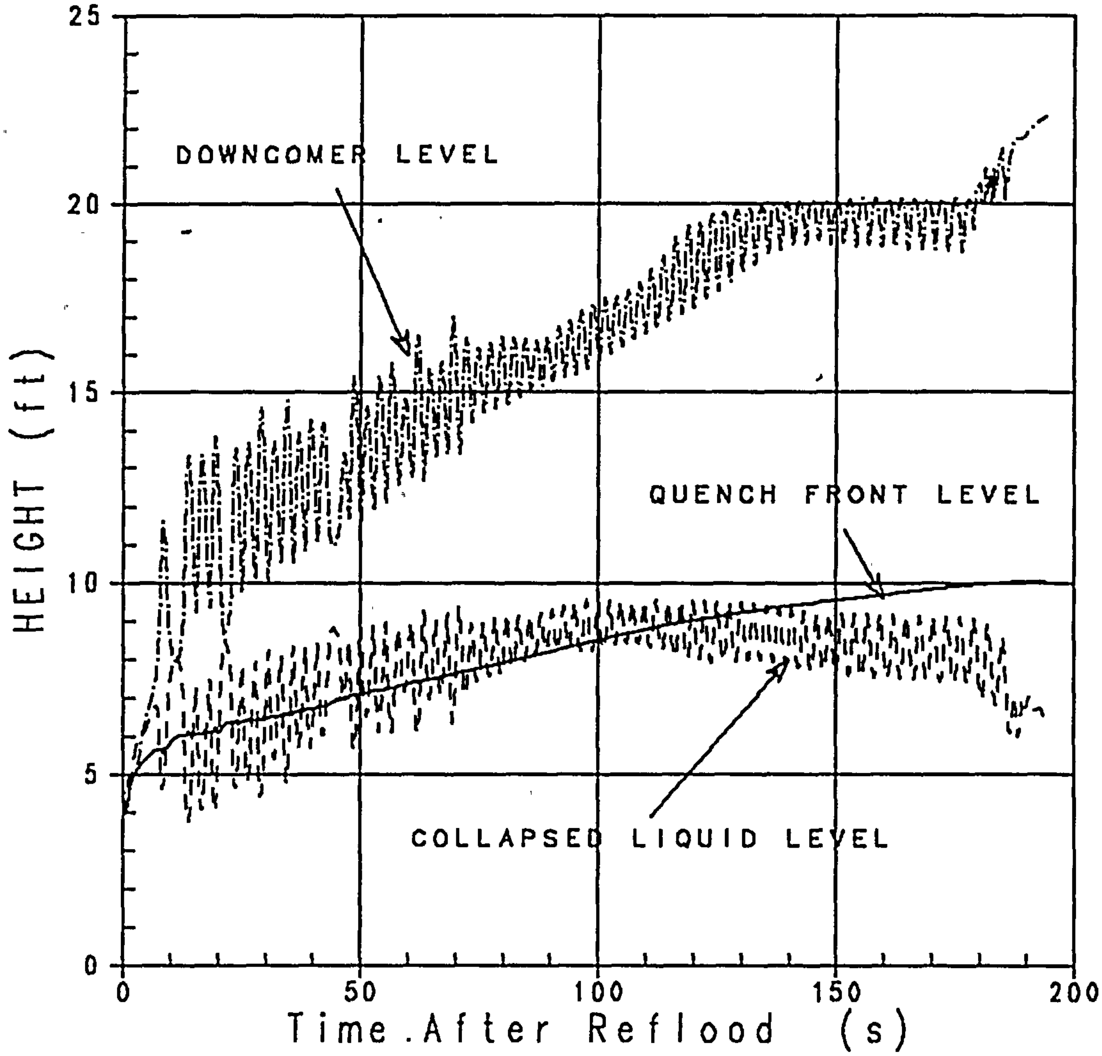
2. Time (from Event Initiation) = 53.8 Seconds After Break for C_D = 0.4, Low T_{AVG}, and 8.5 ft. Skewed Shape Case.

REV. 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

CORE REFLOODING RATE
FOR C_D=0.4, LOW T_{AVG},
8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-41



NOTES:

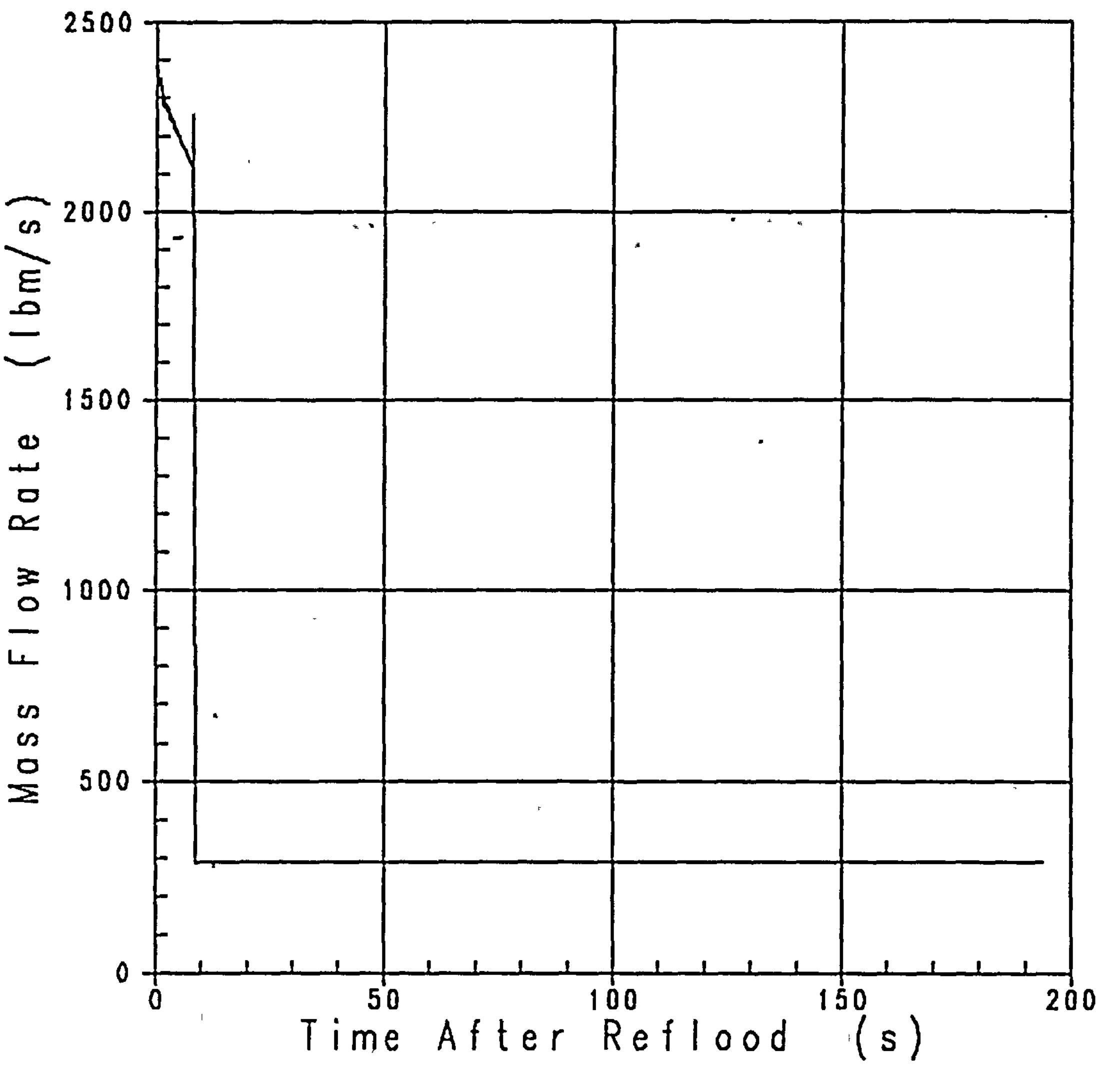
1. Time = 0.0 Seconds is Bottom of Core Recovery Time.
2. Time (from Event Initiation) = 53.8 Seconds After Break for C_D = 0.4, Low T_{AVG}, and 8.5 ft. Skewed Shape Case.

REV. 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

CORE & DOWNCOMER MIXTURE LEVELS DURING RELOOD FOR C_D=0.4, LOW T_{AVG}, 8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-42



NOTES:

1. Time = 0.0 Seconds is Bottom of Core Recovery Time.

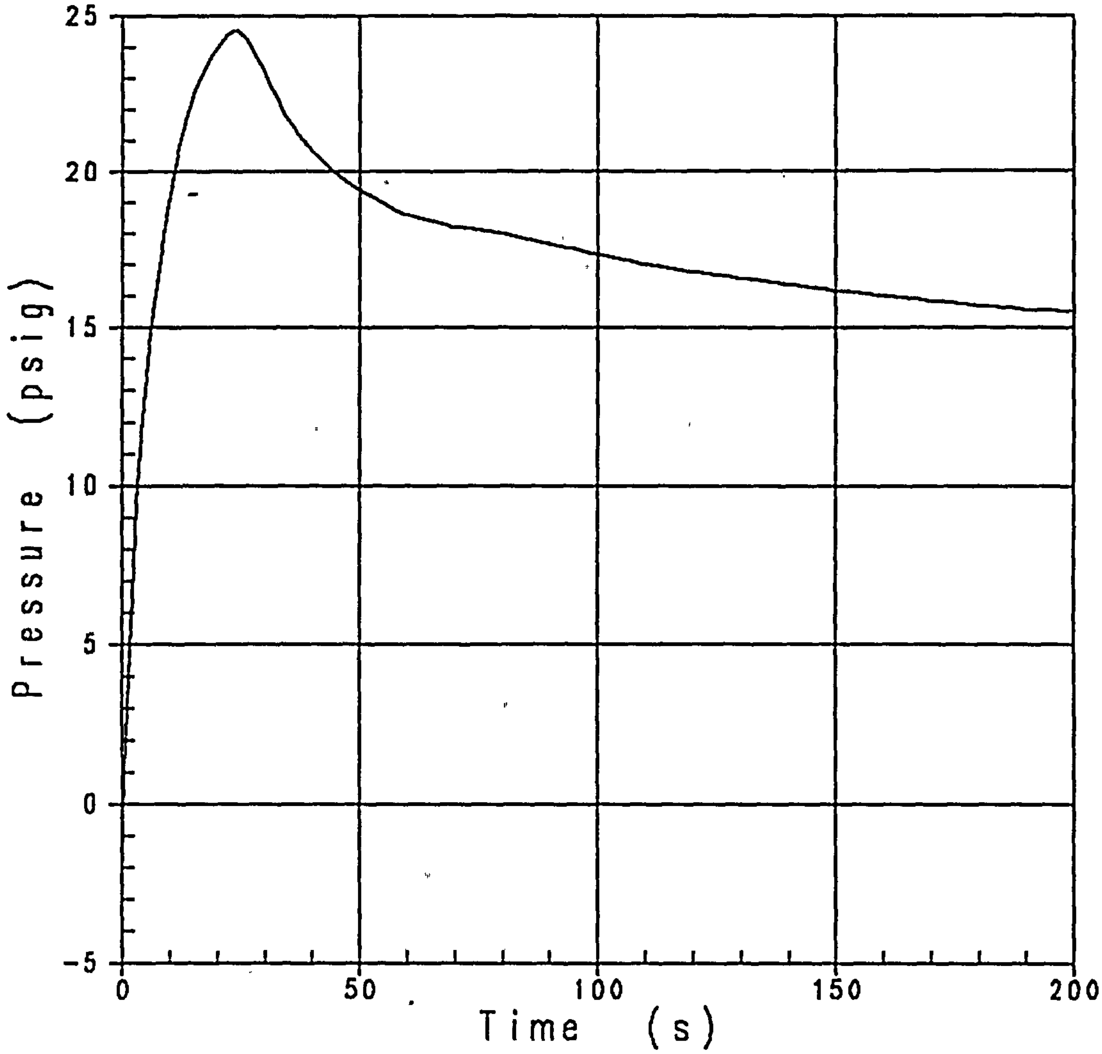
2. Time (from Event Initiation) = 53.8 Seconds After Break for C_D = 0.4, Low T_{AVG}, and 8.5 ft. Skewed Shape Case.

REV. 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

ECCS FLOWS DURING REFLOOD
FOR C_D=0.4, LOW T_{AVG},
8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-43



REV. 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNITS 3 & 4

CONTAINMENT PRESSURE TRANSIENT
FOR C_0=0.4, LOW T_{AVG},
8.5 FT SKEWED POWER SHAPE

FIGURE 14.3.2.1-44

REFERENCES

1. Takeuchi, K. et.al., "MULTIFLEX- A fortran-IV computer program for analyzing Thermal-Hydraulic- Structure System Dynamics", WCAP-8708-P-A, September 1977.

2. Amendment 18 to CP&L Application (FSAR Amendment 9) Docket 50-261.

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The exponential decrease of the heat transfer coefficient is given by:

$$h_s = h_{stag} + (h_{max} - h_{stag})e^{-0.05(t-t_p)} \quad t>t_p \qquad \text{(Equation 14.3.4.3-3)}$$

where:

h_{stag} = $2 + 50X,\ 0 \leq X \leq 1.4.$

h_{stag} = h for stagnant conditions (Btu/hr ft^2 °F).

X = steam-to-air weight ratio in containment.

For a large break, the engineered safety features are quickly brought into operation. Because of the brief period of time required to depressurize the reactor coolant system or the main steam system, the containment safeguards are not a major influence on the blowdown peak pressure; however, they reduce the containment pressure after the blowdown and maintain a low long-term pressure. Also, although the containment structure is not a very effective heat sink during the initial reactor coolant system blowdown, it still contributes significantly as a form of heat removal throughout the rest of the transient.

14.3.4.3.2.2 ACTIVE HEAT REMOVAL

During the injection phase of post-accident operation, the emergency core cooling system pumps water from the refueling water storage tank into the reactor vessel. Since this water enters the vessel at refueling water storage tank and accumulator ambient temperature, which is less than the temperature of the water in the vessel, it can absorb heat from the core until saturation temperature is reached. During the recirculation phase of operation, water is taken from the containment sump and cooled in the residual heat removal heat exchanger. The cooled water is then pumped back to the reactor vessel to absorb more decay heat. The heat is removed from the residual heat removal system heat exchanger by the CCW system.

Another containment heat removal system is the containment spray. Containment spray is used for rapid pressure reduction and for containment iodine removal. During the injection phase of operation, the containment spray pumps draw water from the RWST and spray it into the containment through nozzles mounted high above the operating deck. As the spray droplets fall, they absorb heat from the containment atmosphere. Since the water comes from the RWST, the entire heat capacity of the spray from the RWST temperature to the temperature of the containment atmosphere is available for energy absorption. During the recirculation phase of post-accident operation, water can be drawn from the residual heat removal heat exchanger outlet and sprayed into the containment atmosphere via the recirculation spray system. The spray flow rate modeled is shown in Table 14.3.4.3-4.

When a spray droplet enters the hot, saturated, steam-air containment environment following a loss-of-coolant accident, the vapor pressure of the water at its surface is much less than the partial pressure of the steam in the atmosphere. Hence, there will be diffusion of steam to the drop surface and condensation on the droplet. This mass flow will carry energy to the droplet. Simultaneously, the temperature difference between the atmosphere and the droplet will cause the droplet temperature and vapor pressure to rise. The vapor pressure of the droplet will eventually become equal to the partial pressure of the steam, and the condensation will cease. The temperature of the droplet will essentially equal the temperature of the steam-air mixture.

The equations describing the temperature rise of a falling droplet are as follows.

$$\frac{d}{dt}(Mu) = mh_g + q \qquad \text{(Equation 14.3.4.3-4)}$$

$$\frac{d}{dt}(M) = m \qquad \text{(Equation 14.3.4.3-5)}$$

where,

$q = h_c A * (T_s - T),$

$m = k_g A * (P_s - P_v).$

14.3.4.3.3 DESCRIPTION OF ANALYSIS

Calculation of containment pressure and temperature response is accomplished by use of the computer code COCO (Reference 11). For analytical rigor and convenience, the containment air-steam-water mixture is separated into a water phase and a steam-air phase. Sufficient relationships to describe the transient are provided by the equations of conservation of mass and energy as applied to each system, together with the appropriate boundary conditions.

14.3.4.3.3.1 LOCA CONTAINMENT INTEGRITY

A series of cases was performed for the LOCA containment integrity. Section 14.3.4.1 documented the mass and energy releases for the most-limiting single failure of a diesel generator for a DEPS break and the releases from the blowdown of a DEHL break. Each of these cases was performed at an initial containment pressure of +0.3 psig and +3.0 psig. These two pressures represent the nominal assumed and maximum operating pressures in the containment.

