From: Harriet Nash
To: Shelley.Norton@noaa.gov
Subject: NRC BA
Date: Monday, February 27, 2006 3:07:11 PM
Attachments: St Lucie BA.pdf

Hi Shelley,

The BA is finally being mailed out to you. Attached is a pdf of the document. Please let me know if you have any questions.

Also, did you ever hear from the Baltimore aquarium about the sawfish move?

Harriet

February 24, 2006

Mr. David Bernhart
Assistant Regional Administrator
for Protected Resources
NOAA's National Marine Fisheries Service
Southeast Regional Office
263 13th Avenue, South
St. Petersburg, FL 33701

SUBJECT: BIOLOGICAL ASSESSMENT FOR THE REINITIATION OF A FORMAL CONSULTATION FOR CONTINUED OPERATION OF THE ST. LUCIE NUCLEAR POWER PLANT (TAC NOS. MC7266 AND MC7267)

Dear Mr. Bernhart:

The U.S. Nuclear Regulatory Commission (NRC) staff has prepared the enclosed Biological Assessment (BA) to reinitiate formal consultation, under Section 7 of the Endangered Species Act, regarding the continued operation of the St. Lucie Nuclear Power Plant. In your May 4, 2001, Biological Opinion (BO), the current Incidental Take Statement (ITS), as clarified by letter dated July 30, 2002, authorizes the annual take limit for injured and dead (due to plant operations) loggerhead and green turtles by percentage, up to one percent of the annual total loggerhead and green turtles (combined). Additionally, there are limits causally related to plant operations of two lethal takes of Kemp's ridley turtles each year and of one hawksbill or leatherback turtle injured or killed every two years. There is an annual maximum of 1000 takes for all sea turtle species combined, regardless of cause. The take limits for sea turtles have not been met or exceeded. However, a smalltooth sawfish (*Pristis pectinata*) take occurred on May 16, 2005. Because the smalltooth sawfish is listed as Federally endangered and is not addressed in the current ITS, this take triggered reinitiation of a Section 7 consultation. Therefore, the NRC is requesting a reinitiation of formal consultation with the submission of the enclosed BA.

On September 29, 2005, representatives of the NRC, NOAA's National Marine Fisheries Service, and the Florida Power & Light Company (the licensee that maintains and operates the St. Lucie Nuclear Power Plant) met for a site tour and discussion of the smalltooth sawfish take and rescue. The site tour focused on the intake canal and rescue transportation route from the intake canal over the dune to the Atlantic Ocean. At the meeting the specific sequence of events associated with the sawfish sighting and rescue were discussed in addition to potential mitigation measures, which are described in detail in the enclosed BA.

If you have any questions regarding this BA or the staff's request, please contact Ms. Harriet Nash of the Environmental Branch, at 301-415-4100 or by e-mail at hln@nrc.gov.

Sincerely,

/RA Pao-Tsin For/

Frank Gillespie, Director
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos.: 50-335 and 50-389

Enclosure: As stated

cc w/encl.: See next page

If you have any questions regarding this BA or the staff's request, please contact Ms. Harriet Nash of the Environmental Branch, at 301-415-4100 or by e-mail at hln@nrc.gov.

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St. Lucie

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Biological Assessment

St. Lucie Units 1 and 2
Reinitiation of Section 7 Consultation

St. Lucie County, Florida

February 2006

Docket Nos. 50-335 and 50-389

U.S. Nuclear Regulatory Commission
Rockville, Maryland

1.0 Introduction and Summary of Conclusions

This Biological Assessment (BA) was prepared in support of reinitiating a formal consultation between the U.S. Nuclear Regulatory Commission (NRC) and National Oceanic and Atmospheric Administration's National Marine Fisheries Service (NMFS) in compliance with Section 7 of the Endangered Species Act of 1973, as amended (ESA). The purpose of this BA is to examine the potential impacts on ESA-listed species associated with the continued operation of the St. Lucie Nuclear Power Plant's circulating seawater cooling system, and to support the NRC's July 8, 2005, request to NMFS for reinitiation of formal Section 7 consultation regarding the St. Lucie Nuclear Power Plant. The NRC has been consulting with NMFS regarding sea turtle takes at the St. Lucie Nuclear Power Plant since 1982; several BAs and Biological Opinions (BOs) have been issued since 1982 resulting in periodic revisions to the Incidental Take Statement (ITS), as appropriate. All previous consultations with NMFS have addressed sea turtle takes; however, this reinitiation of formal consultation was triggered by a take of a smalltooth sawfish (*Pristis pectinata*) on May 16, 2005.

Florida Power and Light Company (FPL) is the licensee that operates the St. Lucie Nuclear Power Plant and conducts an ongoing turtle capture-and-release program in the station's intake canal. There have been no procedural changes in the operation of the St. Lucie Nuclear Power Plant's circulating seawater cooling system since the last BO, dated May 4, 2001, which was clarified by letter dated July 30, 2002. Therefore, the NRC staff suggests maintaining the 2001 ITS for sea turtles with an addendum for the smalltooth sawfish. The 2001 BO analyzed the effects of operation of the St. Lucie Nuclear Power Plant's circulating seawater cooling system on loggerhead turtles (*Caretta caretta*), green turtles (*Chelonia mydas*), Kemp's ridley turtles (*Lepidochelys kempi*), leatherback turtles (*Dermochelys coriacea*), and hawksbill turtles (*Eretmochelys imbricata*). This BA provides a brief update of information regarding interactions of the cooling system with these sea turtle species. However, the central focus of this BA is to identify potential impacts of cooling system operation on the smalltooth sawfish, which was listed as endangered on November 16, 2005, based on NMFS's final determination dated April 1, 2003.

The St. Lucie Nuclear Power Plant is located on Hutchinson Island in St. Lucie County, Florida. The island is a barrier island bounded by the Atlantic Ocean to the east and the Indian River Lagoon to the west. The cooling system withdraws water from the Atlantic Ocean to cool the condensers of the two operating reactors, St. Lucie Units 1 and 2, which began operating in 1976 and 1983, respectively. The intake portion of the cooling system consists of three intake structures with velocity caps in the ocean, three buried pipelines, a common intake canal, and two intake well structures (one for each unit). In the intake canal is a series of nets, trash bars, and screens to prevent debris and organisms from being impinged on the intake screens.

Animals occasionally enter the canal system of the St. Lucie Nuclear Power Plant along with seawater that is withdrawn from the Atlantic Ocean for condenser cooling. The intake structures and velocity caps for the plant are located about 365 meters (m) (1200 feet [ft]) offshore where they also serve as artificial reefs. As such, these structures attract turtles and other marine life by providing food and shelter. If an animal passes through the vertical plane of the velocity cap, the animal would enter the intake pipeline, which travels under the ocean floor and barrier island and debouches in the intake canal on the western side of the beach dunes.

Once in the intake canal, the animals cannot escape due to the high flow rates in the intake pipes and must be rescued and returned to the ocean. Therefore, FPL has a capture-and-release program to retrieve sea turtles and return them to the ocean. The capture program includes conservation efforts and collaboration with research organizations, sea turtle stranding programs, and Federal and State agencies. FPL has an existing agreement with Florida Fish and Wildlife Conservation Commission (FFWCC) regarding case-specific decisions on how and where to treat injured turtles that are not healthy enough to be returned immediately to the ocean. The FFWCC is also consulted to conduct turtle necropsies when needed. NRC's long history of consultations with NMFS regarding the St. Lucie Nuclear Power Plant and FPL's commitment to minimize sea turtle injury and mortality have resulted in the modification and addition of barrier nets over time.

According to FPL, the smalltooth sawfish take on May 16, 2005, is the only known occurrence of the species in the St. Lucie Nuclear Power Plant intake canal since the cooling system began operating in 1976. Although the smalltooth sawfish was not listed under the ESA until 2005, the NRC staff believes that a sighting of this species most likely would have been reported given the unusual morphology of the rostrum. Once in the intake canal, the smalltooth sawfish was ensnared in a tangle net used to retrieve turtles. FPL biologists acted quickly to retrieve the specimen, take measurements and photographs, and return the animal to the ocean using the turtle stretcher and cart. The animal appeared healthy and immediately swam away upon release. On September 29, 2005, representatives of NMFS, NRC, and FPL met at the St. Lucie Nuclear Power Plant to discuss the smalltooth sawfish take. The meeting included a tour of the intake canal and the beach. Discussions focused on the series of events immediately following the take and on possible rescue strategies in the event of a future smalltooth sawfish take. Because the occurrence of the smalltooth sawfish at St. Lucie Nuclear Power Plant is rare (one take since 1976), because the FPL biologists acted with vigilance to rescue the animal successfully, and because FPL committed to put proper procedures in place to deal with any future smalltooth sawfish takes, the NRC staff believes that the continued operation of the St. Lucie Nuclear Power Plant's cooling system would not jeopardize the continued existence of the smalltooth sawfish.

2.0 Purpose

This BA is submitted to NMFS in compliance with Section 7 of the ESA, and in support of the NRC's July 8, 2005, request to NMFS for reinitiation of formal Section 7 consultation on ESA-listed species at the St. Lucie Nuclear Power Plant, which is licensed to FPL.

The purpose of this BA is to examine the potential impacts of continued operation of the St. Lucie Nuclear Power Plant's cooling system on ESA-listed species. Since 1982, the NRC has been consulting with NMFS regarding sea turtle takes at St. Lucie Nuclear Power Plant. Historically, the operation of the plant's cooling system has resulted in takes of several sea turtle species: loggerhead turtle (*Caretta caretta*), Kemp's ridley turtle (*Lepidochelys kempii*), green turtle (*Chelonia mydas*), leatherback turtle (*Dermochelys coriacea*), and hawksbill turtle (*Eretmochelys imbricata*). FPL has a program in place to retrieve entrapped turtles and return them to the ocean if they are in healthy condition. If the turtle is injured or dead, FPL coordinates treatment or necropsy with FFWCC. If the turtle is unharmed, it is measured, tagged, and returned to the ocean.

The incidental take limits for turtles have not been exceeded, and FPL's specific protocols designed to retrieve and rescue turtles are in place and followed regularly. This Section 7 consultation reinitiation is in response to a take of smalltooth sawfish (*Pristis pectinata*) that occurred on May 16, 2005. The smalltooth sawfish was measured, photographed, and rescued successfully by FPL biologists. It swam away freely upon release into the Atlantic Ocean. This BA will focus on the smalltooth sawfish.

3.0 Site Description

The St. Lucie Nuclear Power Plant is located on a 457-hectare (1130-acre) site on Hutchinson Island on Florida's east coast (see Figures 1 and 2). The plant is approximately midway between the Ft. Pierce and St. Lucie Inlets. It is bounded on the eastern side by the Atlantic Ocean and on the western side by the Indian River Lagoon, which is a long, shallow estuary. Hutchinson Island is a barrier island that extends 36 kilometers (km) (22.4 miles [mi]) between inlets and attains its maximum width of 2 km (1.2 mi) at the plant site. Elevations approach 5 m (16.4 ft) atop dunes bordering the beach on the eastern side of the island and decrease to sea level in the mangrove swamps that are common on the western side. The Atlantic shoreline of Hutchinson Island is composed of sand and shell hash with intermittent rocky promontories protruding through the beach face along the southern end of the island. Submerged coquinoid rock formations parallel much of the island off the ocean beaches. The ocean bottom immediately offshore from the plant site consists primarily of sand and shell sediments. The Florida Current, which flows parallel to the continental shelf margin, begins to diverge from the coastline at West Palm Beach. At Hutchinson Island, the current is approximately 33 km (20.5 mi) offshore. Oceanic water associated with the western boundary of the current periodically meanders over the inner shelf, especially during summer months.

4.0 Description of the St. Lucie Nuclear Power Plant

St. Lucie Units 1 and 2 consist of two 839-net megawatt-electric (MWe) nuclear-fueled generating units that use nearshore waters from the Atlantic Ocean for the plant's once-through condenser cooling system. The cooling water system removes heat from the condensers and other auxiliary equipment. Eight pumps (four per unit) located at the intake wells circulate water through the system. The pumping capacity ranges from 50,470 to 70,660 liters per second (800,000 to 1,120,000 gallons per minute) (NRC 2003).

Water for this system enters through three submerged intake structures located about 365 m (1200 ft) offshore at a depth of about 7 m (23 ft) (Figure 2). The intake structures have vertical cylindrical openings and are equipped with concrete velocity caps supported by columns extending about 1.8 m (6 ft) from the intake openings. The velocity caps minimize entrainment of fish and other organisms by eliminating vertical flow and slowing horizontal flow. Water passes through these structures and into submerged pipes (two 3.7 m [12 ft] and one 4.9 m [16 ft] in diameter) running under the beach. Flow velocities in the pipes range from 0.11 to 2.1 m/s (0.37 to 6.8 ft/s), depending on the pipe's orientation and size. The three pipes all deliver water into a 1500-m (4921-ft) long intake canal, which transports the water to the plant. The intake canal is a trapezoidal channel about 55 m (180 ft) wide and 9.1 m (30 ft) deep under normal conditions. FPL occasionally dredges the intake canal to remove accumulated sediments and maintain proper flow conditions; most recently, the canal was dredged in 2002 and 2005.

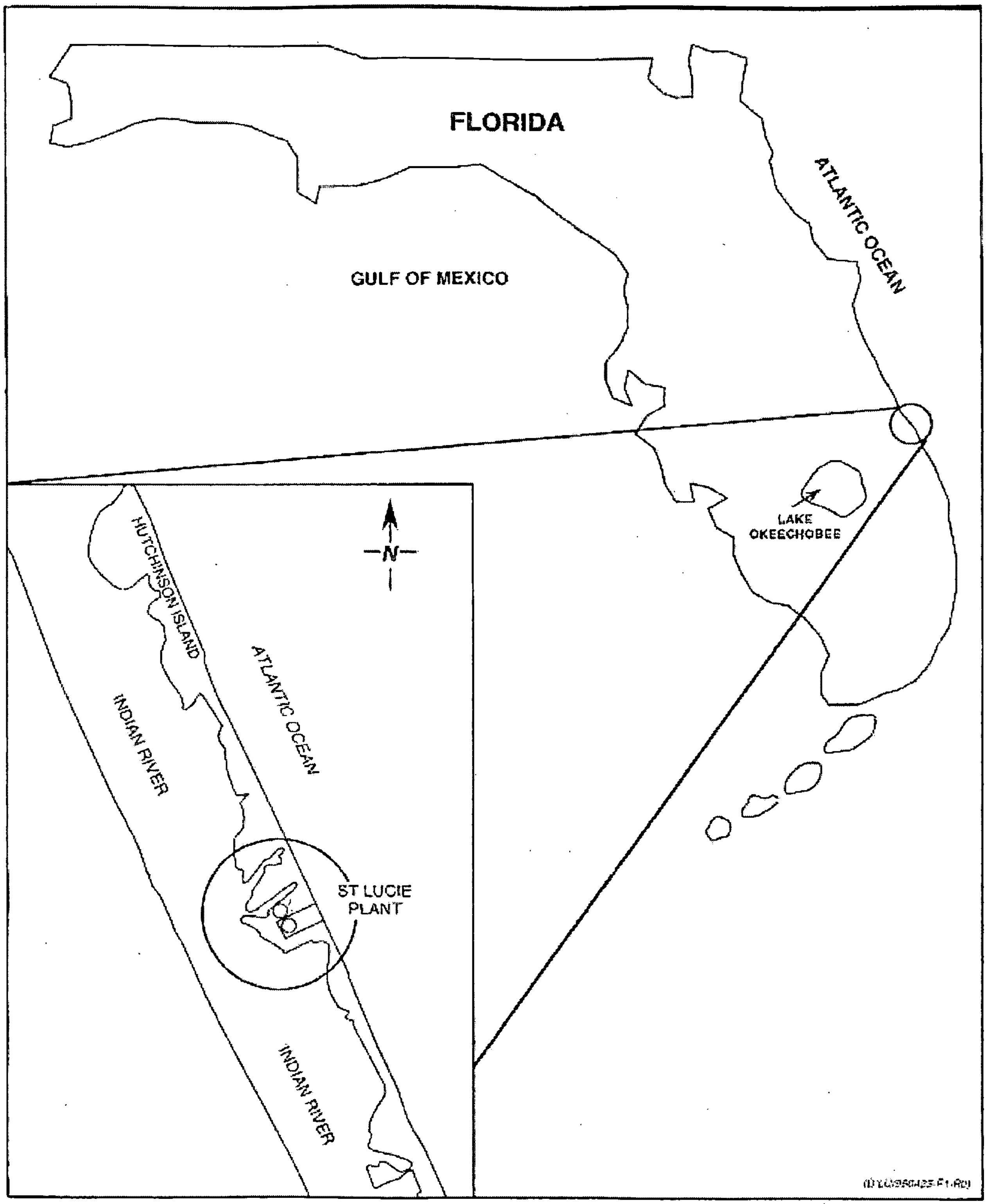

Figure 1. Location of St. Lucie Nuclear Power Plant

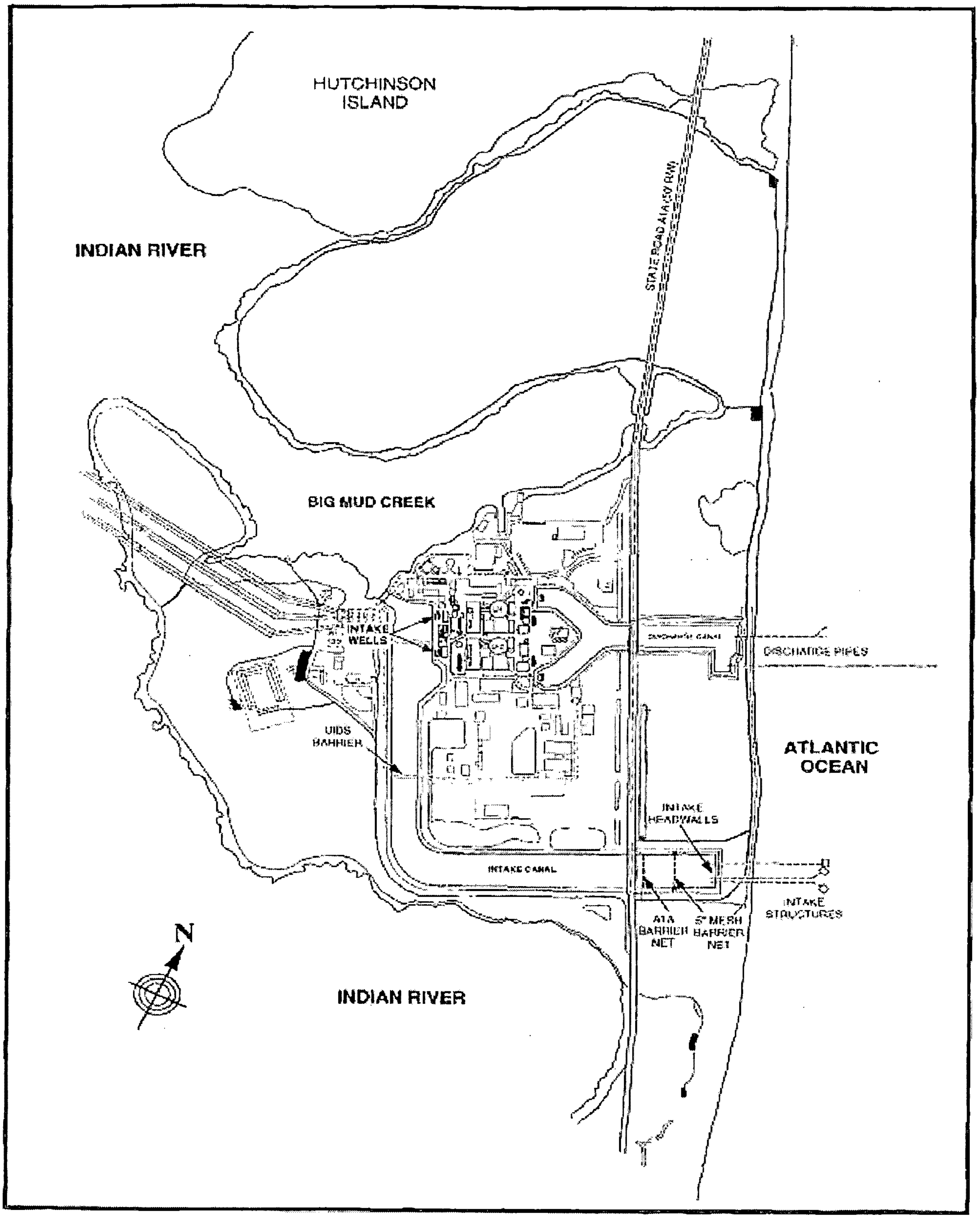

Figure 1. St. Lucie Cooling Water Intake and Discharge System

In addition to the velocity caps on the intake pipes, other measures are in place to minimize impingement of marine biota at the St. Lucie Nuclear Power Plant. In the intake canal, there is a series of barriers to prevent sea turtles and other biota from being impinged on the screens where the water enters the plant. Heading from the intake headwalls toward the intake wells in the intake canal, first there is a 12.7-centimeter (cm) (5-inch [in.]) mesh net that is taut and sloped to prevent turtles from being entangled in the net. The net is monitored hourly by sea turtle biologists who rescue any entrapped turtles. Next, there is a 20-cm (8-in.) mesh barrier net, and finally, there is a rigid security barrier closest to the plant. Additionally, sea turtle biologists deploy two 30.5-m (100-ft) tangle nets in daylight hours (with occasional night hours as well) seven days a week to capture sea turtles between the intake headwall (where the water enters the intake canal from the pipes) and the 12.7-cm (5-in.) mesh barrier net. The nets are set in adjacent eddies and flow with the current without any weights. The tangle nets are inspected at least hourly. The biologists also use dip nets and free diving to capture turtles. Underwater inspections on the 12.7- and 20-cm (5- and 8-in.) mesh barrier nets are conducted quarterly. During these inspections, any holes found in the nets are repaired.

At the plant, water enters through the eight intake wells (four per unit). In front of each well are trash racks (vertical bars spaced 7.6 cm [3 in.] apart) and 1-cm (3/8-in.) mesh traveling screens, which also prevent impingement and entrainment of organisms. Security personnel inspect the intake wells every three hours as an added precautionary measure. After passing through the plant, the heated water is discharged into a 670-m (2198-ft) long canal that leads to two buried discharge pipelines. These pass underneath the dunes and along the ocean floor to the submerged discharge pipes, the first of which is 3.7 m (12 ft) in diameter and terminates approximately 380 m (1250 ft) offshore. The second discharge pipe has a diameter of 4.9 m (16 ft) and ends about 936 m (3070 ft) offshore. The first discharge pipe has a two-port "Y" diffuser, and the second discharge pipe has a multiport diffuser for about the last 430 m (1415 ft) of the pipe. The discharge pipes are approximately 730 m (2400 ft) north of the intake. The diffusers facilitate rapid distribution of the heated water on a large spatial scale to mix efficiently with ambient waters. Discharge temperatures are kept within limits of the Industrial Wastewater Facility Permit for St. Lucie Units 1 and 2.

5.0 Affected Species

Smalltooth Sawfish

Since the St. Lucie cooling water system began operating in 1976, the only protected species under NMFS's jurisdiction that have been affected by plant operations are five sea turtle species (loggerhead turtle, green turtle, Kemp's ridley turtle, leatherback turtle, and hawksbill turtle) and the smalltooth sawfish. Sea turtle biologists discovered a smalltooth sawfish in the intake canal on May 16, 2005. Because the turtle limits have not been met or exceeded and there is no new information available, no changes to turtle incidental take limits are expected, and this section focuses on the smalltooth sawfish. The smalltooth sawfish take triggered the reinitiation of a Section 7 consultation for St. Lucie Units 1 and 2.

Sawfish belong to a group of fishes called elasmobranchs, fishes of the subclass Elasmobranchii that includes sharks, rays, and skates. All elasmobranchs have cartilagenous skeletons. The smalltooth sawfish are in the Suborder Pristoidea, Family Pristidae, Genus *Pristis*, and species *pectinata*. The sawfish family, Pristidae, comprises elasmobranchs that

have a unique rostral extension that is long and flat with teeth along the edges. The smalltooth sawfish has smaller teeth on the rostrum (saw) than most other species in the family. The smalltooth sawfish can have 24 to 32 teeth on each side of the rostrum, and once a sawfish loses its teeth, they do not grow back. These rostral teeth are technically dermal denticles (tiny skin teeth) that are common on shark skin. The rostrum of the smalltooth sawfish is approximately one-quarter the total length of the animal.

The sawfish are similar to sharks, especially the sawshark, in appearance. However, unlike the sawshark, which is a true shark with gills on the side of the head, the sawfish's gills are on the ventral surface like those of rays and skates as the sawfish has a flattened, ray-like head and trunk. While the smalltooth sawfish rests on the bottom, the spiracles, which are located behind the eyes on the dorsal surface, inhale water for breathing while the gills are laid against the bottom. Uncommon with rays and skates, sawfish have large dorsal and caudal fins like those of sharks.

5.1 Status

On April 1, 2003, the NMFS made the final determination to list the smalltooth sawfish *(Pristis pectinata)* as endangered under the ESA. The smalltooth sawfish was the first marine fish to be listed under the ESA; the actual listing occurred on November 16, 2005. After review of the scientific and commercial information available, the status review team determined the U.S. population segment of the smalltooth sawfish was in danger of extinction throughout all or a significant portion of its range. Four factors contributed to the listing of the sawfish: (1) the present or threatened destruction, modification, or curtailment of its habitat or range; (2) overutilization for commercial, recreational, scientific, or educational purposes; (3) the inadequacy of existing regulatory mechanisms; and (4) other natural or manmade factors affecting its continued existence.

The smalltooth sawfish is also listed as critically endangered on the Red List of Threatened Animals issued by the World Conservation Union (IUCN) (Simpfendorfer 2002).

5.2 Distribution

While the smalltooth sawfish is known to occur in the Pacific and Atlantic Oceans, the U.S. population is only known to exist in the Atlantic Ocean. Historically, the U.S. population was found from New York to the Mexican border (Simpfendorfer and Wiley 2005) with the most common occurrences being from Texas to North Carolina. Now the range of the smalltooth sawfish is limited to the Florida peninsula with the most common sightings occurring in the region of the Everglades in the southern part of the state. (NMFS 2005)

5.3 Abundance

Accurate abundance estimates are not available for this species. However, records from museums and anecdotal observations from fishermen indicate that this species was once common throughout its historic range and that smalltooth sawfish have declined dramatically in U.S. waters over the last century. The significant decline was not recognized immediately because the smalltooth sawfish had no commercial value. The decline can be documented by using the data from smalltooth sawfish landings by shrimp trawlers of Louisiana. Several

factors contributed to the decline. The most significant causes for the decline were recreational and commercial fishing and habitat loss. The smalltooth sawfish was taken regularly as bycatch in gillnet, trawl, and seine fisheries (Simpfendorfer 2002).

Information based on encounters with the smalltooth sawfish by fishermen, boaters, divers, and researchers from 1998 to 2004 indicate the majority of the population in Florida can be found from the Caloosahatchee River to Florida Bay. During that time period, 434 smalltooth sawfish encounters were reported throughout Florida, from St. Augustine to the Panhandle. In areas that had frequent historical accounts of the smalltooth sawfish, such as the Indian River Lagoon and the lower St. Johns River, sightings are now rare (Simpfendorfer and Wiley 2005).

5.4 Habitat

Sawfish habitat is found circumglobally in the tropics, and the fish typically reside in shallow or sheltered coastal areas and estuaries. Like only a few other elasmobranchs, sawfish are found in freshwater systems as well. Juvenile sawfish seem to prefer estuarine or freshwater shallows while adults are often found in waters 50 m (164 ft) or deeper (Simpfendorfer 2002). Smalltooth sawfish prefer muddy or sandy substrates close to shore. In the United States, the smalltooth sawfish can be found on inshore bars, mangrove edges, seagrass beds, and sometimes in deeper coastal waters.

5.5 Life History and Behavior

Very little is known about the life history of the smalltooth sawfish because it was not an important commercial species. However, large numbers were caught as bycatch in the early part of the 20th century, which likely contributed to the decline in the population (Poulakis and Seitz 2005). It is known that the smalltooth sawfish are slow-growing, late-maturing, long-living, and slow-reproducing fish, which are all life history characteristics contributing greatly to a potentially rapid population decline and a low recovery rate. Simpfendorfer (2000) calculated the population doubling time for the smalltooth sawfish to be 5.4 to 8.5 years, which would indicate that the recovery time for the depleted population would be very long.

Like all elasmobranchs, the smalltooth sawfish have internal fertilization and low fecundity. The smalltooth sawfish matures at about age 10 and lives 25 to 30 years (NMFS 2005). Typical sizes at maturation are about 270 cm (8.8 ft) for males and approximately 360 cm (11.8 ft) for females (Simpfendorfer 2002). Sawfish are ovoviviparous, and typically produce about 12 young per litter (Banister and Campbell 1985) although some smalltooth sawfish are found to have up to 20 embryos (Poulakis and Seitz 2005). Gestation is probably about one year, and it is thought that the female smalltooth sawfish gives birth during warmer months, thus allowing for continual reproductive cycles in parts of their range with warm waters all year (Passarelli and Curtis, 2005). The embryos resemble the adults, and during development the rostrum is soft and flexible, and its soft teeth are covered by a protective sheath until they are exposed shortly after birth. The rostrum straightens, and the teeth harden soon after birth. The smalltooth sawfish is approximately 2 ft long at birth and can grow up to 18 ft or more. There are no known formal studies on the growth and age of the sawfish, and the size at which the smalltooth sawfish reaches maturity is unknown.

The sawfish diet consists of schooling fish or crab, shrimp, or other benthic prey. The saw can be used to disrupt the bottom and make prey available by dislodging the animals from the substrate. Smalltooth sawfish can also use their rostrum to slash through schools of small fish wounding or stunning the fish to facilitate consumption. The toothed rostrum can also be used as a defensive mechanism by slashing the saw from side to side. Sawfish will defend themselves when threatened but are not known to aggressively attack humans unless they are provoked.

6.0 Incidental Captures

Since St. Lucie Nuclear Power Plant began operation in 1976, only six protected species under NMFS's jurisdiction that have been affected by operation of the plant's cooling water system. Of those six species, five are sea turtles: loggerhead turtle, green turtle, Kemp's ridley turtle, leatherback turtle, and hawksbill turtle. The sixth species is the smalltooth sawfish, which has only been observed once at the St. Lucie Nuclear Power Plant and is the focus of this BA and Section 7 consultation. All animals have entered the cooling water system's intake canal via the pipelines from the ocean. The series of barriers and the biologists' monitoring activities have ensured that the majority of the individuals have been returned to the ocean unharmed or have been treated for injuries.

6.1 Sea Turtles

From initial plant operation in 1976 through 2005, a total of 11,283 sea turtles (including recaptures), representing five different species, has been removed from the intake canal. The majority of the turtles captured were loggerheads (57.4 percent). Table 1 shows the sea turtle capture data over the last five calendar years, all of which have been subject to the existing ITS that took effect when the 2001 BO was issued. Variation in the number of turtles found during different months and years, including dramatic increases in green turtle captures in recent years, have been attributed primarily to natural variations in the occurrence of turtles in the vicinity of the plant, rather than to operational influences of the plant itself. Ongoing evaluations and improvements to the canal capture program during recent years have substantially decreased the amount of time entrapped sea turtles remain in the canal. Turtles confined between the barrier net and intake headwalls typically reside in the canal for a relatively short period prior to capture, and most are in good to excellent condition when caught.

The 12.7-cm (5-in.) mesh barrier net completed in January 1996 substantially reduced sea turtle residence times in the intake canal. However, during major influxes of seaweed and jellyfish, this net experienced design failure and caused mortalities. To prevent this problem, FPL constructed a new, improved barrier net with additional structural support. Construction of this net was completed in November 2002. The improved design and net material has withstood the seaweed and jellyfish events that caused previous design failure of the old barrier net. Additionally, recent dredging of the intake canal (completed in 2002 and in 2005) has reduced current velocities around the new barrier net. These actions have significantly reduced the potential for sea turtle mortalities in the plant's intake canal.

In correspondence regarding the ITS of the May 2001 Biological Opinion, there is language that turtle injury or mortality in the canal shall be counted when "resulting from plant operation." In

Table 1: Sea Turtle Takes* in Recent Years

Turtle Species	2001	2002	2003	2004	2005
Loggerhead	270 (1)	341 (0)	538 (0)	624 (1)	486 (1)
Green	321 (5)	292 (2)	394 (2)	285 (1)	426 (4)
Kemp's ridley	1 (0)	0	2 (0)	1 (0)	3 (0)
Leatherback	2 (0)	0	4 (0)	2 (0)	0
Hawksbill	6 (0)	3 (0)	6 (0)	2 (0)	1 (0)
TOTAL	600 (6)	636 (2)	944 (2)	914 (2)	917 (5)

* Note: Numbers in parentheses indicate the number of injurious or lethal takes that resulted from plant operations and, therefore, apply to the incidental take limit.
Sources: Quantum Resources and FPL 2005; FPL 2006.

6.2 Smalltooth Sawfish

On May 16, 2005, during the course of normal net-monitoring activities in the St. Lucie Nuclear Power Plant intake canal, a smalltooth sawfish (*Pristis pectinata*) became entangled in the northern tangle net at approximately 5:20 pm. The biologist on duty determined that the animal was too large to handle himself and called for assistance at approximately 5:30 pm. A crew of four biologists assembled at the intake canal at 6:00 pm and discussed a plan to remove the sawfish from the net and release it back to the ocean safely. The 30.5-m (100-ft) net was released from the western end anchor point and was pulled into the boat up to the location of the sawfish. The net was then released from the eastern end anchor point, and the remainder of the net was pulled into the boat leaving the entangled sawfish in the water along side the boat. The saw was the only part of the animal that was entangled in the net so the rest of its body remained unencumbered. The animal was pulled into the boat ramp area where the remaining net was offloaded. The animal remained in the shallow water of the boat ramp until preparations were made for its removal. A stretcher was laid out on the boat ramp, and a winch was attached to the remaining net to pull the sawfish onto the stretcher. At approximately 6:30 pm, the animal was pulled from the water up the boat ramp and onto the stretcher. The sawfish was then moved into the back of a trailer normally used for transporting large sea turtles. At this point the net was cut off the sawfish's rostrum to disentangle the animal, and measurements and photographs were taken. The sawfish measured 415 cm (13.62 feet) in total length, and the rostrum itself measured 86 cm (2.82 feet). The animal was then transported in the trailer via an all-terrain vehicle (ATV) across the dune and to the ocean, a distance of about 100 m (328 ft). Two biologists walked behind the trailer holding up the tail end of the stretcher to ensure the animal would not slide out. The trailer was then filled with ocean water by backing it into the nearshore trough at the beach, and the animal was able to float out of the trailer and swim away freely at approximately 6:45 pm. The area where the sawfish was released was monitored for 25 minutes to make sure that the animal had

acclimated and did not wash ashore. There was no sign of the sawfish in the area after it swam away at 6:45 pm.

After the sawfish was released safely by the biologists, FPL contacted NMFS to report the incident. NMFS requested that FPL send photographs and measurement data on the sawfish to Mote Marine Laboratory as a part of Mote's ongoing sawfish research. FPL did so on May 18, 2005. On June 7, 2005, NMFS indicated to FPL that a Section 7 consultation would need to be initiated between the NRC and NMFS concerning the event. On September 29, 2005, NMFS, NRC, and FPL met at the St. Lucie Nuclear Power Plant for a site visit and discussion regarding the smalltooth sawfish take and Section 7 consultation.

7.0 Assessment of Impacts on Threatened and Endangered Species

Impacts to sea turtles have not changed significantly since the last Section 7 consultation. The operation of the cooling water system and the biological monitoring program have not been modified since 2002 when improvements were made. NMFS approved such modifications in a letter dated May 9, 2003, which reiterated that the May 2001 BO and ITS remained valid. Also, FPL biologists conduct a very successful sea turtle tagging program, and the St. Lucie Nuclear Power Plant intake canal is often used as the primary study area for various research projects. The continued operation of the cooling water system for the St. Lucie Nuclear Power Plant is not expected to jeopardize the continued existence of loggerhead turtle, green turtle, Kemp's ridley turtle, leatherback turtle, or hawksbill turtle.

The 2005 smalltooth sawfish take is the only known interaction of the smalltooth sawfish with St. Lucie Units 1 and 2 and, thus, is considered anomalous. The fish was rescued in the intake canal and returned to the ocean where it rapidly swam away with ease. Due to the rarity of the smalltooth sawfish's entrapment in the intake canal (once in 29 years of operation) and FPL's commitment to return any future specimens rapidly to the ocean, the continued operation of the cooling water system for St. Lucie Nuclear Power Plant is not expected to jeopardize the continued existence of the smalltooth sawfish.

8.0 Mitigation Measures

Representatives of NMFS, NRC, and FPL discussed mitigation measures specific to the smalltooth sawfish at the September 29, 2005 meeting. Such measures could include:

- Minimize animal's time out of water by taking measurements in the intake canal
- Develop a method to ensure the animal's spiracles are kept wet during out-of-water transportation over the dunes to the ocean
- Send one or more FPL representatives to an aquarium (such as Sea World) that routinely interacts with the smalltooth sawfish to learn safe handling and transportation techniques (such as using a neoprene sleeve to cover the saw)
- Develop and periodically exercise a rescue and transportation plan, including maintenance and operation of appropriate equipment. Such a plan would reduce the fish's out-of-water time to less than ten minutes.

9.0 Recommendation for Revised Incidental Take Statement

Consistent with the agreement reached in a meeting held with NRC and the NMFS Southeast Region's Regional Administrator on September 26, 2002, the NRC staff has provided suggestions for the revised ITS. The limits for sea turtles have not been met or exceeded, and the NRC staff does not recommend modification of the take limits for sea turtles. The sea turtle take limits are up to one percent of the annual loggerhead and green takes for injurious or lethal loggerhead and green takes, two lethal takes of Kemp's ridley turtles annually, and one lethal take of hawksbill or leatherback every two years. There is also a maximum annual take limit of 1000 for all sea turtle species combined regardless of causation. The NRC staff recommends that the ITS for the St. Lucie Nuclear Power Plant be revised to allow one non-lethal take of the smalltooth sawfish on an annual basis.

Additionally, the NRC staff recommends incorporating into the revised ITS the following reasonable and prudent measures for the protection of the smalltooth sawfish:

1. FPL shall have a transportation plan in place to transport rapidly any future takes of smalltooth sawfish from the intake canal to the ocean for release.

2. FPL shall report all smalltooth sawfish captures and any mortalities per permit conditions.

The NRC staff also recommends adding to the ITS the following terms and conditions:

1. All measurements of individual specimens of smalltooth sawfish captured in the intake canal shall be made while the specimen is in the water in the intake canal.

2. The spiracles of the smalltooth sawfish are to be kept wet during transport of specimens for release into the ocean.

3. The transportation plan shall be exercised annually with the goal of reducing the fish's out-of-water time to less than ten minutes.

The NRC staff finds that these reasonable and prudent measures and terms and conditions would adequately protect any smalltooth sawfish captured in the intake canal and that there is reasonable likelihood that the rescue and release into the ocean would not cause injury or mortality. Therefore, implementation of such measures would ensure that the continued operation of the St. Lucie Nuclear Power Plant's cooling water system would not jeopardize the continued existence of the smalltooth sawfish in U.S. waters.

10.0 References

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September 1, 2005 at http://www.nmfs.noaa.gov/prot_res/species/fish/Smalltooth_sawfish.html.

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U.S. Nuclear Regulatory Commission (NRC). 2005. Letter from P.T. Kuo (NRC) to D. Bernhart (NMFS). July 8, 2005.

From: Harriet Nash
To: Shelley.Norton@noaa.gov
Subject: Smalltooth sawfish consultation
Date: Thursday, June 15, 2006 9:20:15 AM

Hi Shelley,

How are things going? I'm just writing to get an update on the St. Lucie Section 7 consultation regarding the smalltooth sawfish. Sometimes our mail receipt gets held up so please let me know when I should keep an eye out for it. Also, do you know of any opportunities for plant employees to observe a smalltooth sawfish move or transfer?

Thanks,
Harriet

From:	Harriet Nash
To:	Shelley.Norton@noaa.gov
Subject:	Terms and conditions letter
Date:	Thursday, November 30, 2006 10:24:56 AM

Hi Shelley,

I just spoke with Stacy so I'm just reiterating what she told me....probably just duplicating what I told you yesterday. Her main concern is that the attachment to the e-mail you send me today is in the form of a letter simply stating what the terms and conditions are (which I suppose could be an attachment to the letter if it's already written as a separate document). Her management will not accept it if it is not in letter form. If you could do that, it would be great! She's leaving on Saturday morning for a trip to the west coast, and I know the NRC concurrence process would not allow me to get her a formal letter by COB tomorrow. I hope this is possible! Please let me know if you have questions.

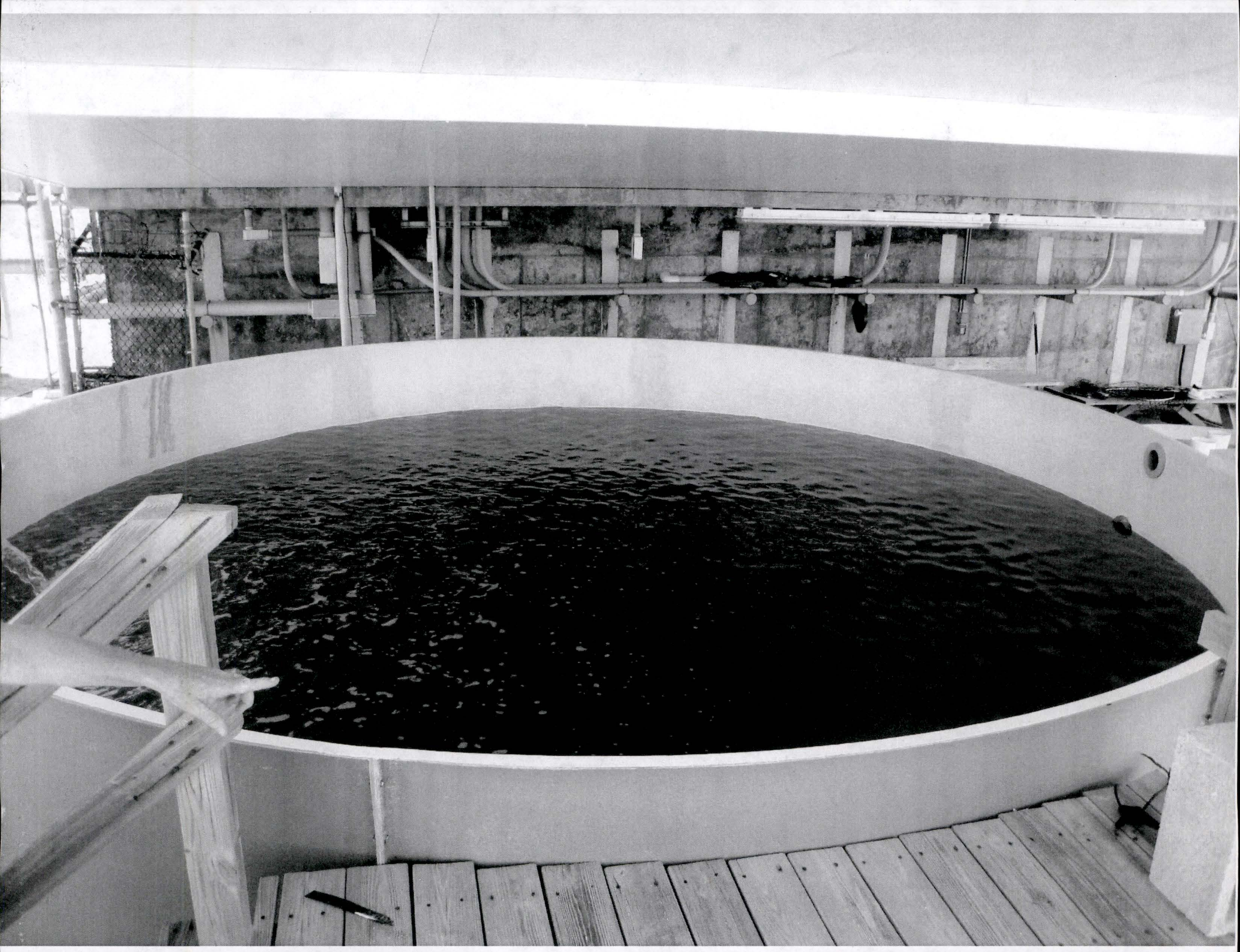
Thanks,
Harriet

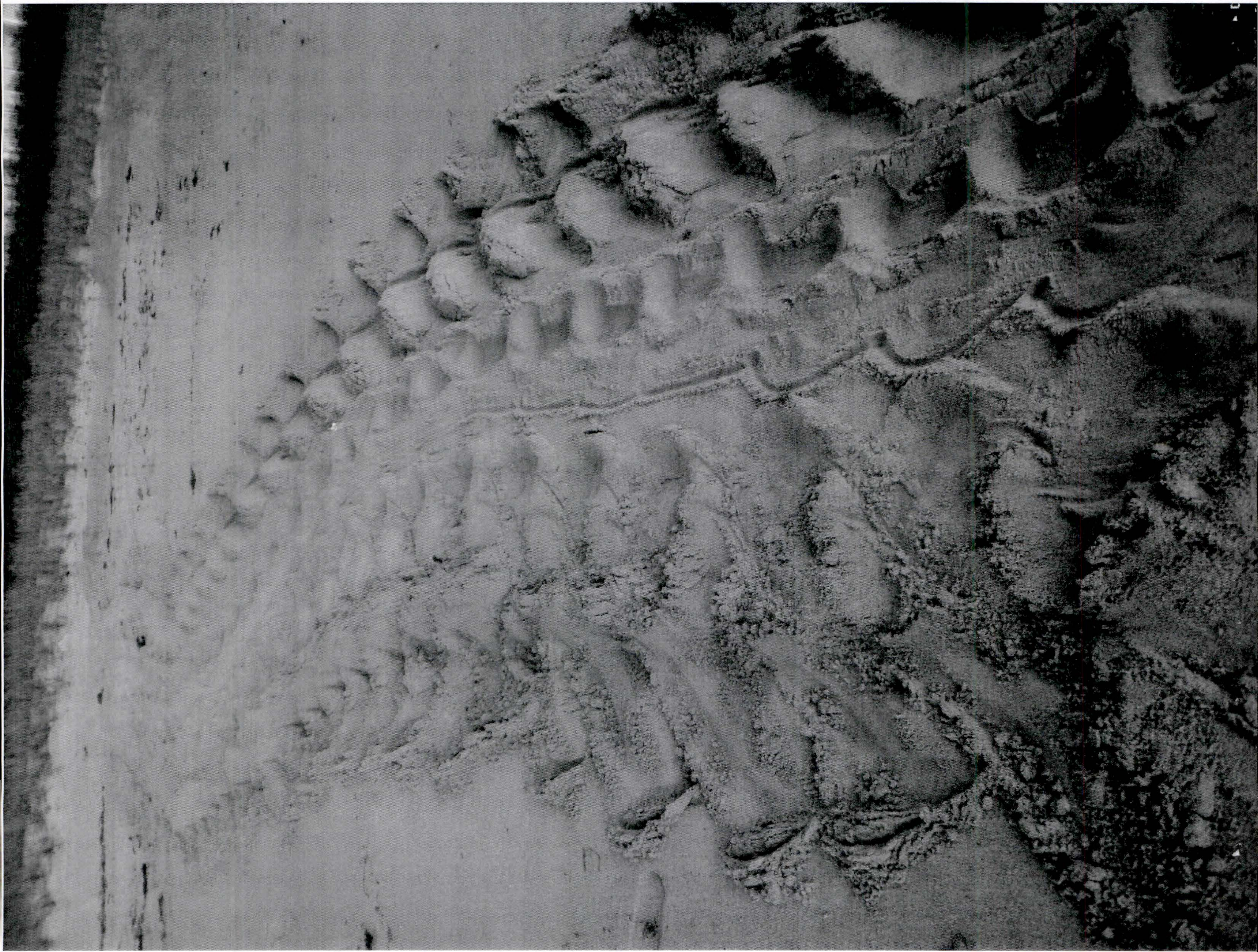
From: Harriet Nash
To: Shelley.Norton@noaa.gov
Subject: Photos
Date: Friday, April 20, 2007 2:55:25 PM
Attachments: Pipe Inspection 019.jpg
Pipe Inspection 012.jpg
Pipe Inspection 013.jpg
Pipe Inspection 017.jpg

Shelley,

Here are the two photos of the tank used for aquaria. Also, I attached a couple of the sea turtle tracks and nest I found just for fun!

Harriet





From:	Harriet Nash
To:	ed_Hollowell@fpl.com; Michael_Bresette@fpl.com; Stacy_Foster@fpl.com; Shelley.Norton@noaa.gov
Cc:	Dennis Logan; Elizabeth Wexler
Subject:	St. Lucie meeting summary
Date:	Monday, April 23, 2007 11:08:27 AM
Attachments:	St Lucie April 18 meeting summary_HLN.wpd

All,

Attached is the first cut at the meeting summary. Liz is out of the office today so please send me your comments if you get to this today. If it's after today, please send them to Liz. We'll try to get this out formally as soon as possible.

I have not included information regarding the discussion of trend analysis (scrapes, etc). If you think this should be included, please let me know. Otherwise, I'm assuming this would factor into the design of the excluder device at the velocity caps.

Also, I think I left Vince's card at home, and he did not sign the paper we passed around at the table. So, if we need his input as well, please forward to him.

Thanks,
Harriet

Stacy Foster

FPL Environmental Services

St. Lucie Nuclear Station

6501 S. Ocean Drive

Jensen Beach, FL 34957

Shelley Norton

National Marine Fisheries Service

263 13[th] Avenue South

St. Petersburg, FL 33701

SUBJECT: SUMMARY OF APRIL 17-18, 2007 MEETING REGARDING FORMAL CONSULTATION UNDER SECTION 7 OF THE ENDANGERED SPECIES ACT REGARDING OPERATION OF THE ST. LUCIE NUCLEAR POWER PLANT (TAC NOS. MD4260 AND MD4261)

Dear Ms. Foster and Ms. Norton:

Under Section 7 of the Endangered Species Act, the U.S. Nuclear Regulatory Commission (NRC) reinitiated formal consultation with the National Marine Fisheries Service (NMFS) regarding the continued operation of the St. Lucie Nuclear Power Plant (SLNPP), after the incidental take limit for sea turtles was exceeded in 2006. At that time, NRC and NMFS were already in consultation regarding the capture of a smalltooth sawfish (*Pristis pectinata*) at SLNPP, and the agencies agreed that the consultations could be combined for a comprehensive biological opinion addressing sea turtles and the smalltooth sawfish. On

April 17-18, 2007, representatives of the NRC, NMFS, and FPL's Environmental Services met to observe the inspection of the southern 12-ft-diameter intake pipe and discuss possible mitigation measures to reduce impingement and entrainment of protected marine species, specifically sea turtles and smalltooth sawfish, into the SLNPP intake canal.

As a result of the October 2006 loggerhead turtle (*Caretta caretta*) hatchling impingements at the intake wells, NRC, NMFS, and FPL discussed potential mitigation measures to prevent pregnant female sea turtles from nesting on the intake canal banks. NRC and NMFS agreed that short chain-link fences should be installed immediately along the banks of the intake canal. This prudent measure should be implemented as soon as possible since the 2007 sea turtle nesting season has already begun.

During the April 2007 outage at SLNPP, Florida Power & Light Company (FPL) inspected the intake and discharge pipes. Inspection results are expected to identify the amount and location of any significant biofouling and debris accumulation in the intake pipes that may adversely affect animals entrained into the intake canal. Based on the pipe inspection report, FPL should develop an implementation plan for cleaning the intake pipes during the fall 2007 outage. Removal of significant biofouling and debris would minimize adverse effects on animals entrained into the intake canal.

The exploration of the intake pipes also revealed a dead-end section in each 12-ft-diameter intake pipe. A live green turtle (*Chelonia mydas*) was discovered in the dead-end section of the southern 12-ft-diameter intake pipe. We observed the turtle breathe from an air pocket in the dead-end pipe section. FPL was able to blow air into that section so the turtle could continue breathing from the pocket overnight. It is expected that the turtle would enter the intake canal when full flow was restored in the pipe. This event, however, revealed the potential for animals to be trapped in this section, and since it has no functional purpose, NRC and NMFS agreed that FPL should seal off the dead-end sections of the 12-ft-diameter intake pipes during the fall 2007 outage.

To reduce the potential for incidental takes in 2007, NRC and NMFS agree that FPL should employ several mitigation measures: install fences along intake canal banks, clean intake pipes, and seal off the dead-end sections of the intake pipes. In addition, the agencies agreed that FPL should develop a plan to install excluder devices at the velocity caps to prevent large marine organisms, such as adult sea turtles and smalltooth sawfish, from entering the intake pipes. Design and installation of such devices would likely be a longer-term project, but should be done as soon as possible. Finally, if FPL conducts any dredging, bank restoration, or other similar activities within the intake canal, FPL should work with NRC and NMFS to identify appropriate mitigation measures to ensure the safety of any marine organisms that might be affected.

NRC should submit to NMFS a biological assessment regarding sea turtles and foreseeable future activities at SLNPP that may affect protected marine species. After receiving the pipe inspection report, FPL should submit to NRC any new or updated information, including an updated description of the cooling system if necessary, for inclusion in the biological assessment for sea turtles. At the meeting, several changes were suggested to FPL's smalltooth sawfish handling, transportation, and release protocol; FPL should sent the revised document to NRC and NMFS for approval. Also, the NRC and NMFS agreed that FPL should continue communicating with both agencies regarding the design and implementation of any mitigation measures and projects that could affect protected marine species.

If there are any questions regarding this meeting summary or the recommendations described, please contact Ms. Elizabeth Wexler at EMW1@nrc.gov or 301-415-1522.

Sincerely,

Harriet Nash, Environmental Scientist
Environmental Branch A
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-335 and 50-389

cc: See next page

From:	Elizabeth Wexler
To:	Ed_Hollowell@fpl.com; Michael_Bresette@fpl.com; stacy_foster@fpl.com; Vince_Munne@fpl.com; Shelley.Norton@noaa.gov; Dennis Logan; Harriet Nash
Subject:	St Lucie Meeting Summary
Date:	Tuesday, May 01, 2007 2:31:11 PM
Attachments:	St Lucie April 18 meeting summary_HLN-FPL.wpd

Hi all,

Attached is the most recent draft of the meeting summary.

Harriet and I discussed the issues that came up in Monday's call. We came up with two concerns:

1. Will a turtle crawl be evident in the sand/sand-like material if there is a heavy rain?
2. If we are using a finer grain material without any vegetation to hold it in place, will this increase sedimentation in the canal, and increase the need for dredging? And on a related note, would the sand have to be replaced periodically, and would there be a plan for that?

Also, please let me know any changes that need to be made to the letter, and I will get the final draft into our concurrance process as soon as possible.

Thank so much,
Liz

Elizabeth Wexler, Scientist
Environmental Branch A
Department of License Renewal
U.S. Nuclear Regulatory Commission
(301) 415-1522

Stacy Foster
Florida Power & Light Company
Environmental Services
700 Universe Blvd.
Juno Beach, FL 33408

Shelley Norton
National Marine Fisheries Service
263 13th Avenue South
St. Petersburg, FL 33701

SUBJECT: SUMMARY OF APRIL 17-18, 2007 MEETING REGARDING FORMAL CONSULTATION UNDER SECTION 7 OF THE ENDANGERED SPECIES ACT REGARDING OPERATION OF THE ST. LUCIE NUCLEAR POWER PLANT (TAC NOS. MD4260 AND MD4261)

Dear Ms. Foster and Ms. Norton:

Under Section 7 of the Endangered Species Act, the U.S. Nuclear Regulatory Commission (NRC) reinitiated formal consultation with the National Marine Fisheries Service (NMFS) regarding the continued operation of the St. Lucie Nuclear Power Plant (SLNPP), after the incidental take limit for sea turtles was exceeded in 2006. At that time, NRC and NMFS were already in consultation regarding the capture of a smalltooth sawfish (*Pristis pectinata*) at SLNPP, and the agencies agreed that the consultations could be combined for a comprehensive biological opinion addressing sea turtles and the smalltooth sawfish.

On April 17-18, 2007, representatives of the NRC, NMFS, and Florida Power & Light Company (FPL) met to observe the inspection of the southern 12-ft-diameter intake pipe and discuss possible mitigation measures to reduce impingement and entrainment of protected marine species, specifically sea turtles and smalltooth sawfish, into the SLNPP intake canal.

As a result of the October 2006 loggerhead turtle (*Caretta caretta*) hatchling impingements at the intake wells, NRC, NMFS, and FPL discussed potential mitigation measures. NRC and NMFS suggested that FPL remove the existing vegetation east of the 5" turtle net and add some form of material that a turtle crawl will be visible in, as soon as possible. NRC and NMFS suggested that this prudent measure should be implemented as soon as possible since the 2007 sea turtle nesting season has already begun.

During the April 2007 outage at SLNPP, FPL inspected the intake and discharge pipes. Inspection results are expected to identify the amount and location of any significant biofouling and debris accumulation that extend into the flow path of the intake pipes. NRC and NMFS suggested that FPL develop an implementation plan based on the pipe inspection report for cleaning the intake pipes during the fall 2007 outage, to remove protruding debris that may adversely affect animals entrained in the intake canal. NRC and NMFS suggested that FPL should coordinate and obtain concurrence of the implementation plan from the NRC and NMFS prior to implementation. NRC and NMFS believe that removal of significant biofouling and debris could reduce adverse effects on animals entrained into the intake canal.

The exploration of the intake pipes also revealed a dead-end section in each 12-ft-diameter intake pipe. A live green turtle (*Chelonia mydas*) was discovered in the dead-end section of the southern 12-ft-diameter intake pipe. The NRC, NMFS, and FPL observed the turtle breathe from an air pocket in the dead-end pipe section. FPL was able to blow air into that section so the turtle could continue breathing from the pocket overnight. It is expected

that the turtle would enter the intake canal when full flow was restored in the pipe. This event, however, revealed the potential for animals to be trapped in this section, and since it has no functional purpose, NRC and NMFS suggested that FPL seal off the dead-end sections of the 12-ft-diameter intake pipes during the fall 2007 outage.

To reduce the potential for incidental takes in 2007, NRC and NMFS suggest that FPL should employ several mitigation measures: remove existing vegetation and add some material that a crawl would be visible in, remove protruding debris in the intake pipes, and seal off the dead-end sections of the intake pipes. In addition, the agencies suggested that FPL should develop a plan to install excluder devices at the velocity caps to prevent large marine organisms, such as adult sea turtles and smalltooth sawfish, from entering the intake pipes. NRC and NMFS observed that the design and installation of such devices would likely be a longer-term project, but suggested to FPL that this project should be done as soon as possible, with a proposed implementation plan to be provided for this project no later than September 30, 2007. Finally, NRC and NMFS suggested that if FPL conducts any dredging, bank restoration, or other similar activities within the intake canal; FPL should work with NRC and NMFS to identify appropriate mitigation measures to ensure the safety of any marine organisms that might be affected.

NRC should submit to NMFS a biological assessment regarding sea turtles and foreseeable future activities at SLNPP that may affect protected marine species. NRC and NMFS suggested that after receiving the final pipe inspection report, FPL should submit to NRC any new or updated information, including an updated description of the cooling system if necessary, for inclusion in the biological assessment for sea turtles.

At the meeting, several changes were suggested to FPL's smalltooth sawfish handling, transportation, and release protocol; FPL should send the revised document to NRC and NMFS for approval. Also, the NRC and NMFS agreed that FPL should continue communicating with both agencies regarding the design and implementation of any mitigation measures and projects that could affect protected marine species.

FPL agreed to take the NRC and NMFS suggestions under advisement. The parties agreed that all proposed recommendations would be discussed further among the parties prior to issuance of a final biological opinion.

If there are any questions regarding this meeting summary or the recommendations described, please contact Ms. Elizabeth Wexler at EMW1@nrc.gov or 301-415-1522.

Sincerely,

Harriet Nash, Environmental Scientist
Environmental Branch A
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-335 and 50-389

cc: See next page

From:	Dennis Logan
To:	Stacy_Foster@fpl.com; Shelley.Norton@noaa.gov
Cc:	Elizabeth Wexler; Harriet Nash
Subject:	St. Lucie: Summary of Site Visit
Date:	Thursday, June 14, 2007 2:35:59 PM

Shelley and Stacy,

Attached is a suumary of our April 17-18 site visit to St. Lucie regarding formal consultation under Section 7 of the Endangered Species Act. You should be receiving a hard copy by mail shortly. If you have any questions please contact me by e-mail or phone at 301-415-0490.

Sincerely,

Dennis Logan, Ph.D.
Aquatic Biologist
License Renewal - Environmental Branch A
Office of Nuclear Reactor Regulation
U.S Nuclear Regulatory Commission
Washington, DC 20555-0001
301-415-0490

From:	Dennis Logan
To:	Stacy_Foster@fpl.com; Shelley.Norton@noaa.gov
Cc:	Elizabeth Wexler; Harriet Nash
Subject:	St. Lucie: Summary of Site Visit - Resent
Date:	Thursday, June 14, 2007 2:39:40 PM
Attachments:	ML0712400971.pdf

Shelley and Stacy,

Attached is a suumary of our April 17-18 site visit to St. Lucie regarding formal consultation under Section 7 of the Endangered Species Act. You should be receiving a hard copy by mail shortly. If you have any questions please contact me by e-mail or phone at 301-415-0490.

Sincerely,

Dennis Logan, Ph.D.
Aquatic Biologist
License Renewal - Environmental Branch A
Office of Nuclear Reactor Regulation
U.S Nuclear Regulatory Commission
Washington, DC 20555-0001
301-415-0490

June 13, 2007

Stacy Foster
Florida Power & Light Company
Environmental Services
700 Universe Blvd.
Juno Beach, FL 33408

Shelley Norton
National Marine Fisheries Service
263 13th Avenue South
St. Petersburg, FL 33701

SUBJECT: SUMMARY OF APRIL 17-18, 2007 SITE VISIT REGARDING FORMAL CONSULTATION UNDER SECTION 7 OF THE ENDANGERED SPECIES ACT REGARDING OPERATION OF THE ST. LUCIE NUCLEAR POWER PLANT (TAC NOS. MD4260 AND MD4261)

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On April 17-18, 2007, representatives of the NRC, NMFS, and Florida Power & Light Company (FPL) met to observe the inspection of the southern 12-ft-diameter intake pipe and discuss possible mitigation measures to reduce impingement and entrainment of protected marine species, specifically sea turtles and smalltooth sawfish, at SLNPP.

As a result of the October 2006 loggerhead turtle (*Caretta caretta*) hatchling impingements at the intake wells, NRC, NMFS, and FPL discussed potential mitigation measures. As a result of a conference call with FPL, NRC, NMFS, and Florida Fish and Wildlife Conservation Commission (FWC) staff, on April 30, 2007, NRC and NMFS suggested that FPL implement measures along the banks of the intake canal east of the 5-in. turtle net, so that a turtle crawl would be visible. NRC and NMFS suggested that this prudent measure should be implemented as soon as possible since the 2007 sea turtle nesting season has already begun.

During the April 2007 outage at SLNPP, FPL inspected the intake and discharge pipes. Inspection results are expected to identify the amount and location of any significant biofouling and debris accumulation that extend into the flow path of the intake pipes. NRC and NMFS suggested that FPL develop an implementation plan based on the pipe inspection report

for cleaning the intake pipes during the fall 2007 outage, to remove protruding debris that may adversely affect animals entrained into the intake canal. NRC and NMFS suggested that FPL should coordinate and obtain concurrence of the implementation plan from the NRC and NMFS prior to implementation. NRC and NMFS believe that removal of significant biofouling and debris could reduce adverse effects on animals entrained into the intake canal. Also, such improvements would likely need to be evaluated for potential effects in the discharge canal. The cooling system is composed of both intake and discharge components whose functions are interdependent. If changes or improvements are made to one component, the other component would likely be affected.

The exploration of the intake pipes also revealed a dead-end section in each 12-ft-diameter intake pipe. A live green turtle (*Chelonia mydas*) was discovered in the dead-end section of the southern 12-ft-diameter intake pipe. The NRC, NMFS, and FPL observed the turtle breathe from an air pocket in the dead-end pipe section. FPL was able to blow air into that section so the turtle could continue breathing from the pocket overnight. This event, however, revealed the potential for animals to be trapped in this section, and since it has no functional purpose, NRC and NMFS suggested that FPL seal off the dead-end sections of the 12-ft-diameter intake pipes during the fall 2007 outage.

To reduce the potential for incidental takes in 2007, NRC and NMFS suggested that FPL should employ several mitigation measures: cut back existing vegetation along the banks of the intake canal, remove protruding debris in the intake pipes, and seal off the dead-end sections of the intake pipes. In addition, the agencies suggested that FPL should develop a plan to install excluder devices at the velocity caps to prevent large marine organisms, such as adult sea turtles and smalltooth sawfish, from entering the intake pipes. NRC and NMFS observed that the design and installation of such devices would likely be a longer-term project, but suggested to FPL that this project should be done as soon as possible, with a proposed implementation plan to be provided for this project no later than September 30, 2007. Finally, NRC and NMFS suggested that if FPL conducts any dredging, bank restoration, or other similar activities within the intake canal, FPL should work with NRC and NMFS to identify appropriate mitigation measures to ensure the safety of any marine organisms that might be affected.

NRC plans to submit to NMFS a biological assessment regarding sea turtles and foreseeable future activities at SLNPP that may affect protected marine species. NRC and NMFS suggested that after receiving the final pipe inspection report, FPL should submit to NRC any new or updated information, including an updated description of the cooling system if necessary, for inclusion in the biological assessment for sea turtles.

At the meeting, several changes were suggested to FPL's smalltooth sawfish handling, transportation, and release protocol; FPL should send the revised document to NRC and NMFS for approval. Also, the NRC and NMFS agreed that FPL should continue communicating with both agencies regarding the design and implementation of any mitigation measures and projects that could affect protected marine species.

FPL agreed to take the NRC and NMFS suggestions under advisement. The parties agreed that all proposed recommendations would be discussed further among the parties prior to issuance of a final biological opinion.

If there are any questions regarding this meeting summary or the recommendations described, please contact Dr. Dennis Logan at DTL1@nrc.gov. or 301-415-0490.

Sincerely,

/RA/
Harriet Nash, Environmental Scientist
Environmental Branch A
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-335 and 50-389

cc: See next page

If there are any questions regarding this meeting summary or the recommendations described, please contact Dr. Dennis Logan at DTL1@nrc.gov. or 301-415-0490.

Sincerely,

/RA/
Harriet Nash, Environmental Scientist
Environmental Branch A
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Office of Nuclear Reactor Regulation

Docket Nos. 50-335 and 50-389

cc: See next page

Adam Accession No. **ML071240097**

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DATE	06/13/07	06/12/07	06/13/07	06/05/07	06/13/07

OFFICIAL RECORD COPY

Letter to S. Foster and S. Norton from H. Nash dated June 13, 2007

SUBJECT: SUMMARY OF APRIL 17-18, 2007 MEETING REGARDING FORMAL CONSULTATION UNDER SECTION 7 OF THE ENDANGERED SPECIES ACT REGARDING OPERATION OF THE ST. LUCIE NUCLEAR POWER PLANT (TAC NOS. MD4260 AND MD4261)

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Subject:	PDF files of St. Lucie Biological Assessment
Date:	Thursday, August 16, 2007 9:53:35 AM
Attachments:	ML0717001610 Attachment.pdf ML0717001100 Cover.pdf

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Shelly and Stacy,

Attached are electronic copies of the cover letter and biological assessment for reinitiation of the Section 7 consultation for sea turtles at St. Lucie. Hard copies should arrive soon.

Dennis

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Biological Assessment

St. Lucie Nuclear Power Plant Units 1 and 2 Reinitiation of Section 7 Consultation to Include Sea Turtles

St. Lucie County, Florida

August 2007

Docket Nos. 50-335 and 50-389

U.S. Nuclear Regulatory Commission
Rockville, Maryland

Enclosure

1.0 Introduction and Summary

This Biological Assessment (BA) was prepared in support of reinitiating a formal consultation between the U.S. Nuclear Regulatory Commission (NRC) and National Oceanic and Atmospheric Administration's National Marine Fisheries Service (NMFS) in compliance with Section 7 of the Endangered Species Act of 1973, as amended (ESA). The purpose of this BA is to examine the potential impacts on Federally-listed sea turtle species associated with the continued operation of the St. Lucie Nuclear Power Plant's (SLNPP's) circulating seawater cooling system and to support the NRC's July 8, 2005 request to NMFS for reinitiation of formal Section 7 consultation regarding the SLNPP. The NRC has been consulting with NMFS regarding sea turtle takes at the SLNPP since 1982. Several BAs and Biological Opinions (BOs) have been issued since 1982 and resulted in periodic revisions to the Incidental Take Statement (ITS), as appropriate. A reinitiation of formal consultation was triggered by a take of a smalltooth sawfish (*Pristis pectinata*) on May 16, 2005. Sea turtles were added to the reinitiation when the plant exceeded the annual incidental take limit for sea turtles in 2006 and entrained a total of 662 Atlantic green turtles (*Chelonia mydas*) and loggerhead turtles (*Caretta caretta*). The incidental take limit of one percent of entrained Atlantic green and loggerhead turtles was exceeded because 29 of the 662 entrained turtles were injured or killed due to plant operation.

Florida Power and Light Company (FPL) is the licensee that operates the SLNPP and conducts an ongoing turtle capture-and-release program in the station's intake canal. There have been no procedural changes in the operation of the SLNPP's circulating seawater cooling system since the last BO, dated May 4, 2001, which was clarified by letter dated July 30, 2002. The 2001 BO analyzed the effects of operation of the SLNPP's circulating seawater cooling system on loggerhead turtles, Atlantic green turtles, Kemp's ridley turtles (*Lepidochelys kempii*), leatherback turtles (*Dermochelys coriacea*), and hawksbill turtles (*Eretmochelys imbricata*). This BA provides a brief update of information regarding recent effects of the cooling system on these sea turtle species.

Three of the five sea turtle species in the 2001 BO, Kemp's ridley, leatherback, and hawksbill, are Federally listed as endangered. The loggerhead is Federally listed as threatened. Atlantic green turtles in U.S. waters are Federally listed as threatened except for the Florida breeding population that is listed as endangered. Due to the inability to distinguish between the two Atlantic green turtle populations away from the nesting beaches, Atlantic green turtles are considered endangered wherever they occur in U.S. waters. All three species occur in the vicinity of the SLNPP, where they are potentially subject to entrainment.

SLNPP is located on Hutchinson Island in St. Lucie County, Florida. The island is a barrier island bounded by the Atlantic Ocean to the east and the Indian River Lagoon to the west. The cooling system withdraws water from the Atlantic Ocean to cool the condensers of the two operating reactors, St. Lucie Units 1 and 2, which began operating in 1976 and 1983, respectively. The intake portion of the cooling system consists of three intake structures with velocity caps in the ocean, three buried pipelines, a common intake canal, and two intake well structures (one for each unit). In the intake canal has a series of nets, trash bars, and screens to prevent debris and organisms from being impinged on the intake screens or entrained into the plant.

Animals occasionally enter the canal system of the SLNPP along with seawater that is withdrawn from the Atlantic Ocean for condenser cooling. The intake structures and velocity caps for the plant are located about 365 meters (m) (1200 feet [ft]) offshore where they also serve as artificial reefs. As such, these structures attract turtles and other marine life by appearing to offer food and shelter. If an animal passes through the vertical plane of the velocity cap, the animal would enter the intake pipeline, which travels under the ocean floor and barrier island and debouches in the intake canal on the western side of the beach dunes.

Once in the intake canal, the animals cannot escape due to the high flow rates in the intake pipes and must be rescued and returned to the ocean. Therefore, FPL has a capture-and-release program to retrieve sea turtles and return them to the ocean. The program includes conservation efforts and collaboration with research organizations, sea turtle stranding programs, and Federal and State agencies. FPL has an existing agreement with Florida Fish and Wildlife Conservation Commission (FWC) regarding case-specific decisions on how and where to treat injured turtles that are not healthy enough to be returned immediately to the ocean. The FWC is also consulted to conduct turtle necropsies when needed. NRC's long history of consultations with NMFS regarding the SLNPP and FPL's commitment to minimize sea turtle injury and mortality has resulted in the modification and addition of barrier nets over time.

In 2006 SLNPP caused 21 loggerhead hatchling mortalities, which most likely resulted from a single hatching at an undetected nest on the intake canal bank. During the same event, three loggerhead hatchlings were retrieved alive and later released on November 4, 2006. The mortalities resulted from drowning after impingement at the intake screens. In addition, other recent turtle injuries were likely caused by hurricane debris and/or biofouling in the intake pipes leading to the intake canal. FPL inspected intakes pipes during an outage in April 2007. Corrective actions will be determined by NMFS, NRC, and FPL based on the inspection results.

This BA includes four mitigation measures for incidental sea turtle takes developed in discussions among NRC, FPL, NMFS, and FWC staff. These include (1) FPL implementing measures along the banks of the intake canal east of the 12.7-cm (5-in.) turtle net so that turtle crawls would be more visible, (2) FPL developing and implementing a plan to install exclusion devices at the velocity caps to prevent large marine organisms, such as adult sea turtles and smalltooth sawfish, from entering the intake pipes, (3) FPL developing and implementing a plan based on the pipe inspection report for cleaning the intake pipes during the fall 2007 outage to remove protruding debris that may adversely affect animals entrained in the intake canal, and (4) FPL sealing off the dead-end sections of the 12-ft-diameter intake pipes during the fall 2007 outage. This BA also suggests a revision to the ITS that FPL develop and execute a plan for periodic examination of intake pipes to ensure that conditions that could adversely affect sea turtles be found and corrected.

2.0 Purpose

This BA was prepared in support of reinitiating a formal consultation between the NRC and the NMFS in compliance with Section 7 of the ESA. On February 24, 2006, the NRC submitted a BA for the reinitiation of formal consultation regarding the continued operation of SLNPP regarding a smalltooth sawfish take in May 2005. On February 1, 2007, FPL notified the NRC that SLNPP exceeded its 2006 incidental take limit for sea turtles, and NRC then discussed this

information with NMFS. In a subsequent letter on April 4, 2007, NRC confirmed to NMFS that sea turtles will be added to the formal consultation on smalltooth sawfish because SLNPP exceeded its annual incidental take limit for sea turtles 2006. The purpose of the present BA is to supplement the February 24, 2007 BA focusing on smalltooth sawfish by adding information on threatened and endangered sea turtles taken by SLNPP.

This BA examines the potential impacts associated with the continued operation of the SLNPP on sea turtle species protected under the ESA. The primary species of concern are loggerhead turtle, Kemp's ridley turtle, Atlantic green turtle, leatherback turtle, and hawksbill turtle. Kemp's ridley turtle is listed as endangered, and the loggerhead turtle is listed as threatened. Atlantic green turtles in U.S. waters are listed as threatened except for the Florida breeding population, which is listed as endangered. Due to the inability to distinguish between these populations away from the nesting beach, these sea turtles are considered endangered wherever they occur in U.S. waters. The leatherback turtle and the hawksbill turtle are also listed as endangered in U.S. waters. NMFS has jurisdiction for these species at sea.

3.0 Site Description

SLNPP is located on a 457-hectare (1130-acre) site on Hutchinson Island on Florida's east coast (Figures 1 and 2). The plant is approximately midway between Ft. Pierce and St. Lucie Inlets. It is bounded on the east side by the Atlantic Ocean and on the west side by the Indian River Lagoon, which is long and shallow. Hutchinson Island is a barrier island that extends 36 km (22.4 mi) between inlets and attains its maximum width of 2 kilometers (km) (1.2 miles [mi]) at the plant site. Elevations approach 5 m (16.4 ft) atop dunes bordering the beach and decrease to sea level in the mangrove swamps that are common on the western side. The Atlantic shoreline of Hutchinson Island is composed of sand and shell hash with intermittent rocky promontories protruding through the beach face along the southern end of the island. Submerged coquinoid rock formations parallel much of the island off the ocean beaches. The ocean bottom immediately offshore from the plant site consists primarily of sand and shell sediments. The Florida Current, which flows north parallel to the continental shelf margin, begins to diverge from the coastline at West Palm Beach. The Florida Current is approximately 33 km (20.5 mi) offshore at Hutchinson Island. Oceanic water associated with the western boundary of the Florida Current periodically meanders over the inner shelf, especially during summer months.

4.0 Description of the St. Lucie Power Plant

St. Lucie Units 1 and 2 consist of two 839-net megawatt-electric (MWe) nuclear-fueled generating units that use near shore waters from the Atlantic Ocean for the plant's once-through condenser and auxiliary cooling systems. The cooling water system removes heat from the condensers and other auxiliary equipment. Eight pumps (four per unit) located at the intake wells circulate water through the system. The pumping capacity ranges from 50,470 to 70,660 liters per second (800,000 to 1,120,000 gallons per minute) (NRC 2003).

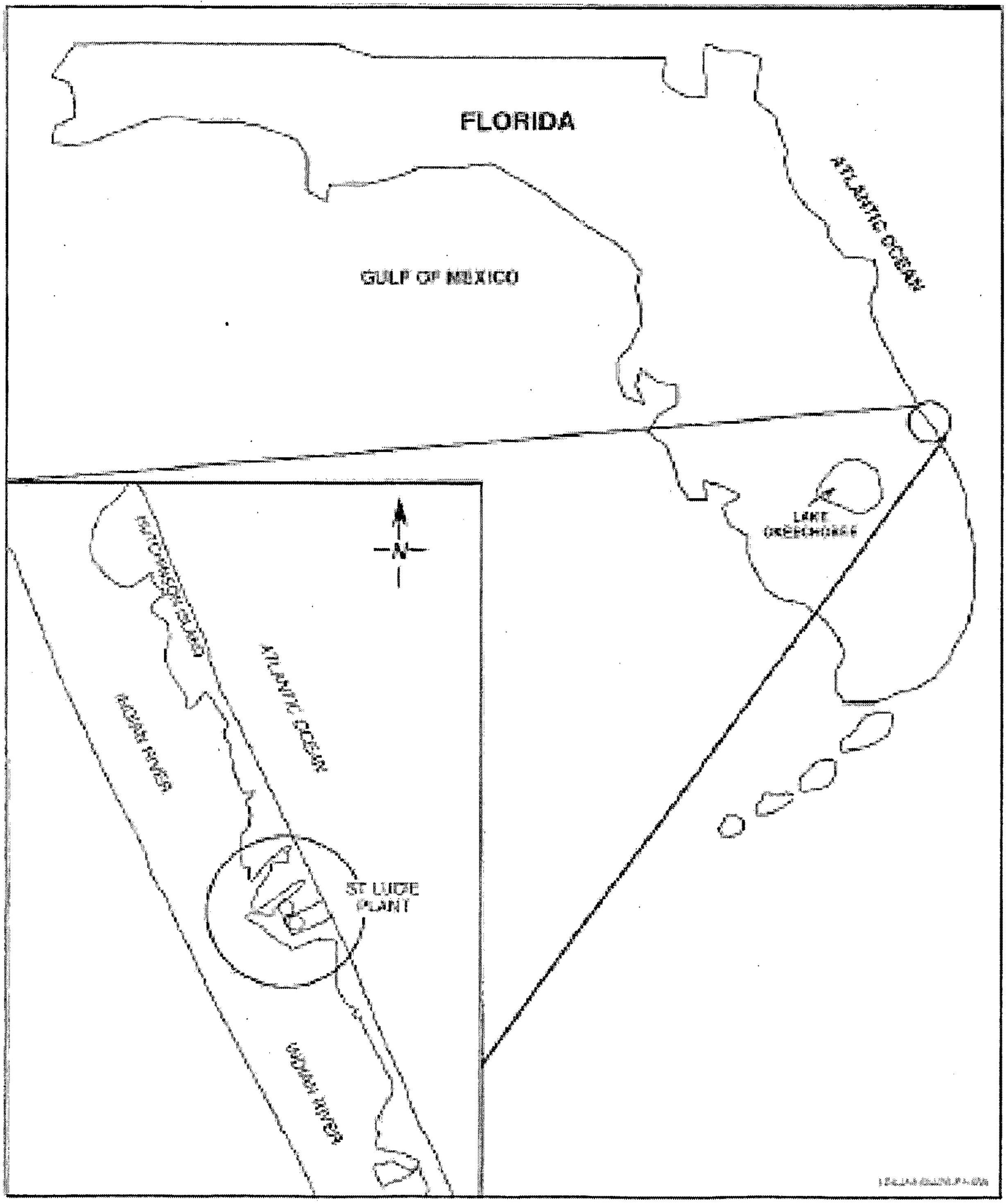

Figure 1. Location of St. Lucie Nuclear Power Plant.

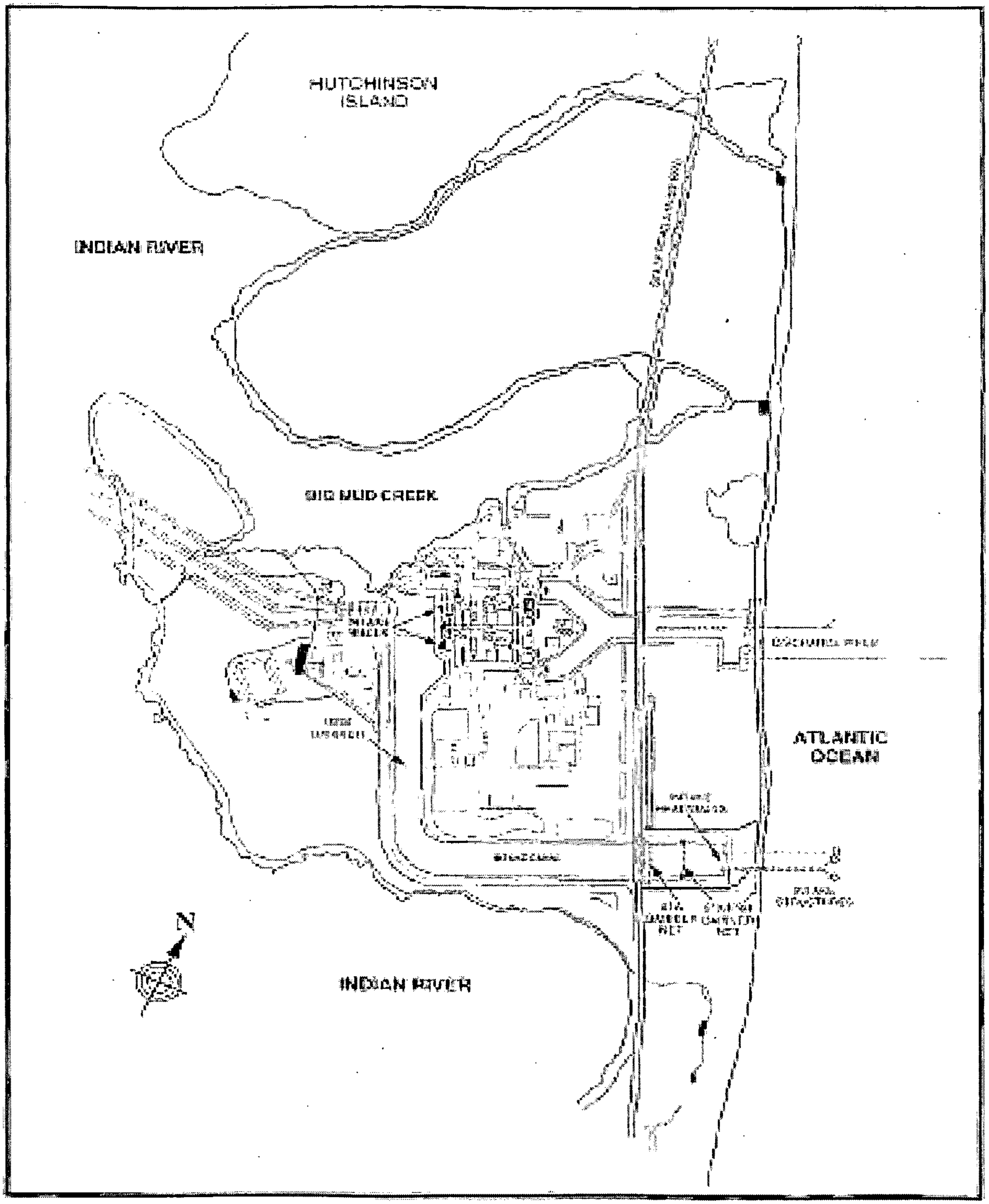

Figure 2. St. Lucie cooling water intake and discharge system.

The cooling system is composed of both intake and discharge components, whose functions are interdependent: if changes or improvements are made to one component (either the intake or discharge side), the other component will be affected. The response of all affected components to changes or improvements requires evaluation to ensure the cooling system operation is kept within design parameters and limits. Unit 1 and Unit 2 condensers and auxiliary cooling systems share common intake and discharge canals and ocean piping. The major components of these canals and ocean piping are (1) three ocean intake structures and associated velocity caps located approximately 1,200 (356 m) from the shoreline; (2) three buried intake pipelines to transport water from the intake structure to the intake canal (one pipeline is 16 ft [4.9 m] in diameter, and two are 12 ft [3.65 m] in diameter); (3) common intake canal to convey sea water to each unit's intake structure; (4) individual unit intake structures; (5) discharge structure for each unit; (6) a common discharge canal; (7) two discharge pipelines to convey water offshore.