Two additional DEPS cases with a diesel failure were performed. These cases were performed with only 1 ECC actuating from the auto-start signal, a second ECC manually actuated at 24 hours after accident initiation, and continuous operation of the recirculation sprays upon actuation during the cold leg recirculation switchover sequence. This differs from the other DEPS cases such that each of those cases assumed that the recirculation sprays would be terminated no later than 18 hours after accident initiation.

The sequence of events for each of the limiting LOCA cases is shown in Tables 14.3.4.3-7 through 14.3.4.3-9.

14.3.4.3.3.2 MSLB CONTAINMENT INTEGRITY

The MSLB mass and energy releases that were performed for the 1.4 ft^2 DER at Hot Zero Power (HZP) as discussed in Section 14.3.4.2 were used to analyze the containment response. The failure of a MSCV was the limiting single failure for MSLB containment integrity. Since the failure was postulated to occur in the secondary steam system safety equipment, all of the containment heat removal equipment was assumed to be operational. This case was analyzed to the time of steam generator dryout. The sequence of events for this case is shown in Table 14.3.4.3-6.

14.3.4.3.4 RESULTS

The results of the transient analysis of the containment at an initial pressure of +0.3 psig for the LOCA cases are shown in Figures 14.3.4.3-1 through 14.3.4.3-6. Figures 14.3.4.3-1 and 14.3.4.3-2 show the response to the DEPS case with 2 ECCs assumed to be operating initially. The containment response to the DEHL blowdown is presented in Figures 14.3.4.3-3 and 14.3.4.3-4. The results of the long-term DEPS transient with only 1 ECC operating initially and a second ECC manually actuated at 24 hours are presented in Figures 14.3.4.3-5 and Figure 14.3.4.3-6. The containment pressure transient for the 1.4 ft^2 DER MSLB at 0% power with a MSCV failure is shown in Figure 14.3.4.3-7. All of these cases show that the containment pressure will remain below design pressure of 55 psig.

In addition, all of the cases performed at the maximum initial containment pressure of +3.0 psig were also below the design pressure. After the peak pressure is attained, the operation of the safeguards system reduced the containment pressure. For the LOCA, at 24 hours following the accident, the containment pressure has been reduced to a value well below 50 percent of the peak calculated value. The containment integrity results are shown in Table 14.3.4.3-10 for LOCA and the MSLB ruptures.

14.3.4.3.5 CONCLUSIONS

The containment integrity analyses have been performed for the thermal uprate program at Turkey Point Units 3 & 4. The analyses included both long-term MSLB and LOCA transients. As described in the results Section 14.3.4.3.4, all cases resulted in a peak containment pressure that was less than 55 psig. In addition, all long-term cases were well below 50% of the peak value within 24 hours. Based on these results, all applicable acceptance criteria have been met and Turkey Point Units 3 & 4 are safe to operate at 2300 MWt (core).

14.3.5 ENVIRONMENTAL CONSEQUENCES OF A LOSS-OF-COOLANT ACCIDENT

14.3.5.1 ANALYSIS

The original licensing basis LOCA dose analysis can be found in its entirety in Appendix 14F. Also refer to Appendix 14F for the discussion of the atmospheric dispersion model, whole body dose computations, and the radiological assessment of containment purging. This section describes the LOCA dose analysis performed as part of the Power Uprating Project.

A large pipe rupture in the reactor coolant system (RCS) is assumed to occur. As a result of the accident, it is assumed that core damage occurs and iodine and noble gas activity is released to the containment atmosphere. A portion of this activity is released via the containment purge system, which is open when the accident occurs and activity is released to the atmosphere through this path until the containment purge system is isolated. Also, once Engineered Safety Features (ESF) recirculation is established, leakage from ESF equipment outside containment releases activity to the outside environment.

The uprated power level of 2346 MWt is used in the analysis. Both offsite and control room doses are determined. This includes not only determining doses due to containment leakage but doses due to an open containment purge system.

Containment Leakage

Following the large break LOCA 50% of the core iodine activity and 100% of the core noble gas activity are assumed to be immediately released to containment when determining doses due to containment leakage. Fifty percent of the iodine released to containment is assumed to instantaneously plate out on containment surfaces for this case. This leaves 25% of the core iodine activity and 100% of the core noble gas activity instantaneously available for leakage from the containment. This iodine is assumed to be 91% elemental, 4% methyl and 5% particulate.

The Technical Specification design basis containment leak rate of 0.25% by weight of containment air is used for the initial 24 hours. Thereafter, the containment leak rate is assumed to be one-half the design value, or 0.125% per day.

In addition to the immediate plateout on containment surfaces of 50% of the iodine activity released to containment, the time-dependent deposition on containment surfaces of the remaining elemental iodine is considered. An elemental iodine deposition coefficient of 5.94 hr^{-1} is determined. Credit is taken for this deposition until a decontamination factor of 100 in the containment inventory of elemental iodine is reached.

The SI signal following the large break LOCA starts the emergency containment filtration (ECF) system filter fans. To account for time to allow the fans to be loaded on the emergency diesel generators, to reach operating speed and to add conservatism, credit for the ECF system filters is not taken in the initial 90 seconds following the accident. After 2 hours following the accident, no further credit for iodine removal by the ECFS filters is taken. The filter efficiencies for the ECF system filters are 90% for elemental iodine, 30% for methyl iodine and 95% particulate iodine.

Containment Purge

The containment purge system is assumed to be open at the time the accident occurs. However, the large break LOCA results in a containment isolation signal, which automatically closes the containment purge system isolation valve. Although the valve closure time is approximately 5 seconds, a closure time of 8 seconds is used in this analysis to account for time for signal generation.

The time at which fuel clad damage would be initiated (i.e., the hot rod burst time) following the accident is well after 8 seconds. Thus, the activity release to containment for this case is limited to the RCS activity prior to the large break LOCA which results in a pre-accident iodine spike. No credit for plateout or deposition on surfaces inside the containment is taken. Since the ECF system units will not be loaded on a diesel generator and running prior to the closure of the containment purge system valve, no credit for ECF system filtration of the iodine is taken.

The iodine release from the RCS to the containment is assumed to be 100% elemental iodine. Since only HEPA filters (which remove particulate iodine)

6. ORNL Nuclear Safety Research and Development Program Bi-Monthly Report for July-August 1968, W.B. Cottrell, ORNL-TM-2368, November 1968.

7. ORNL Nuclear Safety Research and Development Program Bi-Monthly Report for September-October 1968, W.B. Cottrell, ORNL-TM-2425, January 1969.

8. Radiation and Thermal Stability of Spray Solutions, H.E. Zittel and T.H. Row, Nuclear Technology, Oct 1971, pp. 436-443.

9. The Radiation Chemistry of Water and Aqueous Solutions, A.O. Allen, Princeton, NJ, Van Nostrand, 1961.

10. DiNunno, J. J. et al, "Calculation of Distance Factors for Power and Test Reactor Sites," TID 14844, USAEC (1962).

11. Westinghouse WCAP-7552,"An Investigation Into the Radiolytic Hydrogen Production from Containment Spray Solutions," M.J. Bell, August 1970.

12. Reissue Draft Results of Long Term Containment Response for Turkey Point Units 3 & 4 Uprating Project for Equipment Qualification, NTD-NSA-CRA-95-158, R.M. Jakub, June 9, 1995.

13. Westinghouse WCAP-8776,"Corrosion Study for Determining Hydrogen Generation From Aluminum and Zinc During Post-Accident Conditions," R.C. Burchell and D. D. Whyte.

14. NUREG/CR-3803, SAND84-0806,"The Effects of Post-LOCA Conditions on a Protective Coating (Paint) for the Nuclear Power Industry," Revision 3, March 1985.

15. Calculation PTN-BFJN-95-002,"Calculation Related to Corrodible Metal Inventory Inside the Turkey Point Containment Buildings," Revision 0, dated June 1, 1995.

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<u>APPENDIX 14A</u>

TURKEY POINT PLANT UNIT 3
THERMAL UPRATE CYCLE 15 RELOAD SAFETY EVALUATION
REVISION 2

JUNE 1996

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

This report presents a re-evaluation for Turkey Point Unit 3, uprated Cycle 15, and demonstrates that the core reload redesign will not adversely affect the safety of the plant. A redesign was required due to the suspected damage incurred to the Region 15C fuel assembly EE39 during the Cycle 14/15 refueling. The neutronic portion of this analysis was completed by Florida Power & Light Company utilizing the NRC-approved methodology (References 1 and 2). The remainder of this evaluation was accomplished utilizing the methodology described in WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology" (Reference 3).

The Turkey Point Unit 3 operated in Cycle 14 with a full core of Westinghouse 15x15 Optimized Fuel Assemblies (OFAs). For Cycle 15 (startup October 1995), the Turkey Point Unit 3 core was refueled with all Westinghouse 15x15 OFA regions containing the OFA features described in Reference 4 and approved by the NRC in Reference 5. The uprated Cycle 15 reload redesign will continue to use, in Region 17, the Debris Resistant Fuel Assembly (DRFA) design. This design change is described and evaluated in Reference 6.

As part of the Cycle 15 design, Florida Power & Light Company has completed the uprate of Turkey Point Units 3 and 4 from 2200 MWt to 2300 MWt. The analyses performed to support this uprating (Reference 7) were submitted to the NRC for review and approval. The submittal provided to justify the uprating of the Turkey Point units included an Assessment of Unreviewed Safety Questions (10 CFR 50.59) and No Significant Hazards Determination (10 CFR 50.92). The NRC granted licensing approval to uprate Turkey Point Units 3 and 4 (Reference 34) in Facility Operating License Amendment No.s 191 (Unit 3) and 185 (Unit 4). This reload design was re-evaluated using uprated conditions, such that, when NRC approval is received, Florida Power & Light Company was able to uprate Turkey Point Units 3 and 4 to 2300 MWt without a unit shutdown. In addition to the uprating, a Core Operating Limits Report (COLR) has been included as Attachment A to this reload safety evaluation. The supporting documentation for the COLR was included in the uprating submittal to the NRC (Reference 7).

Evaluations have previously been performed by Westinghouse (Reference 8), to support the complete or partial removal of thimble plugs from the Turkey Point units. Reload safety evaluations in support of this cycle have been performed in a manner that they remain bounding whether or not thimble plugs are removed from the core.

All of the accidents comprising the licensing bases (References 4, 7, 9, 10, and 11), which could potentially be affected by the fuel reload redesign, have been reviewed for the uprated Cycle 15 design described herein. Justification for the applicability of the results of the previous analyses is presented.

1.2 GENERAL DESCRIPTION

The Turkey Point Unit 3 reactor core is comprised of 157 fuel assemblies arranged in the core loading pattern configuration shown in Figure 14A-1. During the Cycle 14/15 refueling, 49 Region 14 and 11 Region 15, fuel assemblies were discharged. These fuel assemblies were replaced with 60 fresh Region 17 fuel assemblies. Due to the suspected damage incurred to the Region 15C fuel assembly EE39 during the Cycle 14/15 refueling, four Region 15C fuel assemblies were replaced with four Region 15A fuel assemblies which were going to be discharged. The neutronic evaluation and changes to the core loading pattern are provided in Reference 12 and identified on Figure 14A-1.

The uprated Cycle 15 core uses 448 Westinghouse Wet Annular Burnable Absorber (WABA) rods. Use of the WABA rods has been generically approved by the NRC (Reference 13).

Hafnium burnable absorber rods (240 part-length) will again be used in the core peripheral assemblies in order to reduce the neutron flux at the reactor pressure vessel belt-line weld (refer to Section 2.1 and Figure 14A-2).

A significant number (1632) of Integral Fuel Burnable Absorber (IFBA) rods will be used, again, in Turkey Point Unit 3 as part of the fresh Region 17 fuel assemblies. A more detailed description and evaluation of IFBAs is given in References 14 and 15. The NRC has approved the use of IFBAs for Westinghouse 15x15 fuel assemblies in Reference 16.

Axial blankets will be used again in the Region 17 fuel assemblies. The axial blanket consists of a nominal six inches of natural UO_2 pellets at the top and bottom of the fuel pellet stack to reduce neutron leakage and to improve uranium utilization. This design feature is described and licensed in Reference 14.

The Revised Thermal Design Procedure [RTDP] (Reference 17) has been proposed for the uprated Cycle 15 operation to meet the DNBR licensed design criterion. The RTDP accounts for both the proposed $F_{\Delta H}$ limit and a reduction in flow.

The nominal core design parameters are as follows:

	Current Licensing Basis (Uprated Parameters)
Core Power (MWt)	2300
Pressurizer Pressure (psia)	2250
Core Inlet Temperature (°F)	546.6
Thermal Design Flow (gpm)	255,000
Minimum Measured Flow	264,000
Average Linear Power Density (kw/ft) [1]	5.84

Note:

1. Linear power density based on hot, densified active fuel length of 143.7 inches.

1.3 CONCLUSIONS AND 10 CFR 50.59 ASSESSMENT

From the evaluation presented in this report, it is concluded that the Turkey Point Unit 3 uprated Cycle 15 reload redesign does not result in the previously acceptable safety limits for any accident being exceeded, does not result in any unreviewed safety questions as defined in 10 CFR 50.59, and does not result in any Technical Specifications changes. The basis for this determination is delineated below. The reload design criteria are referenced throughout this document.

1. <u>May the proposed activity increase the probability of occurrence of an accident previously evaluated in the FSAR?</u>

This RSE documents that the probability of an accident previously evaluated in the Turkey Point Unit 3 updated FSAR (Reference 9) is not increased. The uprated Cycle 15 reload core redesign meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. Though fuel and core design are not directly related to the probability of any previously evaluated accident, the demonstrated adherence to applicable standards and acceptance criteria precludes new risks to components and systems that could increase the probability of any previously evaluated accident. Specifically, the mechanical changes as specified in Section 2.1, will not increase the probability of occurrence of an accident previously evaluated in the Turkey Point Unit 3 FSAR (Reference 9). The clad integrity is maintained and the structural integrity of the fuel rods, fuel assemblies, and core is not affected. The mechanical features, noted in Section 2.1, have no impact on fuel rod performance or dimensional stability nor will the core operate in excess of pertinent design basis operating limits. Accordingly, overall reactor system performance is not adversely affected by the reload redesign. Therefore, the probability of occurrence of an accident previously evaluated in the FSAR (Reference 9) has not increased.

2. <u>May the proposed activity increase the consequences of an accident previously evaluated in the FSAR?</u>

This RSE documents that the radiological consequences of an accident previously evaluated in the Turkey Point Unit 3 FSAR (Reference 9) are not increased. The uprated Cycle 15 reload core redesign does not have a direct role in mitigating the radiological consequences of any accident, and does not affect any of the bases (assumptions, actions, etc.) for the current analyses as described in the Turkey Point Unit 3 FSAR (Reference 9). The uprated Cycle 15 reload core redesign meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. The demonstrated adherence to these standards and criteria precludes new risks to components and systems that could: (a) adversely affect the ability of existing components and systems to mitigate the radiological consequences of any accident; and/or (b) adversely affect the integrity of the fuel rod cladding as a fission product barrier. Furthermore, adherence to applicable standards and criteria ensures that these fission product barriers maintain design margin to safety. Specifically, the mechanical changes as specified in Section 2.1, will not increase the radiological consequences of an accident previously evaluated in the Turkey Point Unit 3 FSAR (Reference 9). The mechanical features, noted in Section 2.1, have no impact on chemical, physical or mechanical properties nor will the core operate in excess of pertinent design basis operating limits for the key safety parameters. The lead rod average burnups at the end of the uprated Cycle 15 operation will not exceed the lead rod average burnup limits of WCAP-10125-P-A (Reference 18). No additional mass release or additional fuel failures are anticipated to result from the uprated Cycle 15 reload redesign. Since the predictions presented in the FSAR (Reference 9) are not sensitive to the mechanical changes specified in this report, the radiological consequences of accidents previously evaluated in the Turkey Point Unit 3 FSAR (Reference 9) have not increased.

3. <u>May the proposed activity increase the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the FSAR?</u>

This RSE documents that the probability of a malfunction of equipment important to safety previously evaluated in the Turkey Point Unit 3 FSAR (Reference 9) is not increased. The uprated Cycle 15 reload core redesign meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. Equipment reliability is not degraded. Demonstrated adherence to applicable standards and acceptance criteria precludes new risks to components and systems that could increase the probability of any previously evaluated malfunction of equipment important to safety. Specifically, the mechanical changes as specified in Section 2.1, in compliance with the methodology established in References 3 and 4, will not increase the probability of occurrence of a malfunction of equipment important to safety previously evaluated or cause the performance of a system to degrade below the design bases in the accident analysis in the Turkey Point Unit 3 FSAR (Reference 9). No new performance requirements are being imposed on any system or component such that any design criteria will be exceeded nor will the core operate in excess of pertinent design basis operating limits for the key safety parameters. No new failure modes or limiting single failures have been created with the mechanical features noted in Section 2.1. Therefore, the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the FSAR (Reference 9) has not increased.