Water for the cooling water system enters through three submerged intake structures located about 365 m (1200 ft) offshore at a depth of about 7 m (23 ft) (Figure 2). The intake structures have vertical cylindrical openings and are equipped with concrete velocity caps supported by columns extending about 1.8 m (6 ft) from the intake openings. The velocity caps minimize entrainment of fish and other organisms by eliminating vertical flow and slowing horizontal flow. Water passes through these structures and into submerged pipes (two 3.7 m [12 ft] and one 4.9 m [16 ft] in diameter) running under the beach. Flow velocities in the pipes range from 0.11 to 2.1 m/s (0.37 to 6.8 ft/s), depending on the pipe's orientation and size. The three pipes all deliver water into a 1500-m (4921-ft) long intake canal, which transports the water to the plant. The intake canal is a trapezoidal channel about 55 m (180 ft) wide and 9.1 m (30 ft) deep under normal conditions. FPL occasionally dredges the intake canal to remove accumulated sediments and maintain proper flow conditions; most recently, the canal was dredged in 2002 and 2005.

In addition to the velocity caps on the intake pipes, other measures are in place to minimize impingement of marine biota at the SLNPP. In the intake canal, a series of barriers prevents sea turtles and other biota from being impinged on the screens where the water enters the plant. Heading from the intake canal headwalls toward the intake wells in the intake canal, first there is a 12.7-centimeter (cm) (5-inch [in.]) mesh net that is taut and sloped to prevent turtles from being entangled in the net. The net is monitored hourly by sea turtle biologists who rescue any entrapped turtles. Next is a 20-cm (8-in.) mesh barrier net, and, finally, a rigid security barrier closest to the plant. Additionally, sea turtle biologists deploy two 30.5-m (100-ft) tangle nets in daylight hours (with occasional night hours as well) seven days a week to capture sea turtles between the intake headwall (where the water enters the intake canal from the pipes) and the 12.7-cm (5-in.) mesh barrier net. The nets are set in adjacent eddies and flow with the current without any weights. The biologists inspect tangle nets at least hourly and use dip nets and free diving to capture turtles. Underwater inspections on the 12.7- and 20-cm (5- and 8-in.) mesh barrier nets are conducted quarterly. During these inspections, any holes found in the nets are repaired.

At the plant, water enters through the eight intake wells (four per unit). In front of each well are trash racks (vertical bars spaced 7.6 cm [3 in.] apart) and 1-cm (3/8-in.) mesh traveling screens, which also prevent impingement and entrainment of organisms. Security personnel inspect the intake wells every three hours as an added precautionary measure. After passing through the plant, the heated water is discharged into a 670-m (2198-ft) long canal that leads to two buried discharge pipelines that pass underneath the dunes and along the ocean floor to the submerged discharge pipes, the first of which is 3.7 m (12 ft) in diameter and terminates approximately 380 m (1250 ft) offshore. The second discharge pipe has a diameter of 4.9 m (16 ft) and ends about 936 m (3070 ft) offshore. The first discharge pipe has a two-port "Y" diffuser, and the second discharge pipe has a multiport diffuser for about the last 430 m (1415 ft) of the pipe. The discharge pipes are approximately 730 m (2400 ft) north of the intake. The diffusers facilitate rapid distribution of the heated water on a large spatial scale to mix efficiently with ambient waters. Discharge temperatures are kept within limits of the Industrial Wastewater Facility Permit for St. Lucie Units 1 and 2.

5.0 Information on Sea Turtle Species

5.1 General Biology

Living sea turtles are taxonomically represented by two families, five genera, and seven species (Hopkins and Richardson 1984; Carr 1952). The family Cheloniidae is comprised of four genera and six distinct species. These species are *Caretta caretta* (loggerhead turtle), *Chelonia mydas* (Atlantic green turtle), *Natador depressa* (flatback turtle), *Eretomochelys imbricata* (hawksbill turtle), *Lepidochelys kempii* (Kemp's ridley turtle), and *L. olivacea* (olive ridley turtle). The family Dermochelyidae is comprised of only one genus and species, *Dermochelys coriacea*, commonly referred to as the leatherback turtle.

Most sea turtle species are distributed throughout all of the tropical oceans. The flatback turtle is a major exception as it has a very limited range only in Pacific waters near Australia and Papua New Guinea. Also, the loggerhead occurs primarily in temperate latitudes, and the leatherback, although nesting in the tropics, frequently migrates into cold waters at higher latitudes because of its unique physiology (Mager 1985).

Sea turtles are believed to be descended from species known from the late Jurassic and Cretaceous periods that were included in the extinct family Thallassemyidae (Carr 1952; Hopkins and Richardson 1984). Modern sea turtles have short, thick, incompletely retractile necks, and legs that have been modified to become flippers (Bustard 1972; Carr 1952). All species, except the leatherback, have a hard, bony carapace modified for marine existence by streamlining and weight reduction (Bustard 1972). Chelonians have only a thin layer of bone covered by overlaying scutes and *D. coriacea* has a smooth scaleless black skin and soft carapace with seven longitudinal keels (Carr 1952). These differences in structure are the principal reason for their designation as the only species in the monotypic family Dermochelyidae (Carr 1952).

Sea turtles spend most of their lives in an aquatic environment, and males of many species may never leave the water (Hopkins and Richardson 1984; Nelson 1988). The recognized life stages for these turtles are egg, hatchling, juvenile/subadult, and adult (Hirth 1971). A generalized sea turtle life cycle is presented in Figure 3.

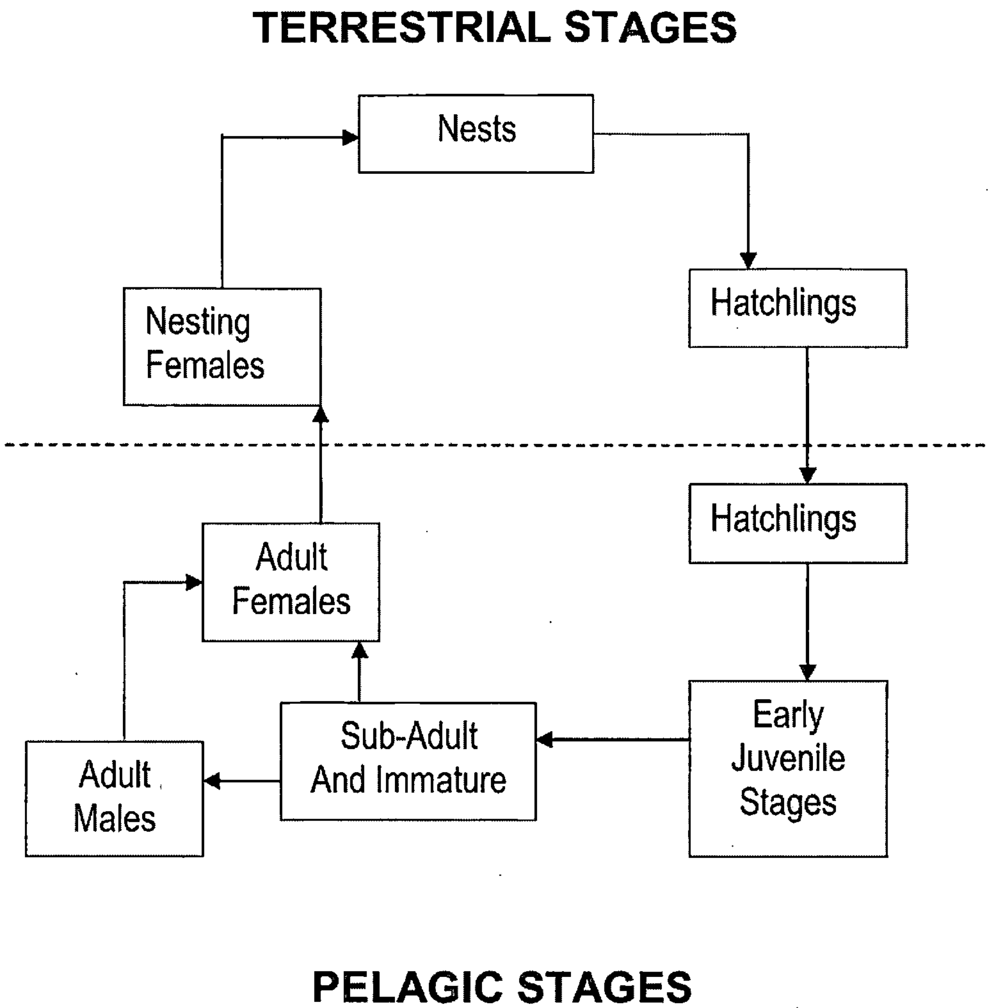

Figure 3. Generalized sea turtle life cycle. (After PSE&G 1989)

Reproductive cycles in adults of all species involve some degree of migration in which the animals return to nest at the same beach year after year (Hopkins and Richardson 1984). Nesting generally begins about mid-April and continues into September (Hopkins and Richardson 1984; Nelson 1988; Carr 1952). Mating and copulation occur just off the nesting beach, and it is theorized that sperm from one nesting season may be stored by the female and thus fertilize a later season's eggs (Ehrhart 1980). A nesting female moved shoreward by the surf lands on the beach and crawls to a point above the high water mark (Carr 1952). She then proceeds to excavate a shallow body pit by twisting her body in the sand (Bustard 1972). After digging the body pit she proceeds to excavate an egg chamber using her rear flippers (Carr 1952). Clutch size, egg size, and egg shape are species specific (Bustard 1972). Incubation periods for loggerhead, Kemp's ridley, Atlantic green, olive ridley, and flatback turtles average 55 days but range from 45 to 65 days depending on local conditions (Nelson 1988). Hawksbill and leatherback turtles have a slightly longer incubation period ranging from 50 to 74 days (Pacific Whale Foundation 2003; Connecticut Department of Environmental Protection 2000).

Hatchlings emerge from the nest at night by breaking the eggshell and digging their way out of the nest (Carr 1952). They find their way across the beach to the surf by orienting to light reflecting off the breaking surf (Hopkins and Richardson 1984). Once in the surf, hatchlings exhibit behavior known as "swim frenzy," during which they swim in a straight line for many hours (Carr 1986). Once into the waters off the nesting beach, hatchlings enter a period known as the "lost year." Researchers are presently trying to determine where young sea turtles spend their earliest years, what habitat(s) they prefer at this age, as well as typical survival rates during the "lost year" (i.e., during their post-hatchling early pelagic stage). It is currently believed the period encompassed by the "lost year" may actually turn out to be several years, and various hypotheses have been put forth regarding sea turtle activities during this period. One is that hatchlings may become associated with floating Sargassum rafts offshore. These rafts provide shelter and are dispersed randomly by the currents (Carr 1986). Another hypothesis is that the "lost year" of some species may be spent in a salt marsh/estuarine system (Garmon 1981).

The functional ecology of sea turtles in the marine and/or estuarine ecosystem is varied. The loggerhead is primarily carnivorous and has jaws well adapted to crushing molluscs and crustaceans and grazing on encrusted organisms attached to reefs, pilings, and wrecks; the Kemp's ridley is omnivorous and feeds on swimming crabs, crustaceans, and molluscs (Seney et al. 2002); the Atlantic green turtle is a herbivore and grazes on marine grasses and algae; the leatherback is a specialized feeder preying primarily upon jellyfish; the olive ridley feeds mostly on shrimp, crabs, sea urchins, and jellyfish; the hawksbill is an omnivorous scavenger feeding mostly on sponges affixed to coral reefs as well as a few other invertebrates; the flatback prefers to eat sea cucumbers, soft corals, and jellyfish. Until recently, sea turtle populations were relatively large and subsequently played a significant role in the marine ecosystem. This role has been greatly reduced in most locations as a result of declining turtle populations. These population declines were a result of, among other things, natural factors such as disease and predation, habitat loss, commercial overutilization, commercial fishing by-catch mortality, and the lack of comprehensive regulatory mechanisms to ensure their protection throughout their geographic range. This has led to several species being threatened with extinction.

Due to changes in habitat use during different life history stages and seasons, sea turtle populations are difficult to census (Meylan 1982). Because of these problems, estimates of population number have been derived from various indices such as numbers of nesting females, numbers of hatchlings per kilometer of nesting beach and number of subadult carcasses (strandings) washed ashore (Hopkins and Richardson 1984). Six of the seven extant species of sea turtles are protected under the ESA. Three turtles, Kemp's ridley, hawksbill, and leatherback, are listed as endangered. The Florida nesting population of Atlantic green turtle and Mexican west coast population of olive ridley are also endangered. All of the remaining populations of Atlantic green turtle, olive ridley, and loggerhead are threatened. The only unlisted species is the locally protected Australian flatback turtle (Hopkins and Richardson 1984).

5.2 Loggerhead (*Caretta caretta*)

5.2.1 Description

The adult loggerhead turtle has a slightly elongated, heart-shaped carapace that tapers towards the posterior and has a broad, triangular head (Pritchard et al. 1983). Loggerheads normally weigh up to 200 kg (450 lb) and attain a straight carapace length (SCL) up to 120 cm (48 in.) (Pritchard et al. 1983). Their general coloration is reddish-brown dorsally and cream-yellow ventrally (Hopkins and Richardson 1984). Morphologically, the loggerhead is distinguishable from other sea turtle species by the following characteristics: (1) a hard shell; (2) two pairs of scutes on the front of the head; (3) five pairs of lateral scales on the carapace; (4) plastron with three pairs of enlarged scutes connecting the carapace; (5) two claws on each flipper; and (6) reddish-brown coloration (Nelson 1988; Dodd 1988; Wolke and George 1981). Loggerhead hatchlings are brown dorsally with light margins ventrally and have five pairs of lateral scales (Pritchard et al. 1983).

5.2.2 Distribution

Loggerhead turtles are circumglobal, inhabiting continental shelves, bays, lagoons, and estuaries in the temperate, subtropical, and tropical waters of the Atlantic, Pacific, and Indian Oceans (Dodd 1988; Mager 1985).

In the western Atlantic Ocean, loggerhead turtles occur from Argentina northward to Newfoundland including the Gulf of Mexico and the Caribbean Sea (Carr 1952; Dodd 1988; Mager 1985; Nelson 1988; Squires 1954). Sporadic nesting is reported throughout the tropical and warmer temperate range of distribution, but the most important nesting areas are on the Atlantic coast of Florida, Georgia, and South Carolina (Hopkins and Richardson 1984). The Florida nesting population of loggerheads has been estimated to be the second largest in the world (Ross 1982).

The foraging range of the loggerhead sea turtle extends throughout the warm waters of the U.S. continental shelf (Shoop et al. 1981). On a seasonal basis, loggerhead turtles are common as far north as the Canadian portions of the Gulf of Maine (Lazell 1980), but during cooler months of the year, distributions shift to the south (Shoop et al. 1981). Loggerheads frequently forage around coral reefs, rocky places, and old boat wrecks; they commonly enter bays, lagoons and estuaries (Dodd 1988). Aerial surveys of loggerhead turtles at sea indicate

that they are most common in waters less than 50 m (164 ft) in depth (Shoop et al. 1981), but they occur pelagically as well (Carr 1986).

5.2.3 Food

Loggerheads are primarily carnivorous (Mortimer 1982). They eat a variety of benthic organisms including molluscs, crabs, shrimp, jellyfish, sea urchins, sponges, squids, and fishes (Nelson 1988; Seney et al. 2002). Adult loggerheads have been observed feeding in reef and hard bottom areas (Mortimer 1982). In the seagrass lagoons of Mosquito Lagoon, Florida, subadult loggerheads fed almost exclusively on horseshoe crab (Mendonca and Ehrhart 1982). Loggerheads may also eat animals discarded by commercial trawlers (Shoop and Ruckdeschel 1982). This benthic feeding characteristic may contribute to the capture of these turtles in trawls.

5.2.4 Nesting

The nesting season of the loggerhead is confined to the warmer months of the year in the temperate zones of the northern hemisphere. In south Florida nesting may occur from April through September but usually peaks in late June and July (Dodd 1988; FPL 1983).

Loggerhead females generally nest every other year or every third year (Hopkins and Richardson 1984), but multi-annual remigration intervals ranging from one to six years have been reported (Bjorndal et al. 1983; Richardson et al. 1978). When a loggerhead nests, it usually produces two to three clutches of eggs per season and lays 35 to 180 eggs per clutch (Hopkins and Richardson 1984). The eggs hatch in 46 to 68 days and hatchlings emerge two or three days later (Crouse 1985; Hopkins and Richardson 1984; Kraemer 1979).

Hatchling loggerheads are a little less than 5 cm (2 in.) in length when they emerge from the nest (Hopkins and Richardson 1984; FPL 1983). They emerge from the nest as a group at night, orient themselves seaward and rapidly move towards the water (Hopkins and Richardson 1984). Many hatchlings fall prey to sea birds and other predators following emergence. Those hatchlings that reach the water quickly move offshore and exist pelagically (Carr 1986).

There are at least four loggerhead nesting subpopulations in the western North Atlantic (Turtle Expert Working Group 2000). The Northern Nesting Subpopulation occurs from North Carolina to northeast Florida. The Southern Florida Nesting Subpopulation is the largest loggerhead nesting assemblage in the Atlantic, occurring from 29 °N on the east coast to Sarasota on the west coast. The Florida Panhandle Nesting Subpopulation is found at Eglin Air Force Base and the beaches near Panama City, Florida. The Yucatan Nesting Subpopulation occurs on the eastern Yucatan Peninsula, Mexico. Historically, only minor nesting activity has occurred elsewhere in the western North Atlantic, with the exception of Central America (Turtle Expert Working Group 2000).

5.2.5 Population Size

Loggerhead sea turtles are the most common sea turtle in the coastal waters of the United States. A number of stock assessments have been performed for loggerhead turtles in U.S. water, but none have developed reliable estimates of absolute population size (TEWG 1998,

2000; NMFS and SEFSC 2001). Population size and temporal trends in abundance have been estimated using nesting data, stranding data, and aerial surveys.

Based on numbers of nesting females, hatchlings per kilometer of nesting beach, and subadult carcasses (strandings) washed ashore, the total number of mature loggerhead females in the southeastern United States has been estimated to be from 35,375 to 72,520 (Hopkins and Richardson 1984; Gordon 1983). The annual average adult female population along the U.S. Atlantic and Gulf coasts for the period 1989-1998 was estimated to be 44,780 individuals based upon nesting data (Turtle Expert Working Group 2000).

Adult and subadult (shell length greater than 60 cm [24 in.]) population estimates have also been based on aerial surveys of pelagic animals observed by NMFS during 1982 to 1984. Based on these studies, the number of adult and subadult loggerhead sea turtles from Cape Hatteras, North Carolina to Key West, Florida was estimated to be 387,594 individuals (NMFS 1987). This number was arrived at by taking the number of observed turtles and converting it to a population abundance estimate using information on the amount of time loggerheads typically spend at the surface.

Some sea turtles that die at sea wash ashore and are found stranded. The NMFS Sea Turtle Salvage and Stranding Network (STSSN) collects stranded sea turtles along both the Atlantic and Gulf Coasts (Turtle Expert Working Group 2000; STSSN 2004). The largest number of loggerhead strandings during the period 1986-2001 (Figure 4) occurred along the southeast Atlantic Coast (14,404 turtles; 61 percent of total), followed by the Gulf Coast (5,320 turtles; 22 percent of total) and the northeast Atlantic Coast (4047 turtles; 17 percent of total). Strandings in the southeast U.S. and the Gulf of Mexico declined in the early 1990s, but have generally increased since then. Strandings in the northeast have more than doubled during the same time period (Turtle Expert Working Group 2000; STSSN 2004).

Frazer (1986) suggested that loggerhead turtle nesting populations in the U.S. were declining, but positive steps have been taken to reverse that trend. In September of 1989, NMFS regulations requiring the use of turtle excluder devices (TEDs) on commercial shrimp trawls were implemented. Based upon onboard observations of offshore shrimp trawling in the southeast Atlantic, NMFS estimated that over 43,000 loggerheads were captured in shrimp trawls annually. The number of loggerhead mortalities from this activity was estimated to be 9874 turtles annually (NMFS 1987). An estimated 5000 to 50,000 loggerheads were killed annually during commercial shrimp fishing activities prior to regulations requiring the use of TEDs (NMFS and FWS 1991a). The use of TEDs may reduce sea turtle mortality in shrimp trawls by as much as 97 percent (Crouse et al. 1992). Studies of TED effects on reducing strandings in South Carolina and Georgia during the period 1980-1997 demonstrated reductions in strandings ranging from 40 to 58 percent (Crowder et al. 1995; Royle and Crowder 1998). Following the implementation of the TED requirement, strandings of drowned threatened and endangered sea turtle species in areas where strandings were historically high decreased dramatically for a few years (Figure 4), which suggests a reduction in shrimp trawl related mortality (Crouse et al. 1992; Turtle Expert Working Group 2000). Increases in strandings since 1993 are indicative of an increasing loggerhead population (Turtle Expert Working Group 2000).

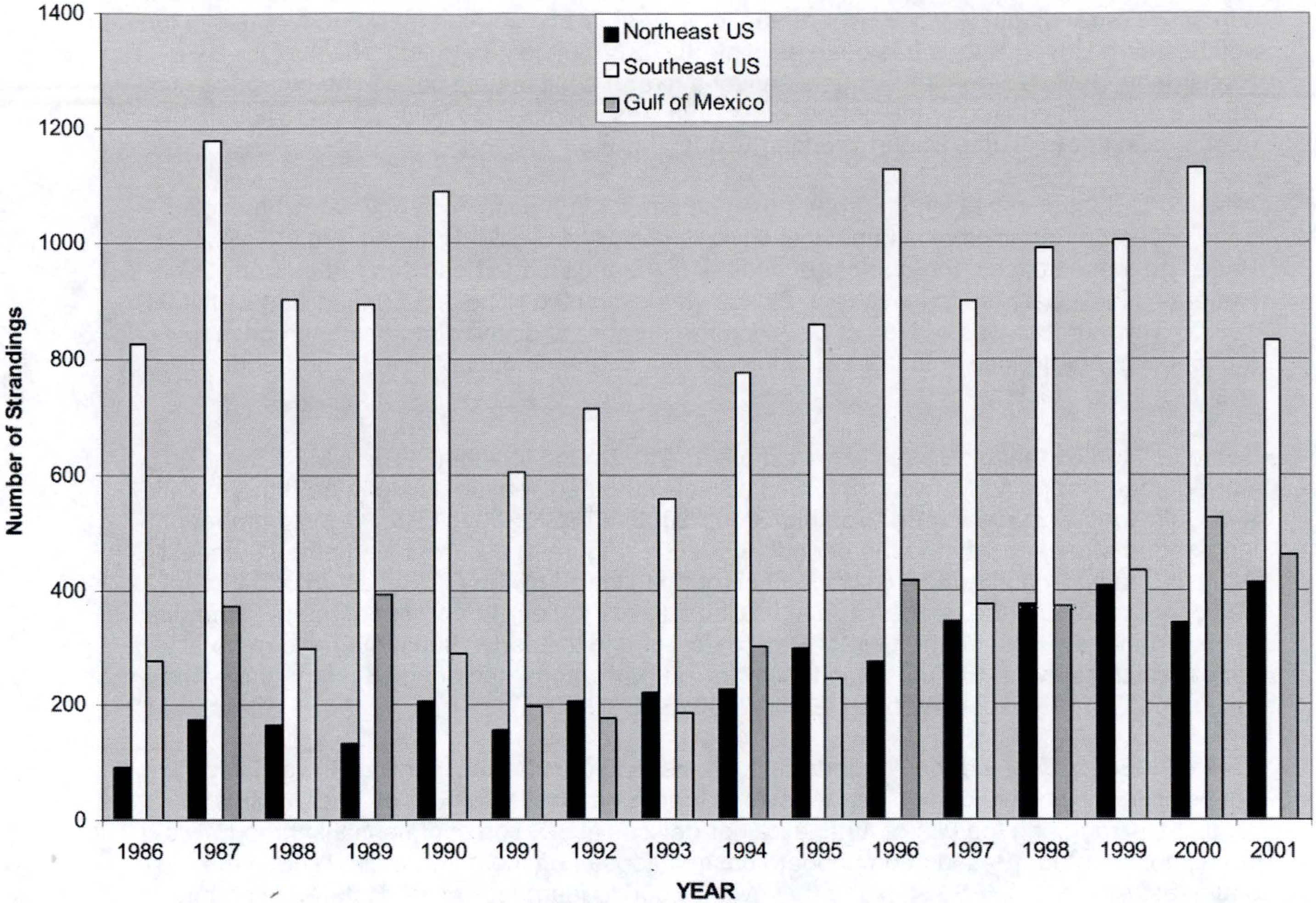

Figure 4. Loggerhead sea turtle strandings by region, 1986-2001 (Turtle Expert Working Group 2000 and STSSN 2004).

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Sea turtle nesting activity on two key beaches also increased considerably subsequent to the implementation of the TED regulations (Crouse et al. 1992). The total number of loggerhead nests laid along the U.S. Atlantic and Gulf coasts is approximately 68,000 to 90,000 per year (OPR 2007). The number of nests increased at an average rate of approximately 3.6 percent per year and reached the maximum observed number (92,182) in 1998 (Turtle Expert Working Group 2000). In addition to the apparent success of the TED program, restrictions on development in coastal areas have become more widespread in recent years and may reduce the rate of nesting habitat loss for sea turtles.

The observed trends in strandings and nesting activity in recent years, along with some evidence of a shift in size class distribution toward smaller turtles, suggest that the U.S. loggerhead population is increasing (Turtle Expert Working Group 2000) and that effective measures have been taken to mitigate a major source of loggerhead mortality. Various population estimates suggest that the number of adult and subadult turtles is probably in the hundreds of thousands in the southeastern United States alone. In addition, large populations of loggerheads occur in many other parts of the world (Ross and Barwani 1982; NMFS and FWS 1991a). These facts suggest that although this species needs to be conserved, it is not in any immediate risk of becoming endangered.

5.3 Kemp's Ridley (*Lepidochelys kempii*)

5.3.1 Description

The adult Kemp's ridley has a circular carapace and a medium-sized pointed head. Kemp's ridleys are the smallest of extant sea turtles. They normally weigh up to 42 kg (90 lb) and attain a SCL up to 70 cm (27 in.) (Pritchard et al. 1983). Their general coloration is olive green dorsally and yellow ventrally (Hopkins and Richardson 1984). Morphologically, the Kemp's ridley is distinguishable from other sea turtle species by the following characteristics: (1) a hard shell; (2) two pairs of scutes on the front of the head; (3) five pairs of lateral scutes on the carapace; (4) plastron with four pairs of scutes, with pores, connecting the carapace; (5) one claw on each front flipper and two on each back flipper; and, (6) olive green coloration (Pritchard et al. 1983; Pritchard and Marquez 1973). Kemp's ridley hatchlings are dark grey-black dorsally and white ventrally (Pritchard et al. 1983; Pritchard and Marquez 1973).

5.3.2 Distribution

Kemp's ridley turtles inhabit sheltered coastal areas and frequent larger estuaries, bays, and lagoons in the temperate, subtropical, and tropical waters of the northwestern Atlantic Ocean and Gulf of Mexico (Mager 1985). The foraging range of adult Kemp's ridley turtles appears to be restricted to the Gulf of Mexico. However, juveniles and subadults occur throughout the warm coastal waters of the U.S. Atlantic coast (Hopkins and Richardson 1984; Pritchard and Marquez 1973). Juveniles and subadults travel northward with vernal warming to feed in the productive coastal waters of Georgia through New England, but return southward with the onset of winter to escape the cold (Henwood and Ogren 1987; Lutcavage and Musick 1985; Morreale et al. 1988; Ogren 1989).

5.3.3 Food

Kemp's ridleys are omnivorous and feed on swimming crabs, crustaceans, fish, jellyfish, and molluscs (Pritchard and Marquez 1973; Seney et al. 2002).

5.3.4 Nesting

Nesting of Kemp's ridleys is mainly restricted to a stretch of beach near Rancho Nuevo, Tamaulipas, Mexico (Pritchard and Marquez 1973; Hopkins and Richardson 1984). Occasional nesting has been reported in Padre Island, Texas and Veracruz, Mexico (Mager 1985; Turtle Expert Working Group 2000). An estimated 40,000 females nested on a single day in 1947, but between 1978 and 1990 there were less than 1000 nests per season (Figures 5 and 6).

The nesting season of the Kemp's ridley is confined to the warmer months of the year primarily from April through July. Kemp's ridley females generally nest every year to every third year (Márquez et al. 1982; Pritchard et al. 1983). They produce two to three clutches of eggs per season and lay 50 to 185 eggs per clutch. The eggs hatch in 45 to 70 days, and hatchlings emerge two to three days later (Hopkins and Richardson 1984).

Hatchling Kemp's ridleys are about 4.2 cm (a little less than 2 in.) in length when they emerge from the nest (Hopkins and Richardson 1984). They emerge from the nest as a group at night, orient themselves seaward and rapidly move towards the water (Hopkins and Richardson 1984). Following emergence, many hatchlings fall prey to sea birds, raccoons, and crabs. Those hatchlings that reach the water quickly move offshore. Their existence after emerging is not well understood but is probably pelagic (Carr 1986). The post-pelagic stages are commonly found dwelling over crab-rich sandy or muddy bottoms. Juveniles frequent bays, coastal lagoons, and river mouths (NMFS and FWS 1992).

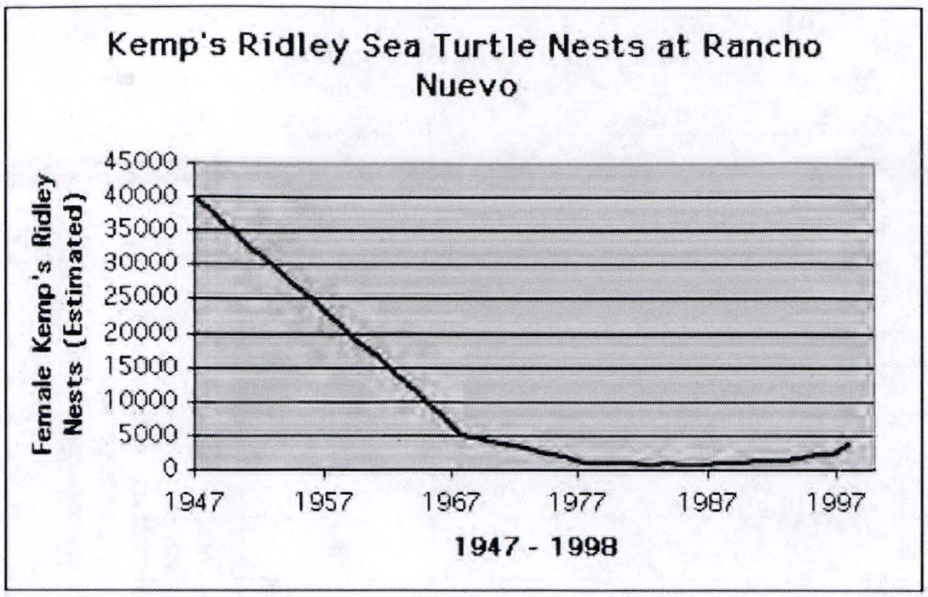

Figure 5. Estimated annual number of nesting female Kemp's Ridley sea turtles at Rancho Nuevo (HEART 1999).

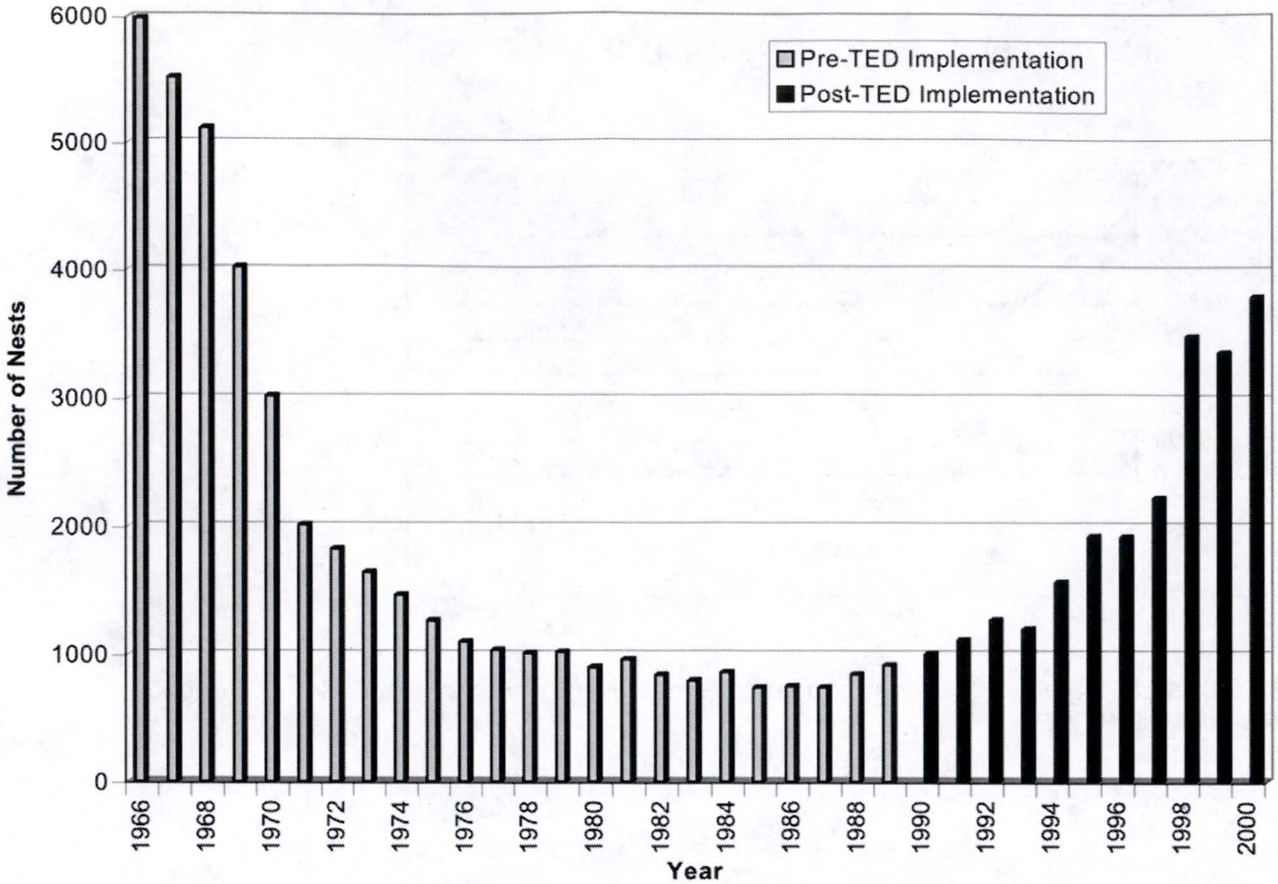

Figure 6. Number of Kemp's ridley nests at Rancho Nuevo before and after implementation of the turtle exclusion device (TED) regulations in 1989. (Turtle Expert Working Group 2000 and Marquez et al. 2001)

5.3.5 Population Size

The Kemp's ridley is the most endangered of the sea turtle species. Based on nesting information from Rancho Nuevo, Ross (1989) estimated that the population was declining at a rate of approximately three percent per year. The lowest number of nests was observed in 1985 (740 nests), but since that time the number of nests has increased by approximately 11.3 percent per year (Turtle Expert Working Group 2000). In 1994, 1565 nests were observed at Rancho Nuevo, and more Kemp's ridley nests have been laid each year since 1990 than in any previous year on record since 1978 (Byles, 1994). By 2000, the number of nests found at Rancho Nuevo increased to 3.788 (Marquez et al. 2001). It has been suggested that this increase in nesting activity reflects the reduction in shrimp trawl related mortality realized since the implementation of the NMFS TED regulations in September of 1989 (Crouse et al. 1992; Turtle Expert Working Group 2000). This hypothesis is supported by analyses of the number of nests counted versus hatchlings released (Turtle Expert Working Group 2000). The results of those analyses indicate that there has been an increase in survivorship from hatchling to maturity during the late 1980s and early 1990s. The increase in nesting activity is also likely to be attributable in part to an increase in recruitment to the population as a result of beach and nest protection efforts at Rancho Nuevo (Marquez et al. 1999; Turtle Expert Working group 2000). The adult Kemp's ridley population was estimated by Márquez (1989) to be approximately 2,200 adults based on the numbers of nests produced at Rancho Nuevo, this species's nesting cycle, male-female ratios, and fecundity. More recently, the Turtle Expert Working Group (1998; 2000) reported that age-based population models suggest that the Kemp's ridley population is increasing rapidly and that the trend was expected to continue into the future. While there is no current population estimate, the nesting population is estimated to be increasing ten percent each year (NOAA Fisheries 2003). As a result, we can expect to find increasing numbers of juveniles and subadults migrating northward each year as Atlantic coastal waters warm to feed in the productive coastal estuaries.

Population estimates of immature *Lepidochelys kempii* are difficult to develop. Increases have been noted in the number of juvenile captures during the late 1980s and early 1990s in long-term tagging studies in the northeast Gulf of Mexico (Ogren, unpublished data). If this increase is indicative of an overall increase in the juvenile population, more recruitment into the adult population should occur in the future (NMFS and FWS 1991a).

Kemp's ridleys also die at sea and wash ashore. The STSSN collects stranded sea turtles along both the Atlantic and Gulf Coasts (Turtle Expert Working Group 2000; STSSN 2004; Figure 7). The largest number of Kemp's ridley strandings during the period 1986-2001 occurred along the Gulf Coast (3,495 turtles; 60 percent of total), followed by the southeast Atlantic Coast (1,555 turtles; 27 percent of total) and the northeast Atlantic Coast (748 turtles; 13 percent of total). The number of strandings along the Gulf Coast increased sharply in 1994 and 1995 but subsequently remained fairly constant (Turtle Expert Working Group 2000). Along the southeast Atlantic Coast, the number of strandings decreased somewhat during the early 1990s but tended to increase from 1993 through 2001.

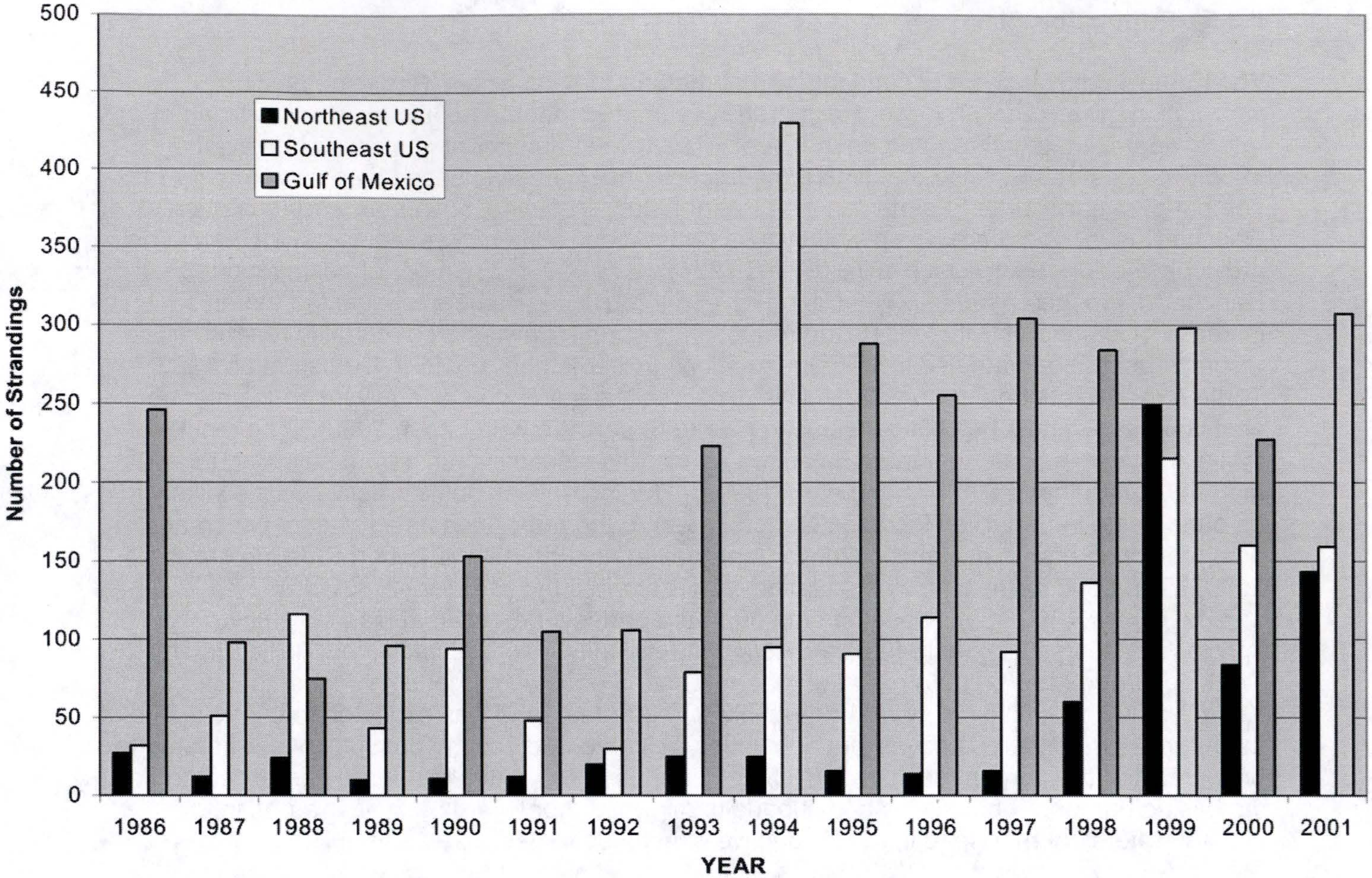

Figure 7. Kemp's ridley sea turtle strandings by region, 1986-2001. (Turtle Expert Working Group 2000 and STSSN 2004)

The number of strandings along the northeast Atlantic Coast was low and variable through 1997, but a noticeable increase was observed during the 1998-2001 period (Figure 7). A dramatic increase in strandings of Kemp's ridleys was also observed along the North Carolina coast from 1993 to 1999 (Boettcher 2002). Prior to 1993, 20 or fewer Kemp's ridley strandings were reported annually. The number of stranded individuals steadily increased from 12 in 1992 to a maximum of 122 in 1999. The timing of these increases in Kemp's ridley strandings seems to coincide with the implementation of the NMFS TED regulations described above, and suggests that the population is increasing.

An analysis of the size of stranded Kemp's ridleys indicated that many more large immature individuals were stranded during the 1990s relative to the 1980s (Turtle Expert Working Group 2000). These results also suggest that juvenile mortality has decreased and that the population is increasing.