4. <u>May the proposed activity increase the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR?</u>

This RSE documents that the radiological consequences of a malfunction of equipment important to safety previously evaluated in the Turkey Point Unit 3 FSAR (Reference 9) are not increased. The uprated Cycle 15 reload core redesign does not have a direct role in mitigating the radiological consequences of any malfunction of equipment important to safety, and does not affect any of the bases (assumptions, actions, etc.) for the current analyses as described in the Turkey Point Unit 3 FSAR (Reference 9). The uprated Cycle 15 reload core redesign meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. The demonstrated adherence to these standards and criteria precludes new risks to components and systems that could: (a) adversely affect the ability of existing components and systems to mitigate the radiological consequences of any accident; and/or (b) adversely affect the integrity of the fuel rod cladding as a fission product barrier. Furthermore, adherence to applicable standards and criteria ensures that these fission product barriers maintain design margin of safety. Specifically, the mechanical changes as specified in Section 2.1, will not increase the radiological consequences of a malfunction of equipment important to safety previously evaluated in the Turkey Point Unit 3 FSAR (Reference 9). The predictions presented in the FSAR (Reference 9) are not sensitive to the fuel rod cladding material or other mechanical changes that do not alter the metallurgical composition of the core. The mechanical features mentioned in Section 2.1 do not change the performance requirements on any system or component such that any design criteria will be exceeded nor will the core operate in excess of pertinent design basis operating limits for the key safety parameters. No new failure modes or limiting single failures have been created with any of the mechanical features mentioned in Section 2.1. The lead rod average burnups at the end of the uprated Cycle 15 operation do not exceed the lead rod average burnup limits of WCAP-10125-P-A (Reference 18). No additional mass release or additional fuel failures are anticipated to result from the uprated Cycle 15 reload redesign. Therefore, the radiological consequences of a malfunction of equipment important to safety previously evaluated in the Turkey Point Unit 3 FSAR (Reference 9) have not increased.

5. <u>May the proposed activity create the possibility of an accident of a different type than any previously evaluated in the FSAR?</u>

This RSE documents that the possibility of an accident which is different from any already in the Turkey Point Unit 3 FSAR (Reference 9) is not created. The uprated Cycle 15 reload core redesign meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. The demonstrated adherence to these standards and criteria precludes risks to components and systems that could introduce a new type of accident. Specifically, the mechanical changes as specified in Section 2.1, will not create the possibility of an accident of a different type than any previously evaluated in the Turkey Point Unit 3 FSAR (Reference 9). The fuel assemblies, containing the mechanical features noted in Section 2.1, will satisfy the same design basis as that used for fuel assemblies in the other fuel regions. All design and performance criteria will continue to be met and no new failure modes or limiting single failure mechanisms have been created nor will the core operate in excess of pertinent design basis operating limits for the key safety parameters. Therefore, the possibility of an accident of a different type than any previously evaluated in the FSAR (Reference 9) has not been created.

6. <u>May the proposed activity create the possibility of a malfunction of equipment important to safety of a different type than any previously evaluated in the FSAR?</u>

This RSE documents that the possibility of a malfunction of equipment important to safety different from any already evaluated in the Turkey Point Unit 3 FSAR (Reference 9) is not created. The uprated Cycle 15 reload core redesign meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. The demonstrated adherence to these standards and criteria precludes risks to components and systems that could introduce a new type of a malfunction of equipment important to safety. Specifically, the mechanical changes as specified in Section 2.1, will not create the possibility of a malfunction of equipment important to safety of a different type than any previously evaluated in the Turkey Point Unit 3 FSAR (Reference 9). All original design and performance criteria continue to be met, and no new failure modes have been created for any system, component, or piece of equipment. No new single failure mechanisms have been introduced nor will the core operate in excess of pertinent design basis operating limits for the key safety parameters. Therefore, the possibility of a malfunction of equipment important to safety of a different type than any previously evaluated in the FSAR (Reference 9) has not been created.

7. <u>Does the proposed activity reduce the margin of safety as defined in the basis for any technical specification?</u>

This RSE documents that the margin of safety as defined in the basis for any Turkey Point Unit 3 Technical Specification (Reference 19) is not reduced. The uprated Cycle 15 reload core redesign meets all key safety parameter limits (Reference 3) which includes margin to the safety limits to ensure that all pertinent licensing basis acceptance criteria are met. The safety analysis limits support the applicable Turkey Point Unit 3 Technical Specifications (Reference 19) for the uprated Cycle 15 (refer to Section 4.0). The mechanical changes as specified in Section 2.1, will not reduce the margin of safety as defined in the basis for any Technical Specification. The uprated Cycle 15 reload redesign and fuel design changes considered the normal core operating conditions allowed in the Technical Specifications. The uprated Cycle 15 reload redesign and fuel design changes were evaluated using standard reload design and approved fuel rod design models (Reference 20) and methods (References 18 and 21). This included considerations of the core physics analysis peaking factors and core average linear heat rate effects. Therefore, the margin of safety as defined in the basis for any Turkey Point Unit 3 Technical Specification (Reference 19) has not been reduced.

There are no unreviewed safety questions or technical specifications changes identified as a result of the Turkey Point Unit 3, Cycle 15 core redesign. Therefore, the uprated Cycle 15 reload redesign is licensable under 10 CFR 50.59 and requires no prior NRC approval. These conclusions are based on the following:

1) the Cycle 14 actual burnup is 13,720 MWD/MTU;

2) the uprated Cycle 15 burnup is limited to 15,680 MWD/MTU which includes a 500 MWD/MTU power coastdown;

3) a mid-cycle re-evaluation of the cycle design to account for the uprated plant licensed power of 2300 MWt; and

4) there is adherence to plant operating limitations given in the Technical Specifications (Reference 19).

2.0 REACTOR DESIGN

2.1 MECHANICAL DESIGN

The mechanical design of the fresh Region 17 fuel assemblies is the same as the Region 16 fuel assemblies used in Cycle 14, except that Region 17 has a bottom grid assembly with grid straps designed with a reduced spring force to alleviate fuel rod bow. The spring force was reduced by decreasing the spring height. This change does not affect the safe operation of the Region 17 fuel assemblies. In addition, the mechanical design of Turkey Point Unit 3, uprated Cycle 15 reload is not impacted by the uprated core thermal power other than as specified below.

Table 14A-1 presents a comparison of pertinent design parameters of the various fuel regions. Fuel rod design evaluations for the Turkey Point Unit 3, uprated Cycle 15 fuel were performed using the NRC-approved models (Reference 20) and methods (Reference 21) and the NRC-approved extended burnup methods (Reference 18) to demonstrate that all of the fuel rod design bases are met. The Reference 21 fuel rod design methodology was introduced in Cycle 15. This improved methodology reduces the densification power spike factor to 1.0 and demonstrates that clad flattening will not occur in Westinghouse fuel designs.

Turkey Point Unit 3, Cycle 15 continues to use the hafnium Pressurized Thermal Shock (PTS) absorber rods. These rods will be used in core peripheral assemblies, Figure 14A-2, in order to reduce the neutron flux at the reactor pressure vessel belt-line weld. The absorber stack in each of these rods is 36 inches long and is centered approximately 18 inches below the core midplane. Descriptions and dimensions are given in Reference 22.

Westinghouse has had considerable experience with Zircaloy clad fuel. This experience is described in WCAP-8183, "Operational Experience with Westinghouse Cores," (Reference 23).

2.2 NUCLEAR DESIGN

The nuclear design models for the uprated Cycle 15 use codes and calculational methods described in Reference 2 and approved by the NRC in Reference 1. All of the methods employed and described in Reference 2 are NRC-approved Westinghouse methods and reflect current practices followed by Westinghouse in Reference 3.

The nuclear design of Turkey Point Unit 3, uprated Cycle 15 reload shows that the core reload will not adversely affect the ability to safely operate at uprated core thermal power. The margin between the design criteria and safety analysis limits has been shown to be met, and that sufficient shutdown margin exists after accounting for the uprated core thermal power.

Table 14A-1 presents the Fuel Assembly Design Parameters for all of the fuel regions present in the uprated Cycle 15. Figure 14A-1 presents the reference core loading pattern. The loading contains two different types of discrete burnable absorbers which are described and distributed as follows: 16 Region 17A assemblies containing 12 WABA rodlets per fuel assembly and 16 Region 17A assemblies containing 16 WABA rodlets per fuel assembly for a total of 448 WABA rods. All of the WABAs are 120 inches in length centered on the fuel mid-plane.

There are also 240 reduced-length (36 in.) hafnium absorber rods in the 12 Region 15A fuel assemblies along the core flats. The hafnium rods are modeled in the uprated Cycle 15 core by approved Westinghouse nuclear design codes, as was done for the Unit 3 Cycle 14 core (Reference 24), based on the description and dimensions provided to Westinghouse (Reference 22). The locations of the hafnium absorber rods are shown in Figure 14A-2.

In addition, 1,632 IFBAs, as shown in Figure 14A-2, are distributed in the following fuel regions: 4 Region 17B assemblies with 80 IFBAs each, 8 Region 17C assemblies with 16 IFBAs each, 8 Region 17D assemblies with 32 IFBAs each and 8 Region 17E assemblies with 116 IFBAs each. The IFBAs stack height is 120 inches centered on the fuel mid-plane. These IFBA configurations are presented in Reference 25 and are considered the new standard IFBA loading patterns.

The uprated Cycle 15 loading pattern meets all peaking factor requirements. Figures 14A-A1 and 14A-A3, in Attachment 14A-A to this reload safety evaluation (RSE), present the Relaxed Axial Offset Control (RAOC) operating bands and the K(z) curve, respectively, appropriate for the uprated Cycle 15. Operation within these bands ensures compliance with the F_Q requirements consistent with the methodology described in Reference 26.

The uprated Cycle 15 loading pattern was also evaluated for the Reactivity Cluster Control Assemblies (RCCAs) parking positions at 228 and 230 steps withdrawn. Figure 14A-A2, in Attachment 14A-A to this reload safety evaluation (RSE), presents the Rod Insertion Limits (RILs) for the 228 steps parking position. The RILs for the 230 parking position are shown in Figure 14A-3 of this RSE.

Table 14A-2 provides a comparison of the range of values that are representative of the uprated Cycle 15 core kinetics parameters with their current limits based on previously performed accident analysis. The delayed neutron fraction characterize the dynamic response of the core to changes in reactivity. The moderator and doppler temperature coefficients are measures of the dominant reactivity feedback mechanisms. The required shutdown margin presented in Table 14A-3 is based on previously performed accident analyses, Reference 7. The available shutdown margin exceeds the minimum required.

The Core Operating Limits Report (COLR) for Turkey Point Unit 3 uprated Cycle 15 is included in Attachment 14A-A to this RSE.

2.3 THERMAL AND HYDRAULIC DESIGN

The thermal hydraulic methodology, DNB correlations, and safety analyses used for the Cycle 15 redesign are consistent with the OFA transition licensing submittal (Reference 4) and the increased $F_{\Delta H}$ limit licensing submittal (Reference 10) and approved in Reference 5. The combination of core temperature and power meets the core safety limits given in Technical Specifications (Reference 19) Figure 2.1-1, and results in no adverse variation in thermal margins from the Cycle 15 reload.

The thermal hydraulic analysis of Turkey Point Unit 3 Cycle 15 reload shows that the core reload will not adversely affect the ability to safely operate at uprated core thermal power. The margin between the design and safety analysis limit DNBRs is more than sufficient to cover all the applicable DNBR penalties.

Analyses (Reference 27) have also been performed for Cycle 15 which support a reduced thermal design flow, an increased $F_{\Delta H}$ limit, and the Revised Thermal Design Procedure. The Revised Thermal Design Procedure (Reference 17) differs from the current procedure in that the DNB correlation uncertainties and the plant parameters uncertainties are combined-statistically instead of being treated separately. The RTDP instrument uncertainty methodology change is provided in Reference 28.

As noted in the Turkey Point Unit 4, Cycle 15 RSE, the DNBR design basis used for the hypothetical steamline break event was 1.45 for the W-3 correlation. The design limit has been approved by the NRC in Reference 29. Although this low pressure limit was approved in conjunction with WCAP-9227-NP, which is not referenced in the Turkey Point FSAR, this SER is an applicable reference for the Unit 3 Cycle 15 reload design.

3.0 POWER CAPABILITY AND ACCIDENT EVALUATION

3.1 POWER CAPABILITY

This section reviews the plant power capability considering the consequences of those incidents examined in the FSAR using the previously accepted design bases. It is concluded that the core reload redesign will not adversely affect the ability to safely operate at 100% rated power during the uprated Cycle 15. For the overpower transient, the fuel centerline temperature limit of 4700 °F can be accommodated with margin in the uprated Cycle 15 core. The revised fuel thermal safety model (Reference 20) was used for fuel temperature evaluations. The LOCA F_Q limit of 2.35 x K(z) is met under all operating conditions.

3.2 ACCIDENT EVALUATION

The effects of the reload redesign, including the mechanical design features described in Section 2.1, on the design basis and postulated incidents analyzed in References 4 and 9, the proposed changes for Reduced Thermal Design Flow / Revised Thermal Design Procedure (Reference 27), and the analyses performed to account for a licensed power uprating (Reference 7), have been examined. In all cases, it was found that the effects can be accommodated within the conservatism of the initial assumptions used in the previous applicable safety analysis, the proposed licensing basis safety analysis (RTDP), or, as in the case of the DRFA, by Turkey Point specific evaluations which demonstrate that the margin to the regulatory limits is maintained.

The investigation into the effects of low initial rod internal pressure (RIP) for IFBA rods on the Large and Small Break LOCA analyses has been completed. It has been demonstrated that RIP uncertainty is not a significant PCT effect for initial cold pressures from 200 to 275 psig on the Large Break LOCA. Further, special IFBA analyses for Small Break LOCA, regardless of initial backfill pressure, are not required. In addition, the revised helium release model has been evaluated (Reference 30) as acceptable. Therefore, operation of the uprated Cycle 15 with 200 psig backfill IFBA fuel meets the requirements of 10 CFR 50.46 with no additional work required.

A safety requirement that the core remain subcritical on soluble boron alone in long term cooling following a Large Break LOCA is adhered to in the uprated Cycle 15 design (Reference 31). This is accomplished by identifying all of the sources of water in the sump following actuation of the ECCS, calculating their respective pre-accident boron concentration and then determining the resultant sump mixture boron concentration. This resultant boron concentration is then compared to the cold zero power critical boron requirement to demonstrate that the core remains subcritical. A reload can typically affect accident input parameters in three major areas: kinetics characteristics, control rod worths, and core peaking factors. The uprated Cycle 15 parameters in each of these areas were examined as discussed below to ascertain whether new accident analyses are required.

As a result of Technical Bulletin NSD-92-003, Westinghouse analyzed a Reactor Trip delay time of 2.0 seconds for the Reactor Coolant Pump undervoltage trip. The evaluation verified that the DNB design basis was met for the Complete Loss of Flow event for Unit 3, uprated Cycle 15.

A generic evaluation has been performed for LOCA to assess the effect of an End-of-Cycle 5 °F full power T_{AVG} coastdown based on uprated conditions with a ± 3 °F T_{AVG} operating window (Reference 32). The evaluation resulted in a 7 °F PCT increase for the Large Break LOCA analysis. Lower vessel average temperature is non-limiting for the Turkey Point Small Break LOCA analysis. Therefore, a full power coastdown of 5 °F in T_{AVG} is acceptable for LOCA provided there are no RSAC violations due to the reduced vessel average temperature.

Reference 32 also evaluated the potential impact of the 5 °F full power T_{AVG} coastdown on the non-LOCA licensing basis safety analyses. It was concluded that all non-LOCA events occurring at the coastdown conditions are bounded by the Chapter 14 FSAR non-LOCA analyses.

3.2.1 KINETICS PARAMETERS

The uprated Cycle 15 kinetics parameters with current limits are given in Table 14A-2. The delayed neutron fractions and moderator temperature coefficient are within the bounds of the current limits for the redesign.

3.2.2 CONTROL ROD WORTHS

Changes in control rod worths may affect shutdown margin, differential rod worths, ejected rod worths, and trip reactivity. Table 14A-3 shows that the uprated Cycle 15 shutdown margin requirements for the redesign are satisfied. As shown in Table 14A-2, the maximum differential rod worth of two RCCA control banks moving together in their highest worth region for the uprated Cycle 15 is less than or equal to the current limit.

3.2.3 CORE PEAKING FACTORS

The peaking factors following control rod ejection are within the bounds of the current limits. Evaluation of peaking factors for the rod out of position and dropped RCCA incidents shows that DNBR is maintained above the appropriate safety analysis minimum value (References 2 and 10).

3.2.4 LOCA CORE AXIAL POWER SHAPE

Large Break LOCA analysis has been traditionally performed using a symmetric, chopped cosine, core axial power shape. Under certain conditions, calculations have shown that there is a potential for top-skewed power distributions to result in Peak Cladding Temperatures (PCTs) greater than those calculated with a chopped cosine axial power distribution.