Onboard observation of offshore shrimp trawling by NMFS in the southeast Atlantic indicated that over 2800 Kemp's ridleys are captured in shrimp trawls annually. The number of Kemp's ridley mortalities attributable to this activity was estimated to be 767 turtles annually and most of these (65 percent) occurred in the western portion of the Gulf of Mexico (NMFS 1987). Magnuson et al. (1990) estimated the annual shrimp trawl by-catch mortality to be between 500 and 5000 individuals. As discussed above, significant reductions in this source of mortality have been achieved as a result of the implementation of the TED regulations by the NMFS in 1989 (Crouse et al. 1992). The reduction in shrimp-trawl-related mortality, as well as the efforts to protect nesting beaches, have probably resulted in the recent indications that the population is steadily increasing (Turtle Expert Working Group 1998; 2000).

Despite these improvements, the data suggest that this population remains at critically low levels. This species was listed as endangered in 1970 and is considered the most endangered of all sea turtles (NMFS and FWS 1991a; Burke et al. 1994).

5.4 Atlantic Green Turtle (*Chelonia mydas*)

5.4.1 Description

The Atlantic green turtle is a medium-to-large sea turtle with a nearly oval carapace and a small, rounded head (Pritchard et al. 1983). Its carapace is smooth and olive brown in color with darker streaks and spots. Its plastron is yellow. Full-grown adult Atlantic greens normally weigh 100 to 150 kg (220 to 330 lb) and attain a SCL of 90 to 100 cm (35 to 40 in.) (Pritchard et al. 1983; Hopkins and Richardson 1984; Witherington and Ehrhart 1989). Morphologically, this species can be distinguished from the other sea turtles by the following characteristics: (1) a relatively smooth shell with no overlapping scutes; (2) one pair of scutes on the front of the head; (3) four pairs of lateral scutes on the carapace; (4) plastron with four pairs of enlarged scutes connecting the carapace; (5) one claw on each flipper; and (6) olive, dark brown mottled coloration (Nelson 1988; Pritchard et al. 1983; Carr 1952). Hatchlings are about 25 grams (0.88 ounces) and 55 millimeters (2.2 in.) long. They have a black carapace that is white on the ventral side.

5.4.2 Distribution

Atlantic green turtles are circumglobally distributed mainly in waters between the northern and southern 20 °C (68 °F) isotherms (Mager 1985). Preferred nesting grounds include sandy beaches of mainland shores, barrier islands, coral islands, and volcanic islands (NOAA Fisheries 2002).

In the western Atlantic, several major assemblages have been identified and studied (Parsons 1962; Pritchard 1966; Schulz 1975; 1982; Carr et al. 1978). In U.S. Atlantic waters, Atlantic green turtles are found around the U.S. Virgin Islands, Puerto Rico, and the continental United States from Texas to Massachusetts (NMFS and FWS and FWS 1991b). Nesting grounds extend from Texas to North Carolina as well as in the U.S. Virgin Islands and Puerto Rico. Eastern Florida has some of the main nesting beaches; other important nesting beaches are found on St. Croix and Puerto Rico (NOAA Fisheries 2002). Critical habitat is designated in waters around Isla Culebra, Puerto Rico.

5.4.3 Food

Atlantic green turtles leave their pelagic habitat phase and enter benthic feeding grounds upon reaching a SCL of 20 to 25 cm (8-10 in.). They are primarily herbivores eating sea grasses and algae (NMFS and FWS 1991b). Jellyfish, sponges, and other organisms living on sea grass blades and algae add to their diet (Mager 1985). Pelagic post-hatchlings are most likely omnivorous (NOAA Fisheries 2002).

5.4.4 Nesting

Atlantic green turtle nesting primarily occurs on the Atlantic coast of Florida from June to September (Hopkins and Richardson 1984). Other important nesting beaches include beaches in Yucatán and Tortuguero, Costa Rica. It is thought that nesting activity is increasing in Florida and Tortuguero; sparse data make it impossible to reliably estimate nesting trends in Yucatán (NOAA Fisheries 2002).

Although males mate annually, females only nest every two to four years (NOAA Fisheries 2002). Mature females may nest one to seven times per season at about 10-to-18-day intervals (Carr et al. 1978). Average clutch sizes vary between 100 and 200 eggs that usually hatch within 45 to 60 days (Hopkins and Richardson 1984). Hatchlings emerge, mostly at night, travel quickly to the water, and swim out to sea. At this point, they enter a period that is poorly understood but is likely spent pelagically in areas where currents concentrate debris and floating vegetation such as *Sargassum* spp. (Carr 1986).

5.4.5 Population Size

Elimination and deterioration of many nesting beaches and less-frequent encounters with Atlantic green turtles provided inferential evidence of declining stocks in the early to mid-1980s (Mager 1985; Hopkins and Richardson 1984). The number of Atlantic green sea turtles that existed before commercial exploitation and the total number that now exists are not known.

Records show drastic declines in the Florida catch during the 1800s, and similar declines occurred in other areas, such as Texas, where they were commercially harvested in the past (Hildebrand 1982; Hopkins and Richardson 1984). Although estimates are not available for the total population, it is estimated, while taking into account the two-year remigration interval, that the nesting population in the southeastern U.S. is recovering and has reached an approximate level of 1,000 nesting females (NOAA Fisheries 2002). Also, in Indian River Lagoon in Florida, a long-term study in juvenile foraging grounds found significant increases between the early and late 1980s in the population of juvenile Atlantic green turtles (NOAA Fisheries 2002).

There are many ongoing threats to the Atlantic green turtle population. While TED regulations have helped reduce incidental take in trawl fisheries, incidental takes with fishing gear interactions continue to occur. Other threats at sea include pollution, foraging habitat loss through human-based direct destruction and secondary siltation, vessel strikes, and suction dredges. Nesting beaches are threatened by erosion control, artificial lighting, beach armoring, and disturbance. Finally, green turtle fibropapillomatosis disease, an often fatal tumor disease, is widespread and may be a contributor to population decline in Hawaii and Florida (NOAA Fisheries 2002). Outside the U.S., some areas continue direct takes of Atlantic green turtles for their shells, eggs, and meat.

5.5 Leatherback Turtle (*Dermochelys coriacea*)

5.5.1 Description

The leatherback turtle is the largest sea turtle. It has an elongated, somewhat triangularly-shaped body with longitudinal ridges or keels. It has a leathery, blue-black shell composed of a thick layer of oily, vascularized, cartilaginous material, strengthened by a mosaic of thousands of small bones. This blue-black shell may also have variable white spotting (Pritchard et al. 1983). Its plastron is white. Leatherbacks normally weigh up to 300 kg (660 lb) and attain a SCL of 140 cm (55 in.) (Pritchard et al. 1983; Hopkins and Richardson 1984). Specimens as large as 910 kg (2,000 lb) have been observed.

Morphologically, this species can be easily distinguished from the other sea turtles by the following characteristics: (1) its smooth unscaled carapace; (2) carapace with seven longitudinal ridges; (3) head and flippers covered with unscaled skin; and, (4) no claws on the flippers (Nelson 1988; Pritchard et al. 1983; Pritchard 1971; Carr 1952).

5.5.2 Distribution

Leatherbacks have a circumglobal distribution and occur in the Atlantic, Indian, and Pacific Oceans. They range as far north as Labrador and Alaska to as far south as Chile and the Cape of Good Hope. Their occurrence farther north than other sea turtle species is probably related to their ability to maintain a warmer body temperature over a longer period of time (NMFS 1985). Thompson (1984) reported that leatherbacks prefer water temperatures of 20 ± 5 °C (68 ± 9 °F) and were likely to be associated with cooler, more productive waters than the Gulf Stream. Aerial surveys have shown leatherbacks to be present from April to November between North Carolina and Nova Scotia, but most likely to be observed from the Gulf of Maine south to Long Island during summer (Shoop et al. 1981).

5.5.3 Food

The diet of the leatherback consists primarily of soft-bodied animals such as jellyfish and tunicates, together with juvenile fishes, amphipods, and other organisms (Hopkins and Richardson 1984).

5.5.4 Nesting

Leatherback turtle nesting occurs on the mid-Atlantic coast of Florida from late February or March to September (Hopkins and Richardson 1984; NMFS 1992). Mature females may nest one to nine times per season at about 9-to-17-day intervals. Average clutch sizes vary between 50 and 170 eggs that usually hatch within 50 to 75 days (Hopkins and Richardson 1984; Tucker 1988). Hatchlings emerge, mostly at night, travel quickly to the water, and swim out to sea. The life history of the leatherback is poorly understood since juvenile turtles are rarely observed.

5.5.5 Population Size

The world population estimate for the leatherback in 1980 was estimated to be about 115,000 females with the discovery of nesting beaches in Mexico (Pritchard 1983). Probably due to exploitation of eggs on the beach and fishery mortality, that number declined to about 34,500 by 1995 (Spotila et al. 1996), and numbers may still be declining.

5.6 Hawksbill Turtle (*Eretmochelys imbricata*)

5.6.1 Description

Hawksbill turtles are small to medium turtles with elongated heads with pointy mouths. The hawksbill turtle is best known for its "tortoise shell" carapace, which is mostly brown, mottled with light and dark spots on the dorsal side. The ventral side is a light yellow or white, acting as a natural camouflage against predators. Identifying characteristics include overlapping costal scutes, serrated marginal scutes, two pairs of prefrontal scales, and two claws on each flipper. The hatchling and juvenile carapaces are heart-shaped and become elongated as the turtles mature.

5.6.2 Distribution

Post-hatchlings are pelagic while juvenile, subadult, and adult hawksbills are found in coral reef environments or in bays and estuaries with mangroves when coral reefs are absent. Generally, hawksbills are found in tropical and subtropical waters, although they have been sighted as far north as Maine in Atlantic waters. Most sightings on the eastern coast of the U.S. have been reported from Florida and Texas.

5.6.3 Food

The hawksbill diet consists mostly of sponges found on coral reefs. Other common prey include mollusks, algae, sea anemones, squid, and other invertebrates.

Hawksbills use their sharp beak-like mouth to forage for sponges in crevices of coral reefs (Pacific Whale Foundation 2003).

5.6.4 Nesting

Hawksbill turtles have solitary nesting behavior and are known to nest in the U.S. in Puerto Rico, U.S Virgin Islands, Florida, and Hawaii. Critical habitat is designated for nesting beaches in Puerto Rico. Individual nesting sites are often under vegetation. Females nest every two to three years, and lay up to six clutches per season with a 15-to-21-day interval; the average clutch size has 130 eggs (Pacific Whale Foundation 2003).

5.6.5 Population Size

Although there are few data about the hawksbill turtle, nesting populations are thought to be declining. An estimate based on data from the early to mid-1990s is approximately 34,000 nesting females (Caribbean Conservation Corporation 2003). Critical habitat is designated for some nesting beaches in Puerto Rico, but Mexico probably has the biggest nesting population in the Atlantic and Caribbean. Most sightings off Texas and Florida are thought to be of populations from the Mexican nesting beaches.

6.0 Incidental Captures and Plant-Related Mortality

Correspondence regarding the ITS of the May 2001 BO contains language that turtle injury or mortality in the canal shall be counted when "resulting from plant operation." In response to this requirement, a qualified veterinarian determines cause of death or injury in cases that are not readily apparent.

From initial plant operation in May 1976 through 2006, FPL captured and removed from the intake canal a total of 6876 loggerhead, including 507 recaptures; 4954 Atlantic green, including 1641 recaptures; 31 leatherback; 45 Kemp's ridley; and 45 hawksbill turtles. Table 1 shows the sea turtle capture data over the last five calendar years, all of which have been subject to the existing ITS that took effect when the 2001 BO was issued. NRC staff believes that variation in the number of turtles found during different months and years, including dramatic increases in Atlantic green turtle captures in recent years, is primarily due to natural variations in the occurrence of turtles in the vicinity of the plant rather than to operational influences of the plant itself.

The plant exceeded the annual incidental take limit for sea turtles in 2006 and entrained a total of 662 Atlantic green and loggerhead turtles. The incidental take limit of 1 percent of entrained Atlantic green and loggerhead turtles was exceeded because 29 of the 662 entrained turtles were injured or killed due to plant operation (Table 2). The first mortality occurred on January 22, 2006, when a small, dead Atlantic green turtle was discovered impinged at the intake well for Unit 2. On October 25 and 26, 2006, 21 loggerhead hatchling mortalities were discovered and likely resulted from a single hatching at an undetected nest on the intake canal bank. During the same event, three loggerhead hatchlings were retrieved alive and later released on November 4, 2006. The January and October mortalities resulted from drowning after impingement at the intake wells.

Table 1. Sea turtle takes (mortalities) at St. Lucie Nuclear power Plant in the last five years.

	Year				
Turtle Species	2002	2003	2004	2005	2006
Loggerhead	341 (0)	583 (0)	623 (2)	485 (2)	395 (21)
Atlantic Green Turtle	292 (3)	394 (3)	286 (1)	427 (2)	267 (8)
Kemp's Ridley	0 (0)	4 (0)	2 (0)	0 (0)	1 (0)
Leatherback	3 (0)	6 (0)	2 (0)	2 (0)	2 (0)
Hawksbill	0 (0)	2 (0)	1 (0)	3 (0)	3 (0)
Total	636 (3)	989 (3)	914 (3)	917 (4)	668 (29)

Source: FPL and Quantum Resources, Inc. 2006.

Table 2. Sea turtle takes causal to operation of St. Lucie Nuclear Power Plant in 2006.

Date (2006)	Species	Number of Turtles	Injury or Mortality
1/22	Atlantic green turtle	1	Mortality
7/12	Atlantic green turtle	1	Injury
7/18	Atlantic green turtle	1	Injury
8/15	Atlantic green turtle	1	Injury
9/2	Atlantic green turtle	1	Injury
9/13	Atlantic green turtle	1	Injury
9/25	Atlantic green turtle	1	Injury
10/12	Atlantic green turtle	1	Injury
10/25	Loggerhead	11/3*	Mortality/Injury
10/26	Loggerhead	10*	Mortality

* Loggerhead hatchlings likely from an undetected nest on intake canal berm were found in Unit 1 and 2 weir pits.

Ongoing evaluations and improvements to the canal capture program during recent years have substantially decreased the amount of time entrapped sea turtles remain in the canal. Turtles confined between the barrier net and intake headwalls typically reside in the canal for a relatively short period prior to capture, and most turtles have been in good to excellent condition when caught. The 12.7-cm (5-in.) mesh barrier net completed in January 1996 substantially reduced sea turtle residence times in the intake canal. During major influxes of seaweed and jellyfish, however, this net experienced design failure and caused mortalities. To prevent this problem, FPL constructed a new, improved barrier net with additional structural support. Construction of this net was completed in November 2002. The improved design and net material has withstood the seaweed and jellyfish events that caused previous design failure of the old barrier net. Additionally, dredging of the intake canal completed in 2002 and in 2005 reduced current velocities around the new barrier net. These actions have significantly reduced the potential for sea turtle mortalities in the plant's intake canal. Recent turtle injuries were likely caused by hurricane debris and/or biofouling in the intake pipes leading to the intake canal. FPL inspected intakes pipes during an outage in April 2007. Corrective actions will be determined by NMFS and NRC based on the inspection results, which have not yet been received.

7.0 Assessment of Plant Operations on Sea Turtles

Until 2006, impacts to sea turtles had not changed significantly since the last Section 7 consultation. The October 2006 impingement and deaths of 21 loggerhead turtle hatchlings brought recognition that this event could happen again with loggerhead or other sea turtle species, even though this was a single event that had not happened before during operation of SLNPP and so might have low probability of occurrence in the future. In addition, seven Atlantic green turtles were injured in 2006, which suggested possible collisions with debris in the intake pipe that might have accumulated due to a recent hurricane.

8.0 Planned Projects

The following three planned projects on the cooling system have the potential to adversely affect sea turtles or smalltooth sawfish. Each includes steps to avoid or minimize such adverse effects.

- **Repair/Replacement of the 5-in. Mesh Turtle Net.** The service life of the anti-fouling coating on the 5-in. mesh turtle net requires replacement of the net approximately every five years. The project will require the use of cranes, work boats, and divers for implementation. Installation of a temporary net will be required during the time period that the permanent net is removed. Any underwater work will be performed by divers.

- **Maintenance Canal Dredging.** Normal plant operation may cause erosion of the canal banks and transport of sediments into the canals, resulting in the partial infilling of areas of the canal. Additionally, environmental events such as hurricanes and severe storms may cause additional erosion of the canal banks and infilling of the canal. Maintenance dredging of the canal may be required to restore the canal profile. Canal dredging is performed with the use of a suction dredge to remove the unwanted material. The suction head of the dredge is fitted with bars to limit the maximum opening size to approximately 5 in. Placement of the cutter head into the water is done slowly to allow

marine life to exit the area and prevent them from being trapped. Canal dredging is performed on an as-required basis. Normal maintenance dredging may be required approximately every 8 to 10 years. Additional dredging may be required due to an environmental event such as a hurricane or severe storm.

- **Hurricane Restoration of Canal Bank.** Hurricanes during 2004 and 2005 have caused significant damage to the canal banks. A project to restore canal bank is scheduled to start during 2007 and continue into 2009. The project involves re-profiling the canal banks and installing an articulating concrete block revetment system. The work plan calls for the use of a suction dredge to remove the cut material. Dredging operations will be done as discussed above. Long reach excavators stationed on barges will be used for final grading of the canal slopes prior to placement of the revetment system. Landscape fabric and the articulating block mats installation will be installed using cranes, supported by divers. This is a one-time hurricane restoration project, and no additional work associated with this project is scheduled beyond its completion date.

9.0 Mitigation Measures

Several mitigation measures for incidental sea turtle takes were developed in discussions among FPL, NRC, and NMFS staff during a site visit on April 17-18, 2007 (NRC 2007) and a subsequent conference call among FPL, NRC, NMFS, and FWC staff on April 30, 2007. Possible measures to prevent or mitigate future nesting along the intake canal bank and to decrease turtle injuries include the following:

- Implement measures, such as cutting back existing vegetation, so that turtle crawls would be more visible. NRC and NMFS suggested that a prudent measure should be implemented as soon as possible since the 2007 sea turtle nesting season has already begun. If turtles might be injured during implementation, mitigation measures should be included.

- FPL could develop a plan to install exclusion devices at the velocity caps to prevent large marine organisms, such as adult sea turtles and smalltooth sawfish, from entering the intake pipes. NRC and NMFS observed that the design and installation of such devices would likely be a longer-term project, but suggested to FPL that this project should be done as soon as possible, with a proposed implementation, maintenance, and inspection plan to be provided for this project no later than September 30, 2007.

- During the April 2007 outage at SLNPP, FPL inspected the intake and discharge pipes. Inspection results are expected to identify the amount and location of any significant structural impediment or biofouling and debris accumulation that extends into the flow path of the intake pipes. NRC and NMFS suggested that FPL develop an implementation and future inspection plan based on the pipe inspection report for cleaning the intake pipes during the fall 2007 outage to remove protruding structures or debris that may adversely affect animals entrained in the intake canal. NRC and NMFS suggested that FPL should coordinate and obtain concurrence of the implementation and future inspection plan from the NRC and NMFS prior to implementation. NRC and NMFS believe that removal of significant biofouling and debris could reduce adverse effects on animals entrained into the intake canal.

- The exploration of the intake pipes in April 2007 also revealed a dead-end section in each 12-ft (3.66-m) diameter intake pipe, and a live Atlantic green turtle was discovered in one of them. FPL blew air into that section so the turtle could continue breathing, and the turtle entered the intake canal on June 15, 2007. Because of the potential for sea turtles to be trapped in this section, which no longer has a functional purpose, NRC and NMFS suggested that FPL could seal off the dead-end sections of the 12-ft (3.66-m) diameter intake pipes during the fall 2007 outage.

- When turtle injuries appeared to be increasing, FPL staff deduced that hurricane debris might have lodged in the plant's intake pipes. To better document turtle injuries that might occur in the future, FPL might submit monthly reports of causal injuries that include the number of scrapes and other damage, whether the number of turtle injuries appears to be decreasing or decreasing, and, if increasing, courses of action that FPL might take to reduce the causal injuries.

10.0 Conclusion and Recommendation for Revised Incidental Take Statement

Examination of the intake pipes in April 2007 revealed both the presence of protruding debris that can could cause injuries to sea turtles and the presence of a turtle trapped in a no-longer-used dead-end pipe section. Both can contribute to incidental takes of sea turtles and resulted in recommendations for mitigative measures. NRC recommends that existing terms and conditions be modified to add requirements for periodic inspections of intake pipes during planned outages, sealing off dead-end sections of intake pipes, and appropriate mitigation measures to protect listed species during maintenance projects in the intake canal. Implementation of such measures would ensure sea turtle protection, and the NRC concludes that the continued operation of SLNPP's cooling water system would not jeopardize the continued existence of sea turtles in U.S. waters.

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August 14, 2007

Mr. David Bernhart
Assistant Regional Administrator for Protected Resources
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SUBJECT: BIOLOGICAL ASSESSMENT FOR THE REINITIATION OF A FORMAL CONSULTATION UNDER THE ENDANGERED SPECIES ACT TO INCLUDE SEA TURTLES AT THE ST. LUCIE NUCLEAR POWER PLANT (TAC NOS. MD4260 AND MD4261)

Dear Mr. Bernhart:

The U.S. Nuclear Regulatory Commission (NRC) staff has prepared the enclosed Biological Assessment (BA) to reinitiate formal consultation under Section 7 of the Endangered Species Act of 1973, as amended, regarding the continued operation of the St. Lucie Nuclear Power Plant (SLNPP). In your May 4, 2001, Biological Opinion (BO), the current Incidental Take Statement (ITS), as clarified by letter dated July 30, 2002, authorizes the annual take limit for injured and dead (due to plant operations) loggerhead (*Caretta caretta*) and green (*Chelonia mydas*) turtles by percentage, up to one percent of the annual total entrained loggerhead and green turtles (combined). Additionally, there are limits causally related to plant operations of two lethal takes of Kemp's ridley turtles (*Lepidochelys kempii*) each year and of one hawksbill (*Eretmochelys imbricata*) or leatherback (*Dermochelys coriacea*) turtle injured or killed every two years. There is an annual maximum of 1000 takes for all sea turtle species combined, regardless of cause. The one percent take limit for sea turtles was exceeded in 2006. The NRC is requesting with the submission of the enclosed BA that sea turtles be included in the reinitiation of formal consultation that is already underway in response to a take of the Federally endangered smalltooth sawfish (*Pristis pectinata*).

On April 17-18, 2007, representatives of the NRC, National Marine Fisheries Service (NMFS), and the Florida Power & Light Company (the licensee that maintains and operates the SLNPP) met to observe the inspection of the southern 12-ft-diameter intake pipe and discuss possible mitigation measures to reduce impingement and entrainment of protected marine species, specifically sea turtles and smalltooth sawfish, into the SLNPP intake canal. At the visit, potential mitigation measures were discussed, and these are described in detail in the enclosed BA.

We look forward to continuing to work closely with NMFS to conclude the Section 7 consultation for SLNPP. If you have any questions or need more information, please contact Dr. Dennis Logan at 301-415-0490 or via e-mail DTL1@nrc.gov.

Sincerely,

/RA/

Eric Benner, Branch Chief
Environmental Branch A
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-335 and 50-389

Enclosure:
As stated

cc w/encl: See next page

We look forward to continuing to work closely with NMFS to conclude the Section 7 consultation for SLNPP. If you have any questions or need more information, please contact Dr. Dennis Logan at 301-415-0490 or via e-mail DTL1@nrc.gov.

Sincerely,

/RA/

Eric Benner, Branch Chief
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Enclosure:
As stated

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6000 Southeast Tower Drive
Stuart, FL 34997

Mr. Bill Parks
Operations Manager
St. Lucie Nuclear Plant
6351 South Ocean Drive
Jensen Beach, Florida 34957-2000

cc:

Mr. Seth B. Duston
Training Manager
St. Lucie Nuclear Plant
6351 South Ocean Drive
Jensen Beach, FL 34957-2000

Shelley Norton
National Marine Fisheries Service
Southeast Regional Office
263 13th Avenue, South
St. Petersburg, FL 33701

From: Brenda Mozafari
To: shelley.norton@noaa.gov
Subject: St. Lucie Biological Opinion
Date: Monday, July 07, 2008 2:52:33 PM

Hello Shelley,

I have been unsuccessful in reaching you by phone.

I am being asked to provide my management with a definite schedule for the biological opinion for the St. Lucie Sawfish issue. Could you please respond with a status so I can respond to my management with a proposed schedule for resolution?

Thanks,

Brenda Mozafari
Senior Project Manager
Nuclear Regulatory Commission
Saint Lucie 1 and 2; Turkey Point 3 and 4

301-415-2020

From: Elizabeth Wexler
To: Shelley Norton; Jodie_Gless@fpl.com
Cc: Dennis Logan
Subject: RE: Additional information
Date: Wednesday, July 16, 2008 10:52:41 AM

Hi Shelley,

Sorry I'm just getting to this now (unless Jodie has already put together the information - if so, please forward to me.)

If not, Shelley, do you just want the total numbers for each species, or do you need it broken down by mortality, causal vs. non-causal, etc.?

Thanks,
Liz

From: Shelley Norton [mailto:Shelley.Norton@noaa.gov]
Sent: Thursday, July 10, 2008 9:12 AM
To: Jodie_Gless@fpl.com; Elizabeth Wexler
Subject: Additional information

Good morning Jodie and Elizabeth, can you provide me with a table of the sea turtle takes by species and by year since the 2001 Biop was issued in May 2001?

Thanks,
Shelley Norton
Jodie_Gless@fpl.com wrote:

Hi Shelley,

It was great speaking with you this morning.

Office phone number: 561-691-2801
Cell phone number: 330-671-5621

Let me know if I can help in any way.

Thanks,

Jodie Gless
Environmental Specialist
561-691-2801

From:	Elizabeth Wexler
To:	Shelley Norton; Jodie_Gless@fpl.com
Cc:	Dennis Logan
Subject:	RE: Additional information
Date:	Wednesday, July 16, 2008 11:16:29 AM
Attachments:	St. Lucie Takes 2001-2007 by species.doc

Shelley,

Attached is a table with the total take numbers for each year, 2001-2007, by species. The ADAMS accession numbers for the annual reports are included in case you want to check on anything. If you'd like me to break down the totals as I mentioned in my earlier email, just let me know.

Note: at the end of each annual report, there is a table summarizing takes from past years. Some of the numbers are off by 1 (I used the numbers reported in the original reports) - perhaps Jodie knows the basis for any discrepancies?

Thanks,
Liz

From: Elizabeth Wexler
Sent: Wednesday, July 16, 2008 10:53 AM
To: 'Shelley Norton'; Jodie_Gless@fpl.com
Cc: Dennis Logan
Subject: RE: Additional information

Hi Shelley,

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Jodie Gless
Environmental Specialist
561-691-2801

Year	Loggerhead	Green	Hawksbill	Leatherback	Kemp's ridley	ADAMS accession number
2001	271	321	6	2	1	ML021220236
2002	341	292	3	0	0	ML031250059
2003	538	394	6	4	2	ML041120158
2004	624	285	2	2	1	ML051250355
2005	486	426	2	0	3	ML061250164
2006	395	267	2	1	3	ML071240324
2007	227	101	1	1	0	ML081300736

From:	Elizabeth Wexler
To:	Shelley Norton
Cc:	Dennis Logan
Subject:	RE: Additional information
Date:	Wednesday, July 16, 2008 12:59:19 PM

Ok, that'll be great.

Thanks,
Liz

From: Shelley Norton [mailto:Shelley.Norton@noaa.gov]
Sent: Wednesday, July 16, 2008 12:58 PM
To: Elizabeth Wexler
Subject: Re: Additional information

Hi Liz, Jodie sent me the information. I will touch base after I put my list of facts together. I just want to make sure I have the correct info stated in the biop. This should be completed by next week.

Thanks,
Shelley

Elizabeth Wexler wrote:
Hi Shelley,

Sorry I'm just getting to this now (unless Jodie has already put together the information - if so, please forward to me.)

If not, Shelley, do you just want the total numbers for each species, or do you need it broken down by mortality, causal vs. non-causal, etc.?

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Sent: Thursday, July 10, 2008 9:12 AM
To: Jodie_Gless@fpl.com; Elizabeth Wexler
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Office phone number: 561-691-2801
Cell phone number: 330-671-5621

Let me know if I can help in any way.

Thanks,

Jodie Gless
Environmental Specialist
561-691-2801

From:	Dennis Logan
To:	Shelley Norton
Cc:	GLESS, JODIE; Bo Pham; Briana Balsam
Subject:	RE: Coordination Letter for Biological Opinion for the SLNPP
Date:	Thursday, April 09, 2009 8:12:55 AM

Shelly,

Mr. Bo Pham has replaced Eric Benner as our Branch Chief. You may have our branch initialism under Eric as REBA, and it is now called RERB. Bo would be the person to whom you should address the coordination letter.

We look forward to receiving your biological opinion for the St. Lucie plant.

Dennis

From: Shelley Norton [Shelley.Norton@noaa.gov]
Sent: Thursday, April 09, 2009 7:01 AM
To: Dennis Logan
Cc: GLESS, JODIE
Subject: Coordination Letter for Biological Opinion for the SLNPP

Hi Dennis, can you tell me who to address the coordination letter to at the NRC? I have Eric Benner? I expect comments back for our legal staff by next week.

Thanks,
Shelley

From:	Logan, Dennis
To:	Shelley Norton; GLESS, JODIE
Subject:	RE: Question from our reviewer
Date:	Monday, June 21, 2010 3:15:23 PM

Shelley,

St. Lucie applied for license renewal for the two units and NRC renewed the licenses in 2003. The new licenses run to March 1, 2036 for Unit 1 and April 6, 2043 for Unit 2.

If you need a reference:

http://www.nrc.gov/reading-rm/doc-collections/news/2003/03-128.html

Dennis

-----Original Message-----
From: Shelley Norton [mailto:Shelley.Norton@noaa.gov]
Sent: Monday, June 21, 2010 1:18 PM
To: GLESS, JODIE; Logan, Dennis
Subject: Question from our reviewer

Hi Dennis and Jodie, I have been asked to state a time frame for the biological opinion. Can you tell me how many years are left on the license or another trigger mechanism that would give us an end date for the biop?

Thanks,
Shelley

--
Shelley Norton
Smalltooth Sawfish and Johnson's Seagrass Coordinator
NOAA Fisheries Service
263 13th Ave South
St. Petersburg, Florida 33701-5505
727-824-5312 Ph
727-824-5309 FAX

From: Bulavinetz, Richard
To: Shelley.Norton@noaa.gov
Subject: St. Lucie Nuclear Plant Proposed Extended Power Uprate (EPU) - Section 7 Consultation
Date: Thursday, January 06, 2011 3:32:09 PM

Shelley:

Per our conversation, the NRC is developing an Environmental Assessment (EA)
for the proposed EPU for St. Lucie Units 1 & 2. Nuclear plant.
Units 1 & 2 are proposed for a 17% power uprate, and Florida Power & Light Company intends to correspondingly
increase the thermal discharges by 17% for each reactor.
The volume of warm water discharge will not increase.
Currently, we have an application for Unit 1 undergoing Acceptance Review.
We anticipate an application being submitted for Unit 2 within 1-2 months.
I will provide you with the information we just discussed over the phone.

Thank you,

Rich

Richard E. Bulavinetz
Aquatic Ecologist
Nuclear Regulatory Commission
Rockville, MD 20852
301-415-3607
301-415-2002 (fax)
richard.bulavinetz@nrc.gov

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From: Bulavinetz, Richard
To: Shelley Norton
Subject: RE: St. Lucie Nuclear Plant Proposed Extended Power Uprate (EPU) - Section 7 Consultation
Date: Friday, January 07, 2011 4:29:17 PM

Sorry – that was ~ 12% - not 17%.
RB

From: Shelley Norton [mailto:Shelley.Norton@noaa.gov]
Sent: Friday, January 07, 2011 7:46 AM
To: Bulavinetz, Richard
Subject: Re: St. Lucie Nuclear Plant Proposed Extended Power Uprate (EPU) - Section 7 Consultation

Thanks Rich.

Shelley

Shelley Norton
Sawfish and Johnson's Seagrass Coordinator
Protected Resources Division
National Marine Fisheries Service
263 13th Ave S
St. Petersburg, FL 33701
Ph: 727-824-5312
Fax: 727-824-5309
shelley.norton@noaa.gov

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Shelley:

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301-415-2002 (fax)
richard.bulavinetz@nrc.gov

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From: Bulavinetz, Richard
To: Shelley Norton
Subject: RE: St. Lucie Nuclear Plant Proposed Extended Power Uprate (EPU) - Section 7 Consultation
Date: Monday, March 14, 2011 10:05:18 AM

Shelley:

I will talk with my supervisor, check on its status and get back to you

Rich

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From: Shelley Norton [mailto:Shelley.Norton@noaa.gov]
Sent: Monday, March 07, 2011 8:26 AM
To: Bulavinetz, Richard
Subject: Re: St. Lucie Nuclear Plant Proposed Extended Power Uprate (EPU) - Section 7 Consultation

Hi Richard, do you know if your letter was signed? I have not received it yet. Just checking.

Thanks,
Shelley

Shelley Norton
Sawfish and Johnson's Seagrass Coordinator
Protected Resources Division
National Marine Fisheries Service
263 13th Ave S
St. Petersburg, FL 33701
Ph: 727-824-5312
Fax: 727-824-5309
shelley.norton@noaa.gov

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Sent: Friday, January 07, 2011 7:46 AM
To: Bulavinetz, Richard
Subject: Re: St. Lucie Nuclear Plant Proposed Extended Power Uprate (EPU) - Section 7 Consultation

Thanks Rich.

Shelley

Shelley Norton
Sawfish and Johnson's Seagrass Coordinator
Protected Resources Division
National Marine Fisheries Service
263 13th Ave S
St. Petersburg, FL 33701
Ph: 727-824-5312
Fax: 727-824-5309
shelley.norton@noaa.gov

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richard.bulavinetz@nrc.gov

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From: Bulavinetz, Richard
To: Shelley Norton
Subject: RE: St. Lucie Nuclear Plant Proposed Extended Power Uprate (EPU) - Section 7 Consultation
Date: Monday, March 21, 2011 8:07:54 AM

Shelley:

Good morning.
I reminded my supervisor about it last week.
I will speak to him about it again.
Sorry for the delay.

Rich

Richard E. Bulavinetz
Aquatic and Terrestrial Ecologist
Nuclear Regulatory Commission
Rockville, MD 20852
301-415-3607
301-415-2002 (fax)
richard.bulavinetz@nrc.gov

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From: Shelley Norton [mailto:Shelley.Norton@noaa.gov]
Sent: Monday, March 21, 2011 7:37 AM
To: Bulavinetz, Richard
Subject: Re: St. Lucie Nuclear Plant Proposed Extended Power Uprate (EPU) - Section 7 Consultation

Good morning Rich, Florida Power and Light is contacting me about the status of their biop. Did you hear anything about the status of your reinitiation letter?

Thanks,
Shelley

Shelley Norton
Sawfish and Johnson's Seagrass Coordinator
Protected Resources Division
National Marine Fisheries Service
263 13th Ave S
St. Petersburg, FL 33701
Ph: 727-824-5312
Fax: 727-824-5309
shelley.norton@noaa.gov

Bulavinetz, Richard wrote:

Shelley:

I will talk with my supervisor, check on its status and get back to you

Rich

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Sent: Monday, March 07, 2011 8:26 AM
To: Bulavinetz, Richard
Subject: Re: St. Lucie Nuclear Plant Proposed Extended Power Uprate (EPU) - Section 7 Consultation

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Thanks,
Shelley

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National Marine Fisheries Service
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Ph: 727-824-5312
Fax: 727-824-5309
shelley.norton@noaa.gov

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From: Shelley Norton [mailto:Shelley.Norton@noaa.gov]
Sent: Friday, January 07, 2011 7:46 AM
To: Bulavinetz, Richard
Subject: Re: St. Lucie Nuclear Plant Proposed Extended Power Uprate (EPU) - Section 7 Consultation

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Shelley

Shelley Norton
Sawfish and Johnson's Seagrass Coordinator

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National Marine Fisheries Service
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Rich

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Aquatic Ecologist
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Rockville, MD 20852
301-415-3607
301-415-2002 (fax)
richard.bulavinetz@nrc.gov

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From:	Balsam, Briana
To:	Shelley (shelley.norton@noaa.gov)
Cc:	Logan, Dennis
Subject:	St. Lucie Section 7 - Letter regarding extended power uprate
Date:	Friday, April 22, 2011 10:05:36 AM
Attachments:	St. Lucie EPU Letter to S. Norton 4-22-11.pdf

Hi Shelley,

We are putting a letter in the mail to you dated today regarding the proposed St. Lucie extended power uprate. I attached a copy of the letter to this email so that you have an advance copy. If you have any questions about it, you can contact either me or Dennis. Thanks,

Briana

Briana A. Balsam
Biologist

Division of License Renewal
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission

301-415-1042
briana.balsam@nrc.gov

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 22, 2011

Ms. Shelley Norton
Sawfish and Johnson's Seagrass Coordinator
Protected Resources Division
National Marine Fisheries Service
263 13th Ave S
St. Petersburg, FL 33701

SUBJECT: ADDITIONAL INFORMATION PERTAINING TO THE ONGOING SECTION 7 CONSULTATION FOR ST. LUCIE PLANT UNIT NOS. 1 AND 2

Dear Ms. Norton:

On January 6, 2011, you spoke with U.S. Nuclear Regulatory Commission (NRC) staff member, Richard Bulavinetz, concerning Florida Power & Light Co.'s (FPL) extended power uprate (EPU) application for the St. Lucie Plant, Units 1 and 2, (St. Lucie) that the NRC staff is currently reviewing. During this phone conversation, you requested additional information concerning the potential impacts to listed aquatic species that would occur as a result of the proposed EPU. This letter responds to your request and provides information on the proposed EPU as well as an analysis of the potential impacts to listed species beyond those already identified in the NRC's Biological Assessments dated February 24, 2006,[1] for smalltooth sawfish (*Pristis pectinata*), and August 14, 2007,[2] for sea turtles.

Section 7 Consultation Background

The NRC has consulted with the National Marine Fisheries Service (NMFS) under Section 7 of the Endangered Species Act for operation of St. Lucie since 1982. NMFS issued the current Biological Opinion on May 4, 2001[3], and subsequently provided clarifications to this Biological Opinion on October 24, 2001.[4] The 2001 Biological Opinion includes an incidental take statement for five species of sea turtles: the loggerhead (*Caretta caretta*), green sea turtle (*Chelonia mydas*), Kemp's ridley (*Lepidochelys kempii*), leatherback (*Dermochelys coriacea*), and hawksbill (*Eretmochelys imbricate*).

For the current ongoing section 7 consultation, the correspondence and event timeline has been as follows:

[1] NRC. Letter from F. Gillespie to D. Bernhart, NMFS Southeast Regional Office. Subject: Biological Assessment and Request to Initiate Section 7 Consultation for the Smalltooth Sawfish at St. Lucie. February 24, 2006. ML060580303.

[2] NRC. Letter from E. Benner to D. Bernhart, NMFS Southeast Regional Office. Subject: Biological Assessment for Reinitiation of Section 7 Consultation Regarding Sea Turtles at St. Lucie. August 14, 2007. ML071700079.

[3] NMFS. Letter from J.E. Powers to K.N. Jabbour, NRC. Subject: Biological Opinion for St. Lucie. May 4, 2001. ML011430173.

[4] NMFS. Letter from G. Cranmore to B.T. Moroney, NRC. Subject: Clarification to Terms and Conditions of the St. Lucie Biological Opinion. October 24, 2001. ML013020208.

- **May 2005:** FPL reported a take of a smalltooth sawfish at St. Lucie on May 16.
- **February 2006:** The NRC initiated a formal section 7 consultation in response to the smalltooth sawfish take and submitted a Biological Assessment to NMFS.
- **December 2006:** The NMFS provided the NRC with a copy of the terms and conditions of the draft Biological Opinion.[5]
- **February 2007:** FPL notified NRC that St. Lucie exceeded its incidental take statement for loggerhead and green turtles in 2006.[6]
- **April 2007:** NRC requested NMFS to reinitiate a formal section 7 consultation in response to the 2006 takes that exceeded the limits set forth in St. Lucie's incidental take statement.[7] NRC, NMFS, and FPL met at St. Lucie to inspect the intake structures and discuss potential mitigation associated with the section 7 consultation for sea turtles.
- **August 2007:** NRC sent NMFS a Biological Assessment to accompany the request to reinitiate section 7 consultation for sea turtles. NRC, NMFS, and FPL held a conference call to discuss mitigation associated with the section 7 consultation, including plans for a turtle excluder.[8]
- **2008-2010:** FPL began feasibility investigations for potential mitigation measures to be included in the terms and conditions of the Biological Opinion. NMFS began developing a Biological Opinion that incorporated the developing information from FPL.
- **December 2010:** FPL submitted a license amendment request for an EPU at St. Lucie, Unit 1.[9]
- **February 2011:** FPL submitted a license amendment request for an EPU at St. Lucie, Unit 2.[10]

Proposed St. Lucie Extended Power Uprate

FPL submitted two separate license amendment requests for EPUs on December 15, 2010, and February 25, 2011, for Unit 1 and Unit 2, respectively. If approved, these two amendment requests would increase the licensed core thermal power for St. Lucie from 2700 megawatts

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[5] NMFS. Letter from S. Norton to H. Nash, NRC. Subject: Terms and Conditions of draft Biological Opinon for St. Lucie. December 19, 2006. ML063620017.

[6] FPL. Letter from G.L. Johnston to NRC. Subject: Notification That Turtle Included Take Was Exceeded. February 1, 2007. ML070460595.

[7] NRC. Letter from E. Benner to D. Bernhart, NMFS Southeast Regional Office. Subject: Reinitiation of Section 7 Consultation Regarding Sea Turtles at St. Lucie. April 4, 2007. ML070870846.

[8] FPL. Memorandum from Stacy Foster to NRC, NMFS, FFWCC, FPL, and Quantum Resources. Subject: Minutes from August 24th Conference Call. August 24, 2007. ML072630242.

[9] FPL. Letter from R.L. Anderson to NRC. Subject: License Amendment Request for Extended Power Uprate. December 15, 2010. ML103560418.

[10] FPL. Letter from R.L. Anderson to NRC. Subject: License Amendment Request for Extended Power Uprate. February 25, 2011. ML110730116.

thermal (MWt) to 3020 MWt, an increase of 11.85 percent.[11] FPL would implement the increased power level in the fall of 2011 for Unit 1 and in the spring of 2012 for Unit 2.