In January of 1995, Westinghouse initiated development of an axial power shape methodology to replace PSSM. The methodology, ESHAPE (Explicit Shape Analysis for PCT Effects), is based on explicit analysis with a set of skewed axial power shapes, which supplements the standard analysis done with the chopped cosine. Development of this methodology was completed in June 1995. Results of multiple plant calculations have shown that the limiting core axial power shape is related to the time of PCT, with early PCT plants (<100 seconds) being cosine shape limited and late PCT plants (>200 seconds) being top skewed shape limited. At intermediate times, the limiting shape is plant dependent. Discussions, with the NRC, have been held on this approach starting on March 21, 1995. At this time, the NRC is considering ESHAPE to be an updated application of methodology described in WCAP-10266-P-A (Reference 33), submitted and approved in December 1987.

Using the ESHAPE Methodology, Westinghouse has determined that plants with early PCT times are cosine shape limited. The Turkey Point Units have a PCT time > 100 seconds and are therefore potentially affected by skewed power shapes. Additional work performed with the ESHAPE methodology for Turkey Point resulted in a maximum PCT increase of 14 °F over the cosine shape Large Break LOCA PCT. As a consequence, all 10 CFR 50.46 limits are met, and the Turkey Point Unit 3, uprated Cycle 15 redesign can be licensed with ESHAPE methodology and the current analysis of record.

3.3 EVENTS REANALYZED

3.3.1 CHEMICAL VOLUME CONTROL SYSTEM MALFUNCTION

As a result of an increased boron dilution flowrate, the Chemical Volume Control System (CVCS) Malfunction event was reanalyzed. The results of this reanalysis are documented in Reference 11 and show that all applicable acceptance criteria are met.

4.0 TECHNICAL SPECIFICATIONS CHANGES

A review of the Turkey Point Unit 3, uprated Cycle 15 RSE has been performed relative to the impact of this RSE on the Turkey Point Technical Specifications (Reference 19) and Core Operating Limits Report (COLR). This review was performed on the Turkey Point Technical Specifications (Reference 19) inclusive of Amendment 181, dated March 27, 1996 and the Cycle 15 COLR, June 1996, attached. As a result of this review, no technical specifications changes are required, assuming approval of the licensing amendment request as specified in Reference 7, based on the subject RSE for the uprated Cycle 15 operation.

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16. Letter from Rossi, C. E. (NRC) to Rahe, E. P. Jr. (Westinghouse), "Acceptance for Referencing of Licensing Topical Report, Reference Core Report VANTAGE 5 Fuel Assembly, Addendum 1," March 12, 1986.

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19. "Florida Power & Light Company, Turkey Point Plant Units No. 3 & 4, Technical Specifications," Docket Nos. 50-250/50-251, as amended through Amendment 181/175, March 27, 1996.

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25. Letter from Metcalf, N. R. (Westinghouse) to Martin, L. A. (FPL), "Florida Power and Light Company New Integral Fuel Burnable Absorber (IFBA) Patterns," 94FP*-G-0058, May 26, 1994.

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29. Letter from Thadani, A. C. (NRC) to Johnson, W. J. (Westinghouse), "Acceptance for Referencing Topical Report, WCAP-9226-P/9227-NP, 'Reactor Core Response to Excessive Secondary Steam Releases'," January 31, 1989.

30. "New Helium Gas Release Model", Westinghouse SECL No. 95-067, September 1995.

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32. SECL-96-009, "Tavg/Power Coastdown for Turkey Point Units 3 and 4", January 17, 1996.

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TABLE 14A-1

FUEL ASSEMBLY DESIGN PARAMETERS

TURKEY POINT UNIT 3 - UPRATED CYCLE 15

Region	15A	15B	15C	15D	15E	16A	16B
Enrichment (w/o U 235)(1)	3.605	3.605	3.606	4.007	4.010	3.616	4.004
Density (% Theoretical)(1)	95.57	95.55	95.48	95.82	95.78	95.41	95.46
Number of Assemblies	17	8	8	8	4	16	8
Approximate Burnup at Beginning of Cycle 15 (MWD/MTU) (2)	33,950	30,943	32,404	25,995	32,622	18,357	18,006
Fuel Type (3)	OFA	OFA	OFA	OFA	OFA	OFA	OFA
Number of IFBA Fuel Rods	---	128	512	128	400	---	---
Axial Blankets	Yes	Yes	Yes	Yes	Yes	Yes	Yes

NOTES:

1. All fuel region values are as-built.
2. Based on Cycle 14 burnup of 13,720 MWD/MTU rounded to the nearest 100 MWD/MTU.
3. The entire Uprated Cycle 15 core is of the DRFA design.

TABLE 14A-1

FUEL ASSEMBLY DESIGN PARAMETERS

TURKEY POINT UNIT 3 - UPRATED CYCLE 15

Region	16C	16D	16E	17A	17B	17C	17D	17E
Enrichment (w/o U 235)[1]	4.004	4.004	4.004	3.605	3.605	3.992	3.992	3.992
Density (% Theoretical)[1]	95.46	95.46	95.46	95.53	95.53	95.48	95.48	95.48
Number of Assemblies	12	4	12	32	4	8	8	8
Approximate Burnup at Beginning of Cycle 15 (MWD/MTU) [2]	16,286	18,646	15,557	0	0	0	0	0
Fuel Type [3]	OFA	OFA	OFA	OFA	OFA	OFA	OFA	OFA
Number of IFBA Fuel Rods	192	128	576	---	320	128	256	928
Axial Blankets	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

NOTES:

1. All fuel region values are as-built.
2. Based on Cycle 14 burnup of 13,720 MWD/MTU rounded to the nearest 100 MWD/MTU.
3. The entire Uprated Cycle 15 core is of the DRFA design.

TABLE 14A-2

KINETICS CHARACTERISTICS

TURKEY POINT UNIT 3 - UPRATED CYCLE 15

	Current Limit	Uprated Cycle 15
Moderator Temperature Coefficient (pcm/°F) [1]		
a. most positive	+5.0 ($\leq$ 70% RTP), linear ramp to 0 at 100% RTP	+5.0 ($\leq$ 70% RTP), linear ramp to 0 at 100% RTP [2]
b. most negative [3]	-58	>-58
Doppler Coefficient (pcm/°F) [1]	-2.9 to -1.0	-2.9 to -1.0
Delayed Neutron Fraction β_{eff}, (%)	0.42 to 0.75	0.42 to 0.75
Minimum Differential Rod Worth of Two Banks Moving Together at HZP (pcm/in) [1]	100	< 100

NOTES:

1. pcm = 10^{-5} $\Delta\rho$

2. Although it is highly unlikely for this design, the moderator temperature coefficient for the all-rods-out condition may be more positive than the current limit at BOC. The moderator temperature coefficient will be kept within the MTC limit by administrative controls (with the appropriate D bank position and/or boron concentration).

3. All rods in condition, corresponds to a most positive moderator density coefficient (MDC) of 0.50 $\Delta\rho$/gm/cc. The most positive MDC is incrementally corrected to nominal operating conditions to obtain the most negative MTC Technical Specification limit of -35 pcm/°F. This correction involves subtracting the incremental change in the MDC associated with a core condition of all rods inserted (most positive MDC) to an all rods withdrawn condition and a conversion for the rate of change of moderator density with temperature at Rated Thermal Power conditions.

TABLE 14A-3

SHUTDOWN REQUIREMENTS AND MARGINS

TURKEY POINT UNIT 3 - CYCLES 14 AND UPRATED 15

	Cycle 14		Uprated Cycle 15	
	BOC	EOC	BOC	EOC
Control Rod Worth (% $\Delta\rho$)				
All Rods Inserted Less Worst Stuck Rod	6.06	6.37	6.24	5.91
(1) Less 7%	5.64	5.93	5.80	5.49
Control Rod Requirements (%$\Delta\rho$)				
Reactivity Defects (Doppler, T_{avg}, Void, Redistribution)	1.79	2.76	1.67	2.91
Rod Insertion Allowance (RIA)	0.50	0.50	0.50	(1)
RCCA Repositioning Allowance	0.10	0.10	---	---
(2) Total Requirements	2.39	3.36	2.17	2.91
Shutdown Margin (1)-(2) (%$\Delta\rho$)	3.25	2.57	3.63	2.58
Required Shutdown Margin (%$\Delta\rho$)	1.00	1.77	1.00	1.77

NOTE:

1. The RIA term is already included in the Reactivity Defects term in the methodology used to compute the EOC shutdown margin.

15	14	13	12	11	10	9	8	7	6	5	4	3	2	1	
						15A	15A	15A							R
				15C	16C	17C	16B	17C	16C	* 15A					P
			15B	17D	17E	16E	17B	16E	17E	17D	15B				N
		15B	16E	17A	15D	16A	16A	16A	15D	17A	16E	15B			M
	* 15A	17D	17A	16B	17A	16C	17A	16D	17A	16B	17A	17D	15C		L
	16C	17E	15D	17A	15E	17A	15C	17A	15E	17A	15D	17E	16C		K
15A	17C	16E	16A	16D	17A	16A	17A	16A	17A	16C	16A	16E	17C	15A	J
15A	16B	17B	16A	17A	15C	17A	15A	17A	15C	17A	16A	17B	16B	15A	H
15A	17C	16E	16A	16C	17A	16A	17A	16A	17A	16D	16A	16E	17C	15A	G
	16C	17E	15D	17A	15E	17A	15C	17A	15E	17A	15D	17E	16C		F
	15C	17D	17A	16B	17A	16D	17A	16C	17A	16B	17A	17D	* 15A		E
		15B	16E	17A	15D	16A	16A	16A	15D	17A	16E	15B			D
			15B	17D	17E	16E	17B	16E	17E	17D	15B				C
				* 15A	16C	17C	16B	17C	16C	15C					B
						15A	15A	15A							A

270° (left of row H)

180°

LEGEND

R — REGION IDENTIFIER

* LOCATION OF REPLACEMENT ASSEMBLIES

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FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNIT 3

UNIT 3 UPRATED CYCLE 15
REDESIGN REFERENCE
CORE LOADING PATTERN

FIGURE 14A-1

	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1
R							20FS	20FS	20FS						
P							16I		16I						
N					32I	116I		80I		116I	32I				
M					12W						12W				
L			32I	12W		16W		12W		16W		12W	32I		
K			116I		16W		16W		16W		16W		116I		
J	20FS	16I				16W		12W		16W				16I	20FS
H	20FS		80I		12W		12W		12W		12W		80I		20FS
G	20FS	16I				16W		12W		16W				16I	20FS
F			116I		16W		16W		16W		16W		116I		
E			32I	12W		16W		12W		16W		12W	32I		
D					12W						12W				
C					32I	116I		80I		116I	32I				
B							16I		16I						
A							20FS	20FS	20FS						

270°

180°

TYPE		TOTAL
##W	- NUMBER OF WABA RODLETS	448
##I	- NUMBER OF IFBA RODS	1632
##FS	- NUMBER OF FLUX SUPPRESSION RODLETS ...	240

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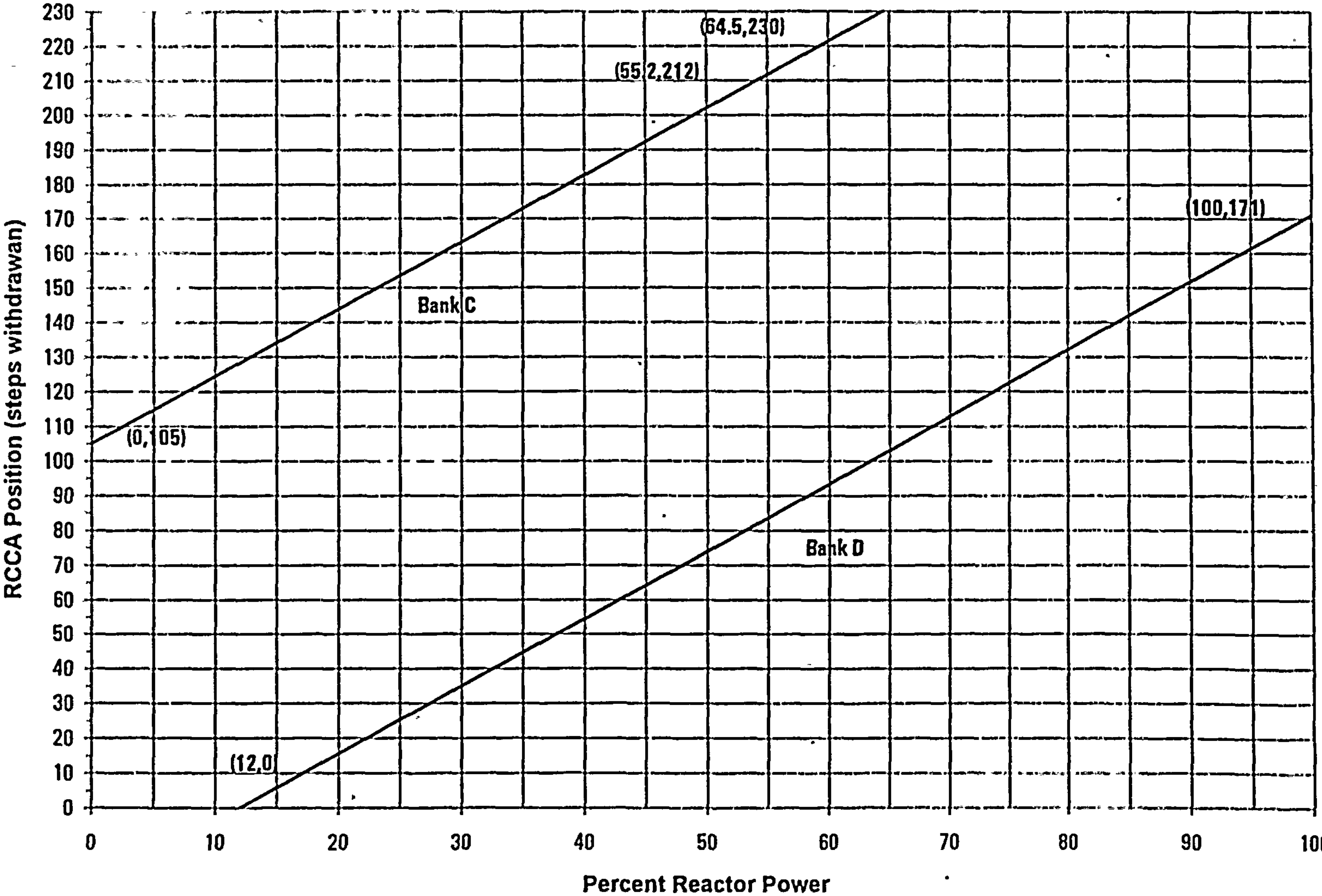
FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNIT 3

UNIT 3 UPRATED CYCLE 15
BURNABLE ABSORBER
LOCATIONS

FIGURE 14A-2



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FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNIT 3

UNIT 3 UPRATED CYCLE 15
ROD INSERTION LIMIT
ARO = 230 STEPS WITHDRAWN
OVERLAP = 102 STEPS

FIGURE 14A-3

APPENDIX 14A - ATTACHMENT A

TURKEY POINT PLANT UNIT 3
THERMAL UPRATED CYCLE 15
CORE OPERATING LIMITS REPORT (COLR)

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ATTACHMENT A

CORE OPERATING LIMITS REPORT (COLR)

1.0 INTRODUCTION

The Core Operating Limits Report (COLR) for Turkey Point Unit 3 Uprated Cycle 15 has been prepared in accordance with the requirements of Technical Specifications 6.9.1.7.

The Technical Specifications affected by this report are:

3.2.1	Axial Flux Difference (AFD)
3.1.3.6	Control Rod Insertion Limits
3.2.2	Heat Flux Hot Channel Factor - $F_Q(z)$
3.2.3	Nuclear Enthalpy Rise Hot Channel Factor

2.0 OPERATING LIMITS

The AFD, $F_Q(z)$, K(z) and Rod Bank Insertion Limits have been developed using the NRC approved methodology specified in Technical Specification 6.9.1.7. These limits are provided in the following subsections:

2.1 AXIAL FLUX DIFFERENCE (TS 3.2.1)

The Axial Flux Difference (AFD) limits are provided in Figure 14A-A1.

2.2 CONTROL ROD INSERTION LIMITS (TS 3.1.3.6)

The control rod banks shall be limited in physical insertion as shown in Figure 14A-A2.

2.3 HEAT FLUX HOT CHANNEL FACTOR $F_Q(z)$ (TS 3.2.2)

- $[F_Q]^L$ = 2.35 per Reference A1.
- K(z) is provided in Figure 14A-A3.

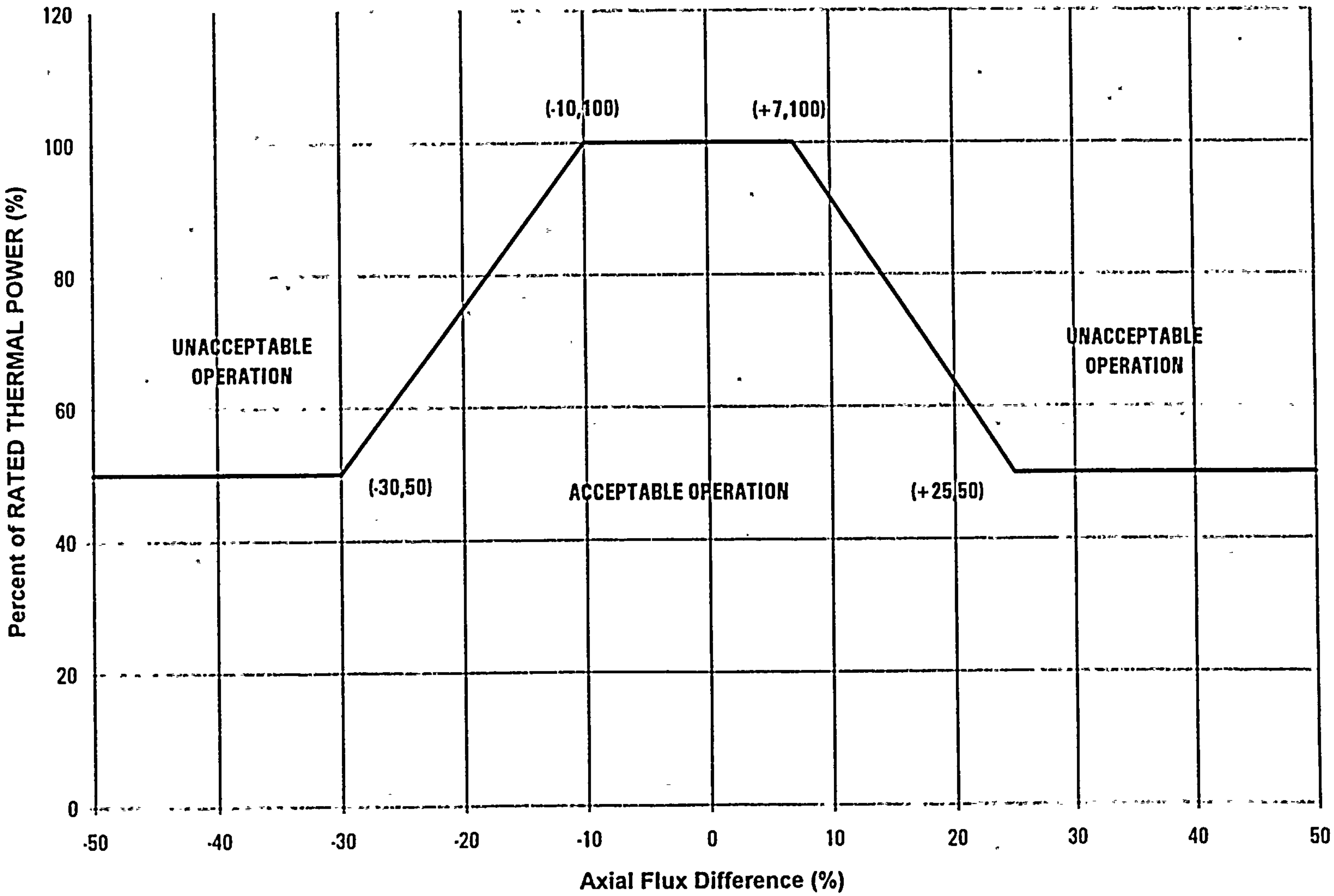
2.4 NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (TS 3.2.3)

- $F_{\Delta H}^{RTP}$ = 1.64 per Reference A1.
- $PF_{\Delta H}$ = 0.3 per Reference A2.

3.0 REFERENCES

A1. Letter from Metcalf, N. R. (Westinghouse) to Knuckles, E. R. (FP&L), "LOCA Future Limits for Turkey Point 3 Cycle 15 and Turkey Point 4 Cycle 16 Uprating," 95FP*-G-0137, November 14, 1995.

A2. Letter from Metcalf, N. R. (Westinghouse) to Perryman, J. L. (FP&L), "Florida Power & Light Company, Turkey Point Unit 3 Cycle 15 and Unit 4 Cycle 16, Design Initialization at Uprate (2300 MWt) Conditions," 96FP*-G-0009, January 31, 1996.

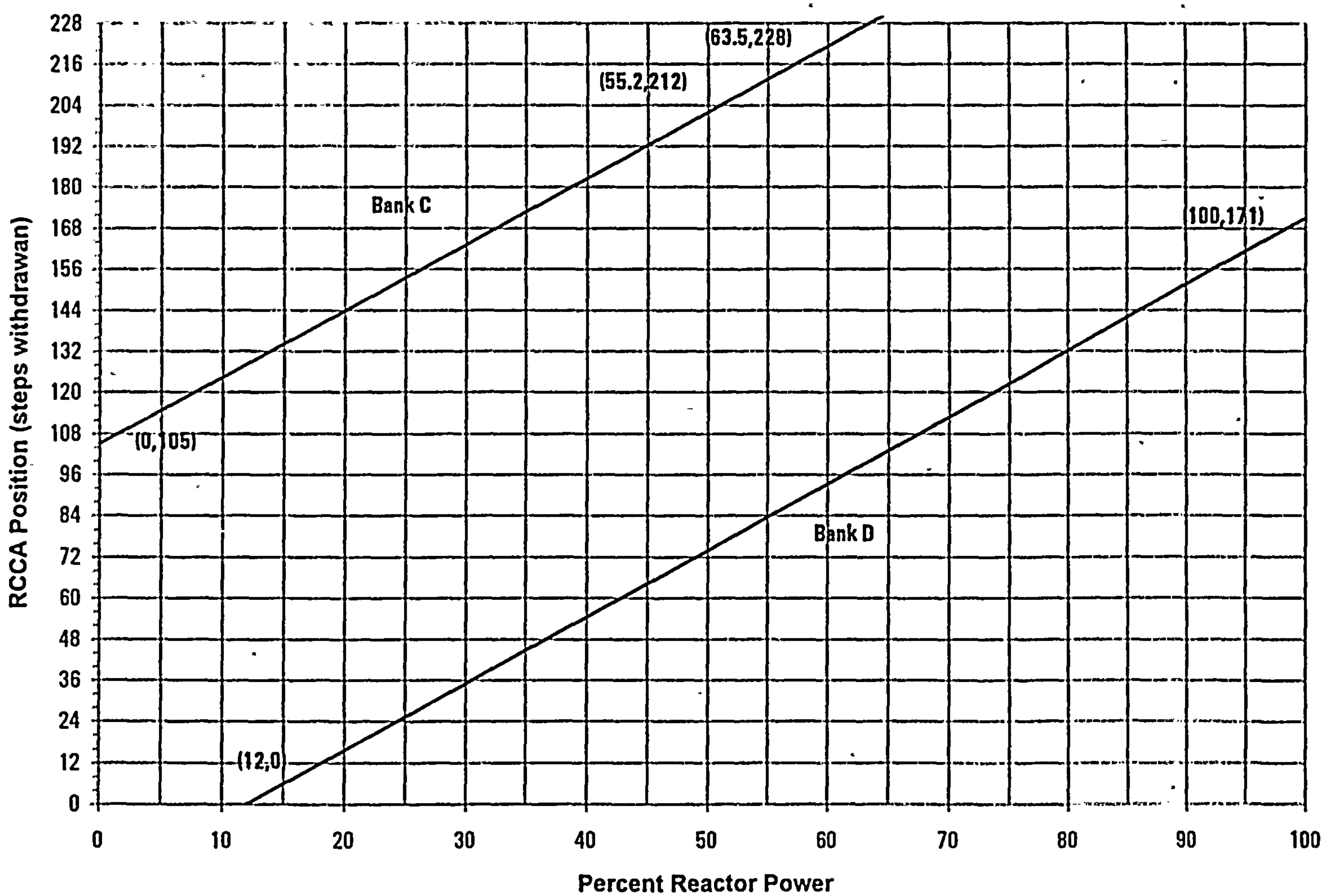


REV. 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNIT 3

UNIT 3 UPRATED CYCLE 15
AXIAL FLUX DIFFERENCE AS A
FUNCTION OF RATED THERMAL POWER

FIGURE 14A-A1

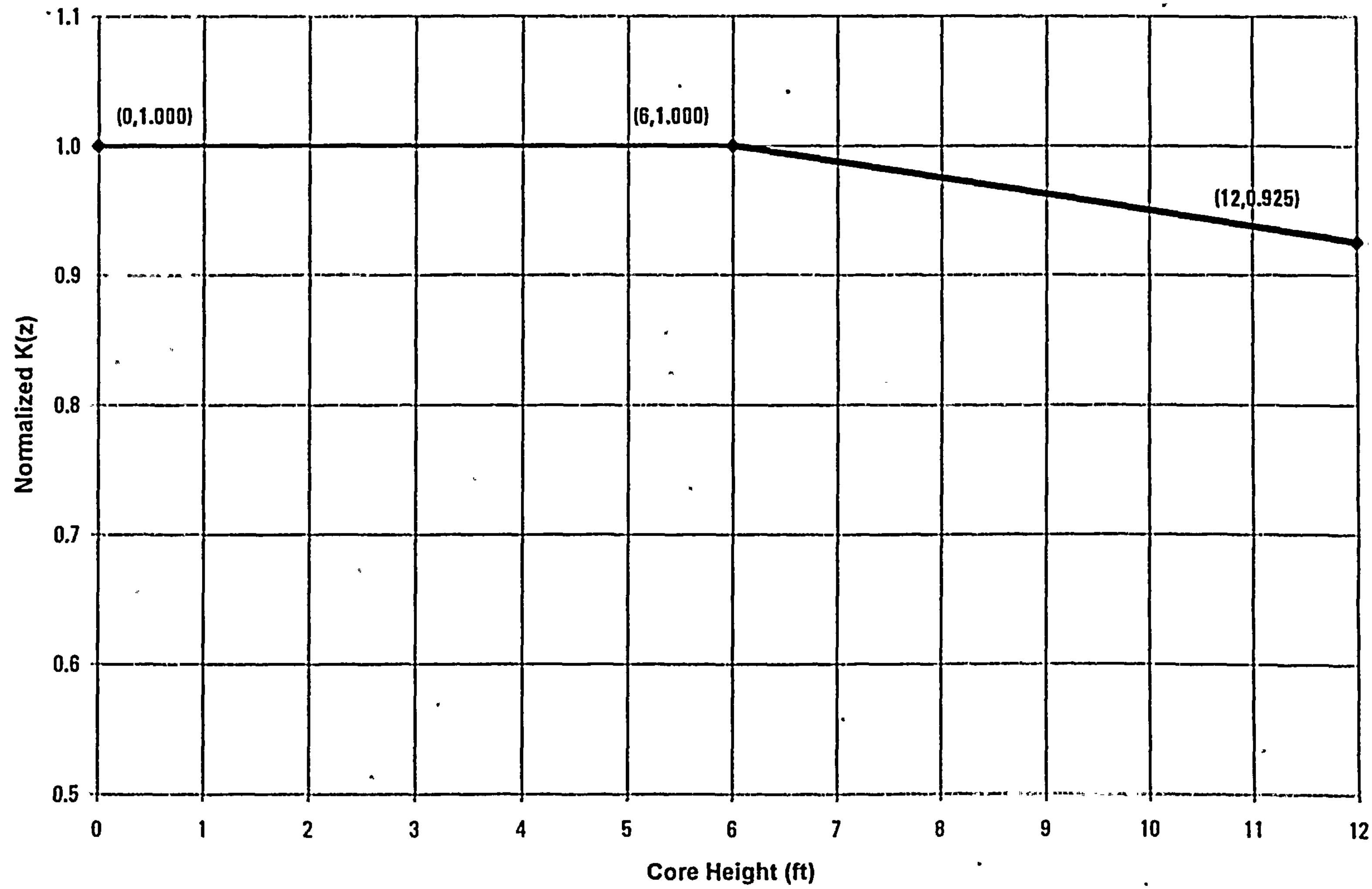


REV. 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNIT 3

UNIT 3 UPRATED CYCLE 15
ROD BANK INSERTION LIMITS
VERSUS THERMAL POWER
ARO = 228 STEPS WITHDRAWN
OVERLAP = 100 STEPS

FIGURE 14A-A2



REV. 14 (2/97)

FLORIDA POWER & LIGHT COMPANY
TURKEY POINT PLANT UNIT 3

UNIT 3 UPRATED CYCLE 15
K(z) NORMALIZED $F_q(z)$ AS A
FUNCTION OF CORE HEIGHT

FIGURE 14A-A3

APPENDIX 14B

TURKEY POINT PLANT UNIT 4
THERMAL UPRATE CYCLE 16 RELOAD SAFETY EVALUATION
REVISION 1

JUNE 1996

Prepared by:
W. H. Slagle

Approved: Signature on File
J. Shefcheck, Manager
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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

This report presents a re-evaluation for Turkey Point Unit 4, uprated Cycle 16, and demonstrates that the core reload will not adversely affect the safety of the plant. The neutronic portion of this analysis was completed by Florida Power & Light Company utilizing the NRC-approved methodology (References 1 and 2). The remainder of this evaluation was accomplished utilizing the methodology described in WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology" (Reference 3).

The Turkey Point Unit 4 operated in Cycle 15 with a full core of Westinghouse 15x15 Optimized Fuel Assemblies (OFAs). For Cycle 16 (startup April 1996), the Turkey Point Unit 4 core was refueled with all Westinghouse 15x15 OFA regions containing the OFA features described in Reference 4 and approved by the NRC in Reference 5. The uprated Cycle 16 reload will continue to use, in Region 18, the Debris Resistant Fuel Assembly (DRFA) design. This design change is described and evaluated in Reference 6.

As part of the Cycle 16 design, Florida Power & Light Company has completed the uprate of Turkey Point Units 3 and 4 from 2200 MWt to 2300 MWt. The analyses performed to support this uprating (Reference 7) were submitted to the NRC for review and approval. The submittal provided to justify the uprating of the Turkey Point units included an Assessment of Unreviewed Safety Questions (10 CFR 50.59) and No Significant Hazards Determination (10 CFR 50.92). The NRC granted licensing approval to uprate Turkey Point Units 3 and 4 (Reference 33) in Facility Operating License Amendment No.s 191 (Unit 3) and 185 (Unit 4). The reload design was re-evaluated using uprated conditions, such that, when NRC approval was received, Florida Power & Light Company was able to uprate Turkey Point Units 3 and 4 to 2300 MWt without a unit shutdown. In addition to the uprating, a Core Operating Limits Report (COLR) has been included as Attachment A to this reload safety evaluation. The supporting documentation for the COLR was included in the uprating submittal to the NRC (Reference 7).

Evaluations have previously been performed by Westinghouse (Reference 8), to support the complete or partial removal of thimble plugs from the Turkey Point units. Reload safety evaluations in support of this cycle have been performed in a manner that they remain bounding whether or not thimble plugs are removed from the core.

All of the accidents comprising the licensing bases (References 4, 7, 9, 10, and 11), which could potentially be affected by the fuel reload, have been reviewed for the uprated Cycle 16 design described herein. Justification for the applicability of the results of the previous analyses is presented.

1.2 GENERAL DESCRIPTION

The Turkey Point Unit 4 reactor core is comprised of 157 fuel assemblies arranged in the core loading pattern configuration shown in Figure 14B-1. During the Cycle 15/16 refueling, 13 Region 14, 40 Region 15, and 11 Region 16, fuel assemblies were discharged. These fuel assemblies were replaced with 64 fresh Region 18 fuel assemblies.

The uprated Cycle 16 core uses 528 Westinghouse Wet Annular Burnable Absorber (WABA) rods. Use of the WABA rods has been generically approved by the NRC (Reference 12).

Hafnium burnable absorber rods (240 part-length) will again be used in the core peripheral assemblies in order to reduce the neutron flux at the reactor pressure vessel belt-line weld (refer to Section 2.1 and Figure 14B-2).

A significant number (2624) of Integral Fuel Burnable Absorber (IFBA) rods will be used, again, in Turkey Point Unit 4 as part of the fresh Region 18 fuel assemblies. A more detailed description and evaluation of IFBAs is given in References 13 and 14. The NRC has approved the use of IFBAs for Westinghouse 15x15 fuel assemblies in Reference 16.

Axial blankets will be used again in the Region 18 fuel assemblies. The axial blanket consists of a nominal six inches of natural UO_2 pellets at the top and bottom of the fuel pellet stack to reduce neutron leakage and to improve uranium utilization. This design feature is described and licensed in Reference 13.

The Revised Thermal Design Procedure [RTDP] (Reference 16) has been proposed for the uprated Cycle 16 operation to meet the DNBR licensed design criterion. The RTDP accounts for both the proposed $F_{\Delta H}$ limit and a reduction in flow.