If approved, the proposed EPU would not change the rate of water withdrawal or quantity of water withdrawn at St. Lucie. Additionally, FPL would not change any component of the cooling system design; therefore, the description of the physical cooling water system provided in the 2007 Biological Assessment would remain relevant under EPU conditions.

The proposed EPU would increase the temperature of discharged water. However, St. Lucie's Industrial Wastewater Facility Permit would continue to limit the maximum temperature of heated discharge water and the thermal mixing zone volume. The permit specifies the following limitations for water discharged from the diffusers into the Atlantic Ocean:

- Discharged water may not exceed a maximum of 115°F (46°C) or rise more than 30°F (16.7°C) above the ambient water temperature during normal operations.
- Discharged water may not cause the ocean surface temperature to exceed 97°F (36°C) as an instantaneous maximum.
- Discharged water may not be more than 17°F above the ambient water temperature in the receiving body of water outside a thermal mixing zone of 466,092 ft^3 (13,198 m^3); and
- The total area of the mixing zone for St. Lucie may not exceed 511,804 ft^2 (47,548 m^2).

Note that the Industrial Wastewater Facility Permit, as in effect today, specifies that discharged water may not exceed a maximum of 113°F (45°C). However, the Florida Department of Environmental Protection revised FPL's permit to allow FPL to discharge water 2°F (1°C) higher—at a temperature 115°F (46°C)—upon NRC's approval of the proposed EPU.

Potential Effects to Listed Species

Because the proposed EPU would not change the rate or quantity of water withdrawn at St. Lucie, the NRC staff does not anticipate any additional entrainment or impingement impacts to the smalltooth sawfish or sea turtles beyond those discussed in the 2006 and 2007 Biological Assessments or presently under consideration for NMFS's developing Biological Opinion.

The proposed EPU would increase the temperature of discharged water and the temperature of ocean water within the thermal plume surrounding the discharge point, which is located approximately 3,400 ft (1,040 m) offshore. However, the increase in the temperature would be relatively small, and the multiport diffusers on the discharge pipes would continue to rapidly dilute heated water and limit high temperatures to the mixing zone area specified in the Industrial Wastewater Facility Permit. As a conservative measure, the NRC considered the upper limits of the Industrial Wastewater Facility Permit listed above to assess impacts to listed species.

[11] FPL. License Amendment Request for Extended Power Uprate, Attachment 2: Supplemental Environmental Report. December 15, 2010. ML103560435.

The smalltooth sawfish is a tropical species that occupies waters in the western Atlantic Ocean from Brazil through the Caribbean and Central America, the Gulf of Mexico, and the Atlantic U.S. The species distribution indicates that it has a high thermal tolerance. The sea turtle species that occur in the vicinity of St. Lucie have wide geographic distributions that span temperate, subtropical, and tropical waters. Because the smalltooth sawfish has a high thermal tolerance and sea turtles are able to tolerate a wide range of water temperatures, these species are unlikely to be adversely affected by higher water temperatures within the thermal plume at the St. Lucie discharge under EPU conditions. For smalltooth sawfish specifically, because the species lives in close association with the sea bottom and the thermal effluent rises to the water's surface, exposure of smalltooth sawfish to the thermal plume should be minimal even in the area immediately surrounding the discharge point. For sea turtles specifically, because water within the thermal plume is more turbulent and the thermal plume is relatively small, the sea turtles are likely to avoid this area altogether. However, if smalltooth sawfish or sea turtles do inhabit the discharge area, because these species tolerate warmer water temperatures, they are unlikely to be sensitive to the localized area of elevated water temperatures. The NRC staff does not anticipate any adverse impacts to smalltooth sawfish or sea turtle species as a result of the proposed EPU at St. Lucie.

If you have any questions or require additional information concerning the proposed EPU at St. Lucie, please contact Ms. Briana Balsam, Biologist, by phone at 301-415-1042, or by e-mail at Briana.Balsam@nrc.gov, or Dr. Dennis Logan, Aquatic Biologist, by phone at 301-415-0490, or by e-mail at Dennis.Logan@nrc.gov.

Sincerely,

Andrew S. Imboden, Chief
Environmental Review Branch
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-335 and 50-389

cc: Listserv

The smalltooth sawfish is a tropical species that occupies waters in the western Atlantic Ocean from Brazil through the Caribbean and Central America, the Gulf of Mexico, and the Atlantic U.S. The species distribution indicates that it has a high thermal tolerance. The sea turtle species that occur in the vicinity of St. Lucie have wide geographic distributions that span temperate, subtropical, and tropical waters. Because the smalltooth sawfish has a high thermal tolerance and sea turtles are able to tolerate a wide range of water temperatures, these species are unlikely to be adversely affected by higher water temperatures within the thermal plume at the St. Lucie discharge under EPU conditions. For smalltooth sawfish specifically, because the species lives in close association with the sea bottom and the thermal effluent rises to the water's surface, exposure of smalltooth sawfish to the thermal plume should be minimal even in the area immediately surrounding the discharge point. For sea turtles specifically, because water within the thermal plume is more turbulent and the thermal plume is relatively small, the sea turtles are likely to avoid this area altogether. However, if smalltooth sawfish or sea turtles do inhabit the discharge area, because these species tolerate warmer water temperatures, they are unlikely to be sensitive to the localized area of elevated water temperatures. The NRC staff does not anticipate any adverse impacts to smalltooth sawfish or sea turtle species as a result of the proposed EPU at St. Lucie.

If you have any questions or require additional information concerning the proposed EPU at St. Lucie, please contact Ms. Briana Balsam, Biologist, by phone at 301-415-1042, or by e-mail at Briana.Balsam@nrc.gov, or Dr. Dennis Logan, Aquatic Biologist, by phone at 301-415-0490, or by e-mail at Dennis.Logan@nrc.gov.

Sincerely,

/RA/

Andrew S. Imboden, Chief
Environmental Review Branch
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-335 and 50-389

cc: Listserv

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ADAMS Accession Number: ML11108A014 *concurrence via email

OFFICE	LA: DLR*	DLR/RERB	DLR/RERB	BC: DLR/RERB
NAME	IKing	BBalsam	DLogan	AImboden
DATE	04/20/2011	04/21/2011	04/22/2011	04/22/2011

OFFICIAL RECORD COPY

Letter to Shelley Norton from Andrew S. Imboden dated April 22, 2011

SUBJECT: ADDITIONAL INFORMATION PERTAINING TO THE ONGOING SECTION 7 CONSULTATION FOR ST. LUCIE PLANT UNIT NOS. 1 AND 2

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RidsRgn2MailCenter

B. Balsam
D. Logan
A. Imboden
S. Klementowicz

From:	Balsam, Briana
To:	Shelley Norton; Gless, Jodie; Logan, Dennis
Subject:	RE: Clarifying questions on the operations at the St. Lucie Nuclear Power Plant
Date:	Monday, September 26, 2011 3:04:43 PM

Hi Shelley,

I think that FPL will be the best ones to answer the first 5 questions, but for #6, St. Lucie's current operating licenses expire on March 1, 2036 (Unit 1) and April 6, 2043 (Unit 2). If, before that time, St. Lucie applies for a second renewed license, then--yes, we would reinitiate at that time. We would also (of course) reinitiate if St. Lucie met any of the criteria in 50 CFR 402.16.

Briana

-----Original Message-----
From: Shelley Norton [mailto:Shelley.Norton@noaa.gov]
Sent: Monday, September 26, 2011 2:59 PM
To: Gless, Jodie; Logan, Dennis; Balsam, Briana
Subject: Clarifying questions on the operations at the St. Lucie Nuclear Power Plant

Good afternoon, can you please clarify the following questions below?

1. Are sea turtle biologists on-sight during daylight hours every day (365 days a year)?

2. Are sea turtle biologists taking blood samples from captured sea turtles? If so, what is the Section 10 (a)(1)(A) permit number authorizing this work?

3. I measured the distance between the headwall and the 5-in barrier net using Google Earth and calculated it to be approximately 475-ft. Is this correct?

4. I also measured the width of the intake canal from the Google Earth image and determined it is 200-ft across. Is this correct? The description I have from the NRC states 300-ft.

5. What is the average residency time of a sea turtle in the intake canal? How are you calculating this residency time?

6. What is the trigger for reinitation consultation on this opinion? Is this biological opinion going to be reinitiated during the relicensing of the plant? I need to put a timeframe on the opinion.

Thanks,
Shelley

Shelley Norton
Sawfish and Johnson's Seagrass Coordinator
NOAA Fisheries Service
263 13th Ave South
St. Petersburg, Florida 33701-5505
727-551-5781 Ph
727-824-5309 FAX

From: Balsam, Briana
To: Shelley Norton
Subject: RE: Clarifying questions on the operations at the St. Lucie Nuclear Power Plant
Date: Monday, October 24, 2011 10:15:34 AM
Attachments: StLucie License.pdf

Shelley,

I attached a copy of the St. Lucie, Unit 1, license. (The wording pertaining to the ESA is identical in Unit 2's license, but let me know if you want a copy of that one, too). The conditions related to the ESA are in Appendix B, Section 4.2, page 341 of the PDF file.

Briana

-----Original Message-----
From: Shelley Norton [mailto:Shelley.Norton@noaa.gov]
Sent: Monday, October 24, 2011 10:06 AM
To: Balsam, Briana
Subject: Re: Clarifying questions on the operations at the St. Lucie Nuclear Power Plant

Hi Briana, are you in the office today/

Thanks,
Shelley

Balsam, Briana wrote:
> Hi Shelley,
>
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> Briana
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> From: Shelley Norton [mailto:Shelley.Norton@noaa.gov]
> Sent: Monday, September 26, 2011 2:59 PM
> To: Gless, Jodie; Logan, Dennis; Balsam, Briana
> Subject: Clarifying questions on the operations at the St. Lucie Nuclear Power Plant
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> 263 13th Ave South
> St. Petersburg, Florida 33701-5505
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>
>

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St. Petersburg, Florida 33701-5505
727-551-5781 Ph
727-824-5309 FAX

FLORIDA POWER AND LIGHT COMPANY

DOCKET NO. 50-335

ST. LUCIE PLANT UNIT NO. 1

RENEWED FACILITY OPERATING LICENSE NO. DPR-67

The U.S. Nuclear Regulatory Commission (the Commission) having previously made the findings set forth in License No. DPR-67 issued March 1, 1976, has now found that:

a. The application to renew License No. DPR-67 filed by the Florida Power and Light Company (FPL or the licensee), complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter 1, and all required notifications to other agencies or bodies have been duly made;

b. Actions have been identified and have been or will be taken with respect to (1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21(a)(1), and (2) time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c), such that there is reasonable assurance that the activities authorized by this renewed license will continue to be conducted in accordance with the current licensing basis, as defined in 10 CFR 54.3, for St. Lucie Plant Unit No.1, and that any changes made to the plant's current licensing basis in order to comply with 10 CFR 54.29(a) are in accord with the Act and the Commission's regulations;

c. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission;

d. There is reasonable assurance: (i) that the activities authorized by this renewed operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission;

e. FPL is technically and financially qualified to engage in the activities authorized by this renewed operating license in accordance with the rules and regulations of the Commission;

f. FPL has satisfied the applicable provisions of 10 CFR Part 140, " Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

g. The renewal of this operating license will not be inimical to the common defense and security or to the health and safety of the public; and

h. After weighing the environmental, economic, technical, and other benefits of the facility against environmental and other costs and considering available alternatives, the

issuance of Renewed Facility Operating License No. DPR-67, subject to the conditions for protection of the environment set forth herein, is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

On the basis of the foregoing findings regarding this facility, Facility Operating License No. DPR-67, issued March 1, 1976, is superseded by Renewed Facility Operating License No. DPR-67, which is hereby issued to FPL to read as follows:

1. This renewed license applies to the St. Lucie Plant, Unit No. 1, a pressurized water nuclear reactor, and associated steam generators and electrical generating equipment (the facility). The facility is located on the licensee's site on Huchinson Island in St. Lucie County, Florida, and is described in the Updated Final Safety Analysis Report, as supplemented and amended, and the Environmental Report, as supplemented and amended.

2. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses FPL:

   A. Pursuant to Section 104b of the Act and 10 CFR Part 50, "Licensing of Production and Utilization Facilities," to possess, use, and operate the facility as a utilization facility at the designated location on the St. Lucie site in accordance with the procedures and limitations set forth in this renewed license;

   B. Pursuant to the Act and 10 CFR Part 70, to receive, possess, and use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report as supplemented and amended;

   C. Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

   D. Pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use in amounts as required any byproduct, source, or special nuclear material, without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

   E. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

3. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all

applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

A. Maximum Power Level

FPL is authorized to operate the facility at steady state reactor core power levels not in excess of 2700 megawatts (thermal).

B. Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 211 are hereby incorporated in the renewed license. FPL shall operate the facility in accordance with the Technical Specifications.

Appendix B, the Environmental Protection Plan (Non-Radiological), contains environmental conditions of the renewed license. If significant detrimental effects or evidence of irreversible damage are detected by the monitoring programs required by Appendix B of this license, FPL will provide the Commission with an analysis of the problem and plan of action to be taken subject to Commission approval to eliminate or significantly reduce the detrimental effects or damage.

C. Updated Final Safety Analysis Report

The Updated Final Safety Analysis Report supplement submitted pursuant to 10 CFR 54.21(d), as revised on March 28, 2003, describes certain future activities to be completed before the period of extended operation. FPL shall complete these activities no later than March 1, 2016, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

The Updated Final Safety Analysis Report supplement as revised on March 28, 2003, described above, shall be included in the next scheduled update to the Updated Final Safety Analysis Report required by 10 CFR 50.71(e)(4), following issuance of this renewed license. Until that update is complete, FPL may make changes to the programs described in such supplement without prior Commission approval, provided that FPL evaluates each such change pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

D. Sustained Core Uncovery Actions

Procedural guidance shall be in place to instruct operators to implement actions that are designed to mitigate a small-break loss-of-coolant accident prior to a calculated time of sustained core uncovery.

E. Fire Protection

FPL shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report for the facility (The fire protection program and features were originally described in FPL submittals L-83-514 dated October 7, 1983, L-83-227 dated April 12, 1983, L-83-261 dated April 25, 1983, L-83-453 dated August 24, 1983, L-83-488 dated September 16, 1983, L-83-588 dated December 14, 1983, L-84-346 dated November 28, 1984, L-84-390 dated December 31, 1984, and L-85-71 dated February 21, 1985) and as approved by NRC letter dated July 17, 1984, and supplemented by NRC letters dated February 21, 1985, March 5, 1987, and October 4, 1988, subject to the following provision:

> FPL may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

F. Physical Protection

The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provision of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contains Safeguards Information protected under 10 CFR 73.21, is entitled: "Florida Power and Light & FPL Energy Seabrook Physical Security Plan, Training and Qualification Plan and Safeguards Contingency Plan - Revision 3," submitted by letter dated May 18, 2006. St. Lucie shall fully implement and maintain in effect all provisions of the Commission-approved cyber security plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). St. Lucie CSP was approved by License Amendment No. 211

G. Mitigation Strategy License Condition

Develop and maintain strategies for addressing large fires and explosions and that include the following key areas:

(a) Fire fighting response strategy with the following elements:
   1. Pre-defined coordinated fire response strategy and guidance
   2. Assessment of mutual aid fire fighting assets
   3. Designated staging areas for equipment and materials
   4. Command and control
   5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:
   1. Protection and use of personnel assets
   2. Communications
   3. Minimizing fire spread
   4. Procedures for implementing integrated fire response strategy
   5. Identification of readily-available pre-staged equipment
   6. Training on integrated fire response strategy
   7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:
   1. Water spray scrubbing
   2. Dose to onsite responders

H. Control Room Habitability

Upon implementation of Amendment No. 205, adopting TSTF-448, Revision 3, the determination of control room envelope (CRE) unfiltered air inleakage as required by SR 4.7.7.1.e, in accordance with TS 6.8.4.m, the assessment of CRE habitability as required by Specification 6.8.4.m.c. (ii), and the measurement of CRE pressure as required by Specification 6.8.4.m.d, shall be considered met. Following implementation:

(a) The first performance of SR 4.7.7.1.e, in accordance with Specification 6.8.4.m.c(i), shall be within the specified Frequency of 6 years, plus the 18-month allowance of SR 4.0.2, as measured from September 2003, the date of the most recent successful tracer gas test, as stated in FPL letters to NRC dated December 9, 2003, and October 29, 2004, in response to Generic Letter 2003-01.

(b) The first performance of the periodic assessment of CRE habitability, Specification 6.8.4.m.c(ii), shall be within 3 years, plus the 9-month allowance of SR 4.0.2, as measured from September 2003, the date of the most recent successful tracer gas test, as stated in FPL letters to NRC dated December 9, 2003, and October 29, 2004, in response to Generic Letter 2003-01, or within the next 9 months if the time period since the most recent successful tracer gas test is greater than 3 years.

(c) The first performance of the periodic measurement of CRE pressure, Specification 6.8.4.c.d, shall be within 36 months in a staggered test basis, plus the 138 days allowed by SR 4.0.2, as measured from June 30, 2006, which is the date of the most recent successful pressure measurement test, or within 138 days if not performed previously.

4. This renewed license is effective as of the date of issuance and shall expire at midnight on March 1, 2036.

FOR THE NUCLEAR REGULATORY COMMISSION

ORIGINAL SIGNED BY
J. E. Dyer, Director
Office of Nuclear Reactor Regulation

Attachments:
1. Appendix A, Technical Specifications
2. Appendix B, Environmental Protection Plan

ST. LUCIE PLANT

UNIT 1

TECHNICAL SPECIFICATIONS

APPENDIX "A"

TO

LICENSE NO. DPR-67

DEFINITIONS

SECTION PAGE

1.0 DEFINITIONS

DEFINITIONS

INDEX

SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

INDEX

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

INDEX

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INDEX

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

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INDEX

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

SECTION PAGE

3/4.11 RADIOACTIVE EFFLUENTS

INDEX

INDEX

INDEX

DESIGN FEATURES

INDEX

ADMINISTRATIVE CONTROLS

ADMINISTRATIVE CONTROLS

SECTION 1.0

DEFINITIONS

1.0 DEFINITIONS

The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications.

ACTION

1.1 ACTION shall be that part of a specification which prescribes remedial measures required under designated conditions.

AXIAL SHAPE INDEX

1.2 The AXIAL SHAPE INDEX (Y_E) is the power level detected by the lower excore nuclear instrument detectors (L) less the power level detected by the upper excore nuclear instrument detectors (U) dividied by the sum of these power levels. The AXIAL SHAPE INDEX (Y_I) used for the trip and pretrip signals in the reactor protection system is the above value (Y_E) modified by an appropriate multiplier (A) and a constant (B) to determine the true core axial power distribution for that channel.

$$Y_E = \frac{L-U}{L+U} \qquad\qquad Y_I = AY_E + B$$

AZIMUTHAL POWER TILT - T_q

1.3 AZIMUTHAL POWER TILT shall be the maximum difference between the power generated in any core quadrant (upper or lower) and the average power of all quadrants in that half (upper or lower) of the core divided by the average power of all quadrants in that half (upper or lower) of the core.

$$\text{AZIMUTHAL POWER TILT} = \max \left\{ \frac{\text{Power in any core quadrant (upper or lower)}}{\text{Average power of all quadrants (upper or lower)}} \right\} - 1$$

CHANNEL CALIBRATION

1.4 A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel output such that it responds with the necessary range and accuracy to known values of the parameter which the channel monitors. The CHANNEL CALIBRATION shall encompass the entire channel including the sensor and alarm and/or trip functions, and shall include the CHANNEL FUNCTIONAL TEST. The CHANNEL CALIBRATION may be performed by any series of sequential, overlapping or total channel steps such that the entire channel is calibrated.

CHANNEL CHECK

1.5 A CHANNEL CHECK shall be the qualitative assessment of channel behavior during operation by observation. This determination shall include, where possible, comparison of the channel indication and/or status with other indications and/or status derived from independent instrument channels measuring the same parameter.

CHANNEL FUNCTIONAL TEST

1.6 A CHANNEL FUNCTIONAL TEST shall be the injection of a simulated signal into the channel as close to the primary sensor as practicable to verify OPERABILITY including alarm and/or trip functions.

CONTAINMENT VESSEL INTEGRITY

1.7 CONTAINMENT VESSEL INTEGRITY shall exist when:

a. All containment vessel penetrations required to be closed during accident conditions are either:

1. Capable of being closed by an OPERABLE containment automatic isolation valve system, or

2. Closed by manual valves, blind flanges, or deactivated automatic valves secured in their closed position except for valves that are open on an intermittent basis under administrative control.

b. All containment vessel equipment hatches are closed and sealed,

c. Each containment vessel air lock is in compliance with the requirements of Specification 3.6.1.3,

d. The containment leakage rates are within the limits of Specification 3.6.1.2, and

e. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

CONTROLLED LEAKAGE

1.8 CONTROLLED LEAKAGE shall be the seal water flow supplied from the reactor coolant pump seals.

CORE ALTERATION

1.9 CORE ALTERATION shall be the movement or manipulation of any fuel, sources, reactivity control components, or other components affecting reactivity within the reactor vessel with the vessel head removed and fuel in the vessel. Exceptions to the above include shared (4 fingered) control element assemblies (CEAs) withdrawn into the upper guide structure (UGS) or evolutions performed with the UGS in place such as CEA latching/unlatching or verification of latching/unlatching which do not constitute a CORE ALTERATION. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.

CORE OPERATING LIMITS REPORT (COLR)

1.9a The COLR is the unit-specific document that provides cycle specific parameter limits for the current operating reload cycle. These cycle-specific parameter limits shall be determined for each reload cycle in accordance with Specification 6.9.1.11. Plant operation within these limits is addressed in individual Specifications.

DOSE EQUIVALENT I-131

1.10 DOSE EQUIVALENT I-131 shall be that concentration of I-131 (μCi/gram) which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134 and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Federal Guidance Report 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion."

$\bar{E}$ - AVERAGE DISINTEGRATION ENERGY

1.11 $\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MEV) for isotopes, other than iodines, with half lives greater than 15 minutes, making up at least 95% of the total non-iodine activity in the coolant.

ENGINEERED SAFETY FEATURES RESPONSE TIME

1.12 The ENGINEERED SAFETY FEATURES REPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

FREQUENCY NOTATION

1.13 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

GASEOUS RADWASTE TREATMENT SYSTEM

1.14 A GASEOUS RADWASTE TREATMENT SYSTEM is any system designed and installed to reduce radioactive gaseous effluents by collecting primary coolant system offgases from the primary system and providing for delay or holdup for the purpose of reducing the total radioactivity prior to release to the environment.

IDENTIFED LEAKAGE

1.15 IDENTIFIED LEAKAGE shall be:

a. Leakage (except CONTROLLED LEAKAGE) into closed systems, such as pump seal or valve packing leaks that are captured, and conducted to a sump or collecting tank, or

b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be PRESSURE BOUNDARY LEAKAGE, or

c. Reactor Coolant System leakage through a steam generator to the secondary system (Primary-to-secondary leakage).

LOW TEMPERATURE RCS OVERPRESSURE PROTECTION RANGE

1.16 The LOW TEMPERATURE RCS OVERPRESSURE PROTECTION RANGE is that operating condition when (1) the cold leg temperature is $\leq$ 304°F during heatup or $\leq$ 281°F during cooldown and (2) the Reactor Coolant System has pressure boundary integrity. The Reactor Coolant System does not have pressure boundary integrity when the Reactor Coolant System is open to containment and the minimum area of the Reactor Coolant System opening is greater than 1.75 square inches.

MEMBER(S) OF THE PUBLIC

1.17 MEMBER OF THE PUBLIC means an individual in a controlled or unrestricted area. However, an individual is not a member of the public during any period in which the individual receives an occupational dose.

OFFSITE DOSE CALCULATION MANUAL (ODCM)

1.18 THE OFFSITE DOSE CALCULATION MANUAL (ODCM) shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring Alarm/Trip Setpoints, and in the conduct of the Environmental Radiological Monitoring Program. The ODCM shall also contain (1) the Radioactive Effluent Controls and Radiological Environmental Monitoring Programs required by Section 6.8.4 and (2) descriptions of the information that should be included in the Annual Radiological Environmental Operating and Annual Radioactive Effluent Release Reports required by Specifications 6.9.1.7 and 6.9.1.8.

OPERABLE – OPERABILITY

1.19 A system, subsystem, train, component or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s), and when all necessary attendant instrumentation, controls, electrical power, cooling or seal water, lubrication or other auxiliary equipment that are required for the system, subsystem, train, component or device to perform its function(s) are also capable of performing their related support function(s).

OPERATIONAL MODE

1.20 An OPERATIONAL MODE (i.e., MODE) shall correspond to any one inclusive combination of core reactivity condition, power level and average reactor coolant temperature specified in Table 1.2.

PHYSICS TESTS

1.21 PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation and (1) described in Chapter 14.0 of the FSAR, (2) authorized under the provisions of 10 CFR 50.59, or (3) otherwise approved by the Commission.

PRESSURE BOUNDARY LEAKAGE

1.22 PRESSURE BOUNDARY LEAKAGE shall be leakage (except primary-to-secondary leakage) through a non-isolable fault in a Reactor Coolant System component body, pipe wall or vessel wall.

PROCESS CONTROL PROGRAM (PCP)

1.23 The PROCESS CONTROL PROGRAM (PCP) shall contain the current formulas, sampling, analyses, test, and determinations to be made to ensure that processing and packing of solid radioactive wastes based on demonstrated processing of actual or simulated wet solid wastes will be accomplished in such a way as to assure compliance with 10 CFR Parts 20, 61, and 71, State regulations, burial ground requirements, and other requirements governing the disposal of solid radioactive waste.

PURGE – PURGING

1.24 PURGE or PURGING is the controlled process of discharging air or gas from a confinement to maintain temperature, pressure, humidity, concentration or other operating condition, in such a manner that replacement air or gas is required to purify the confinement.

RATED THERMAL POWER

1.25 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 2700 MWt.

REACTOR TRIP SYSTEM RESPONSE TIME

1.26 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until electrical power to the CEA drive mechanism is interrupted. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

REPORTABLE EVENT

1.27 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

SHIELD BUILDING INTEGRITY

1.28 SHIELD BUILDING INTEGRITY shall exist when:

a. Each door is closed except when the access opening is being used for normal transit entry and exit;

b. The shield building ventilation system is in compliance with Specification 3.6.6.1, and

c. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

SHUTDOWN MARGIN

1.29 SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all full-length control element assemblies (shutdown and regulating) are fully inserted except for the single assembly of highest reactivity worth which is assumed to be fully withdrawn.

SITE BOUNDARY

1.30 SITE BOUNDARY means that line beyond which the land or property is not owned, leased, or otherwise controlled by the licensee.

SOURCE CHECK

1.31 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

STAGGERED TEST BASIS

1.32 A STAGGERED TEST BASIS shall consist of:

a. A test schedule for n systems, subsystems, trains or other designated components obtained by dividing the specified test interval into n equal subintervals, and

b. The testing of one system, subsystem, train or other designated component at the beginning of each subinterval.

THERMAL POWER

1.33 THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

UNIDENTIFIED LEAKAGE

1.34 UNIDENTIFIED LEAKAGE shall be all leakage which is not IDENTIFIED LEAKAGE or CONTROLLED LEAKAGE.

UNRESTRICTED AREA

1.35 Unrestricted area means an area, access to which is neither limited nor controlled by the licensee.

UNRODDED INTEGRATED RADIAL PEAKING FACTOR - F_r

1.36 The UNRODDED INTEGRATED RADIAL PEAKING FACTOR is the ratio of the peak pin power to the average pin power in an unrodded core, excluding tilt.

TABLE 1.1

FREQUENCY NOTATION

NOTATION	FREQUENCY
S	At least once per 12 hours
D	At least once per 24 hours
W	At least once per 7 days
4/M*	At least 4 per month at intervals of no greater than 9 days and a minimum of 48 per year
M	At least once per 31 days
Q	At least once per 92 days
SA	At least once per 184 days
R	At least once per 18 months
S/U	Prior to each reactor startup
P**	Completed prior to each release
N.A.	Not applicable

* For Radioactive Effluent Sampling
** For Radioactive Batch Releases Only

TABLE 1.2

OPERATIONAL MODES

MODE		REACTIVITY CONDITION, K_{eff}	%RATED THERMAL POWER*	AVERAGE COOLANT TEMPERATURE
1.	POWER OPERATION	≥ 0.99	$> 5\%$	$\geq 325°F$
2.	STARTUP	≥ 0.99	$\leq 5\%$	$\geq 325°F$
3.	HOT STANDBY	< 0.99	0	$\geq 325°F$
4.	HOT SHUTDOWN	< 0.99	0	$325°F > T_{avg} > 200°F$
5.	COLD SHUTDOWN	< 0.99	0	$\leq 200°F$
6.	REFUELING**	≤ 0.95	0	$\leq 140°F$

* Excluding decay heat.
** Fuel in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

REACTOR CORE

2.1.1 The combination of THERMAL POWER, pressurizer pressure, and maximum cold leg coolant temperature shall not exceed the limits shown on Figure 2.1-1.

APPLICABILITY: MODES 1 and 2.

ACTION:

Whenever the point defined by the combination of maximum cold leg temperature and THERMAL POWER has exceeded the appropriate pressurizer pressure line, be in HOT STANDBY within 1 hour.

REACTOR COOLANT SYSTEM PRESSURE

2.1.2 The Reactor Coolant System pressure shall not exceed 2750 psia.

APPLICABILITY: MODES 1, 2, 3, 4 and 5.

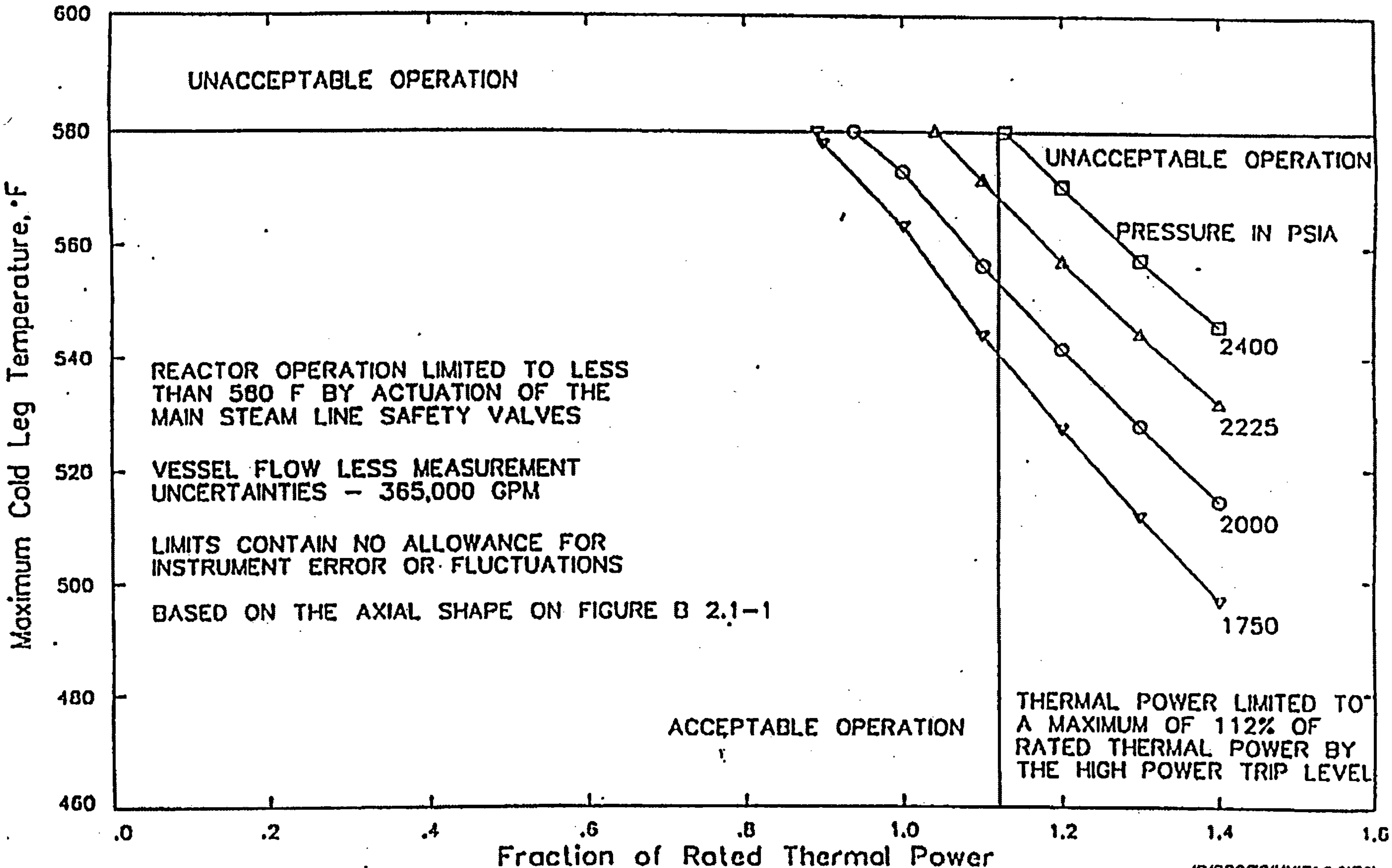
ACTION:

MODES 1 and 2

Whenever the Reactor Coolant System pressure has exceeded 2750 psia, be in HOT STANDBY with the Reactor Coolant System pressure within its limit within 1 hour.

MODES 3, 4 and 5

Whenever the Reactor Coolant System pressure has exceeded 2750 psia, reduce the Reactor Coolant System pressure to within its limit within 5 minutes.



(D/OPS/TS(UNIT1 2-2)R0)

FIGURE 2.1-1: REACTOR CORE THERMAL MARGIN SAFETY LIMIT – FOUR REACTOR COOLANT PUMPS OPERATING

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR TRIP SETPOINTS

2.2.1 The reactor protective instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2-1.

APPLICABILITY: AS SHOWN FOR EACH CHANNEL IN TABLE 3.3-1.

ACTION:

With a reactor protective instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1.1 until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

TABLE 2.2-1

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Power Level – High (1) Four Reactor Coolant Pumps Operating	≤ 9.61% above THERMAL POWER, with a minimum setpoint of 15% of RATED THERMAL POWER, and a maximum of < 107.0% of RATED THERMAL POWER.	≤ 9.61% above THERMAL POWER, and a minimum setpoint of 15% of RATED THERMAL POWER and a maximum of ≤ 107.0% of RATED THERMAL POWER.
3. Reactor Coolant Flow – Low (1) Four Reactor Coolant Pumps Operating	≥ 95% of design reactor coolant flow with 4 pumps operating *	≥ 95% of design reactor coolant flow with 4 pumps operating *
4. Pressurizer Pressure – High	≤ 2400 psia	≤ 2400 psia
5. Containment Pressure – High	≤ 3.3 psig	≤ 3.3 psig
6. Steam Generator Pressure – Low (2)	≥ 600 psia	≥ 600 psia
7. Steam Generator Water Level – Low	≥ 20.5% Water Level – each steam generator	≥ 19.5% Water Level – each steam generator
8. Local Power Density – High (3)	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-1 and 2.2-2.	Trip set point adjusted to not exceed the limit lines of Figures 2.2-1 and 2.2-2.

* Design reactor coolant flow with 4 pumps operating is 365,000 gpm.

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
9. Thermal Margin/Low Pressure (1)		
Four Reactor Coolant Pumps Operating	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-3 and 2.2-4.	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-3 and 2.2-4.
9a. Steam Generator Pressure Difference High (1) (logic in TM/LP)	≤ 135 psid	≤ 135 psid
10. Loss of Turbine – Hydraulic Fluid Pressure – Low (3)	≥ 800 psig	≥ 800 psig
11. Rate of Change of Power – High (4)	≤ 2.49 decades per minute	≤ 2.49 decades per minute

TABLE NOTATION

(1) Trip may be bypassed below 1% of RATED THERMAL POWER; bypass shall be automatically removed when Wide Range Logarithmic Neutron Flux power is ≥ 1% of RATED THERMAL POWER.

(2) Trip may be manually bypassed below 685 psig; bypass shall be automatically removed at or above 685 psig.

(3) Trip may be bypassed below 15% of RATED THERMAL POWER; bypass shall be automatically removed when Power Range Neutron Flux power is ≥ 15% of RATED THERMAL POWER.

(4) Trip may be bypassed below 10^{-4}% and above 15% of RATED THERMAL POWER.