The nominal core design parameters are as follows:

	Current Licensing Basis (Uprated Parameters)
Core Power (MWt)	2300
Pressurizer Pressure (psia)	2250
Core Inlet Temperature (°F)	546.6
Thermal Design Flow (gpm)	255,000
Minimum Measured Flow	264,000
Average Linear Power Density (kw/ft) [1]	5.84

Note:

1. Linear power density based on hot, densified active fuel length of 143.7 inches.

1.3 CONCLUSIONS AND 10 CFR 50.59 ASSESSMENT

From the evaluation presented in this report, it is concluded that the Turkey Point Unit 4 uprated Cycle 16 reload design does not result in the previously acceptable safety limits for any accident being exceeded, does not result in any unreviewed safety questions as defined in 10 CFR 50.59, and does not result in any Technical Specifications changes. The basis for this determination is delineated below. The reload design criteria are referenced throughout this document.

1. <u>May the proposed activity increase the probability of occurrence of an accident previously evaluated in the FSAR?</u>

This RSE documents that the probability of an accident previously evaluated in the Turkey Point Unit 4 updated FSAR (Reference 9) is not increased. The uprated Cycle 16 reload core design meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. Though fuel and core design are not directly related to the probability of any previously evaluated accident, the demonstrated adherence to applicable standards and acceptance criteria precludes new risks to components and systems that could increase the probability of any previously evaluated accident. Specifically, the mechanical changes as specified in Section 2.1, will not increase the probability of occurrence of an accident previously evaluated in the Turkey Point Unit 4 FSAR (Reference 9). The clad integrity is maintained and the structural integrity of the fuel rods, fuel assemblies, and core is not affected. The mechanical features, noted in Section 2.1, have no impact on fuel rod performance or dimensional stability nor will the core operate in excess of pertinent design basis operating limits. Accordingly, overall reactor system performance is not adversely affected by the reload design. Therefore, the probability of occurrence of an accident previously evaluated in the FSAR (Reference 9) has not increased.

2. <u>May the proposed activity increase the consequences of an accident previously evaluated in the FSAR?</u>

This RSE documents that the radiological consequences of an accident previously evaluated in the Turkey Point Unit 4 FSAR (Reference 9) are not increased. The uprated Cycle 16 reload core design does not have a direct role in mitigating the radiological consequences of any accident, and does not affect any of the bases (assumptions, actions, etc.) for the current analyses as described in the Turkey Point Unit 4 FSAR (Reference 9). The uprated Cycle 16 reload core design meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. The demonstrated adherence to these standards and criteria precludes new risks to components and systems that could: (a) adversely affect the ability of existing components and systems to mitigate the radiological consequences of any accident; and/or (b) adversely affect the integrity of the fuel rod cladding as a fission product barrier. Furthermore, adherence to applicable standards and criteria ensures that these fission product barriers maintain design margin to safety. Specifically, the mechanical design as specified in Section 2.1, will not increase the radiological consequences of an accident previously evaluated in the Turkey Point Unit 4 FSAR (Reference 9). The mechanical features, noted in Section 2.1, have no impact on chemical, physical or mechanical properties nor will the core operate in excess of pertinent design basis operating limits for the key safety parameters. The lead rod average burnups at the end of the uprated Cycle 16 operation will not exceed the lead rod average burnup limits of WCAP-10125-P-A (Reference 17). No additional mass release or additional fuel failures are anticipated to result from the uprated Cycle 16 reload. Since the predictions presented in the FSAR (Reference 9) are not sensitive to the mechanical changes specified in this report, the radiological consequences of accidents previously evaluated in the Turkey Point Unit 4 FSAR (Reference 9) have not increased.

3. <u>May the proposed activity increase the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the FSAR?</u>

This RSE documents that the probability of a malfunction of equipment important to safety previously evaluated in the Turkey Point Unit 4 FSAR (Reference 9) is not increased. The uprated Cycle 16 reload core design meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. Equipment reliability is not degraded. Demonstrated adherence to applicable standards and acceptance criteria precludes new risks to components and systems that could increase the probability of any previously evaluated malfunction of equipment important to safety. Specifically, the mechanical design as specified in Section 2.1, in compliance with the methodology established in References 3 and 4, will not increase the probability of occurrence of a malfunction of equipment important to safety previously evaluated or cause the performance of a system to degrade below the design bases in the accident analysis in the Turkey Point Unit 4 FSAR (Reference 9). No new performance requirements are being imposed on any system or component such that any design criteria will be exceeded nor will the core operate in excess of pertinent design basis operating limits for the key safety parameters. No new failure modes or limiting single failures have been created with the mechanical features noted in Section 2.1. Therefore, the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the FSAR (Reference 9) has not increased.

4. <u>May the proposed activity increase the consequences of a malfunction of equipment important to safety previously evaluated in the FSAR?</u>

This RSE documents that the radiological consequences of a malfunction of equipment important to safety previously evaluated in the Turkey Point Unit 4 FSAR (Reference 9) are not increased. The uprated Cycle 16 reload core design does not have a direct role in mitigating the radiological consequences of any malfunction of equipment important to safety, and does not affect any of the bases (assumptions, actions, etc.) for the current analyses as described in the Turkey Point Unit 4 FSAR (Reference 9). The uprated Cycle 16 reload core design meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. The demonstrated adherence to these standards and criteria precludes new risks to components and systems that could: (a) adversely affect the ability of existing components and systems to mitigate the radiological consequences of any accident; and/or (b) adversely affect the integrity of the fuel rod cladding as a fission product barrier. Furthermore, adherence to applicable standards and criteria ensures that these fission product barriers maintain design margin of safety. Specifically, the mechanical design as specified in Section 2.1, will not increase the radiological consequences of a malfunction of equipment important to safety previously evaluated in the Turkey Point Unit 4 FSAR (Reference 9). The predictions presented in the FSAR (Reference 9) are not sensitive to the fuel rod cladding material or other mechanical changes that do not alter the metallurgical composition of the core. The mechanical features mentioned in Section 2.1 do not change the performance requirements on any system or component such that any design criteria will be exceeded nor will the core operate in excess of pertinent design basis operating limits for the key safety parameters. No new failure modes or limiting single failures have been created with any of the mechanical features mentioned in Section 2.1. The lead rod average burnups at the end of the uprated Cycle 16 operation do not exceed the lead rod average burnup limits of WCAP-10125-P-A (Reference 17). No additional mass release or additional fuel failures are anticipated to result from the uprated Cycle 16 reload. Therefore, the radiological consequences of a malfunction of equipment important to safety previously evaluated in the Turkey Point Unit 4 FSAR (Reference 9) have not increased.

5. <u>May the proposed activity create the possibility of an accident of a different type than any previously evaluated in the FSAR?</u>

This RSE documents that the possibility of an accident which is different from any already in the Turkey Point Unit 4 FSAR (Reference 9) is not created. The uprated Cycle 16 reload core design meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. The demonstrated adherence to these standards and criteria precludes risks to components and systems that could introduce a new type of accident. Specifically, the mechanical design, as specified in Section 2.1, will not create the possibility of an accident of a different type than any previously evaluated in the Turkey Point Unit 4 FSAR (Reference 9). The fuel assemblies, containing the mechanical features noted in Section 2.1, will satisfy the same design basis as that used for fuel assemblies in the other fuel regions. All design and performance criteria will continue to be met and no new failure modes or limiting single failure mechanisms have been created nor will the core operate in excess of pertinent design basis operating limits for the key safety parameters. Therefore, the possibility of an accident of a different type than any previously evaluated in the FSAR (Reference 9) has not been created.

6. May the proposed activity create the possibility of a malfunction of equipment important to safety of a different type than any previously evaluated in the FSAR?

This RSE documents that the possibility of a malfunction of equipment important to safety different from any already evaluated in the Turkey Point Unit 4 FSAR (Reference 9) is not created. The uprated Cycle 16 reload core design meets all key safety parameter limits (Reference 3) and ensures that all pertinent licensing basis acceptance criteria are met. The demonstrated adherence to these standards and criteria precludes risks to components and systems that could introduce a new type of a malfunction of equipment important to safety. Specifically, the mechanical design as specified in Section 2.1, will not create the possibility of a malfunction of equipment important to safety of a different type than any previously evaluated in the Turkey Point Unit 4 FSAR (Reference 9). All original design and performance criteria continue to be met, and no new failure modes have been created for any system, component, or piece of equipment. No new single failure mechanisms have been introduced nor will the core operate in excess of pertinent design basis operating limits for the key safety parameters. Therefore, the possibility of a malfunction of equipment important to safety of a different type than any previously evaluated in the FSAR (Reference 9) has not been created.

7. Does the proposed activity reduce the margin of safety as defined in the basis for any technical specification?

This RSE documents that the margin of safety as defined in the basis for any Turkey Point Unit 4 Technical Specification is not reduced. The uprated Cycle 16 reload core design meets all key safety parameter limits (Reference 3) which includes margin to the safety limits to ensure that all pertinent licensing basis acceptance criteria are met. The safety analysis limits support the applicable Turkey Point Unit 4 Technical Specifications (Reference 18) for the uprated Cycle 16 (refer to Section 4.0). The mechanical design as specified in Section 2.1, will not reduce the margin of safety as defined in the basis for any Technical Specification (Reference 18). The uprated Cycle 16 reload design and fuel design considered the normal core operating conditions allowed in the Technical Specifications. The uprated Cycle 16 reload design and fuel design changes were evaluated using standard reload design (Reference 3) and approved fuel rod design models (Reference 19) and methods (References 17 and 20). This included considerations of the core physics analysis peaking factors and core average linear heat rate effects. Therefore, the margin of safety as defined in the basis for any Turkey Point Unit 4 Technical Specification (Reference 18) has not been reduced.

There are no unreviewed safety questions or technical specifications changes identified as a result of the Turkey Point Unit 4, Cycle 16 core design. Therefore, the uprated Cycle 16 reload design is licensable under 10 CFR 50.59 and requires no prior NRC approval. These conclusions are based on the following:

1) the Cycle 15 actual burnup is 13,850 MWD/MTU;

2) the uprated Cycle 16 burnup is limited to 16,500 MWD/MTU which includes a 500 MWD/MTU power coastdown;

3) a mid-cycle re-evaluation of the cycle design to account for the uprated plant licensed power of 2300 MWt; and

4) there is adherence to plant operating limitations given in the Technical Specifications (Reference 18).

2.0 REACTOR DESIGN

2.1 MECHANICAL DESIGN

The mechanical design of the fresh Region 18 fuel assemblies is the same as the Region 17 fuel assemblies used in Cycle 15. The Region 18 fuel assemblies will contain the new standard IFBA patterns already implemented in Turkey Point Unit 3, Cycle 15. In addition, the mechanical design of Turkey Point Unit 4, uprated Cycle 16 reload is not impacted by the uprated core thermal power other than as specified below.

Table 14B-1 presents a comparison of pertinent design parameters of the various fuel regions. Fuel rod design evaluations for the Turkey Point Unit 4, uprated Cycle 16 fuel were performed using the NRC-approved models (Reference 19) and methods (Reference 20) and the NRC-approved extended burnup methods (Reference 17) to demonstrate that all of the fuel rod design bases are met. The Reference 20 fuel rod design methodology was introduced in Cycle 16 and in Turkey Point Unit 3, Cycle 15. This improved methodology reduces the densification power spike factor to 1.0 and demonstrates that clad flattening will not occur in Westinghouse fuel designs.

Turkey Point Unit 4, Cycle 16 continues to use the hafnium Pressurized Thermal Shock (PTS) absorber rods. These rods will be used in core peripheral assemblies, Figure 14B-2, in order to reduce the neutron flux at the reactor pressure vessel belt-line weld. The absorber stack in each of these rods is 36 inches long and is centered approximately 19.4 inches below the core midplane. Descriptions and dimensions are given in Reference 21.

Westinghouse has had considerable experience with Zircaloy clad fuel. This experience is described in WCAP-8183, "Operational Experience with Westinghouse Cores," (Reference 22).

2.2 NUCLEAR DESIGN

The nuclear design models for the uprated Cycle 16 use codes and calculational methods described in Reference 2 and approved by the NRC in Reference 1. All of the methods employed and described in Reference 2 are NRC-approved Westinghouse methods and reflect current practices followed by Westinghouse in Reference 3.

The nuclear design of Turkey Point Unit 4, uprated Cycle 16 reload shows that the core reload will not adversely affect the ability to safely operate at uprated core thermal power. The margin between the design criteria and safety analysis limits has been shown to be met, and that sufficient shutdown margin exists after accounting for the uprated core thermal power.

Table 14B-1 presents the Fuel Assembly Design Parameters for all of the fuel regions present in the uprated Cycle 16. Figure 14B-1 presents the reference core loading pattern. The loading contains two different types of discrete burnable absorbers which are described and distributed as follows: 16 Region 18A assemblies containing 12 WABA rodlets per fuel assembly, 4 Region 18B assemblies containing 12 WABA rodlets per fuel assembly, 12 Region 18C assemblies containing 8 WABA rodlets per fuel assembly, 8 Region 18D assemblies containing 16 WABA rodlets per fuel assembly, and 4 Region 18E assemblies containing 16 WABA rodlets per fuel assembly for a total of 528 WABA rods. All of the WABAs are 120 inches in length centered on the fuel mid-plane.

There are also 240 reduced-length (36 in.) hafnium absorber rods in the 8 Region 16A and 4 Region 16B fuel assemblies along the core flats. The hafnium rods are modeled in the uprated Cycle 16 core by approved Westinghouse nuclear design codes, as was done for the Unit 4 Cycle 15 core (Reference 23), based on the description and dimensions provided to Westinghouse (Reference 21). The locations of the hafnium absorber rods are shown in Figure 14B-2.

In addition, 2,624 IFBAs, as shown in Figure 14B-2, are distributed in the following fuel regions: 20 Region 18A assemblies with 32 IFBAs each, 4 Region 18B assemblies with 48 IFBAs each, 12 Region 18C assemblies with 64 IFBAs each, 24 Region 18D assemblies with 32 IFBAs each, and 4 Region 18E assemblies with 64 IFBAs each. The IFBAs stack height is 120 inches centered on the fuel mid-plane. These IFBA configurations are presented in Reference 24 and are considered the new standard IFBA loading patterns.

The uprated Cycle 16 loading pattern meets all peaking factor requirements. Figures 14B-A1 and 14B-A3, in Attachment 14B-A to this reload safety evaluation (RSE), present the Relaxed Axial Offset Control (RAOC) operating bands and the K(z) curve, respectively, appropriate for the uprated Cycle 16. Operation within these bands ensures compliance with the F_Q requirements consistent with the methodology described in Reference 25.

The uprated Cycle 16 loading pattern was also evaluated for the Reactivity Cluster Control Assemblies (RCCAs) parking positions at 228 and 230 steps withdrawn. Figure 14B-A2, in Attachment 14B-A to this reload safety evaluation (RSE), presents the Rod Insertion Limits (RILs) for the 228 steps parking position. The RILs for the 230 parking position are shown in Figure 14B-3 of this RSE.

Table 14B-2 provides a comparison of the range of values that are representative of the uprated Cycle 16 core kinetics parameters with their current limits based on previously performed accident analysis. The delayed neutron fraction characterize the dynamic response of the core to changes in reactivity. The moderator and doppler temperature coefficients are measures of the dominant reactivity feedback mechanisms. The required shutdown margin presented in Table 14B-3 is based on previously performed accident analyses, Reference 7. The available shutdown margin exceeds the minimum required.

The Core Operating Limits Report (COLR) for Turkey Point Unit 4 uprated Cycle 16 is included in Attachment 14B-A to this RSE.

2.3 THERMAL AND HYDRAULIC DESIGN

The thermal hydraulic methodology, DNB correlations, and safety analyses used for the Cycle 16 are consistent with the OFA transition licensing submittal (Reference 4) and the increased $F_{\Delta H}$ limit licensing submittal (Reference 10) and approved in Reference 5. The combination of core temperature and power meets the core safety limits given in Technical Specifications (Reference 18) Figure 2.1-1, and results in no adverse variation in thermal margins from the Cycle 16 reload.

The thermal hydraulic analysis of Turkey Point Unit 4 Cycle 16 reload shows that the core reload will not adversely affect the ability to safely operate at uprated core thermal power. The margin between the design and safety analysis limit DNBRs is more than sufficient to cover all the applicable DNBR penalties.

Analyses (Reference 26) have also been performed for Cycle 16 which support a reduced thermal design flow, an increased $F_{\Delta H}$ limit, and the Revised Thermal Design Procedure. The Revised Thermal Design Procedure (Reference 16) differs from the current procedure in that the DNB correlation uncertainties and the plant parameters uncertainties are combined-statistically instead of being treated separately. The RTDP instrument uncertainty methodology change is provided in Reference 27.

As noted in the Turkey Point Unit 4, Cycle 15 RSE, the DNBR design basis used for the hypothetical steamline break event was 1.45 for the W-3 correlation. The design limit has been approved by the NRC in Reference 28. Although this low pressure limit was approved in conjunction with WCAP-9227-NP, which is not referenced in the Turkey Point FSAR, this SER is an applicable reference for the Unit 4 Cycle 16 reload design.

3.0 POWER CAPABILITY AND ACCIDENT EVALUATION

3.1 POWER CAPABILITY

This section reviews the plant power capability considering the consequences of those incidents examined in the FSAR (Reference 9) using the previously accepted design bases. It is concluded that the core reload will not adversely affect the ability to safely operate at 100% rated power during the uprated Cycle 16. For the overpower transient, the fuel centerline temperature limit of 4700 °F can be accommodated with margin in the uprated Cycle 16 core. The revised fuel thermal safety model (Reference 19) was used for fuel temperature evaluations. The LOCA F_Q limit of 2.35 x K(z) is met under all operating conditions.

3.2 ACCIDENT EVALUATION

The effects of the reload, including the mechanical design features described in Section 2.1, on the design basis and postulated incidents analyzed in References 4 and 9, the proposed changes for Reduced Thermal Design Flow / Revised Thermal Design Procedure (Reference 26), and the analyses performed to account for a licensed power uprating (Reference 7), have been examined. In all cases, it was found that the effects can be accommodated within the conservatism of the initial assumptions used in the previous applicable safety analysis, the proposed licensing basis safety analysis (RTDP), or, as in the case of the DRFA, by Turkey Point specific evaluations which demonstrate that the margin to the regulatory limits is maintained.

The investigation into the effects of low initial rod internal pressure (RIP) for IFBA rods on the Large and Small Break LOCA analyses has been completed. It has been demonstrated that RIP uncertainty is not a significant PCT effect for initial cold pressures from 200 to 275 psig on the Large Break LOCA. Further, special IFBA analyses for Small Break LOCA, regardless of initial backfill pressure, are not required. In addition, the revised helium release model has been evaluated (Reference 29) as acceptable. Therefore, operation of the uprated Cycle 16 with 200 psig backfill IFBA fuel with and without the new helium release model meets the requirements of 10 CFR 50.46 with no additional work required.

A safety requirement that the core remain subcritical on soluble boron alone in long term cooling following a Large Break LOCA is adhered to in the uprated Cycle 16 design (Reference 30). This is accomplished by identifying all of the sources of water in the sump following actuation of the ECCS, calculating their respective pre-accident boron concentration and then determining the resultant sump mixture boron concentration. This resultant boron concentration is then compared to the cold zero power critical boron requirement to demonstrate that the core remains subcritical. A reload can typically affect accident input parameters in three major areas: kinetics characteristics, control rod worths, and core peaking factors. The uprated Cycle 16 parameters in each of these areas were examined as discussed below to ascertain whether new accident analyses are required.

As a result of Technical Bulletin NSD-92-003, Westinghouse analyzed a Reactor Trip delay time of 2.0 seconds for the Reactor Coolant Pump undervoltage trip. The evaluation verified that the DNB design basis was met for the Complete Loss of Flow event for Unit 4, uprated Cycle 16.

A generic evaluation has been performed for LOCA to assess the effect of an End-of-Cycle 5 °F full power T_{AVG} coastdown based on uprated conditions with a ± 3 °F T_{AVG} operating window (Reference 31). The evaluation resulted in a 7 °F PCT increase for the Large Break LOCA analysis. Lower vessel average temperature is non-limiting for the Turkey Point Small Break LOCA analysis. Therefore, a full power coastdown of 5 °F in T_{AVG} is acceptable for LOCA provided there are no RSAC violations due to the reduced vessel average temperature.

Reference 31 also evaluated the potential impact of the 5 °F full power T_{AVG} coastdown on the non-LOCA licensing basis safety analyses. It was concluded that all non-LOCA events occurring at the coastdown conditions are bounded by the Chapter 14 FSAR non-LOCA analyses.

3.2.1 KINETICS PARAMETERS

The uprated Cycle 16 kinetics parameters with current limits are given in Table 14B-2. The delayed neutron fractions and moderator temperature coefficient are within the bounds of the current limits.

3.2.2 CONTROL ROD WORTHS

Changes in control rod worths may affect shutdown margin, differential rod worths, ejected rod worths, and trip reactivity. Table 14B-3 shows that the uprated Cycle 16 shutdown margin requirements are satisfied. As shown in Table 14B-2, the maximum differential rod worth of two RCCA control banks moving together in their highest worth region for the uprated Cycle 16 is less than or equal to the current limit.

3.2.3 CORE PEAKING FACTORS

The peaking factors following control rod ejection are within the bounds of the current limits. Evaluation of peaking factors for the rod out of position and dropped RCCA incidents shows that DNBR is maintained above the appropriate safety analysis minimum value (References 2 and 10).

3.2.4 LOCA CORE AXIAL POWER SHAPE

Large Break LOCA analysis has been traditionally performed using a symmetric, chopped cosine, core axial power shape. Under certain conditions, calculations have shown that there is a potential for top-skewed power distributions to result in Peak Cladding Temperatures (PCTs) greater than those calculated with a chopped cosine axial power distribution.

In January of 1995, Westinghouse initiated development of an axial power shape methodology to replace PSSM. The methodology, ESHAPE (Explicit Shape Analysis for PCT Effects), is based on explicit analysis with a set of skewed axial power shapes, which supplements the standard analysis done with the chopped cosine. Development of this methodology was completed in June 1995. Results of multiple plant calculations have shown that the limiting core axial power shape is related to the time of PCT, with early PCT plants (<100 seconds) being cosine shape limited and late PCT plants (>200 seconds) being top skewed shape limited. At intermediate times, the limiting shape is plant dependent. Discussions, with the NRC, have been held on this approach starting on March 21, 1995. At this time, the NRC is considering ESHAPE to be an updated application of methodology described in WCAP-10266-P-A (Reference 32), submitted and approved in December 1987.

Using the ESHAPE Methodology, Westinghouse has determined that plants with early PCT times are cosine shape limited. The Turkey Point Units have a PCT time > 100 seconds and are therefore potentially affected by skewed power shapes. Additional work performed with the ESHAPE methodology for Turkey Point resulted in a maximum PCT increase of 14 °F over the cosine shape Large Break LOCA PCT. As a consequence, all 10 CFR 50.46 limits are met, and the Turkey Point Unit 4, uprated Cycle 16 can be licensed with ESHAPE methodology and the current analysis of record.

3.3 EVENTS REANALYZED

3.3.1 CHEMICAL VOLUME CONTROL SYSTEM MALFUNCTION

As a result of an increased boron dilution flowrate, the Chemical Volume Control System (CVCS) Malfunction event was reanalyzed. The results of this reanalysis are documented in Reference 11 and show that all applicable acceptance criteria are met.

4.0 TECHNICAL SPECIFICATIONS CHANGES

A review of the Turkey Point Unit 4, uprated Cycle 16 RSE has been performed relative to the impact of this RSE on the Turkey Point Technical Specifications (Reference 18) and Core Operating Limits Report (COLR). This review was performed on the Turkey Point Technical Specifications (Reference 18) inclusive of Amendment 175, dated March 27, 1996 and the Cycle 16 COLR, June 1996, attached. As a result of this review, no technical specifications changes are required, assuming approval of the licensing amendment request as specified in Reference 7, based on the subject RSE for the uprated Cycle 16 operation.

5.0 REFERENCES

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19. Weiner, R. A., et al., "Improved Fuel Performance Models for Westinghouse Fuel Rod Design and Safety Evaluation," WCAP-11873-A, August 1988.

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TABLE 14B-1

FUEL ASSEMBLY DESIGN PARAMETERS

TURKEY POINT UNIT 4 - UPRATED CYCLE 16

Region	16A	16B	16D	16E	17A	17B	17C
Enrichment (w/o U 235)[1]	3.611	3.610	4.004	4.005	3.611	3.619	3.619
Density (% Theoretical)[1]	95.15	95.17	95.28	95.27	95.73	95.73	95.73
Number of Assemblies	9	16	8	8	20	4	8
Approximate Burnup at Beginning of Cycle 16 (MWD/MTU) [2]	33,627	33,100	25,861	31,354	17,954	18,596	15,301
Fuel Type [3]	OFA	OFA	OFA	OFA	OFA	OFA	OFA
Number of IFBA Fuel Rods	---	512	128	384	---	64	256
Axial Blankets	Yes	Yes	Yes	Yes	Yes	Yes	Yes

NOTES:

1. All fuel region values are as-built.
2. Based on Cycle 15 burnup of 13,850 MWD/MTU rounded to the nearest 100 MWD/MTU.
3. The entire Uprated Cycle 16 core is of the DRFA design.

TABLE 14B-1

FUEL ASSEMBLY DESIGN PARAMETERS

TURKEY POINT UNIT 4 - UPRATED CYCLE 16

Region	17D	17E	17F	18A	18B	18C	18D	18E
Enrichment (w/o U 235)[1]	3.619	4.010	4.004	3.605	3.604	3.614	3.998	4.004
Density (% Theoretical)[1]	95.73	95.51	95.51	95.67	95.67	95.67	95.47	95.47
Number of Assemblies	4	8	8	20	4	12	24	4
Approximate Burnup at Beginning of Cycle 15 (MWD/MTU)[2]	15,436	17,605	15,472	0	0	0	0	0
Fuel Type[3]	OFA	OFA	OFA	OFA	OFA	OFA	OFA	OFA
Number of IFBA Fuel Rods	192	---	512	640	192	768	768	256
Axial Blankets	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes

NOTES:

1. All fuel region values are as-built.
2. Based on Cycle 15 burnup of 13,850 MWD/MTU rounded to the nearest 100 MWD/MTU.
3. The entire Uprated Cycle 16 core is of the DRFA design.

TABLE 14B-2

KINETICS CHARACTERISTICS

TURKEY POINT UNIT 4 - UPRATED CYCLE 16

	Current Limit	Uprated Cycle 16
Moderator Temperature Coefficient (pcm/°F) (1)		
a. most positive	+5.0 (≤ 70% RTP), linear ramp to 0 at 100% RTP	+5.0 (≤ 70% RTP), linear ramp to 0 at 100% RTP (2)
b. most negative (3)	-58	> -58
Doppler Coefficient (pcm/°F) (1)	-2.9 to -1.0	-2.9 to -1.0
Delayed Neutron Fraction β_{eff}, (%)	0.42 to 0.75	0.42 to 0.75
Minimum Differential Rod Worth of Two Banks Moving Together at HZP (pcm/in) (1)	100	< 100

NOTES:

1. pcm = 10^{-5} $\Delta\rho$

2. Although it is highly unlikely for this design, the moderator temperature coefficient for the all-rods-out condition may be more positive than the current limit at BOC. The moderator temperature coefficient will be kept within the MTC limit by administrative controls (with the appropriate D bank position and/or boron concentration).

3. All rods in condition, corresponds to a most positive moderator density coefficient (MDC) of 0.50 $\Delta\rho$/gm/cc. The most positive MDC is incrementally corrected to nominal operating conditions to obtain the most negative MTC Technical Specification limit of -35 pcm/°F. This correction involves subtracting the incremental change in the MDC associated with a core condition of all rods inserted (most positive MDC) to an all rods withdrawn condition and a conversion for the rate of change of moderator density with temperature at Rated Thermal Power conditions.

TABLE 14B-3

SHUTDOWN REQUIREMENTS AND MARGINS

TURKEY POINT UNIT 4 - CYCLES 15 AND UPRATED 16

	Cycle 15		Uprated Cycle 16	
	BOC	EOC	BOC	EOC
Control Rod Worth (% $\Delta\rho$)				
All Rods Inserted Less Worst Stuck Rod	6.32	6.14	6.51	5.83
(1) Less 7%	5.88	5.71	6.05	5.42
Control Rod Requirements (%$\Delta\rho$)				
Reactivity Defects (Doppler, T_{avg}, Void, Redistribution)	1.93	2.74	1.79	2.89
Rod Insertion Allowance (RIA)	0.50	0.50	0.50	(1)
RCCA Repositioning Allowance	0.10	0.10	---	---
(2) Total Requirements	2.53	3.34	2.29	2.89
Shutdown Margin (1)-(2) (%$\Delta\rho$)	3.35	2.37	3.76	2.53
Required Shutdown Margin (%$\Delta\rho$)	1.00	1.77	1.00	1.77

NOTE:

1. The RIA term is already included in the Reactivity Defects term in the methodology used to compute the EOC shutdown margin.

	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1
R							16A	16B	16A						
P					16B	17E	18D	17D	18D	17E	16B				
N				16E	18D	18D	17F	18E	17F	18D	18D	16E			
M			16E	18A	18A	17A	17C	17A	17C	17A	18A	18A	16E		
L		16B	18D	18A	16B	18A	17A	18B	17B	18A	16B	18A	18D	16B	
K		17E	18D	17A	18A	16D	18C	17A	18C	16D	18A	17A	18D	17E	
J	16A	18D	17F	17C	17B	18C	16D	18C	16D	18C	17A	17C	17F	18D	16A
H (270°)	16B	17D	18E	17A	18B	17A	18C	16A	18C	17A	18B	17A	18E	17D	16B
G	16A	18D	17F	17C	17A	18C	16D	18C	16D	18C	17B	17C	17F	18D	16A
F		17E	18D	17A	18A	16D	18C	17A	18C	16D	18A	17A	18D	17E	
E		16B	18D	18A	16B	18A	17B	18B	17A	18A	16B	18A	18D	16B	
D			16E	18A	18A	17A	17C	17A	17C	17A	18A	18A	16E		
C				16E	18D	18D	17F	18E	17F	18D	18D	16E			
B					16B	17E	18D	17D	18D	17E	16B				
A							16A	16B	16A						

180°

LEGEND

R REGION IDENTIFIER

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TURKEY POINT PLANT UNIT 4

UNIT 4 UPRATED CYCLE 16
REFERENCE
CORE LOADING PATTERN

FIGURE 14B-1

	15	14	13	12	11	10	9	8	7	6	5	4	3	2	1
R							20FS	20FS	20FS						
P							32I		32I						
N					32I	32I 16W		64I 16W		32I 16W	32I				
M				32I	32I 12W						32I 12W	32I			
L			32I	32I 12W		32I 12W		48I 12W		32I 12W		32I 12W	32I		
K			32I 16W		32I 12W		64I 8W		64I 8W		32I 12W		32I 16W		
J	20FS	32I				64I 8W		64I 8W		64I 8W				32I	20FS
270° H	20FS		64I 16W		48I 12W		64I 8W		64I 8W		48I 12W		64I 16W		20FS
G	20FS	32I				64I 8W		64I 8W		64I 8W				32I	20FS
F			32I 16W		32I 12W		64I 8W		64I 8W		32I 12W		32I 16W		
E			32I	32I 12W		32I 12W		48I 12W		32I 12W		32I 12W	32I		
D				32I	32I 12W						32I 12W	32I			
C					32I	32I 16W		64I 16W		32I 16W	32I				
B							32I		32I						
A							20FS	20FS	20FS						

180°

TYPE		TOTAL
##W	- NUMBER OF WABA RODLETS	528
##I	- NUMBER OF IFBA RODS	2624
##FS	- NUMBER OF FLUX SUPPRESSION RODLETS ...	240