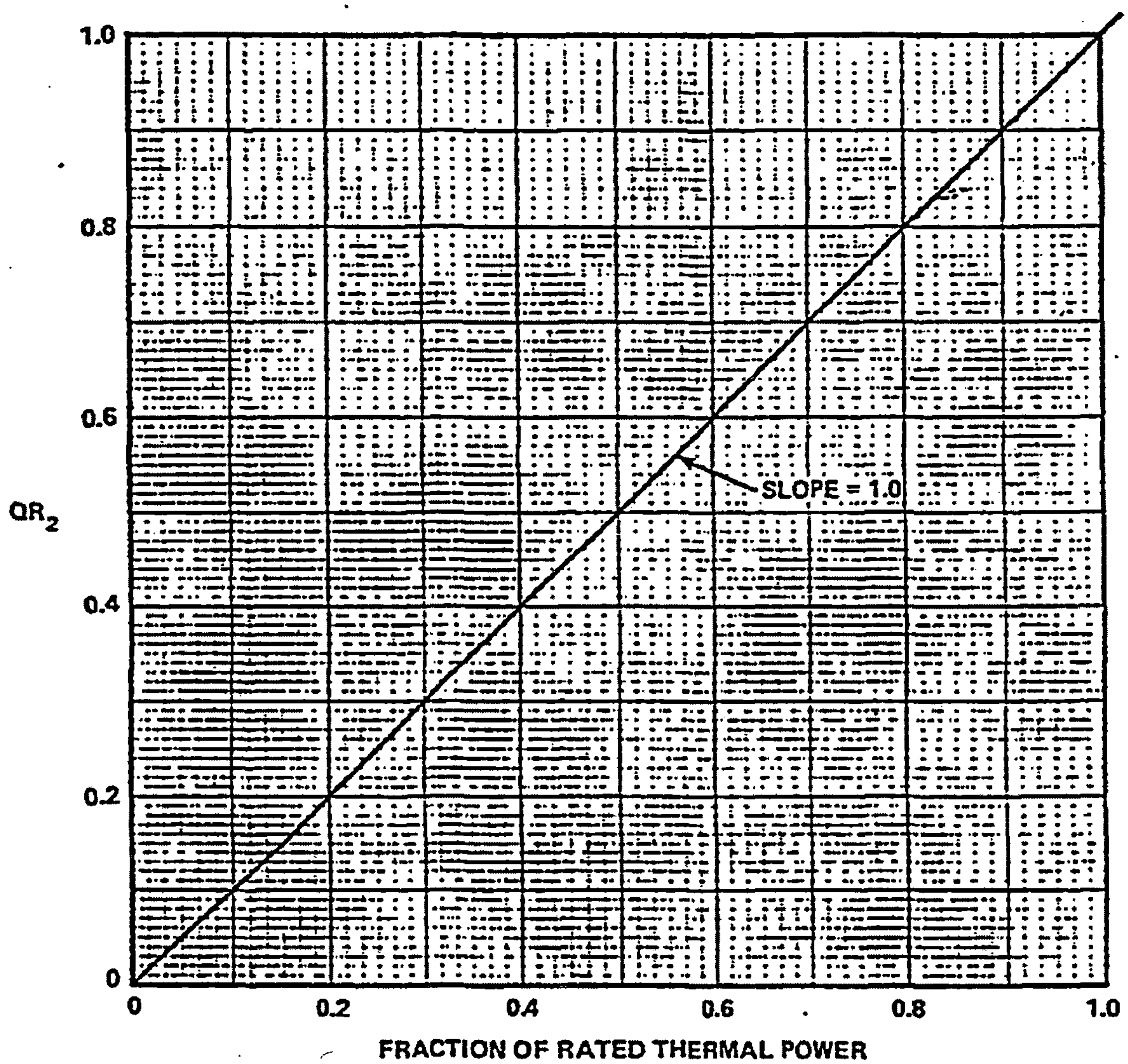


FIGURE 2.2-1

Local Power Density — High Trip Setpoint
Part 1 (Fraction of RATED THERMAL POWER Versus QR_2)

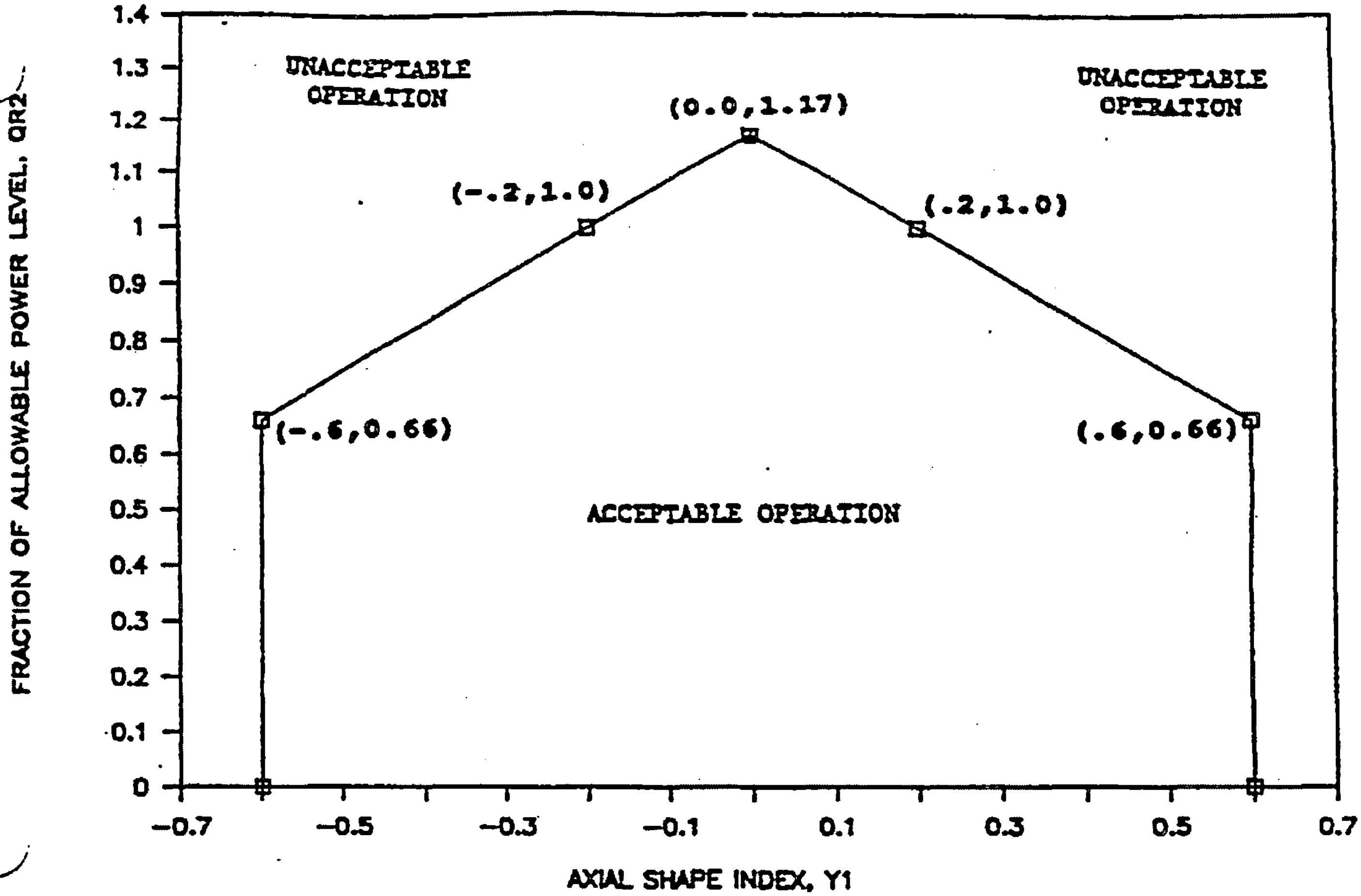


FIGURE 2.2-2

LOCAL POWER DENSITY- HIGH TRIP SETPOINT PART 2 (QR2 Versus Y1)

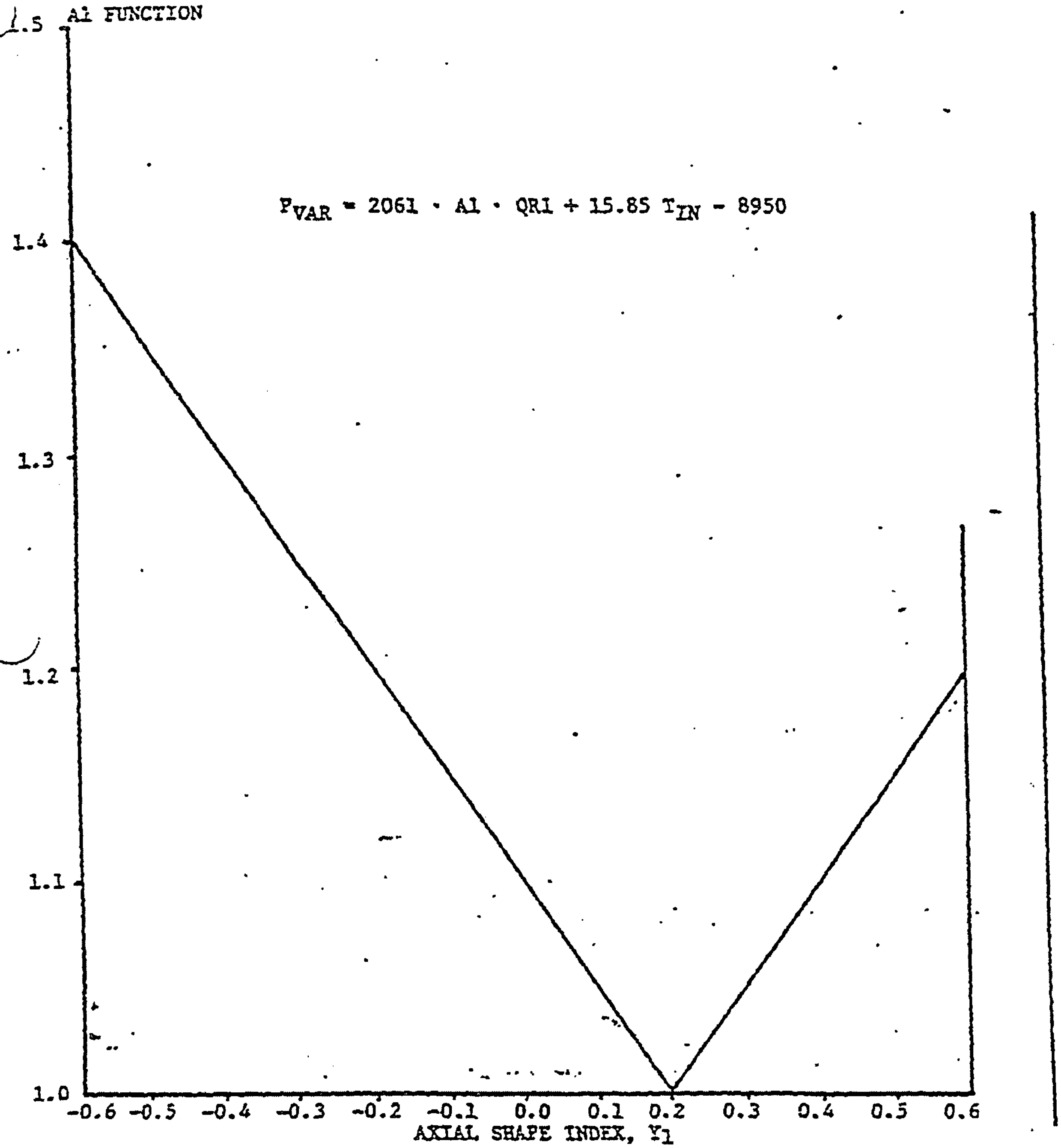


FIGURE 2.2-3

Thermal Margin/Low Pressure Trip Setpoint

$$P_{VAR} = 2061 \cdot A1 \cdot QR1 + 15.85\ T_{IN} - 8950$$

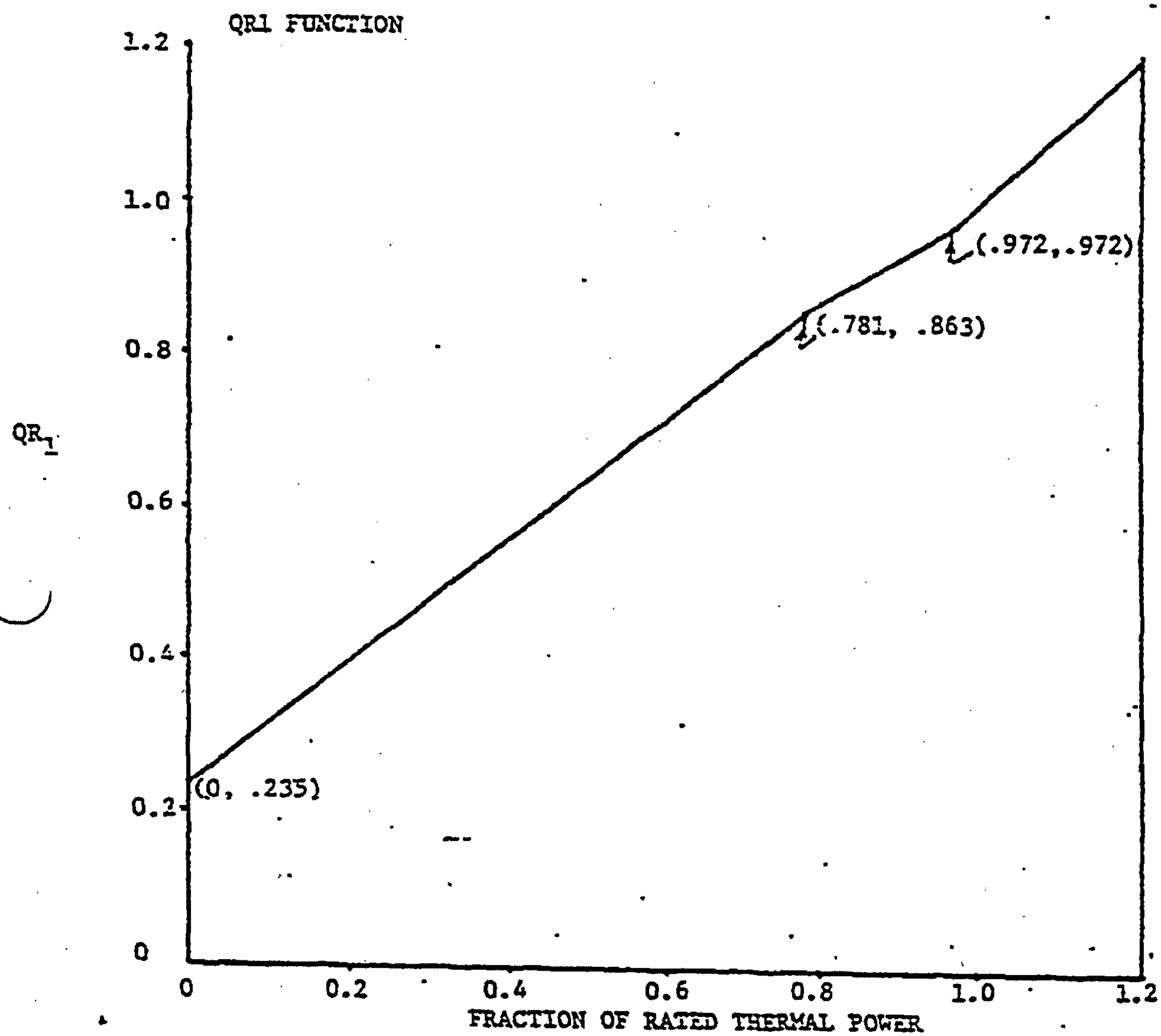


FIGURE 2.2-4

Thermal Margin/Low Pressure Trip Setpoint
Part 2 (Fraction of RATED THERMAL POWER Versus QR_1)

SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

3/4 LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

3/4.0 APPLICABILITY

LIMITING CONDITION FOR OPERATION

3.0.1 Compliance with the Limiting Conditions for Operation (LCO) contained in the succeeding specifications is required during the OPERATIONAL MODES or other conditions specified therein; except that upon failure to meet the Limiting Conditions for Operation, the associated ACTION requirements shall be met.

3.0.2 Noncompliance with a specification shall exist when the requirements of the Limiting Condition for Operation (LCO) and associated ACTION requirements are not met within the specified time intervals. If the Limiting Condition for Operation is restored prior to expiration of the specified time intervals, completion of the ACTION requirements is not required.

3.0.3 When a Limiting Condition for Operation (LCO) is not met, except as provided in the associated ACTION requirements, within 1 hour action shall be initiated to place the unit in a MODE in which the specification does not apply by placing it, as applicable in:

1. At least HOT STANDBY within the next 6 hours,
2. At least HOT SHUTDOWN within the following 6 hours, and
3. At least COLD SHUTDOWN within the subsequent 24 hours.

Where corrective measures are completed that permit operation under the ACTION requirements, the ACTION may be taken in accordance with the specified time limits as measured from the time of failure to meet the LCO. Exceptions to these requirements are stated in the individual specifications.

This specification is not applicable in MODES 5 or 6.

3.0.4 Entry into an OPERATIONAL MODE or other specified applicability condition shall not be made when the conditions of the Limiting Condition for Operation are not met and the associated ACTION requires a shutdown if they are not met within a specified time interval. Entry into an OPERATIONAL MODE or specified condition may be made in accordance with ACTION requirements when conformance to them permits continued operation of the facility for an unlimited period of time. This provision shall not prevent passage through or to OPERATIONAL MODES as required to comply with ACTION statements. Exceptions to these requirements are stated in the individual specifications.

APPLICABILITY

SURVEILLANCE REQUIREMENTS

4.0.1 Surveillance Requirements shall be applicable during the OPERATIONAL MODES or other conditions specified for individual Limiting Conditions for Operation unless otherwise stated in an individual Surveillance Requirement. Failure to perform a Surveillance Requirement within the allowed surveillance interval, defined by Specification 4.0.2, shall constitute noncompliance with the OPERABILITY requirements for a Limiting Condition for Operation. Surveillance Requirements do not have to be performed on inoperable equipment.

4.0.2 Each Surveillance Requirement shall be performed within the specified surveillance interval with a maximum allowable extension not to exceed 25% of the specified surveillance interval.

4.0.3 If it is discovered that a Surveillance was not performed within its specified frequency, then compliance with the requirement to declare the Limiting Condition for Operation not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified frequency, whichever is greater. This delay period is permitted to allow performance of the Surveillance. A risk evaluation shall be performed for any Surveillance delayed greater than 24 hours and the risk impact shall be managed.

If the Surveillance is not performed within the delay period, the Limiting Condition for Operation must immediately be declared not met, and the applicable ACTION(s) must be taken.

When the Surveillance is performed within the delay period and the Surveillance is not met, the Limiting Condition for Operation must immediately be declared not met, and the applicable ACTION(s) must be taken.

4.0.4 Entry into an OPERATIONAL MODE or other specified applicability condition shall not be made unless the Surveillance Requirement(s) associated with the Limiting Condition for Operation have been performed within the stated surveillance interval or as otherwise specified. This provision shall not prevent passage through or to OPERATIONAL MODES as required to comply with ACTION requirements.

4.0.5 Surveillance Requirements for inservice inspection of ASME Code Class 1, 2 and 3 components shall be applicable as follows:

a. 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).

b. deleted

SURVEILLANCE REQUIREMENTS (Continued)

4.0.5 (Continued)

c. deleted

d. Performance of the above inservice inspection activities shall be in addition to other specified Surveillance Requirements.

e. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 BORATION CONTROL

SHUTDOWN MARGIN - T_{avg} > 200 °F

LIMITING CONDITION FOR OPERATION

3.1.1.1 The SHUTDOWN MARGIN shall be within the limits specified in the COLR.

APPLICABILITY: MODES 1, 2*, 3 and 4.

ACTION:

With the SHUTDOWN MARGIN not within limits immediately initiate and continue boration at $\geq$ 40 gpm of greater than or equal to 1720 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.1.1 The SHUTDOWN MARGIN shall be determined to be within the COLR limits:

a. Within one hour after detection of an inoperable CEA(s) and at least once per 12 hours thereafter while the CEA(s) is inoperable. If the inoperable CEA is not fully inserted, and is immovable as a result of excessive friction or mechanical interference or is known to be untrippable, the above required SHUTDOWN MARGIN shall be increased by an amount at least equal to the withdrawn worth of the immovable or untrippable CEA(s).

b. When in MODES 1 or 2#, at least once per 12 hours by verifying that CEA group withdrawal is within the Power Dependent Insertion Limits of Specification 3.1.3.6.

c. When in MODE 2## at least once during CEA withdrawal and at least once per hour thereafter until the reactor is critical.

d. Prior to initial operation above 5% RATED THERMAL POWER after each fuel loading, by consideration of the factors of e below, with the CEA groups at the Power Dependent Insertion Limits of Specification 3.1.3.6.

---

* See Special Test Exception 3.10.1.

\# With $K_{eff} \geq 1.0$.

\## With $K_{eff} < 1.0$.

SURVEILLANCE REQUIREMENTS (Continued)

e. When in MODES 3 or 4, at least once per 24 hours by consideration of the following factors:

1. Reactor coolant system boron concentration,
2. CEA position,*
3. Reactor coolant system average temperature,
4. Fuel burnup based on gross thermal energy generation,
5. Xenon concentration, and
6. Samarium concentration.

4.1.1.1.2 The overall core reactivity balance shall be compared to predicted values to demonstrate agreement within ± 1000 pcm at least once per 31 Effective Full Power Days (EFPD). This comparison shall consider at least those factors stated in Specification 4.1.1.1.1.e, above. The predicted reactivity values shall be adjusted (normalized) to correspond to the actual core conditions prior to exceeding a fuel burnup of 60 Effective Full Power Days after each fuel loading.

*For Modes 3 and 4, during calculation of shutdown margin with all CEA's verified fully inserted, the single CEA with the highest reactivity worth need not be assumed to be stuck in the fully withdrawn position.

SHUTDOWN MARGIN - $T_{avg} \leq 200$ °F

LIMITING CONDITION FOR OPERATION

3.1.1.2 The SHUTDOWN MARGIN shall be:

Within the limits specified in the COLR, and in addition with the Reactor Coolant System drained below the hot leg centerline, one charging pump shall be rendered inoperable.*

APPLICABILITY: MODE 5.

ACTION:

If the SHUTDOWN MARGIN requirements cannot be met, immediately initiate and continue boration at $\geq$ 40 gpm of greater than or equal to 1720 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN requirements of Specification 3.1.1.2 shall be determined:

a. Within one hour after detection of an inoperable CEA(s) and at least once per 12 hours thereafter while the CEA(s) is inoperable. If the inoperable CEA is immovable or untrippable, the above required SHUTDOWN MARGIN shall be increased by an amount at least equal to the withdrawn worth of the immovable or untrippable CEA(s).

b. At least once per 24 hours by consideration of the following factors:

1. Reactor coolant system boron concentration,
2. CEA position,
3. Reactor coolant system average temperature,
4. Fuel burnup based on gross thermal energy generation,
5. Xenon concentration, and
6. Samarium concentration.

c. At least once per 24 hours, when the Reactor Coolant System is drained below the hot leg centerline, by consideration of the factors in 4.1.1.2.b and by verifying at least one charging pump is rendered inoperable.*

---

* Breaker racked-out.

BORON DILUTION

LIMITING CONDITION FOR OPERATION

3.1.1.3 The flow rate of reactor coolant to the reactor pressure vessel shall be ≥ 3000 gpm whenever a reduction in Reactor Coolant System boron concentration is being made.

APPLICABILITY: ALL MODES.

ACTION:

With the flow rate of reactor coolant to the reactor pressure vessel < 3000 gpm, immediately suspend all operations involving a reduction in boron concentration of the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

4.1.1.3 The flow rate of reactor coolant to the reactor pressure vessel shall be determined to be ≥ 3000 gpm within one hour prior to the start of and at least once per hour during a reduction in the Reactor Coolant System boron concentration by either:

a. Verifying at least one reactor coolant pump is in operation, or

b. Verifying that at least one low pressure safety injection pump is in operation and supplying ≥ 3000 gpm to the reactor pressure vessel.

MODERATOR TEMPERATURE COEFFICIENT

LIMITING CONDITION FOR OPERATION

3.1.1.4 The moderator temperature coefficient (MTC) shall be maintained within the limits specified in the COLR. The maximum positive limit shall be:

a. Less positive than +7 pcm/°F whenever THERMAL POWER is ≤ 70% of RATED THERMAL POWER, and

b. Less positive than +2 pcm/°F whenever THERMAL POWER is > 70% of RATED THERMAL POWER.

APPLICABILITY: MODES 1 and 2*#.

ACTION:

With the moderator temperature coefficient outside any one of the above limits, be in HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.1.4.1 The MTC shall be determined to be within its limits by confirmatory measurements. MTC measured values shall be extrapolated and/or compensated to permit direct comparison with the above limits.

---

* With $K_{eff} \geq 1.0$.

\# See Special Test Exception 3.10.2.

SURVEILLANCE REQUIREMENTS (Continued)

4.1.1.4.2 The MTC shall be determined at the following frequencies and THERMAL POWER conditions during each fuel cycle:

a. Prior to initial operation above 5% of RATED THERMAL POWER, after each refueling.

b. At any THERMAL POWER, within 7 EFPD after initially reaching a RATED THERMAL POWER equilibrium boron concentration.

c. At any THERMAL POWER, within 7 EFPD after reaching a RATED THERMAL POWER equilibrium boron concentration of 300 ppm.

REACTIVITY CONTROL SYSTEMS

MINIMUM TEMPERATURE FOR CRITICALITY

LIMITING CONDITION FOR OPERATION

3.1.1.5 The Reactor Coolant System lowest operating loop temperature (T_{avg}) shall be $\geq$ 515°F when the reactor is critical.

APPLICABILITY: MODES 1 and 2#.

ACTION:

With a Reactor Coolant System operating loop temperature (T_{avg}) < 515°F, restore T_{avg} to within its limit within 15 minutes or be in HOT STANDBY within the next 15 minutes.

SURVEILLANCE REQUIREMENTS

4.1.1.5 The Reactor Coolant System temperature (T_{avg}) shall be determined to be $\geq$ 515°F.

a. Within 15 minutes prior to achieving reactor criticality, and

b. At least once per 30 minutes when the reactor is critical and the Reactor Coolant System temperature (T_{avg}) is < 525°F.

With $K_{eff} \geq 1.0$.

3/4.1.2 BORATION SYSTEMS

FLOW PATHS – SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE and capable of being powered from an OPERABLE emergency power source.

a. A flow path from the boric acid makeup tank via either a boric acid pump or a gravity feed connection and any charging pump to the Reactor Coolant System if only the boric acid makeup tank in Specification 3.1.2.7a is OPERABLE, or

b. The flow path from the refueling water tank via either a charging pump or a high pressure safety injection pump* to the Reactor Coolant System if only the refueling water tank in Specification 3.1.2.7b is OPERABLE.

APPLICABILITY: MODES 5 and 6.

ACTION:

With none of the above flow paths OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes** until at least one injection path is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

---

* The flow path from the RWT to the RCS via a single HPSI pump shall only be established if: (a) the RCS pressure boundary does not exist, or (b) RCS pressure boundary integrity exists and no charging pumps are operable. In the latter case: 1) all charging pumps shall be disabled; 2) heatup and cooldown rates shall be limited in accordance with Figure 3.1-1b; and 3) at RCS temperatures below 115°F, any two of the following valves in the operable HPSI header shall be verified closed and have their power removed:

High Pressure Header	Auxiliary Header
HCV-3616	HCV-3617
HCV-3626	HCV-3627
HCV-3636	HCV-3637
HCV-3646	HCV-3647

** Plant temperature changes are allowed provided the temperature change is accounted for in the calculated SHUTDOWN MARGIN.

SURVEILLANCE REQUIREMENTS

b. At least once per 24 hours, when the Reactor Auxiliary Building air temperature is less than 55°F, by verifying that the Boric Acid Makeup Tank solution temperature is greater than 55°F, when the flowpath from the Boric Acid Makeup Tank is required to be OPERABLE.

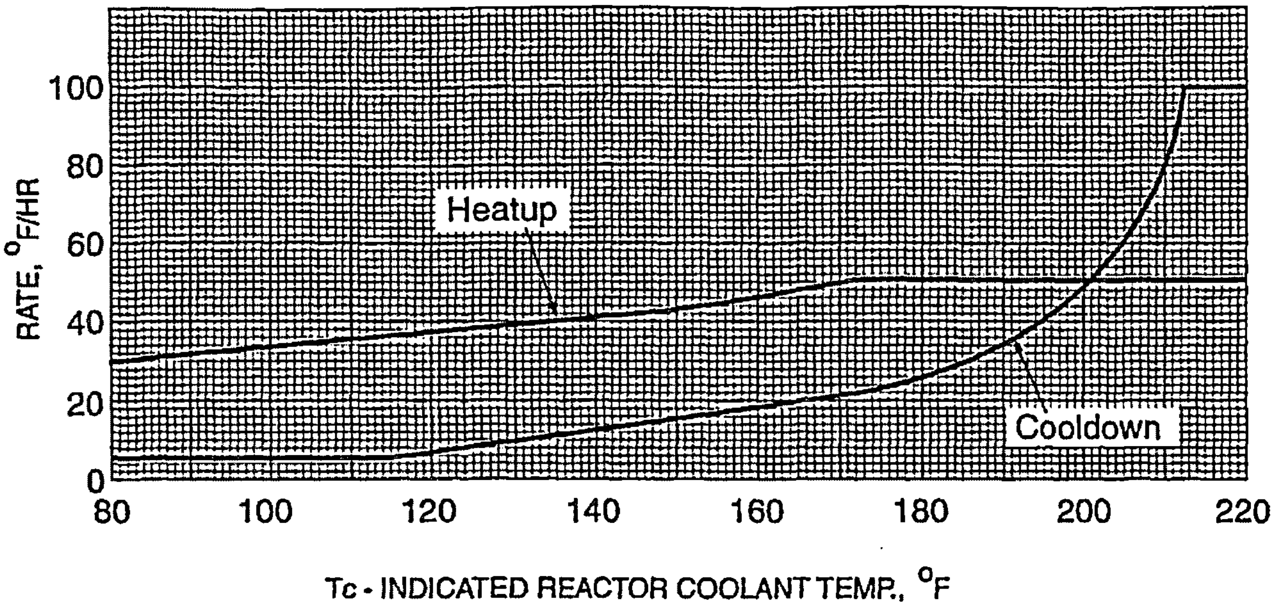


FIGURE 3.1-1b

MAXIMUM ALLOWABLE HEATUP AND COOLDOWN RATES, SINGLE HPSI PUMP IN OPERATION (Applicable to 35 EFPY)

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FLOW PATHS – OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.2 At least two of the following three boron injection flow paths shall be OPERABLE:

a. One flow path from the boric acid makeup tank(s) with the tank meeting Specification 3.1.2.8 part a) or b), via a boric acid makeup pump through a charging pump to the Reactor Coolant System.

b. One flow path from the boric acid makeup tank(s) with the tank meeting Specification 3.1.2.8 part a) or b), via a gravity feed valve through a charging pump to the Reactor Coolant System.

c. The flow path from the refueling water storage tank via a charging pump to the Reactor Coolant System.

OR

At least two of the following three boron injection flow paths shall be OPERABLE:

a. One flow path from each boric acid makeup tank with the combined tank contents meeting Specification 3.1.2.8 c), via both boric acid makeup pumps through a charging pump to the Reactor Coolant System.

b. One flow path from each boric acid makeup tank with the combined tank contents meeting Specification 3.1.2.8 c), via both gravity feed valves through a charging pump to the Reactor Coolant System.

c. The flow path from the refueling water storage tank, via a charging pump to the Reactor Coolant System.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one of the above required boron injection flow paths to the Reactor Coolant System OPERABLE, restore at least two boron injection flow paths to the Reactor Coolant System to OPERABLE status within 72 hours or make the reactor subcritical within the next 2 hours and borate to a SHUTDOWN MARGIN equivalent to the requirements of Specification 3.1.1.2 at 200°F; restore at least two flow paths to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.2 At least two of the above required flow paths shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown by verifying that each automatic valve in the flow path actuates to its correct position on a Safety Injection Actuation Signal.

c. At least once per 24 hours when the Reactor Auxiliary Building air temperature is below 55°F by verifying that the solution temperature of the Boric Acid Makeup Tank(s) is above 55°F.

CHARGING PUMPS – SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.3 At least one charging pump or high pressure safety injection pump* in the boron injection flow path required OPERABLE pursuant to Specification 3.1.2.1 shall be OPERABLE and capable of being powered from an OPERABLE emergency bus.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no charging pump or high pressure safety injection pump* OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes** until at least one of the required pumps is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.2.3 At least one of the above required pumps shall be demonstrated OPERABLE by verifying the charging pump develops a flow rate of greater than or equal to 40 gpm or the high pressure safety injection pump develops a total head of greater than or equal to 2571 ft. when tested pursuant to the Inservice Testing Program.

---

* The flow path from the RWT to the RCS via a single HPSI pump shall be established only if: (a) the RCS pressure boundary does not exist, or (b) RCS pressure boundary integrity exists and no charging pumps are operable. In the latter case: 1) all charging pumps shall be disabled; 2) heatup and cooldown rates shall be limited in accordance with Figure 3.1-1b; and 3) at RCS temperatures below 115°F, any two of the following valves in the operable HPSI header shall be verified closed and have their power removed:

High Pressure Header	Auxiliary Header
HCV-3616	HCV-3617
HCV-3626	HCV-3627
HCV-3636	HCV-3637
HCV-3646	HCV-3647

** Plant temperature changes are allowed provided the temperature change is accounted for in the calculated SHUTDOWN MARGIN.

CHARGING PUMPS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.4 At least two charging pumps shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one charging pump OPERABLE, restore at least two charging pumps to OPERABLE status within 72 hours or be in HOT STANDBY within the next 6 hours; restore at least two charging pumps to OPERABLE status within the next 48 hours or be in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.4 At least two charging pumps shall be demonstrated OPERABLE by verifying that each pump develops a flow rate of greater than or equal to 40 gpm when tested pursuant to the Inservice Testing Program.

BORIC ACID PUMPS – SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.5 At least one boric acid pump shall be OPERABLE if only the flow path through the boric acid pump in Specification 3.1.2.1a above, is OPERABLE.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no boric acid pump OPERABLE as required to complete the flow path of Specification 3.1.2.1a, suspend all operations involving CORE ALTERATIONS or positive reactivity changes* until at least one boric acid pump is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.2.5 The above required boric acid pump shall be demonstrated OPERABLE by verifying that the pump develops the specified discharge pressure when tested pursuant to the Inservice Testing Program.

* Plant temperature changes are allowed provided the temperature change is accounted for in the calculated SHUTDOWN MARGIN.

REACTIVITY CONTROL SYSTEMS

BORIC ACID PUMPS – OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.6 At least the boric acid pump(s) in the boron injection flow path(s) required OPERABLE pursuant to Specification 3.1.2.2a shall be OPERABLE if the flow path through the boric acid pump in Specification 3.1.2.2a is OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one boric acid pump required for boron injection flow path(s) pursuant to Specification 3.1.2.2a inoperable, restore the boric acid pump to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.6 The above required boric acid pump(s) shall be demonstrated OPERABLE by verifying that the pump(s) develop the specified discharge pressure when tested pursuant to the Inservice Testing Program.

BORATED WATER SOURCES – SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.7 As a minimum, one of the following borated water sources shall be OPERABLE:

a. One boric acid makeup tank with a minimum borated water volume of 3650 gallons of 2.5 to 3.5 weight percent boric acid (4371 to 6119 ppm boron).

b. The refueling water tank with:

1. A minimum contained volume of 125,000 gallons,

2. A minimum boron concentration of 1720 ppm, and

3. A minimum solution temperature of 40°F.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no borated water sources OPERABLE, suspend all operations involving positive reactivity changes* until at least one borated water source is restored to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.1.2.7 The above required borated water source shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1. Verifying the boron concentration of the water,

2. Verifying the water level of the tank, and.

b. At least once per 24 hours by verifying the RWT temperature when it is the source of borated water and the site ambient air temperature is < 40°F.

c. At least once per 24 hours when the Reactor Auxiliary Building air temperature is less than 55°F by verifying that the Boric Acid Makeup Tank solution temperature is greater than 55°F when that Boric Acid Makeup Tank is required to be OPERABLE.

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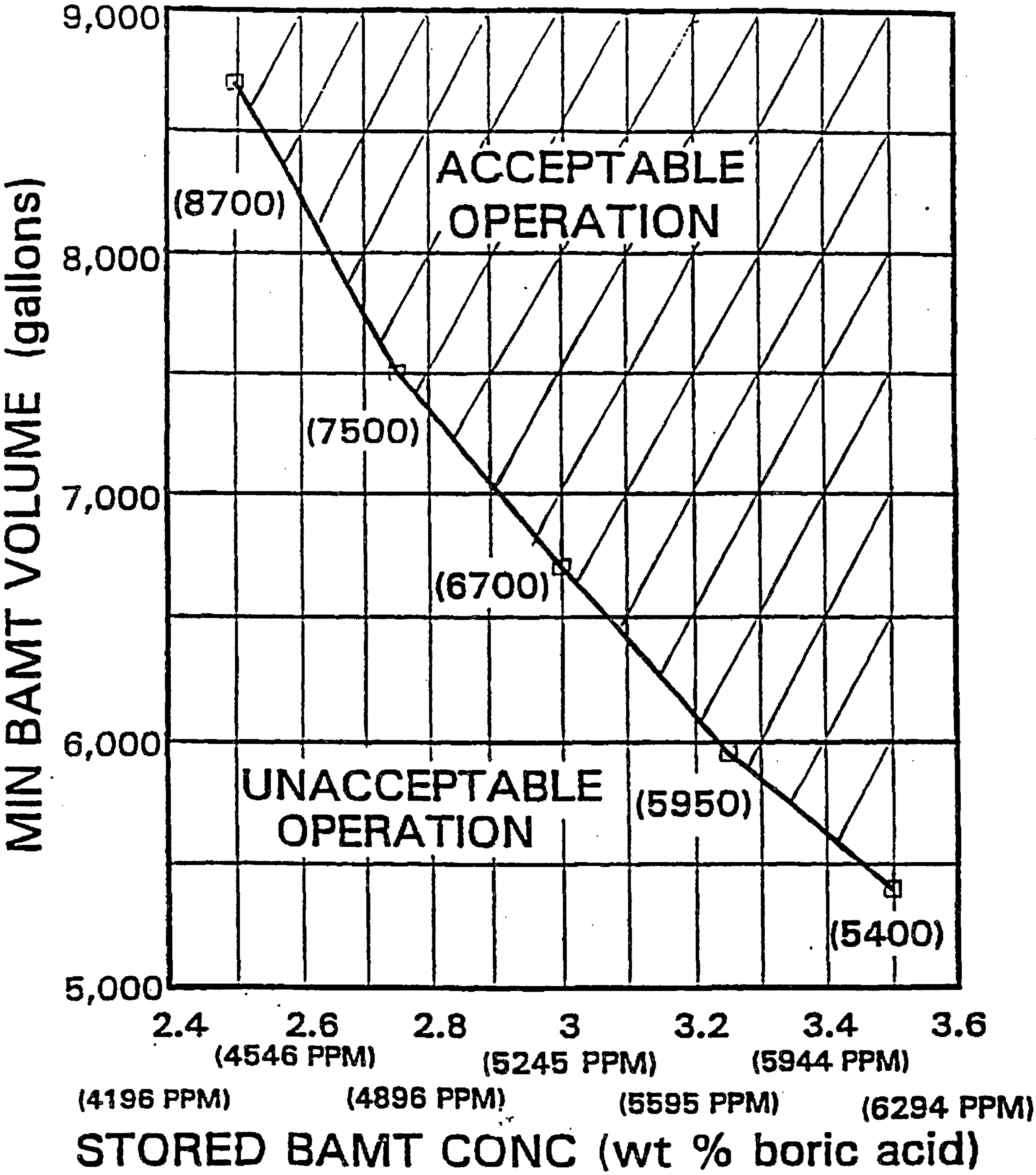
* Plant temperature changes are allowed provided the temperature change is accounted for in the calculated SHUTDOWN MARGIN.

FIGURE 3.1-1 ST. LUCIE 1 MIN BAMT VOLUME

VS STORED BAMT CONCENTRATION



REACTIVITY CONTROL SYSTEMS

BORATED WATER SOURCES – OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.8 At least two of the following four borated water sources shall be OPERABLE:

a. Boric Acid Makeup Tank 1A in accordance with Figure 3.1-1.

b. Boric Acid Makeup Tank 1B in accordance with Figure 3.1-1.

c. Boric Acid Makeup Tanks 1A and 1B with a minimum combined contained borated water volume in accordance with Figure 3.1-1.

d. The refueling water tank with:

1. A minimum contained volume of 477,360 gallons of water,
2. A minimum boron concentration of 1720 ppm,
3. A maximum solution temperature of 100°F,
4. A minimum solution temperature of 55°F when in MODES 1 and 2, and
5. A minimum solution temperature of 40°F when in MODES 3 and 4.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one borated water source OPERABLE, restore at least two borated water sources to OPERABLE status within 72 hours or make the reactor subcritical within the next 2 hours and borate to a SHUTDOWN MARGIN equivalent to the requirements of Specification 3.1.1.2 at 200°F; restore at least two borated water sources to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.8 At least two borated water sources shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1. Verifying the boron concentration of the water source,

SURVEILLANCE REQUIREMENTS (Continued)

2. Verifying the water level in each water source.

b. At least once per 24 hours by verifying the RWT temperature.

c. At least once per 24 hours by verifying that the Boric Acid Makeup Tank solution temperature is greater than 55°F when the Reactor Auxiliary Building air temperature is below 55°F.

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

FULL LENGTH CEA POSITION

LIMITING CONDITION FOR OPERATION

3.1.3.1 The CEA Block Circuit and all full length (shutdown and regulating) CEAs shall be OPERABLE with each CEA of a given group positioned within 7.5 inches (indicated position) of all other CEAs in its group.

APPLICABILITY: MODES 1* and 2*.

ACTION:

a. With one or more full length CEAs inoperable due to being immovable as a result of excessive friction or mechanical interference or known to be untrippable, determine that the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied within 1 hour and be in HOT STANDBY within 6 hours.

b. With the CEA Block Circuit inoperable, within 6 hours either:

   1. With one CEA position indicator per group inoperable, take action per Specification 3.1.3.3, or

   2. With the group overlap and/or sequencing interlocks inoperable, maintain CEAs in groups 3, 4, 5 and 6 fully withdrawn and withdraw the CEAs in group 7 to less than 5% insertion and place and maintain the CEA drive system mode switch in either the "Manual" or "Off" position, or

   3. Be in at least HOT STANDBY.

c. With one full length CEA inoperable due to causes other than addressed by Action a above, but within its above specified alignment requirements and either fully withdrawn or within the long term steady state insertion limits if in CEA group 7, operation in MODES 1 and 2 may continue.

d. With one or more full length CEAs misaligned from any other CEAs in its group by more than 7.5 inches but less than 15 inches, operation in MODES 1 and 2 may continue, provided that within one hour the misaligned CEA(s) is either:

   1. Restored to OPERABLE status within its above specified alignment requirements, or

*See Special Test Exceptions 3.10.2 and 3.10.5.

2. Declared inoperable and satisfy SHUTDOWN MARGIN requirements of Specification 3.1.1.1. After declaring the CEA inoperable, operation in MODES 1 and 2 may continue pursuant to the requirements of Specification 3.1.3.6 for up to 7 days per occurrence with a total accumulated time of ≤ 14 days per calendar year provided all of the following conditions are met:

   a) Within 1 hour, the remainder of the CEAs in the group with the inoperable CEA shall be aligned to within 7.5 inches of the inoperable CEA while maintaining the allowable CEA sequence and insertion limits shown on COLR Figure 3.1-2; the THERMAL POWER level shall be restricted pursuant to Specification 3.1.3.6 during subsequent operation.

   b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours.

Otherwise, be in at least HOT STANDBY within the next 6 hours.

e. With one full length CEA misaligned from any other CEA in its group by 15 or more inches, operation in MODES 1 and 2 may continue provided that the misaligned CEA is positioned within 7.5 inches of other CEAs in its group in accordance with the time constraints shown in COLR Figure 3.1-1a.

f. With one full-length CEA misaligned from any other CEA in its group by 15 or more inches beyond the time constraints shown in COLR Figure 3.1-1a, reduce power to ≤ 70% of RATED THERMAL POWER prior to completing ACTION f.1 or f.2.

1. Restore the CEA to OPERABLE status within its specified alignment requirements, or

2. Declare the CEA inoperable and satisfy the SHUTDOWN MARGIN requirements of Specification 3.1.1.1. After declaring the CEA inoperable, operation in MODES 1 and 2 may continue pursuant to the requirements of Specification 3.1.3.6 provided:

   a) Within 1 hour, the remainder of the CEAs in the group with the inoperable CEA shall be aligned to within 7.5 inches of the inoperable CEA while maintaining the allowable CEA sequence and insertion limits shown on COLR Figure 3.1-2; the THERMAL POWER level shall be restricted pursuant to Specification 3.1.3.6 during subsequent operation.

LIMITING CONDITION FOR OPERATION (continued)

b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours.

Otherwise, be in at least HOT STANDBY within the next 6 hours.

g. With more than one full length CEA inoperable or misaligned from any other CEA in its group by 15 inches (indicated position) or more, be in HOT STANDBY within 6 hours.

h. With one full-length CEA inoperable due to causes other than addressed by ACTION a above, and inserted beyond the long term steady state insertion limits but within its above specified alignment requirements, operation in MODES 1 and 2 may continue pursuant to the requirements of Specification 3.1.3.6.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The position of each full-length CEA shall be determined to be within 7.5 inches (indicated position) of all other CEAs in its group at least once per 12 hours except during time intervals when the Deviation Circuit and/or CEA Block Circuit are inoperable, then verify the individual CEA positions at least once per 4 hours.

4.1.3.1.2 Each full length CEA not fully inserted shall be determined to be OPERABLE by inserting it at least 7.5 inches at least once per 92 days.

4.1.3.1.3 The CEA Block Circuit shall be demonstrated OPERABLE at least once per 92 days by a functional test which verifies that the circuit prevents any CEA from being misaligned from all other CEAs in its group by more than 7.5 inches (indicated position).

4.1.3.1.4 The CEA Block Circuit shall be demonstrated OPERABLE by a functional test which verifies that the circuit maintains the CEA group overlap and sequencing requirements of Specification 3.1.3.6 and that the circuit prevents the regulating CEAs from being inserted beyond the Power Dependent Insertion Limit of COLR Figure 3.1-2:

*a. Prior to each entry into MODE 2 from MODE 3, except that such verification need not be performed more often than once per 92 days, and

b. At least once per 6 months.

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* The licensee shall be excepted from compliance during the startup test program for an entry into MODE 2 from MODE 3 made in association with a measurement of power defect.

DELETED

POSITION INDICATOR CHANNELS

LIMITING CONDITION FOR OPERATION

3.1.3.3 All shutdown and regulating CEA reed switch position indicator channels and CEA pulse counting position indicator channels shall be OPERABLE and capable of determining the absolute CEA positions within $\pm$ 2.25 inches.

APPLICABILITY: MODES 1 and 2.

ACTION:

a. Deleted.

b. With a maximum of one reed switch position indicator channel per group or one (except as permitted by ACTION item d. below) pulse counting position indicator channel per group inoperable and the CEA(s) with the inoperable position indicator channel partially inserted, within 6 hours either:

1. Restore the inoperable position indicator channel to OPERABLE status, or

2. Be in HOT STANDBY, or

3. Reduce THERMAL POWER to $\leq$ 70% of the maximum allowable THERMAL POWER level for the existing Reactor Coolant Pump combination; if negative reactivity insertion is required to reduce THERMAL POWER, boration shall be used. Operation at or below this reduced THERMAL POWER level may continue provided that within the next 4 hours either:

a) The CEA group(s) with the inoperable position indicator is fully withdrawn while maintaining the withdrawal sequence required by Specification 3.1.3.6 and when this CEA group reaches its fully withdrawn position, the "Full Out" limit of the CEA with the inoperable position indicator is actuated and verifies this CEA to be fully withdrawn. Subsequent to fully withdrawing this CEA group(s), the THERMAL POWER level may be returned to a level consistent with all other applicable specifications; or

LIMITING CONDITION FOR OPERATION

b) The CEA group(s) with the inoperable position indicator is fully inserted, and subsequently maintained fully inserted, while maintaining the withdrawal sequence and THERMAL POWER level required by Specification 3.1.3.6 and when this CEA group reaches its fully inserted position, the "Full In" limit of the CEA with the inoperable position indicator is actuated and verifies this CEA to be fully inserted. Subsequent operation shall be within the limits of Specification 3.1.3.6.

c. With a maximum of one reed switch position indicator channel per group or one pulse counting position indicator channel per group inoperable and the CEA(s) with the inoperable position indicator channel at either its fully inserted position or fully withdrawn position, operation may continue provided:

1. The position of this CEA is verified immediately and at least once per 12 hours thereafter by its "Full In" or "Full Out" limit (as applicable),

2. The fully inserted CEA group(s) containing the inoperable position indicator channel is subsequently maintained fully inserted, and

3. Subsequent operation is within the limits of Specification 3.1.3.6.

d. With one or more pulse counting position indicator channels inoperable, operation in MODES 1 and 2 may continue for up to 24 hours provided all of the reed switch position indicator channels are OPERABLE.