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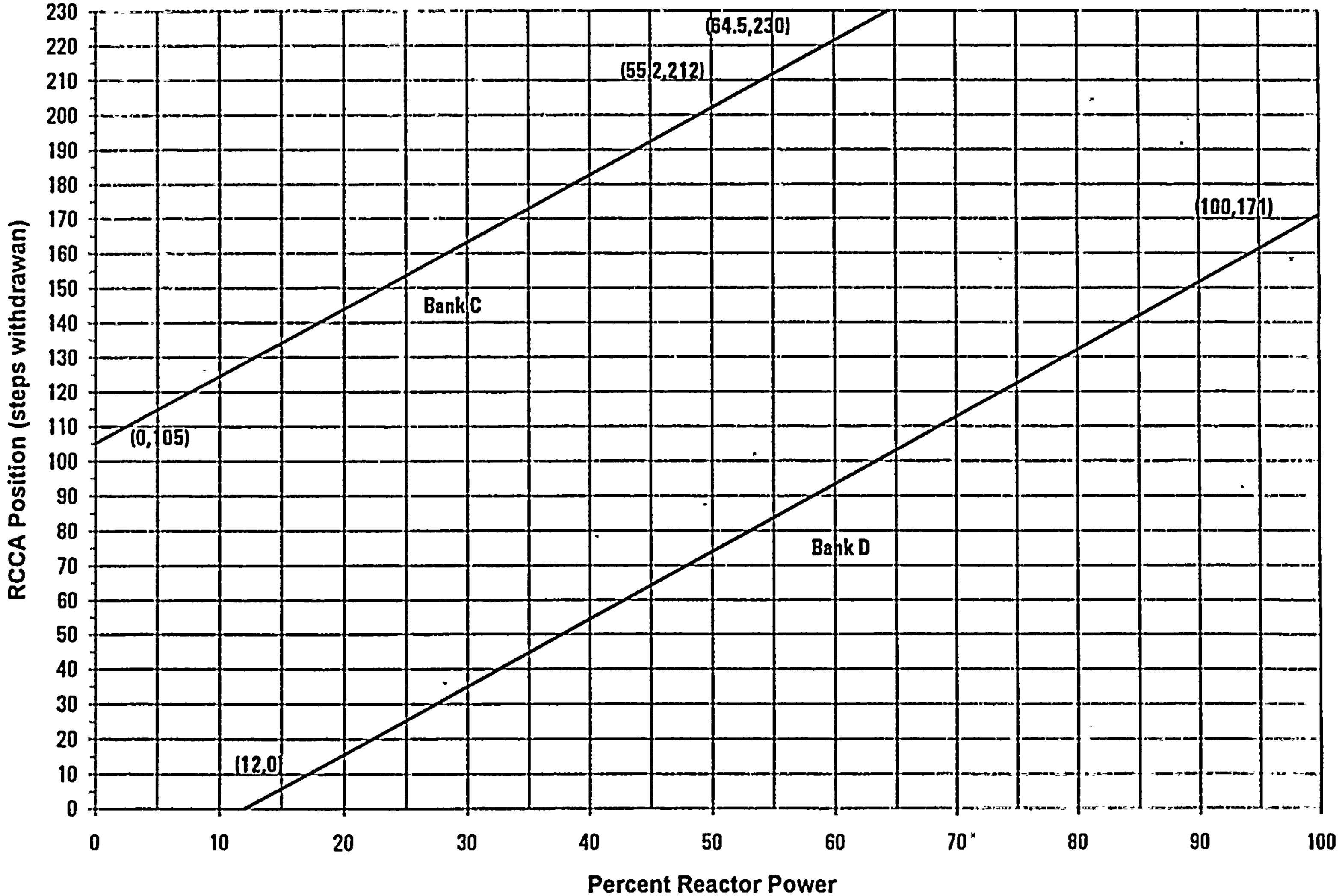
UNIT 4 UPRATED CYCLE 16
BURNABLE ABSORBER
LOCATIONS

FIGURE 14B-2



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TURKEY POINT PLANT UNIT 4

UNIT 4 UPRATED CYCLE 16
ROD INSERTION LIMIT
ARO = 230 STEPS WITHDRAWN
OVERLAP = 102 STEPS

FIGURE 14B-3

APPENDIX 14B - ATTACHMENT A

TURKEY POINT PLANT UNIT 4
THERMAL UPRATED CYCLE 16
CORE OPERATING LIMITS REPORT (COLR)

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ATTACHMENT A

CORE OPERATING LIMITS REPORT (COLR)

1.0 INTRODUCTION

The Core Operating Limits Report (COLR) for Turkey Point Unit 4 Uprated Cycle 16 has been prepared in accordance with the requirements of Technical Specifications 6.9.1.7.

The Technical Specifications affected by this report are:

3.2.1	Axial Flux Difference (AFD)
3.1.3.6	Control Rod Insertion Limits
3.2.2	Heat Flux Hot Channel Factor - $F_Q(z)$
3.2.3	Nuclear Enthalpy Rise Hot Channel Factor

2.0 OPERATING LIMITS

The AFD, $F_Q(z)$, K(z) and Rod Bank Insertion Limits have been developed using the NRC approved methodology specified in Technical Specification 6.9.1.7. These limits are provided in the following subsections:

2.1 AXIAL FLUX DIFFERENCE (TS 3.2.1)

The Axial Flux Difference (AFD) limits are provided in Figure 14B-A1.

2.2 CONTROL ROD INSERTION LIMITS (TS 3.1.3.6)

The control rod banks shall be limited in physical insertion as shown in Figure 14B-A2.

2.3 HEAT FLUX HOT CHANNEL FACTOR $F_Q(z)$ (TS 3.2.2)

- $[F_Q]^L$ = 2.35 per Reference A1.
- K(z) is provided in Figure 14B-A3.

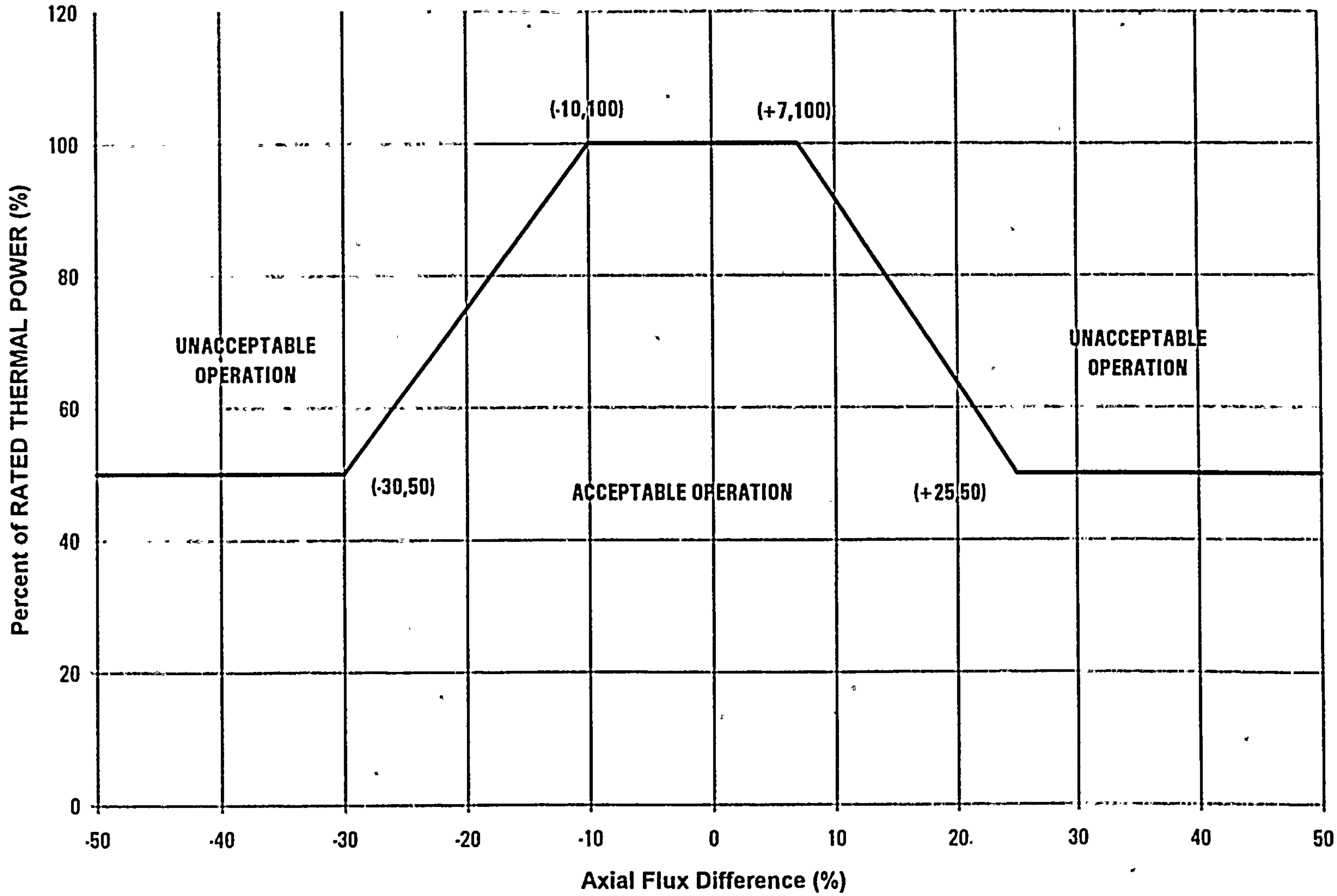
2.4 NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (TS 3.2.3)

- $F_{\Delta H}^{RTP}$ = 1.64 per Reference A1.
- $PF_{\Delta H}$ = 0.3 per Reference A2.

3.0. REFERENCES

A1. Letter from Metcalf, N. R. (Westinghouse) to Knuckles, E. R. (FP&L), "LOCA Future Limits for Turkey Point 3 Cycle 15 and Turkey Point 4 Cycle 16 Uprating," 95FP*-G-0137, November 14, 1995.

A2. Letter from Metcalf, N. R. (Westinghouse) to Perryman, J. L. (FP&L), "Florida Power & Light Company, Turkey Point Unit 3 Cycle 15 and Unit 4 Cycle 16, Design Initialization at Uprate (2300 MWt) Conditions," 96FP*-G-0009, January 31, 1996.



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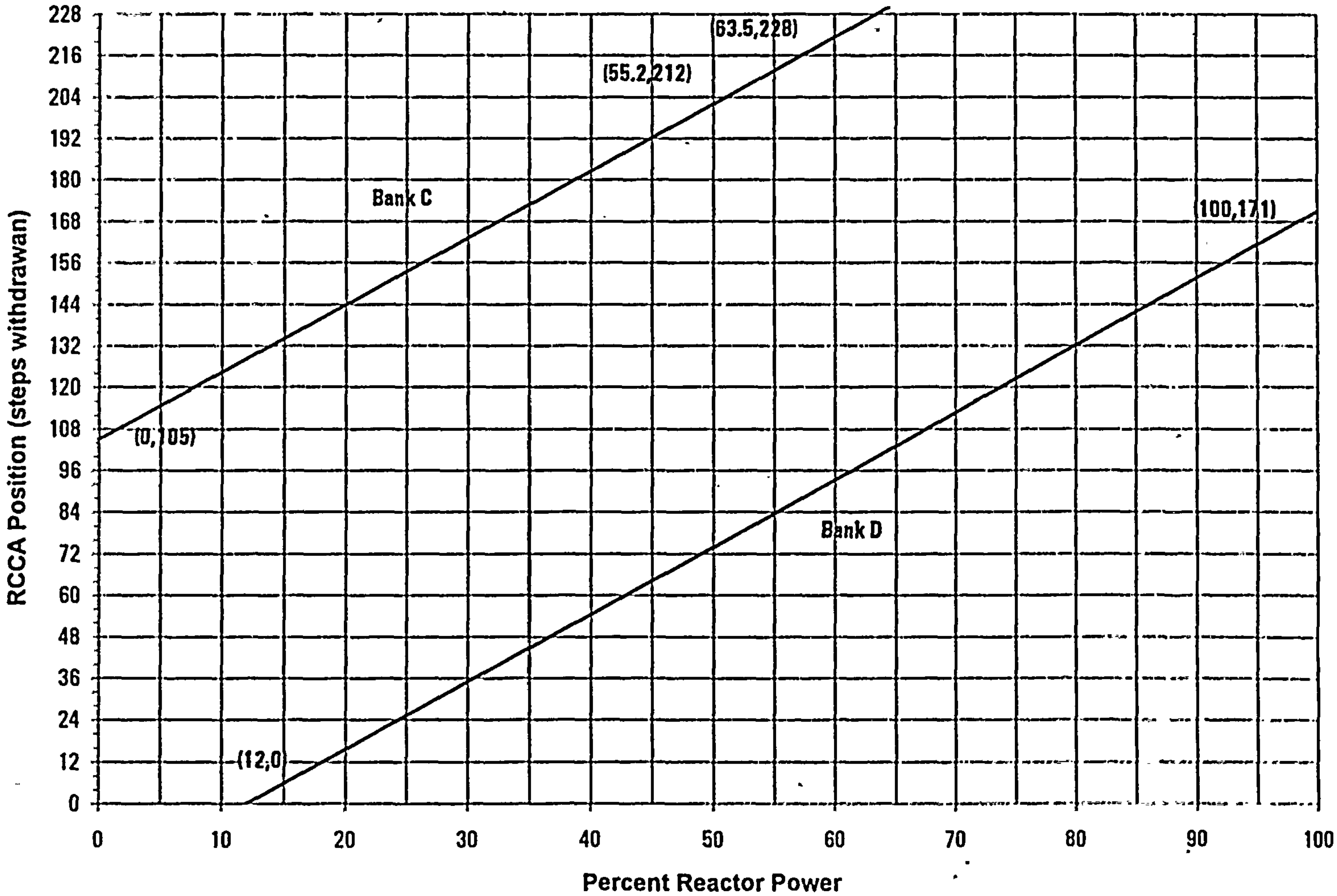
TURKEY POINT PLANT UNIT 4

UNIT 4 UPRATED CYCLE 16
AXIAL FLUX DIFFERENCE AS A
FUNCTION OF RATED THERMAL POWER

FIGURE 14B-A1



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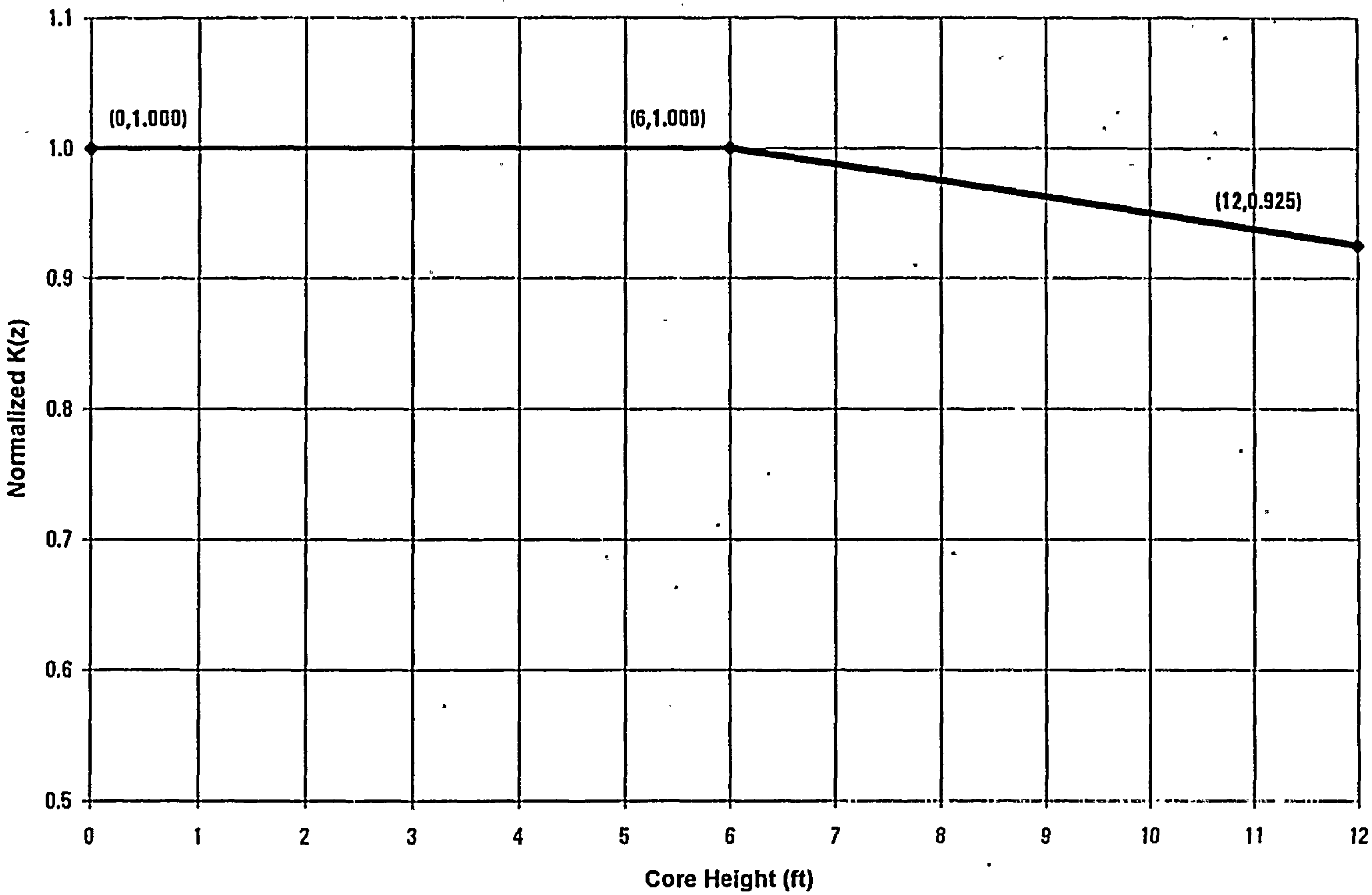
TURKEY POINT PLANT UNIT 4

UNIT 4 UPRATED CYCLE 16
ROD BANK INSERTION LIMITS
VERSUS THERMAL POWER
ARO = 228 STEPS WITHDRAWN
OVERLAP = 100 STEPS

FIGURE 14B-A2



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TURKEY POINT PLANT UNIT 4

UNIT 4 UPRATED CYCLE 16
K(z) NORMALIZED $F_Q(z)$ AS A
FUNCTION OF CORE HEIGHT

FIGURE 14B-A3