SURVEILLANCE REQUIREMENTS

4.1.3.3 Each position indicator channel shall be determined to be OPERABLE by verifying the pulse counting position indicator channels and the reed switch position indicator channels agree within 4.5 inches at least once per 12 hours except during time intervals when the Deviation circuit is inoperable, then compare the pulse counting position indicator and reed switch position indicator channels at least once per 4 hours.

CEA DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual full length (shutdown and control) CEA drop time, from a fully withdrawn position, shall be ≤ 3.1 seconds from when electrical power is interrupted to the CEA drive mechanism until the CEA reaches its 90 percent insertion position with:

a. $T_{avg} \geq 515°F$, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODE 3.

ACTION:

a. With the drop time of any full length CEA determined to exceed the above limit, restore the CEA drop time to within the above limit prior to proceeding to MODE 1 or 2.

b. With the CEA drop times within limits but determined at less than full reactor coolant flow, operation may proceed provided THERMAL POWER is restricted to less than or equal to the maximum THERMAL POWER level allowable for the reactor coolant pump combination operating at the time of CEA drop time determination.

SURVEILLANCE REQUIREMENTS

4.1.3.4 The CEA drop time of full length CEAs shall be demonstrated through measurement prior to reactor criticality:

a. For all CEAs following each removal of the reactor vessel head,

b. For specifically affected individual CEAs following any maintenance on or modification to the CEA drive system which could affect the drop time of those specific CEAs, and

c. At least once per 18 months.

SHUTDOWN CEA INSERTION LIMIT

LIMITING CONDITION FOR OPERATION

3.1.3.5 All shutdown CEAs shall be withdrawn to at least 129.0 inches.

APPLICABILITY: MODES 1 and 2*#.

ACTION:

With a maximum of one shutdown CEA withdrawn, except for surveillance testing pursuant to Specification 4.1.3.1.2, to less than 129.0 inches, within one hour either:

a. Withdraw the CEA to at least 129.0 inches, or

b. Declare the CEA inoperable and apply Specification 3.1.3.1.

SURVEILLANCE REQUIREMENTS

4.1.3.5 Each shutdown CEA shall be determined to be withdrawn to at least 129.0 inches:

a. Within 15 minutes prior to withdrawal of any CEAs in regulating groups during an approach to reactor criticality, and

b. At least once per 12 hours thereafter.

*See Special Test Exception 3.10.2.

#With $K_{eff} \geq 1.0$.

REGULATING CEA INSERTION LIMITS

LIMITING CONDITION FOR OPERATION

3.1.3.6 The regulating CEA groups shall be limited to the withdrawal sequence and to the insertion limits specified in the COLR (regulating CEAs are considered to be fully withdrawn when withdrawn to at least 129.0 inches) with CEA insertion between the Long Term Steady State Insertion Limits and the Power Dependent Insertion Limits restricted to:

a. ≤ 4 hours per 24 hour interval,

b. ≤ 5 Effective Full Power Days per 30 Effective Full Power Day interval, and

c. ≤ 14 Effective Full Power Days per calendar year.

APPLICABILITY: MODES 1* and 2*#.

ACTION:

a. With the regulating CEA groups inserted beyond the Power Dependent Insertion Limits, except for surveillance testing pursuant to Specification 4.1.3.1.2, within two hours either:

1. Restore the regulating CEA groups to within the limits, or

2. Reduce THERMAL POWER to less than or equal to that fraction of RATED THERMAL POWER which is allowed by the CEA group position and insertion limits specified in the COLR.

b. With the regulating CEA groups inserted between the Long Term Steady State Insertion Limits and the Power Dependent Insertion Limits for intervals > 4 hours per 24 hour interval, except during operation pursuant to the provisions of ACTION items c. and d. of Specification 3.1.3.1, operation may proceed provided either:

1. The Short Term Steady State Insertion Limits are not exceeded, or

2. Any subsequent increase in THERMAL POWER is restricted to ≤ 5% of RATED THERMAL POWER per hour.

* See Special Test Exceptions 3.10.2 and 3.10.5.

With $K_{eff} \geq 1.0$.

REGULATING CEA INSERTION LIMITS (Continued)

LIMITING CONDITION FOR OPERATION

c. With the regulating CEA groups inserted between the Long Term Steady State Insertion Limits and the Power Dependent Insertion Limits for intervals > 5 EFPD per 30 EFPD interval or > 14 EFPD per calendar year, except during operations pursuant to the provisions of ACTION items c. and d. of Specification 3.1.3.1, either:

1. Restore the regulating groups to within the Long Term Steady State Insertion Limits within two hours, or

2. Be in HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.6 The position of each regulating CEA group shall be determined to be within the Power Dependent Insertion Limits at least once per 12 hours except during time intervals when the PDIL Auctioneer Alarm Circuit is inoperable; then verify the individual CEA positions at least once per 4 hours. The accumulated times during which the regulating CEA groups are inserted between the Long Term Steady State Insertion Limits and the Power Dependent Insertion Limits shall be determined at least once per 24 hours.

DELETED

LINEAR HEAT RATE

LIMITING CONDITION FOR OPERATION

3.2.1 The linear heat rate shall not exceed the limits specified in the COLR.

APPLICABILITY: MODE 1.

ACTION:

With the linear heat rate exceeding its limits, as indicated by four or more coincident incore channels or by the AXIAL SHAPE INDEX outside of the power dependent control limits of COLR Figure 3.2-2, within 15 minutes initiate corrective action to reduce the linear heat rate to within the limits and either:

a. Restore the linear heat rate to within its limits within one hour, or

b. Be in HOT STANDBY within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.2.1.1 The provisions of Specification 4.0.4 are not applicable.

4.2.1.2 The linear heat rate shall be determined to be within its limits by continuously monitoring the core power distribution with either the excore detector monitoring system or with the incore detector monitoring system.

4.2.1.3 Excore Detector Monitoring System - The excore detector monitoring system may be used for monitoring the linear heat rate by:

a. Verifying at least once per 12 hours that the full length CEAs are withdrawn to and maintained at or beyond the Long Term Steady State Insertion Limit of Specification 3.1.3.6.

b. Verifying at least once per 31 days that the AXIAL SHAPE INDEX alarm setpoints are adjusted to within the limits shown on COLR Figure 3.2-2.

SURVEILLANCE REQUIREMENTS (continued)

c. Verifying that the AXIAL SHAPE INDEX is maintained within the allowable limits of COLR Figure 3.2-2, where 100 percent of maximum allowable power represents the maximum THERMAL POWER allowed by the following expression:

$$M \times N$$

where:

1. M is the maximum allowable THERMAL POWER level for the existing Reactor Coolant Pump combination.

2. N is the maximum allowable fraction of RATED THERMAL POWER as determined by the F_r^T curve of COLR Figure 3.2-3.

4.2.1.4 Incore Detector Monitoring System# - The incore detector monitoring system may be used for monitoring the linear heat rate by verifying that the incore detector Local Power Density alarms:

a. Are adjusted to satisfy the requirements of the core power distribution map which shall be updated at least once per 31 days of accumulated operation in MODE 1.

b. Have their alarm setpoint adjusted to less than or equal to the limits shown on COLR Figure 3.2-1.

If the incore system becomes inoperable, reduce power to M x N within 4 hours and monitor linear heat rate in accordance with Specification 4.2.1.3.

Pages 3/4 2-4 (Amendment 106), 3/4 2-5 (Amendment 63), and 3/4 2-6 through 3/4 2-8 (Amendment 109) have been deleted from the Technical Specifications. The next page is 3/4 2-9.

POWER DISTRIBUTION LIMITS

TOTAL INTEGRATED RADIAL PEAKING FACTOR - F_r^T

LIMITING CONDITION FOR OPERATION

3.2.3 The calculated value of F_r^T shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1*.

ACTION:

With F_r^T not within limits, within 6 hours either:

a. Be in at least HOT STANDBY, or

b. Reduce THERMAL POWER to bring the combination of THERMAL POWER and F_r^T to within the limits of COLR Figure 3.2-3 and withdraw the full length CEAs to or beyond the Long Term Steady State Insertion Limits of Specification 3.1.3.6. The THERMAL POWER limit determined from COLR Figure 3.2-3 shall then be used to establish a revised upper THERMAL POWER level limit on COLR Figure 3.2-4 (truncate Figure 3.2-4 at the allowable fraction of RATED THERMAL POWER determined by COLR Figure 3.2-3) and subsequent operation shall be maintained within the reduced acceptable operation region of COLR Figure 3.2-4.

SURVEILLANCE REQUIREMENTS

4.2.3.1 The provisions of Specification 4.0.4 are not applicable.

4.2.3.2 F_r^T shall be calculated by the expression $F_r^T = F_r(1+T_q)$ when F_r is calculated with a non-full core power distribution analysis code and shall be calculated as $F_r^T = F_r$ when calculations are performed with a full core power distribution analysis code. F_r^T shall be determined to be within its limit at the following intervals.

a. Prior to operation above 70 percent of RATED THERMAL POWER after each fuel loading.

b. At least once per 31 days of accumulated operation in MODE 1, and

c. Within four hours if the AZIMUTHAL POWER TILT (T_q) is > 0.03.

* See Special Test Exception 3.10.2.

SURVEILLANCE REQUIREMENTS (Continued)

4.2.3.3 F_r shall be determined each time a calculation of F_r^T is required by using the incore detectors to obtain a power distribution map with all full length CEAs at or above the Long Term Steady State Insertion Limit for the existing Reactor Coolant Pump combination.

4.2.3.4 T_q shall be determined each time a calculation of F_r^T is made using a non-full core power distribution analysis code. The value of T_q used to determine F_r^T in this case shall be the measured value of T_q.

AZIMUTHAL POWER TILT - T_q

LIMITING CONDITION FOR OPERATION

3.2.4 The AZIMUTHAL POWER TILT (T_q) shall not exceed 0.03.

APPLICABILITY: MODE 1*

ACTION:

a. With the indicated AZIMUTHAL POWER TILT determined to be > .030 but ≤ 0.10, either correct the power tilt within two hours or determine within the next 2 hours and at least once per subsequent 8 hours, that the TOTAL INTEGRATED RADIAL PEAKING FACTOR (F_r^T) is within the limits of Specification 3.2.3.

b. With the indicated AZIMUTHAL POWER TILT determined to be > 0.10, operation may proceed for up to 2 hours provided that the TOTAL INTEGRATED RADIAL PEAKING FACTOR (F_r^T) is within the limits of Specification 3.2.3. Subsequent operation for the purpose of measurement and to identify the cause of the tilt is allowable provided the THERMAL POWER level is restricted to ≤ 20% of the maximum allowable THERMAL POWER level for the existing Reactor Coolant Pump combination.

SURVEILLANCE REQUIREMENT

4.2.4.1 The provisions of Specification 4.0.4 are not applicable.

4.2.4.2 The AZIMUTHAL POWER TILT shall be determined to be within the limit by:

a. Calculating the tilt at least once per 7 days when the Subchannel Deviation Alarm is OPERABLE,

*See Special Test Exception 3.10.2.

SURVEILLANCE REQUIREMENTS (Continued)

b. Calculating the tilt at least once per 12 hours when the Subchannel Deviation Alarm is inoperable, and

c. Using the incore detectors to determine the AZIMUTHAL POWER TILT at least once per 12 hours when one excore channel is inoperable and THERMAL POWER is > 75% of RATED THERMAL POWER.

POWER DISTRIBUTION LIMITS

DNB PARAMETERS

LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB related parameters shall be maintained within the limits shown on Table 3.2-1:

a. Cold Leg Temperature

b. Pressurizer Pressure

c. Reactor Coolant System Total Flow Rate

d. AXIAL SHAPE INDEX

APPLICABILITY: MODE 1.

ACTION:

With any of the above parameters exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to ≤ 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5.1 Each of the parameters of Table 3.2-1 shall be verified to be within their limits by instrument readout at least once per 12 hours.

4.2.5.2 The Reactor Coolant System total flow rate shall be determined to be within its limit by measurement* at least once per 18 months.

* Not required to be performed until THERMAL POWER is ≥ 90% of RATED THERMAL POWER.

TABLE 3.2-1

DNB MARGIN

LIMITS

Parameter	Four Reactor Coolant Pumps Operating
Cold Leg Temperature	$\leq$ 549°F
Pressurizer Pressure	$\geq$ 2225 psia *
Reactor Coolant Flow Rate	$\geq$ 365,000 gpm
AXIAL SHAPE INDEX	COLR Figure 3.2-4

* Limit not applicable during either a THERMAL POWER ramp increase in excess of 5% of RATED THERMAL POWER or a THERMAL POWER step increase of greater than 10% of RATED THERMAL POWER.

3/4.3 INSTRUMENTATION

3/4.3.1 REACTOR PROTECTIVE INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.1.1 As a minimum, the reactor protective instrumentation channels and bypasses of Table 3.3-1 shall be OPERABLE.

APPLICABILITY: As shown in Table 3.3-1.

ACTION:

As shown in Table 3.3-1.

SURVEILLANCE REQUIREMENTS

4.3.1.1.1 Each reactor protective instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the modes and at the frequencies shown in Table 4.3-1.

4.3.1.1.2 The logic for the bypasses shall be demonstrated OPERABLE during the at power CHANNEL FUNCTIONAL TEST of channels affected by bypass operation. The total bypass function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by bypass operation.

4.3.1.1.3 The REACTOR TRIP SYSTEM RESPONSE TIME of each reactor trip function shall be demonstrated to be within its limit at least once per 18 months. Neutron detectors are exempt from response time testing. Each test shall include at least one channel per function such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific reactor trip function as shown in the "Total No. of Channels" column of Table 3.3-1.

TABLE 3.3-1

REACTOR PROTECTIVE INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1, 2 and *	1
2. Power Level - High	4	2(a)	3(f)	1, 2	2#
3. Reactor Coolant Flow - Low	4/SG	2(a)/SG	3/SG	1, 2 (e)	2#
4. Pressurizer Pressure - High	4	2	3	1, 2	2#
5. Containment Pressure - High	4	2	3	1, 2	2#
6. Steam Generator Pressure - Low	4/SG	2(b)/SG	3/SG	1, 2	2#
7. Steam Generator Water Level - Low	4/SG	2/SG	3/SG	1, 2	2#
8. Local Power Density - High	4	2(c)	3	1	2#
9. Thermal Margin/Low Pressure	4	2(a)	3	1, 2 (e)	2#
9a. Steam Generator Pressure Difference - High	4	2(a)	3	1, 2 (e)	2#
10. Loss of Turbine--Hydraulic Fluid Pressure - Low	4	2(c)	3	1	2#

TABLE 3.3-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
11. Wide Range Logarithmic Neutron Flux Monitor					
a. Startup and Operating-- Rate of Change of Power - High	4	2(d)	3	1, 2 and *	2#
b. Shutdown	4	0	2	3, 4, 5	3
12. Reactor Protection System Logic	4	2	4	1, 2*	4
13. Reactor Trip Breakers	4	2	4	1, 2*	4

TABLE NOTATION

* With the protective system trip breakers in the closed position and the CEA drive system capable of CEA withdrawal.

\# The provisions of Specification 3.0.4 are not applicable.

(a) Trip may be bypassed below 1% of RATED THERMAL POWER; bypass shall be automatically removed when Wide Range Logarithmic Neutron Flux power is $\geq$ 1% of RATED THERMAL POWER.

(b) Trip may be manually bypassed below 685 psig; bypass shall be automatically removed at or above 685 psig.

(c) Trip may be bypassed below 15% of RATED THERMAL POWER; bypass shall be automatically removed when Power Range Neutron Flux power is $\geq$ 15% of RATED THERMAL POWER.

(d) Trip may be bypassed below 10^{-4}% and above 15% of RATED THERMAL POWER; bypass shall be automatically removed when Wide Range Logarithmic Neutron Flux power is $\geq 10^{-4}$% and Power Range Neutron Flux power $\leq$ 15% of RATED THERMAL POWER.

(e) Deleted.

(f) There shall be at least two decades of overlap between the Wide Range Logarithmic Neutron Flux Monitoring Channels and the Power Range Neutron Flux Monitoring Channels.

ACTION STATEMENTS

ACTION 1 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours and/or open the protective system trip breakers.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in either the bypassed or tripped condition within 1 hour. For the purposes of testing and maintenance, the inoperable channel may be bypassed for up to 48 hours from time of initial loss of OPERABILITY; however, the inoperable channel shall then be either restored to OPERABLE status or placed in the tripped condition.

TABLE 3.3-1 (Continued)

ACTION STATEMENTS

b. Within one hour, all functional units receiving an input from the inoperable channel are also bypassed or tripped.

c. The Minimum Channels OPERABLE requirement is met; however, one additional channel may be bypassed for up to 48 hours while performing tests and maintenance on than channel provided the other inoperable channel is placed in the tripped condition.

ACTION 3 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, verify compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.1 or 3.1.1.2, as applicable, within 1 hour and at least once per 12 hours thereafter.

ACTION 4 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, be in HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 1 hour for surveillance testing per Specification 4.3.1.1.1.

DELETED

TABLE 4.3-1

REACTOR PROTECTIVE INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	S/U(1)	N.A.
2. Power Level - High				
a. Nuclear Power	S	D(2), M(3), Q(5)	M	1, 2
b. ΔT Power	S	D(4), Q	M	1
3. Reactor Coolant Flow - Low	S	R	M	1, 2
4. Pressurizer Pressure - High	S	R	M	1, 2
5. Containment Pressure - High	S	R	M	1, 2
6. Steam Generator Pressure - Low	S	R	M	1, 2
7. Steam Generator Water Level - Low	S	R	M	1, 2
8. Local Power Density - High	S	R	M	1
9. Thermal Margin/Low Pressure	S	R	M	1, 2
9a. Steam Generator Pressure Difference - High	S	R	M	1, 2
10. Loss of Turbine--Hydraulic Fluid Pressure - Low	N.A.	N.A.	S/U(1)	N.A.
11. Wide Range Logarithmic Neutron Flux Monitor	S	N.A.	S/U(1)	1, 2, 3, 4, 5 and *
12. Reactor Protection System Logic	N.A.	N.A.	M and S/U(1)	1, 2 and *
13. Reactor Trip Breakers	N.A.	N.A.	M	1, 2 and *

TABLE 4.3-1 (Continued)

TABLE NOTATION

* - With reactor trip breaker closed.

(1) - If not performed in previous 7 days.

(2) - Heat balance only, above 15% of RATED THERMAL POWER; adjust "Nuclear Power Calibrate" potentiometer to null "Nuclear Pwr - ΔT Pwr." During PHYSICS TESTS, these daily calibrations of nuclear power and ΔT power may be suspended provided these calibrations are performed upon reaching each major test power plateau and prior to proceeding to the next major test power plateau.

(3) - Above 15% of RATER THERMAL POWER, recalibrate the excore detectors which monitor the AXIAL SHAPE INDEX by using the incore detectors or restrict THERMAL POWER during subsequent operations to $\leq$ 90% of the maximum allowed THERMAL POWER level with the existing Reactor Coolant Pump combination.

(4) - Adjust "ΔT Pwr Calibrate" potentiometers to make ΔT power signals agree with calorimetric calculation.

(5) - Neutron detectors may be excluded from CHANNEL CALIBRATION.

3/4.3.2 ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2.1 The Engineered Safety Feature Actuation System (ESFAS) instrumentation channels and bypasses shown in Table 3.3-3 shall be OPERABLE with their trip setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-4.

APPLICABILITY: As shown in Table 3.3-3.

ACTION:

a. With an ESFAS instrumentation channel trip setpoint less conservative than the value shown in the Allowable Values column of Table 3.3-4, declare the channel inoperable and apply the applicable ACTION requirement of Table 3.3-3 until the channel is restored to OPERABLE status with the trip setpoint adjusted consistent with the Trip Setpoint value.

b. With an ESFAS instrumentation channel inoperable, take the ACTION shown in Table 3.3-3.

SURVEILLANCE REQUIREMENTS

4.3.2.1.1 Each ESFAS instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the modes and at the frequencies shown in Table 4.3-2.

4.3.2.1.2 The logic for the bypasses shall be demonstrated OPERABLE during the at power CHANNEL FUNCTIONAL TEST of channels affected by bypass operation. The total bypass function shall be demonstrated OPERABLE at least once per 18 months during CHANNEL CALIBRATION testing of each channel affected by bypass operation.

4.3.2.1.3 The ENGINEERED SAFETY FEATURES RESPONSE TIME of each ESFAS function shall be demonstrated to be within the limit at least once per 18 months. Each test shall include at least one channel per function such that all channels are tested at least once every N times 18 months where N is the total number of redundant channels in a specific ESF function as shown in the "Total No. of Channels" Column of Table 3.3-3.

TABLE 3.3-3

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. SAFETY INJECTION (SIAS)					
a. Manual (Trip Buttons)	2	1	2	1, 2, 3, 4	8
b. Containment Pressure – High	4	2	3	1, 2, 3	9#
c. Pressurizer Pressure – Low	4	2	3	1, 2, 3(a)	9#
2. CONTAINMENT SPRAY (CSAS)					
a. Manual (Trip Buttons)	2	1	2	1, 2, 3, 4	8
b. Containment Pressure – High-High	4	2(b)	3	1, 2, 3	10a#, 10b#, 10c
3. CONTAINMENT ISOLATION (CIS)					
a. Manual (Trip Buttons)	2	1	2	1, 2, 3, 4	8
b. Containment Pressure – High	4	2	3	1, 2, 3	9#
c. Containment Radiation – High	4	2	3	1, 2, 3, 4	9#
d. SIAS	(See Functional Unit 1 above)				
4. MAIN STEAM LINE ISOLATION (MSIS)					
a. Manual (Trip Buttons)	2/steam generator	1/steam generator	2/operating steam generator	1, 2, 3, 4	8
b. Steam Generator Pressure – Low	4/steam generator	2/steam generator	3/steam generator	1, 2, 3(c)	9#

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
5. CONTAINMENT SUMP RECIRCULATION (RAS)					
a. Manual RAS (Trip Buttons).	2	1	2	1, 2, 3, 4	8
b. Refueling Water Tank - Low	4	2	3	1, 2, 3	13
6. LOSS OF POWER					
a. 4.16 kv Emergency Bus Under-voltage (Loss of Voltage)	2/Bus	2/Bus	1/Bus	1, 2, 3	12
b. 4.16 kv Emergency Bus Under-voltage (Degraded Voltage)	2/Bus	2/Bus	1/Bus	1, 2, 3	12
c. 480 V Emergency Bus Under-voltage (Degraded Voltage)	2/Bus	2/Bus	1/Bus	1, 2, 3	12
7. AUXILIARY FEEDWATER (AFAS)					
a. Manual (Trip Buttons)	4/SG	2/SG	4/SG	1, 2, 3	11
b. Automatic Actuation Logic	4/SG	2/SG	3/SG	1, 2, 3	11
c. SG Level (1A/1B) - Low	4/SG	2/SG	3/SG	1, 2, 3	14a#, 14b#, 14c
8. AUXILIARY FEEDWATER ISOLATION					
a. SG 1A – SG 1B Differential Pressure	4/SG	2/SG	3/SG	1, 2, 3	14a#, 14b#, 14c
b. Feedwater Header 1A – 1B Differential Pressure	4/SG	2/SG	3/SG	1, 2, 3	14a#, 14c

TABLE 3.3-3 (Continued)

TABLE NOTATION

(a) Trip function may be bypassed in this MODE when pressurizer pressure is < 1725 psia; bypass shall be automatically removed when pressurizer pressure is ≥ 1725 psia.

(b) An SIAS signal is first necessary to enable CSAS logic.

(c) Trip function may be bypassed in this MODE below 685 psig; bypass shall be automatically removed at or above 685 psig.

The provisions of Specification 3.0.4 are not applicable.

ACTION STATEMENTS

ACTION 8 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION 9 - With the number of OPERABLE channels one less than the Total Number of Channels, operation may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in either the bypassed or tripped condition within 1 hour. For the purposes of testing and maintenance, the inoperable channel may be bypassed for up to 48 hours from time of initial loss of OPERABILITY; however, the inoperable channel shall then be either restored to OPERABLE status or placed in the tripped condition.

b. Within one hour, all functional units receiving an input from the inoperable channel are also bypassed or tripped.

c. The Minimum Channels OPERABLE requirement is met; however, one additional channel may be bypassed for up to 48 hours while performing tests and maintenance on that channel provided the other inoperable channel is placed in the tripped condition.

TABLE 3.3-3 (continued)

TABLE NOTATION

ACTION 10 - With the number of OPERABLE channels one less than the Total Number of Channels, operation may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the bypassed or tripped condition and the Minimum Channels OPERABLE requirement is demonstrated within 1 hour. If the inoperable channel can not be restored to OPERABLE status within 48 hours, then place the inoperable channel in the tripped condition.

b. Within 1 hour, all functional units receiving an input from the inoperable channel are also bypassed or tripped.

c. With the number of channels OPERABLE one less than the Minimum Channels OPERABLE, operation may proceed provided one of the inoperable channels has been bypassed and the other inoperable channel has been placed in the tripped condition within 1 hour. Restore one of the inoperable channels to OPERABLE status within 48 hours or be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

ACTION 11 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channels to OPERABLE status within 48 hours or be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

ACTION 12 - With the number of OPERABLE Channels one less than the Total Number of Channels, operation may proceed until performance of the next required CHANNEL FUNCTIONAL TEST provided the inoperable channel is placed in the tripped condition within 1 hour.

TABLE 3.3-3 (continued)

TABLE NOTATION

ACTION 13 - With the number of OPERABLE channels one less than the Total Number of Channels, operation may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in either the bypassed or tripped condition within 1 hour. If OPERABILITY can not be restored within 48 hours, be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. The Minimum Channels OPERABLE requirement is met; however, one additional channel may be bypassed for up to 2 hours while performing tests and maintenance on that channel provided the other inoperable channel is placed in the tripped condition.

ACTION 14 - With the number of channels OPERABLE one less than the Total Number of Channels, operation may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in either the bypassed or tripped condition within 1 hour. If an inoperable SG level channel can not be restored to OPERABLE status within 48 hours, then AFAS-1 or AFAS-2 as applicable in the inoperable channel shall be placed in the bypassed condition. If an inoperable SG DP or FW Header DP channel can not be restored to OPERABLE status within 48 hours, then both AFAS-1 and AFAS-2 in the inoperable channel shall be placed in the bypassed condition. The channel shall be returned to OPERABLE status no later than during the next COLD SHUTDOWN.

b. Within 1 hour, all functional units receiving an input from the inoperable channel are also bypassed or tripped.

c. With the number of channels OPERABLE one less than the Minimum Channels OPERABLE, operation may proceed provided one of the inoperable channels has been bypassed and the other inoperable channel has been placed in the tripped condition within 1 hour. Restore one of the inoperable channels to OPERABLE status within 48 hours or be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

TABLE 3.3-4

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. SAFETY INJECTION (SIAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	≤ 5 psig	≤ 5 psig
c. Pressurizer Pressure - Low	≥ 1600 psia	≥ 1600 psia
2. CONTAINMENT SPRAY (CSAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure -- High-High	≤ 10 psig	≤ 10 psig
3. CONTAINMENT ISOLATION (CIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	≤ 5 psig	≤ 5 psig
c. Containment Radiation - High	≤ 10 R/hr	≤ 10 R/hr
d. SIAS	----- (See FUNCTIONAL UNIT 1 above) ----	
4. MAIN STEAM LINE ISOLATION (MSIS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator Pressure - Low	≥ 585 psig	≥ 585 psig
5. CONTAINMENT SUMP RECIRCULATION (RAS)		
a. Manual RAS (Trip Buttons)	Not Applicable	Not Applicable
b. Refueling Water Tank - Low	48 inches above tank bottom	48 inches above tank bottom

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
6. LOSS OF POWER		
a. 4.16 kv Emergency Bus Undervoltage (Loss of Voltage)	≥ 2900 volts with a 1 ± .5 second time delay	≥ 2900 volts with a 1 ± .5 second time delay
b. 4.16 kv Emergency Bus Undervoltage (Degraded Voltage)	≥ 3831 volts with a 18 ± 2 second time delay	≥ 3831 volts with a 18 ± 2 second time delay
c. 480 volts Emergency Bus Undervoltage (Degraded Voltage)	≥ 415 volts with a ≤ 9 second time delay	≥ 415 volts with a ≤ 9 second time delay
7. AUXILIARY FEEDWATER (AFAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. SG 1A & 1B Level Low	≥ 19.0%	≥ 18.0 %
8. AUXILIARY FEEDWATER ISOLATION		
a. Steam Generator ΔP – High	≤ 275 psid	89.2 to 281 psid
b. Feedwater Header High ΔP	≤ 150.0 psid	56.0 to 157.5 psid

DELETED

DELETED

TABLE 4.3-2

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. SAFETY INJECTION (SIAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Containment Pressure - High	S	R	M	1, 2, 3
c. Pressurizer Pressure - Low	S	R	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
2. CONTAINMENT SPRAY (CSAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Containment Pressure -- High - High	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
3. CONTAINMENT ISOLATION (CIS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Containment Pressure - High	S	R	M	1, 2, 3
c. Containment Radiation - High	S	R	M	1, 2, 3, 4
d. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
e. SIAS	N.A.	N.A.	R	N.A.
4. MAIN STEAM LINE ISOLATION (MSIS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Steam Generator Pressure - Low	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3
5. CONTAINMENT SUMP RECIRCULATION (RAS)				
a. Manual RAS (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Refueling Water Storage Tank - Low	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1)	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
6. LOSS OF POWER				
a. 4.16 kv Emergency Bus Under-voltage (Loss of Voltage)	S	R	M	1, 2, 3
b. 4.16 kv Emergency Bus Under-voltage (Degraded Voltage)	S	R	M	1, 2, 3
c. 480 V Emergency Bus Under-voltage (Degraded Voltage)	S	R	M	1, 2, 3
7. AUXILIARY FEEDWATER (AFAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	1, 2, 3
b. SG Level (A/B) - Low	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M	1, 2, 3
8. AUXILIARY FEEDWATER ISOLATION				
a. SG Level (A/B) - Low and SG Differential Pressure (BtoA/AtoB) - High	N.A.	R	M	1, 2, 3
b. SG Level (A/B) - Low and Feedwater Header Differential Pressure (BtoA/AtoB) - High	N.A.	R	M	1, 2, 3

TABLE 4.3-2 (Continued)

TABLE NOTATION

(1) The logic circuits shall be tested manually at least once per 31 days.

INSTRUMENTATION

3/4.3.3 MONITORING INSTRUMENTATION

RADIATION MONITORING

LIMITING CONDITION FOR OPERATION

3.3.3.1 The radiation monitoring instrumentation channels shown in Table 3.3-6 shall be OPERABLE with their alarm/trip setpoints within the specified limits.

APPLICABILITY: As shown in Table 3.3-6.

ACTION:

a. With a radiation monitoring channel alarm/trip setpoint exceeding the value shown in Table 3.3-6, adjust the setpoint to within the limit within 4 hours or declare the channel inoperable.

b. With one or more radiation monitoring channels inoperable, take the ACTION shown in Table 3.3-6.

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.1 Each radiation monitoring instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operations during the modes and at the frequencies shown in Table 4.3-3.

4.3.3.2 At lease once per 18 months, each Control Room Isolation radiation monitoring instrumentation channel shall be demonstrated OPERABLE by verifying that the response time of the channel is within limits.

TABLE 3.3-6

RADIATION MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
1. AREA MONITORS					
a. Fuel Storage Pool Area	1	*	$\leq$ 15 mR/hr	$10^{-1} - 10^{4}$ mR/hr	13
b. Containment (CIS)	3	****	$\leq$ 90 mR/hr	$1 - 10^{5}$ mR/hr	16
c. Containment Area – Hi Range	1	1, 2, 3, & 4	$\leq$ 10 R/hr	$1 - 10^{7}$ R/hr	15
d. Control Room Isolation	1 per intake	ALL MODES	$\leq$ 320 cpm	$10 - 10^{7}$ cpm	17
2. PROCESS MONITORS					
a. Containment					
i. Gaseous Activity RCS Leakage Detection	1	1, 2, 3 & 4	Not Applicable	$10 - 10^{6}$ cpm	14
ii. Particulate Activity RCS Leakage Detection	1	1, 2, 3 & 4	Not Applicable	$10 - 10^{6}$ cpm	14
b. Fuel Storage Pool Area Ventilation System					
i. Gaseous Activity	1	**	***	$10^{-7} - 10^{5}$ µCi/cc	12
ii. Particulate Activity	1	**	***	$1 - 10^{6}$ cpm	12

* With fuel in the storage pool or building.

** With recently irradiated fuel in the storage pool.

*** The Alarm Setpoints are determined and set in accordance with requirements of the Offsite Dose Calculation Manual.

**** During movement of recently irradiated fuel assemblies within containment.

TABLE 3.3-6 (Continued)

RADIATION MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	MEASUREMENT RANGE	ACTION
2. PROCESS MONITORS (Continued)					
c. Noble Gas Effluent Monitors					
i. Radwaste Building Exhaust System (Plant Vent Exhaust Monitor)	1	1, 2, 3 & 4	***	$10^{-7} - 10^{5}$ µCi/cc	15
ii. Steam Generator Blowdown Treatment Facility Building Exhaust System	1	1, 2, 3 & 4	***	$10^{-7} - 10^{-2}$ µCi/cc	15
iii. Steam Safety Valve Discharge	1/Header	1, 2, 3 & 4	***	$10^{-1} - 10^{3}$ µCi/cc	15
iv. ECCS Exhaust	1/Train	1, 2, 3 & 4	***	$10^{-7} - 10^{5}$ µCi/cc	15

*** The Alarm Setpoints are determined and set in accordance with requirements of the Offsite Dose Calculation Manual.

TABLE 3.3-6 (Continued)

TABLE NOTATION

ACTION 12 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.9.12.

ACTION 13 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, perform area surveys of the monitored area with portable monitoring instrumentation at least once per 24 hours.

ACTION 14 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.4.6.1.

ACTION 15 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, either restore the inoperable Channel(s) to OPERABLE status within 72 hours, or:

1) Initiate the preplanned alternate method of monitoring the appropriate parameter(s),and

2) Prepare and submit a Special Report to the Commission pursuant to Specification6.9.2 within 14 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

ACTION 16 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirements, comply with the ACTION requirements of Specification 3.9.9.

ACTION 17 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, within 1 hour initiate and maintain operation of the control room emergency ventilation system in the recirculation mode of operation.

TABLE 4.3-3

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. AREA MONITORS				
a. Fuel Storage Pool Area	S	R	M	*
b. Containment (CIS)	S	R	M	***
c. Containment Area – High Range	S	R	M	1, 2, 3 & 4
d. Control Room Isolation	S	R	M	All Modes
2. PROCESS MONITORS				
a. Fuel Storage Pool Area – Ventilation System				
i. Gaseous Activity	S	R	M	**
ii. Particulate Activity	S	R	M	**
b. Containment				
i. Gaseous Activity RCS Leakage Detection	S	R	M	1, 2, 3 & 4
ii. Particulate Activity RCS Leakage Detection	S	R	M	1, 2, 3 & 4

* With fuel in the storage pool or building.
** With irradiated fuel in the storage pool.
*** During movement of recently irradiated fuel within containment.

TABLE 4.3-3 (Continued)

RADIATION MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE IS REQUIRED
2. PROCESS MONITORS (Continued)				
c. Noble Gas Effluent Monitors				
i. Radwaste Building Exhaust System Plant Vent Monitor	S	R	M	1, 2, 3 & 4
ii. Steam Generator Blowdown Treatment Building Exhaust System	S	R	M	1, 2, 3 & 4
iii. Steam Safety Valve Discharge	S	R	M	1, 2, 3 & 4
iv. ECCS Exhaust	S	R	M	1, 2, 3 & 4

PAGE 3/4 3-26 (ORIGINAL) HAS BEEN DELETED FROM THE TECHNICAL SPECIFICATIONS. THE NEXT PAGE IS 3/4 3-27.

Pages 3/4 3-28 through 3/4 3-32 have been DELETED.

The next page is 3/4 3-33.

INSTRUMENTATION

REMOTE SHUTDOWN INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.5 The remote shutdown monitoring instrumentation channels shown in Table 3.3-9 shall be OPERABLE with readouts displayed external to the control room.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With the number of OPERABLE remote shutdown monitoring channels less than required by Table 3.3-9, either:

a. Restore the inoperable channel to OPERABLE status within 30 days, or

b. Be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.3.3.5 Each remote shutdown monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3-6.

TABLE 3.3-9

REMOTE SHUTDOWN MONITORING INSTRUMENTATION

INSTRUMENT	READOUT LOCATION	MEASUREMENT RANGE	MINIMUM CHANNELS OPERABLE
1. Reactor Trip Breaker Indication	SWGR	OPEN-CLOSE	1/trip breaker
2. Pressurizer Pressure	Hot Shutdown Panel	1500-2500 psia	1
3. Pressurizer Level	Hot Shutdown Panel	0-100%	1
4. Main Steam Pressure	Hot Shutdown Panel	0-1200 psig	1/steam generator
5. Steam Generator Level	Hot Shutdown Panel	0-100%	1/steam generator
6. Cold Leg Temperature	Hot Shutdown Panel	0-600°F	1

TABLE 4.3-6

REMOTE SHUTDOWN MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Reactor Trip Breaker Indication	M	N.A.
2. Pressurizer Pressure	M	R
3. Pressurizer Level	M	R
4. Steam Generator Level	M	R
5. Main Steam Pressure	M	R
6. Cold Leg Temperature	M	R

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Pages 3/4 3-38 through 3/4 3-40 (Amendment No. 115) have been deleted from the Technical Specifications. The next page is 3/4 3-41.

INSTRUMENTATION

ACCIDENT MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.8 The accident monitoring instrumentation channels shown in Table 3.3-11 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. Actions per Table 3.3-11.

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.8 Each accident monitoring instrumentation channel shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 4.3-7.

TABLE 3.3-11

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	TOTAL NO. OF CHANNELS	MINIMUM CHANNELS OPERABLE	ACTION
1. Pressurizer Water Level	2	1	1, 6
2. Auxiliary Feedwater Flow Rate	1/pump	1/pump	7
3. RCS Subcooling Margin Monitor	2	1	1, 6
4. PORV Position Indicator Acoustic Flow Monitor	1/valve	1/valve	2
5. PORV Block Valve Position Indicator	1/valve	1/valve	2
6. Safety Valve Position Indicator	1/valve	1/valve	3
7. Incore thermocouples	4/core quadrant	2/core quadrant	1, 6
8. Containment Sump Water Level (Narrow Range)	1*	1*	4, 5
9. Containment Sump Water Level (Wide Range)	2	1	4, 5
10. Reactor Vessel Level Monitoring System	2**	1**	4, 5
11. Containment Pressure	2	1	1, 6

* The non-safety grade containment sump water level instrument may be substituted.

** Definition of OPERABLE: A channel is composed of eight (8) sensors in a probe, of which four (4) sensors must be OPERABLE.

TABLE 3.3-11 (continued)

ACTION STATEMENTS

ACTION 1 - With the number of OPERABLE channels less than the Total No. of Channels shown in Table 3.3-11, either restore the inoperable channel(s) to OPERABLE status within 30 days or be in HOT STANDBY in 6 hours and HOT SHUTDOWN in 12 hours.

ACTION 2 - With position indication inoperable, restore the inoperable indicator to OPERABLE status or close the associated PORV block valve and remove power from its operator within 48 hours or be in HOT STANDBY in 6 hours and HOT SHUTDOWN in 12 hours.

ACTION 3 - With any individual valve position indicator inoperable, obtain quench tank temperature, level and pressure information once per shift to determine valve position.

ACTION 4 - With the number of OPERABLE Channels one less than the Total Number of Channels shown in Table 3.3-11, either restore the inoperable channel to OPERABLE status within 7 days if repairs are feasible without shutting down or prepare and submit a Special Report to the Commission pursuant to the specification 6.9.2 within 30 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status.

ACTION 5 - With the number of OPERABLE Channels less than the Minimum Channels OPERABLE requirements of Table 3.3-11, either restore the inoperable channel(s) to OPERABLE status within 48 hours if repairs are feasible without shutting down or:

1. Initiate an alternate method of monitoring the reactor vessel inventory; and

2. Prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 30 days following the event outlining the action taken, the cause of the inoperability and the plans and schedule for restoring the system to OPERABLE status; and

3. Restore the Channel to OPERABLE status at the next scheduled refueling.

ACTION 6 - With the number of OPERABLE accident monitoring channels less than the Minimum Channels OPERABLE requirements of Table 3.3-11, either restore the inoperable channel(s) to OPERABLE status within 48 hours or be in HOT STANDBY in 6 hours and HOT SHUTDOWN in 12 hours.

ACTION 7 - With the number of OPERABLE accident monitoring channels less than the Minimum Channels OPERABLE requirements of Table 3.3-11, either restore the inoperable channel(s) to OPERABLE status within 72 hours or be in HOT STANDBY in 6 hours and HOT SHUTDOWN in 12 hours.

TABLE 4.3-7

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
1. Pressurizer Water Level	M	R
2. Auxiliary Feedwater Flow Rate	M	R
3. Reactor Coolant System Subcooling Margin Monitor	M	R
4. PORV Position Indicator	M	R
5. PORV Block Valve Position Indicator	M	R
6. Safety Valve Position Indicator	M	R
7. Incore Thermocouples	M	R
8. Containment Sump Water Level (Narrow Range)	M	R
9. Containment Sump Water Level	M	R
10. Reactor Vessel Level Monitoring System	M	R
11. Containment Pressure	M	R

3/4.4 REACTOR COOLANT SYSTEM

REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

STARTUP AND POWER OPERATION

LIMITING CONDITION FOR OPERATION

3.4.1.1 Both reactor coolant loops and both reactor coolant pumps in each loop shall be in operation.

APPLICABILITY: MODES 1 and 2.

ACTION:

With less than the above required reactor coolant pumps in operation, be in at least HOT STANDBY within 1 hour.

SURVEILLANCE REQUIREMENTS

4.4.1.1 The above required reactor coolant loops shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

REACTOR COOLANT SYSTEM

HOT STANDBY

LIMITING CONDITION FOR OPERATION

3.4.1.2 The reactor coolant loops listed below shall be OPERABLE and at least one of these reactor coolant loops shall be in operation.*

a. Reactor Coolant Loop A and its associated steam generator and at least one associated reactor coolant pump.

b. Reactor Coolant Loop B and its associated steam generator and at least one associated reactor coolant pump.

APPLICABILITY: MODE 3.

ACTION:

a. With less than the above required reactor coolant loops OPERABLE, restore the required loops to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. With no reactor coolant loop in operation, suspend operations that would cause introduction into the RCS, coolant with boron concentration less than required to meet SHUTDOWN MARGIN of Technical Specification 3.1.1.1 and within one (1) hour initiate corrective action to return the required reactor coolant loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.2.1 At least the above required reactor coolant pumps, if not in operation, shall be determined to be OPERABLE once per 7 days by verifying correct breaker alignments and indicated power availability.

4.4.1.2.2 At least one reactor coolant loop shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

4.4.1.2.3 The required steam generators shall be determined OPERABLE by verifying the secondary side water level to be $\geq$ 10% of narrow range indication at least once per 12 hours.

* All reactor coolant pumps may be de-energized for up to 1 hour provided (1) no operations are permitted that would cause introduction into the RCS, coolant with boron concentration less than required to meet the SHUTDOWN MARGIN of Technical Specification 3.1.1.1 and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

REACTOR COOLANT SYSTEM

HOT SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.1.3 At least two of the loops listed below shall be OPERABLE and at least one reactor coolant or shutdown cooling loop shall be in operation.*

a. Reactor Coolant Loop A and its associated steam generator and at least one associated reactor coolant pump,

b. Reactor Coolant Loop B and its associated steam generator and at least one associated reactor coolant pump,

c. Shutdown Cooling Loop A,

d. Shutdown Cooling Loop B.

APPLICABILITY: MODE 4.

ACTION:

a. With less than the above required reactor coolant or shutdown cooling loops OPERABLE, within one (1) hour initiate corrective action to return the required loops to OPERABLE status. If the remaining OPERABLE loop is a shutdown cooling loop, be in COLD SHUTDOWN within 30 hours.

b. With no reactor coolant or shutdown cooling loop in operation, suspend operations that would cause introduction into the RCS, coolant with boron concentration less than required to meet SHUTDOWN MARGIN of Technical Specification 3.1.1.1 and within one (1) hour initiate corrective action to return the required reactor coolant loop to operation.

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* All reactor coolant pumps and shutdown cooling pumps may be de-energized for up to 1 hour provided (1) no operations are permitted that would cause introduction into the RCS, coolant with boron concentration less than required to meet the SHUTDOWN MARGIN of Technical Specification 3.1.1.1 and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

SURVEILLANCE REQUIREMENTS

4.4.1.3.1 The required reactor coolant pump(s), if not in operation, shall be determined to be OPERABLE once per 7 days by verifying correct breaker alignments and indicated power availability.

4.4.1.3.2 The required steam generator(s) shall be determined OPERABLE by verifying the secondary side water level to be $\geq$ 10% of narrow range indication at least once per 12 hours.

4.4.1.3.3 At least one reactor coolant or shutdown cooling loop shall be verified to be in operation and circulating reactor coolant at least once per 12 hours.

REACTOR COOLANT SYSTEM

COLD SHUTDOWN – LOOPS FILLED

LIMITING CONDITION FOR OPERATION

3.4.1.4.1 At least one shutdown cooling loop shall be OPERABLE and in operation* and either:

a. One additional shutdown cooling loop shall be OPERABLE#, or

b. The secondary side water level of at least two steam generators shall be greater than 10% of narrow range indication.

APPLICABILITY: MODE 5 with reactor coolant loops filled##.

ACTION:

a. With less than the above required loops OPERABLE or with less than the required steam generator level, within one (1) hour initiate corrective action to return the required loops to OPERABLE status or to restore the required level.

b. With no shutdown cooling loop in operation, suspend operations that would cause introduction into the RCS, coolant with boron concentration less than required to meet SHUTDOWN MARGIN of Technical Specification 3.1.1.2 and within one (1) hour initiate corrective action to return the required shutdown loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.4.1.1 The secondary side water level of at least two steam generators when required shall be determined to be within limits at least once per 12 hours.

4.4.1.4.1.2 At least one shutdown cooling loop shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

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* The shutdown cooling pump may be de-energized for up to 1 hour provided 1) no operations are permitted that would cause introduction into the RCS, coolant with boron concentration less than required to meet the SHUTDOWN MARGIN of Technical Specification 3.1.1.2 and 2) core outlet temperature is maintained at least 10°F below saturation temperature.

One shutdown cooling loop may be inoperable for up to 2 hours for surveillance testing provided the other shutdown cooling loop is OPERABLE and in operation.

A reactor coolant pump shall not be started with two idle loops unless the secondary water temperature of each steam generator is less than 30°F above each of the Reactor Coolant System cold leg temperatures.

COLD SHUTDOWN – LOOPS NOT FILLED

LIMITING CONDITION FOR OPERATION

3.4.1.4.2 Two shutdown cooling loops shall be OPERABLE# and at least one shutdown cooling loop shall be in operation*.

APPLICABILITY: MODE 5 with reactor coolant loops not filled.

ACTION:

a. With less than the above required loops OPERABLE, within one (1) hour initiate corrective action to return the required loops to OPERABLE status.

b. With no shutdown cooling loop in operation, suspend operations that would cause introduction into the RCS, coolant with boron concentration less than required to meet SHUTDOWN MARGIN of Technical Specification 3.1.1.2 and within one (1) hour initiate corrective action to return the required shutdown cooling loop to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.4.2 At least one shutdown cooling loop shall be determined to be in operation and circulating reactor coolant at least once per 12 hours.

One shutdown cooling loop may be inoperable for up to 2 hours for surveillance testing provided the other shutdown cooling loop is OPERABLE and in operation.

* The shutdown cooling pump may be de-energized for up to 1 hour provided 1) no operations are permitted that would cause introduction into the RCS, coolant with boron concentration less than required to meet the SHUTDOWN MARGIN of Technical Specification 3.1.1.2 and 2) core outlet temperature is maintained at least 10°F below saturation temperature.

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REACTOR COOLANT SYSTEM

SAFETY VALVES - OPERATING

LIMITING CONDITION FOR OPERATION

3.4.3 All pressurizer code safety valves shall be OPERABLE with a lift setting of $\geq$ 2422.8 psig and $\leq$ 2560.3 psig.

APPLICABILITY: MODES 1, 2, 3, and 4 with all RCS cold leg temperatures > 281°F.

ACTION:

a. With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in HOT STANDBY within 6 hours and in HOT SHUTDOWN within the next 6 hours.

b. With two or more pressurizer code safety valves inoperable, be in HOT STANDBY within 6 hours and in HOT SHUTDOWN with all RCS cold leg temperatures $\leq$ 281°F within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.3 Verify each pressurizer code safety valves is OPERABLE in accordance with the Inservice Testing Program. Following testing, as-left lift settings shall be within +/- 1% of 2500 psia.

PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.4 The pressurizer shall be OPERABLE with a steam bubble, and with at least 150 kw of pressurizer heaters capable of being supplied by emergency power.

APPLICABILITY: MODES 1 and 2.

ACTION:

With the pressurizer inoperable, be in at least HOT STANDBY with the reactor trip breakers open within 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.4 In accordance with 4.8.1.1.2.

REACTOR COOLANT SYSTEM

STEAM GENERATOR (SG) TUBE INTEGRITY

LIMITING CONDITION FOR OPERATION

3.4.5 SG tube integrity shall be maintained

AND

All SG tubes satisfying the tube repair criteria shall be plugged in accordance with the SG Program.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION: *

a. With one or more SG tubes satisfying the tube repair criteria and not plugged in accordance with the Steam Generator Program;

1. Within 7 days verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection, and

2. Plug the affected tube(s) in accordance with the Steam Generator Program prior to entering HOT SHUTDOWN following the next refueling outage or SG tube inspection.

b. With the requirements and associated allowable outage time of Action a above not met or SG tube integrity not maintained, be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.5.1 Verify SG tube integrity in accordance with the Steam Generator Program.

4.4.5.2 Verify that each inspected SG tube that satisfies the tube repair criteria is plugged in accordance with the Steam Generator Program prior to entering HOT SHUTDOWN following a SG tube inspection.

* Separate Action entry is allowed for each SG tube.

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REACTOR COOLANT SYSTEM

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.6.1 The following RCS leakage detection systems will be OPERABLE:

a. The reactor cavity sump inlet flow monitoring system; and

b. One containment atmosphere radioactivity monitor (gaseous or particulate).

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With the required reactor cavity sump inlet flow monitoring system inoperable, perform a RCS water inventory balance at least once per 24* hours and restore the sump inlet flow monitoring system to OPERABLE status within 30 days; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With the required radioactivity monitor inoperable, analyze grab samples of the containment atmosphere or perform a RCS water inventory balance at least once per 24* hours, and restore the required radioactivity monitor to OPERABLE status within 30 days; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With all required monitors inoperable, enter LCO 3.0.3 immediately.

d. The provisions of Specification 3.0.4 are not applicable if at least one of the required monitors is OPERABLE.

SURVEILLANCE REQUIREMENTS

4.4.6.1 The RCS leakage detection instruments shall be demonstrated OPERABLE by:

a. Performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION of the required containment atmosphere radioactivity monitor at the frequencies specified in Table 4.3-3.

b. Performance of the CHANNEL CALIBRATION of the required reactor cavity sump inlet flow monitoring system at least once per 18 months.

* Not required to be performed until 12 hours after establishment of steady state operation.

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REACTOR COOLANT SYSTEM

REACTOR COOLANT SYSTEM LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.6.2 Reactor Coolant System operational leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 GPM UNIDENTIFIED LEAKAGE,

c. 150 gallons per day primary-to-secondary leakage through any one steam generator (SG),

d. 10 GPM IDENTIFIED LEAKAGE from the Reactor Coolant System, and.

e. Leakage as specified in Table 3.4.6-1 for each Reactor Coolant System Pressure Isolation Valve identified in Table 3.4.6-1.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, or with primary-to-secondary leakage not within limit, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System operational leakage greater than any one of the above limits, excluding primary-to-secondary leakage, PRESSURE BOUNDARY LEAKAGE, and Reactor Coolant System Pressure Isolation Valve leakage, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With any Reactor Coolant System Pressure Isolation Valve leakage greater than the limit in 3.4.6.2.e above reactor operation may continue provided that at least two valves, including check valves, in each high pressure line having a non-functional valve are in and remain in the mode corresponding to the isolated condition. Motor operated valves shall be placed in the closed position, and power supplies deenergized. (Note, however, that this may lead to ACTION requirements for systems involved.) Otherwise, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.2 Reactor Coolant System operational leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the containment atmosphere gaseous and particulate radioactivity at least once per 12 hours.

REACTOR COOLANT SYSTEM

REACTOR COOLANT SYSTEM LEAKAGE

SURVEILLANCE REQUIREMENTS (Continued)

b. Monitoring the containment sump inventory and discharge at least once per 12 hours,

c. *Performance of a Reactor Coolant System water inventory balance at least once per 72 hours except when operating in the shutdown cooling mode,

d. Monitoring the reactor head flange leakoff system at least once per 24 hours, and

e. Verifying each Reactor Coolant System Pressure Isolation Valve leakage (Table 3.4.6-1) to be within limits:

   1. Prior to entering MODE 2 after refueling,

   2. Prior to entering MODE 2, whenever the plant has been in COLD SHUTDOWN for 7 days or more if leakage testing has not been performed in the previous 9 months,

   3. Prior to returning the valve to service following maintenance, repair or replacement work on the valve.

   4. The provision of Specification 4.0.4 is not applicable for entry into MODE 3 or 4.

f. Whenever integrity of a pressure isolation valve listed in Table 3.4.6-1 cannot be demonstrated the integrity of the remaining check valve in each high pressure line having a leaking valve shall be determined and recorded daily. In addition, the position of one other valve located in each high pressure line having a leaking valve shall be recorded daily; and

g. Primary-to-secondary leakage shall be verified ≤150 gallons per day through any one steam generator at least once per 72 hours.**

* Not required to be performed until 12 hours after establishment of steady state operation. Not applicable to primary-to-secondary leakage.

** Not required to be performed until 12 hours after establishment of steady state operation.

TABLE 3.4.6-1

PRIMARY COOLANT SYSTEM PRESSURE ISOLATION VALVES

Check Valve No.
V3227
V3123
V3217
V3113
V3237
V3133
V3247
V3143
V3124
V3114
V3134
V3144

NOTES

(a) Maximum Allowable Leakage (each valve):

1. Leakage rates less than or equal to 1.0 gpm are acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between previous measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are unacceptable.

(b) To satisy ALARA requirements, leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating valve compliance with the leakage criteria.

(c) Mimimum test differential pressure shall not be less than 150 psid.

CHEMISTRY

LIMITING CONDITION FOR OPERATION

3.4.7 The Reactor Coolant System chemistry shall be maintained within the limits specified in Table 3.4-1.

APPLICABILITY: ALL MODES.

ACTION:

MODES 1, 2, 3 and 4

a. With any one or more chemistry parameter in excess of its Steady State Limit but within its Transient Limit, restore the parameter to within its Steady State Limit within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any one or more chemistry parameter in excess of its Transient Limit, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

MODES 5 and 6

With the concentration of either chloride or fluoride in the Reactor Coolant System in excess of its Steady State Limit for more than 24 hours or in excess of its Transient Limit, reduce the pressurizer pressure to $\leq$ 500 psia, if applicable, and perform an analysis to determine the effects of the out-of-limit condition on the structural integrity of the Reactor Coolant System; determine that the Reactor Coolant System remains acceptable for continued operations prior to increasing the pressurizer pressure above 500 psia or prior to proceeding to MODE 4.

SURVEILLANCE REQUIREMENTS

4.4.7 The Reactor Coolant System chemistry shall be determined to be within the limits by analysis of those parameters at the frequencies specified in Table 4.4-3.

TABLE 3.4-1

REACTOR COOLANT SYSTEM

CHEMISTRY LIMITS

PARAMETER	STEADY STATE LIMIT	TRANSIENT LIMIT
DISSOLVED OXYGEN	$\leq$ 0.10 ppm*	$\leq$ 1.00 ppm*
CHLORIDE	$\leq$ 0.15 ppm	$\leq$ 1.50 ppm
FLUORIDE	$\leq$ 0.10 ppm	$\leq$ 1.00 ppm

*Limit not applicable with $T_{avg} \leq 250°F$.

TABLE 4.4-3

REACTOR COOLANT SYSTEM

CHEMISTRY LIMITS SURVEILLANCE REQUIREMENTS

PARAMETER	MINIMUM SAMPLING FREQUENCIES	MAXIMUM TIME BETWEEN SAMPLES
DISSOLVED OXYGEN	3 times per 7 days*	72 hours
CHLORIDE	3 times per 7 days	72 hours
FLUORIDE	3 times per 7 days	72 hours

* Not required with $T_{avg} \leq 250°F$.

LIMITING CONDITION FOR OPERATION

3.4.8 The specific activity of the primary coolant shall be limited to:

a. $\leq$ 1.0 μCi/gram DOSE EQUIVALENT I-131, and

b. $\leq 100/\bar{E}$ μCi/gram.

APPLICABILITY: MODES 1, 2, 3, 4 and 5.

ACTION:

MODES 1, 2 and 3*:

a. With the specific activity of the primary coolant >1.0 μCi/gram DOSE EQUIVALENT I-131 for more than 100 hours during one continuous time interval or exceeding the limit line shown on Figure 3.4-1, be in HOT STANDBY with T_{avg} <500°F within 6 hours.

b. With the specific activity of the primary coolant $>100/\bar{E}$ μCi/gram, be in HOT STANDBY with T_{avg} <500°F within 6 hours.

MODES 1, 2, 3, 4 and 5:

With the specific activity of the primary coolant >1.0 μCi/gram DOSE EQUIVALENT I-131 or $>100/\bar{E}$ μCi/gram, perform the sampling and analysis requirement of item 4 a) of Table 4.4-4 until the specific activity of the primary coolant is restored to within its limits.

SURVEILLANCE REQUIREMENTS

4.4.8 The specific activity of the primary coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-4.

*With $T_{avg} \geq 500°F$.

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TABLE 4.4-4

PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	MINIMUM FREQUENCY	MODES IN WHICH SAMPLE AND ANALYSIS REQUIRED
1. Gross Activity Determination	3 times per 7 days with a maximum time of 72 hours between samples	1, 2, 3 and 4
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	1 per 14 days	1
3. Radiochemical for $\bar{E}$ Determination	1 per 6 months	1[*]
4. Isotopic Analysis for Iodine Including I-131, I-133, and I-135	a) Once per 4 hours, whenever the DOSE EQUIVALENT I-131 exceeds 1.0 μCi/gram, and	1[#], 2[#], 3[#], 4[#] and 5[#]
	b) One sample between 2 and 6 hours following a THERMAL POWER change exceeding 15 percent of the RATED THERMAL POWER within a one hour period.	1, 2, 3

[#] Until the specific activity of the primary coolant system is restored within its limits.

[*] After at least 2 EFPD and at least 20 days since the last shutdown of longer than 48 hours.

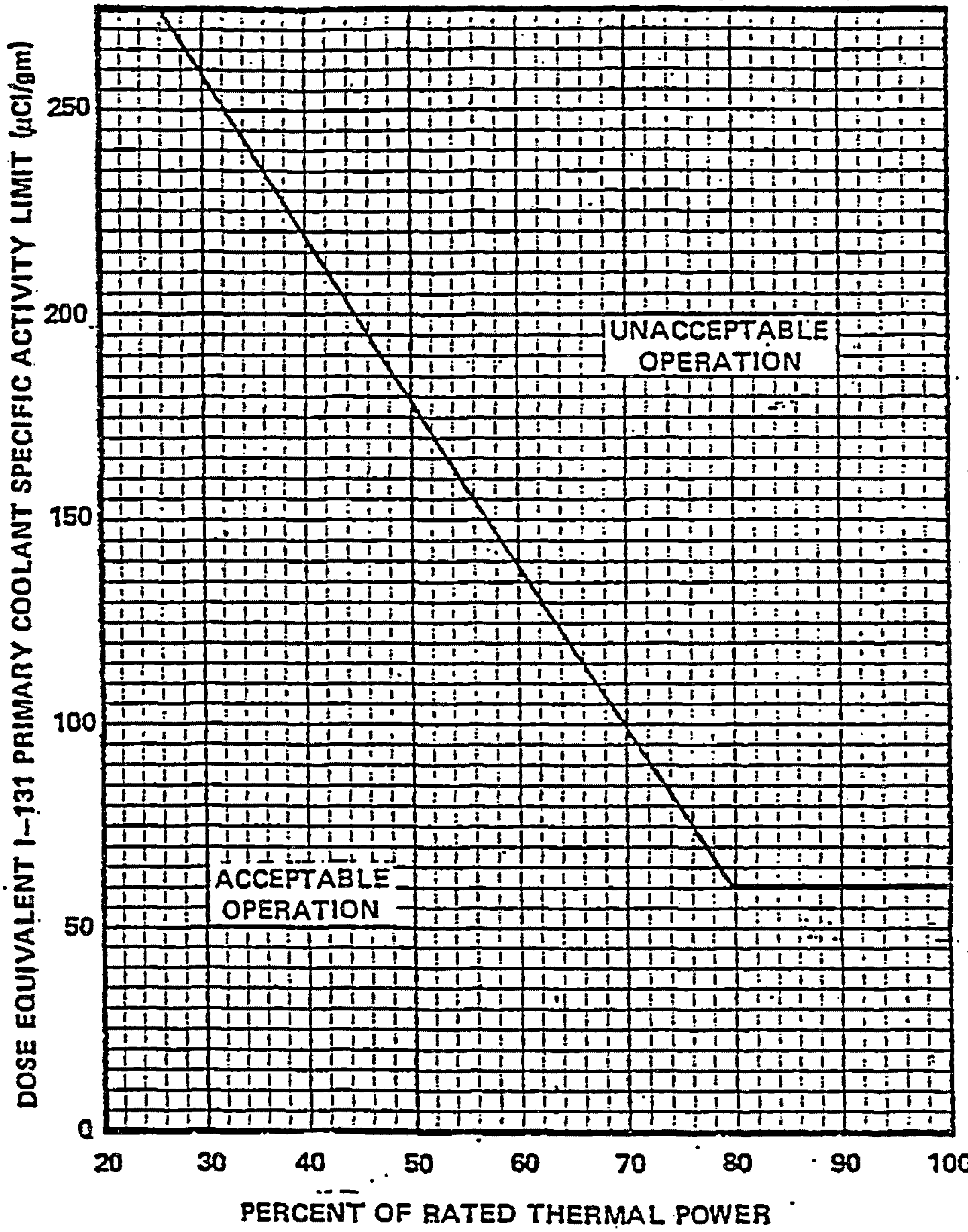


FIGURE 3.4-1

DOSE EQUIVALENT I–131 Primary Coolant Specific Activity Limit Versus Percent of RATED THERMAL POWER with the Primary Coolant Specific Activity >1.0 μCi/gram Dose Equivalent I-131

3/4.4.9 PRESSURE/TEMPERATURE LIMITS

REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.9.1 The Reactor Coolant System (except the pressurizer) temperature and pressure shall be limited in accordance with the limit lines shown on Figures 3.4-2a, 3.4-2b and 3.4-3 during heatup, cooldown, criticality, and inservice leak and hydrostatic testing.

APPLICABILITY: At all times. *#

ACTION:

With any of the above limits exceeded, restore the temperature and/or pressure to within the limits within 30 minutes; perform an analysis to determine the effects of the out-of-limit condition on the fracture toughness properties of the Reactor Coolant System; determine that the Reactor Coolant System remains acceptable for continued operations or be in at least HOT STANDBY within the next 6 hours and reduce the RCS T_{avg} to less than 200°F within the following 30 hours in accordance with Figures 3.4-2b and 3.4-3.

* When the flow path from the RWT to the RCS via a single HPSI pump is established per 3.1.2.1 or 3.1.2.3 and RCS pressure boundary integrity exists, the heatup and cooldown rates shall be established in accordance with Fig. 3.1-1b.

\# During hydrostatic testing operations above system design pressure, a maximum temperature change in any one hour period shall be limited to 5°F.

SURVEILLANCE REQUIREMENTS

4.4.9.1

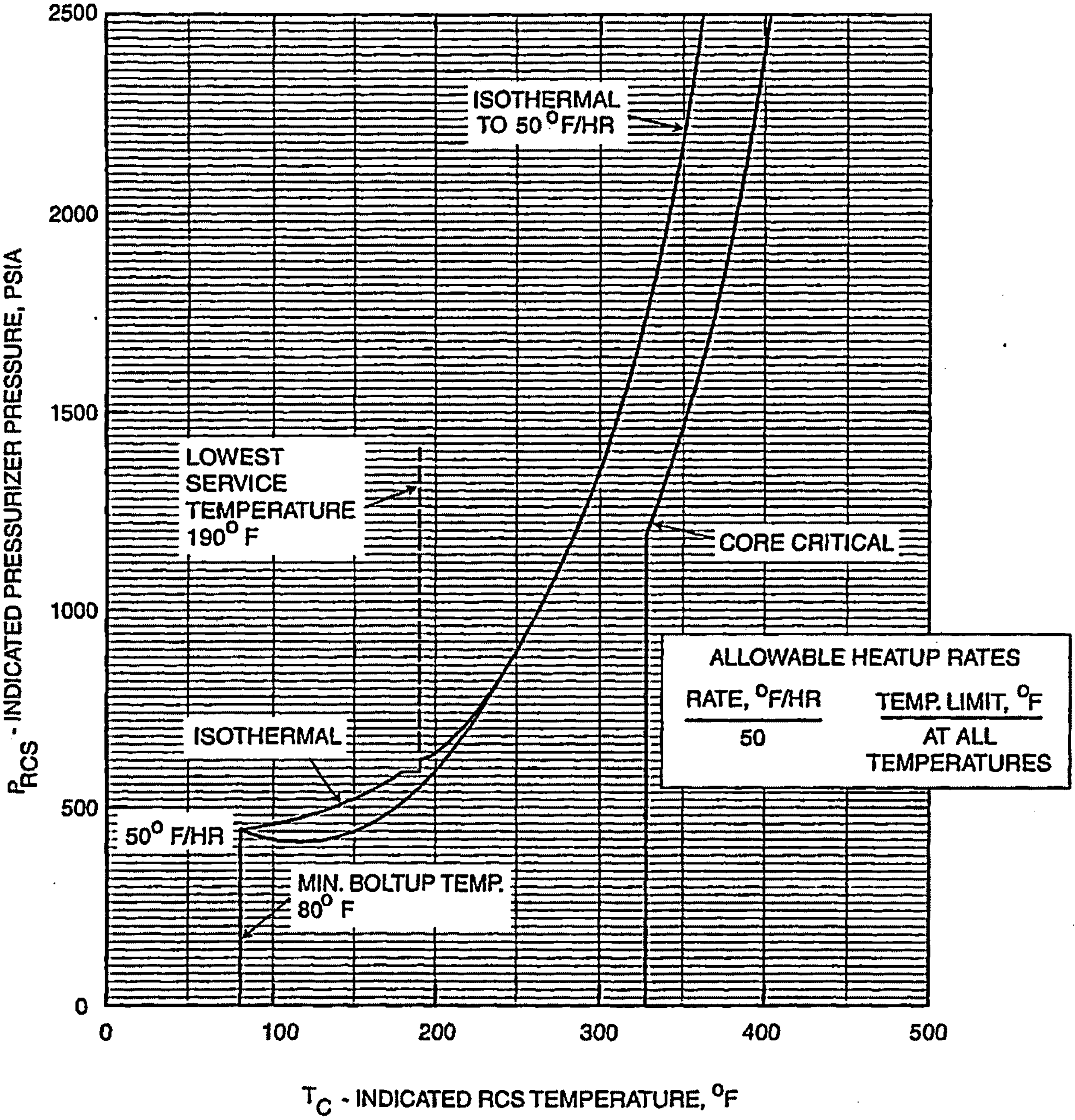
a. The Reactor Coolant System temperature and pressure shall be determined to be within the limits at least once per 30 minutes during system heatup, cooldown, and inservice leak and hydrostatic testing operations.

b. The Reactor Coolant System temperature and pressure conditions shall be determined to be to the right of the criticality limit line within 15 minutes prior to achieving reactor criticality.

c. The reactor vessel material irradiation surveillance specimens shall be removed and examined, to determine changes in material properties as required by 10 CFR 50 Appendix H. The results of these examinations shall be used to update Figures 3.4-2a, 3.4-2b and 3.4-3.

FIGURE 3.4-2a

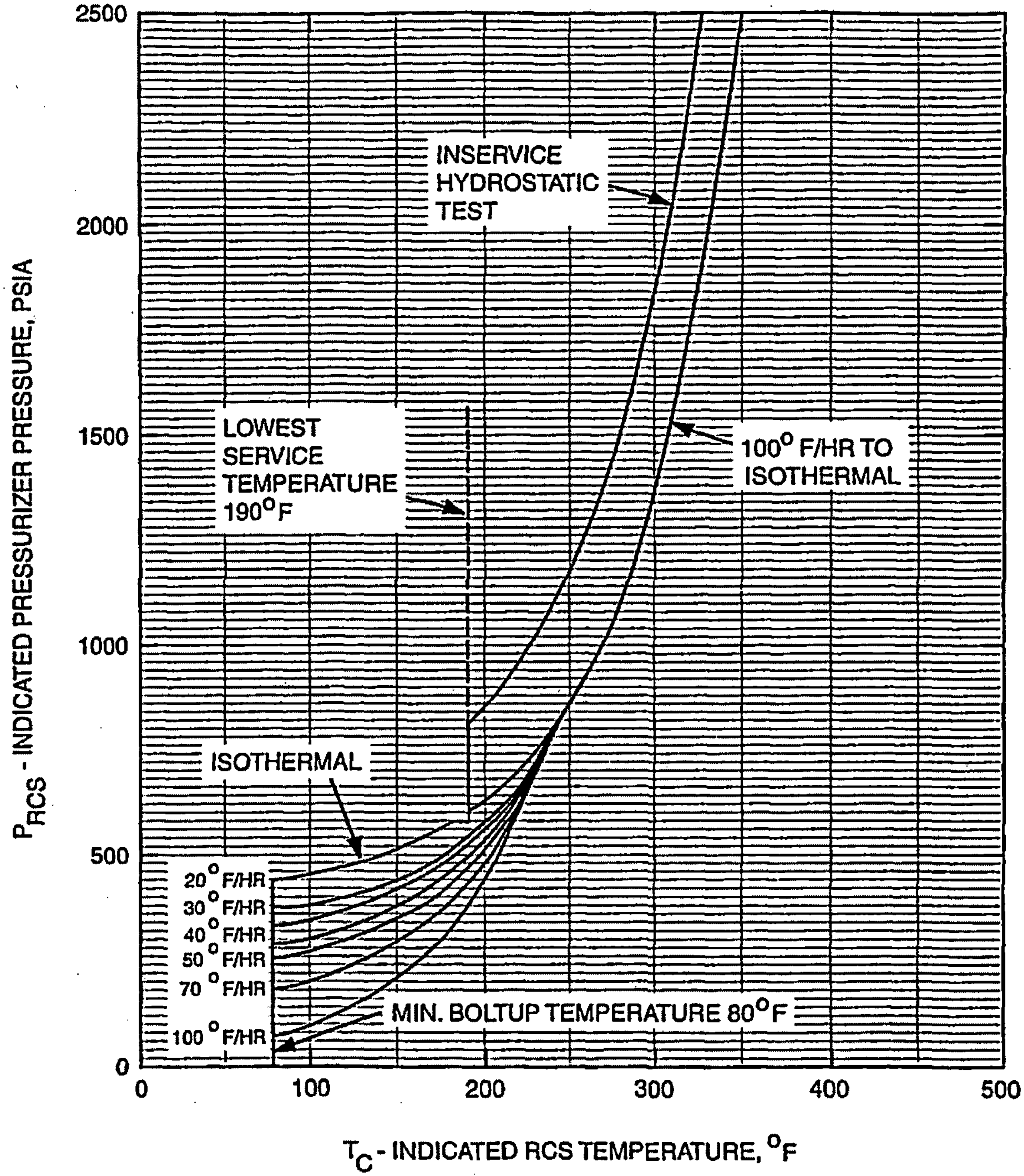
ST. LUCIE UNIT 1 P/T LIMITS, 35 EFPY
HEATUP AND CORE CRITICAL



Limiting Material: Lower Shell Axial Welds (Ht. #305424)
Limiting ART Values at 35 EFPY: 1/4T, 191°F
3/4T, 137°F

FIGURE 3.4-2b

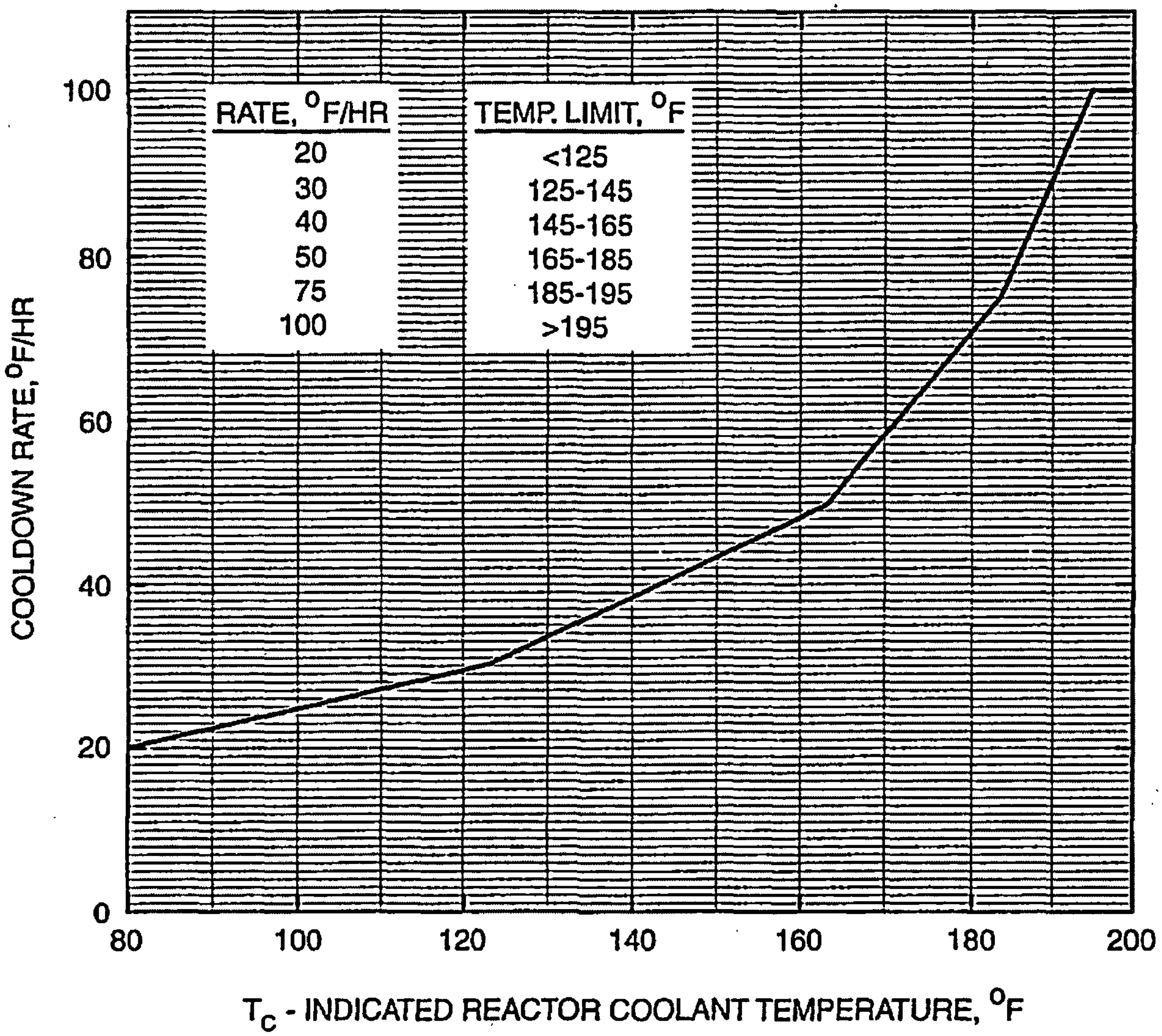
ST. LUCIE UNIT 1 P/T LIMITS, 35 EFPY
COOLDOWN AND INSERVICE TEST



Limiting Material: Lower Shell Axial Welds (Ht. #305424)
Limiting ART Values at 35 EFPY: 1/4T, 191°F
3/4T, 137°F

FIGURE 3.4-3

ST. LUCIE UNIT 1, 35 EFPY
MAXIMUM ALLOWABLE COOLDOWN RATES



NOTE: A MAXIMUM COOLDOWN RATE OF 100°F/HR IS ALLOWED AT ANY TEMPERATURE ABOVE 195°F

DELETED

LIMITING CONDITION FOR OPERATION

3.4.9.2 The pressurizer temperature shall be limited to:

a. A maximum heatup of 100°F in any one hour period,

b. A maximum cooldown of 200°F in any one hour period, and

c. A maximum Reactor Coolant System spray water temperature differential of 350°F.

APPLICABILITY: At all times.

ACTION:

With the pressurizer temperature limits in excess of any of the above limits, restore the temperature to within the limits within 30 minutes; perform an analysis to determine the effects of the out-of-limit condition on the fracture toughness properties of the pressurizer; determine that the pressurizer remains acceptable for continued operation or be in at least HOT STANDBY within the next 6 hours and reduce the pressurizer pressure to less than 500 psia within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.9.2 The pressurizer temperatures shall be determined to be within the limits at least once per 30 minutes during system heatup or cooldown. The spray water temperature differential shall be determined to be within the limit at least once per 12 hours during steady state operation.

DELETED

SURVEILLANCE REQUIREMENTS (Continued)

Pages 3/4 4-28 through 3/4 4-55 (Amendment No. 90), and Pages 3/4 4-56 through 3/4 4-57 (Amendment No. 80) have been deleted from the Technical Specifications. The next page is 3/4 4-58.

REACTOR COOLANT SYSTEM

PORV BLOCK VALVES

LIMITING CONDITION FOR OPERATION

3.4.12 Each Power Operated Relief Valve (PORV) Block Valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

With one or more block valve(s) inoperable, within 1 hour either restore the block valve(s) to OPERABLE status or close the block valve(s) and remove power from the block valve(s); otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.12 Each block valve shall be demonstrated OPERABLE at least once per 92 days by operating the valve through one complete cycle of full travel.

POWER OPERATED RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.4.13 Two power operated relief valves (PORVs) shall be OPERABLE, with their setpoints selected to the low temperature mode of operation as follows:

a. A setpoint of less than or equal to 350 psia shall be selected:

1. During cooldown when the temperature of any RCS cold leg is less than or equal to 215°F and

2. During heatup and isothermal conditions when the temperature of any RCS cold leg is less than or equal to 193°F.

b. A setpoint of less than or equal to 530 psia shall be selected:

1. During cooldown when the temperature of any RCS cold leg is greater than 215°F and less than or equal to 281°F.

2. During heatup and isothermal conditions when the temperature of any RCS cold leg is greater than or equal to 193°F and less than or equal to 304°F.

APPLICABILITY: MODE 4 when the temperature of any RCS cold leg is less than or equal to 304°F, MODE 5, and MODE 6 when the head is on the reactor vessel; and the RCS is not vented through greater than a 1.75 square inch vent.

ACTION:

a. With one PORV inoperable in MODE 4, restore the inoperable PORV to OPERABLE status within 7 days; or depressurize and vent the RCS through greater than a 1.75 square inch vent within the next 8 hours.

b. With one PORV inoperable in MODES 5 or 6, either (1) restore the inoperable PORV to OPERABLE status within 24 hours, or (2) complete depressurization and venting of the RCS through greater than a 1.75 square inch vent within a total of 32 hours.

c. With both PORVs inoperable, restore at least one PORV to operable status or complete depressurization and venting of the RCS through greater than a 1.75 square inch vent within 24 hours.

d. With the RCS vented per ACTIONS a, b, or c, verify the vent pathway at least once per 31 days when the pathway is provided by a valve(s) that is locked, sealed, or otherwise secured in the open position; otherwise, verify the vent pathway every 12 hours.

e. In the event either the PORVs or the RCS vent(s) are used to mitigate an RCS pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the PORVs or RCS vent(s) on the transient, and any corrective action necessary to prevent recurrence.

f. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.13 Each PORV shall be demonstrated OPERABLE by:

a. Verifying the PORV isolation valve is open at least once per 72 hours; and

b. Performance of a CHANNEL FUNCTION TEST, but excluding valve operation, at least once per 31 days; and

c. Performance of a CHANNEL CALIBRATION at least once per 18 months.

REACTOR COOLANT SYSTEM

REACTOR COOLANT PUMP - STARTING

LIMITING CONDITION FOR OPERATION

3.4.14 If the steam generator temperature exceeds the primary temperature by more than 30°F, the first idle reactor coolant pump shall not be started.

APPLICABILITY: MODES 4# and 5.

ACTION:

If a reactor coolant pump is started when the steam generator temperature exceeds primary temperature by more than 30°F, evaluate the subsequent transient to determine compliance with Specification 3.4.9.1.

SURVEILLANCE REQUIREMENTS

4.4.14 Prior to starting a reactor coolant pump, verify that the steam generator temperature does not exceed primary temperature by more than 30°F.

#Reactor Coolant System Cold Leg Temperature is less than 304°F.

3/4.4.15 REACTOR COOLANT SYSTEM VENTS

LIMITING CONDITION FOR OPERATION

3.4.15 At least one Reactor Coolant System vent path consisting of two vent valves and one block valve powered from emergency buses shall be OPERABLE and closed at each of the following locations:

a. Pressurizer steam space, and

b. Reactor vessel head.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one of the above Reactor Coolant System vent paths inoperable, STARTUP and/or POWER OPERATION may continue provided the inoperable vent path is maintained closed with power removed from the valve actuator of all the vent valves and block valves in the inoperable vent path; restore the inoperable vent path to OPERABLE status within 30 days, or be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With both Reactor Coolant System vent paths inoperable, maintain the inoperable vent paths closed with power removed from the valve actuators of all the vent valves and block valves in the inoperable vent paths, and restore at least one of the vent paths to OPERABLE status within 72 hours or be in HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.15 Each Reactor Coolant System vent path shall be demonstrated OPERABLE at least once per 18 months by:

1. Verifying all manual isolation valves in each vent path are locked in the open position.

2. Cycling each vent valve through at least one complete cycle of full travel from the control room.

3. Verifying flow through the Reactor Coolant System vent paths during venting.

SAFETY INJECTION TANKS (SIT)

LIMITING CONDITION FOR OPERATION

3.5.1 Each reactor coolant system safety injection tank shall be OPERABLE with:

a. The isolation valve open,

b. Between 1090 and 1170 cubic feet of borated water,

c. A minimum boron concentration of 1720 PPM, and

d. A nitrogen cover-pressure of between 200 and 250 psig.

APPLICABILITY: MODES 1, 2 and 3.*

ACTION:

a. With one SIT inoperable due to boron concentration not within limits, or due to an inability to verify the required water volume or nitrogen cover-pressure, restore the inoperable SIT to OPERABLE status within 72 hours; otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With one SIT inoperable due to reasons other than those stated in ACTION-a, restore the inoperable SIT to OPERABLE status within 24 hours; otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.5.1 Each safety injection tank shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1. Verifying that the borated water volume and nitrogen cover-pressure in the tanks are within their limits, and

2. Verifying that each safety injection tank isolation valve is open.

* With pressurizer pressure ≥ 1750 psia.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 31 days and once within 6 hours after each solution volume increase of ≥ 1% of tank volume by verifying the boron concentration of the safety injection tank solution. This latter surveillance is not required when the volume increase makeup source is the RWT and the RWT has not been diluted since verifying that the RWT boron concentration is equal to or greater than the safety injection tank boron concentration limit.

c. At least once per 31 days when the RCS pressure is above 1750 psia, by verifying that power to the isolation valve operator is removed by maintaining the breaker open under administrative control.

d. At least once per 18 months by verifying that each safety injection tank isolation valve opens automatically under each of the following conditions:

   1. When the RCS pressure exceeds 350 psia, and

   2. Upon receipt of a safety injection test signal.

ECCS SUBSYSTEMS - OPERATING

LIMITING CONDITION FOR OPERATION

3.5.2 Two independent ECCS subsystems shall be OPERABLE with each subsystem comprised of:

a. One OPERABLE high-pressure safety injection (HPSI) pump,

b. One OPERABLE low-pressure safety injection pump, and

c. An independent OPERABLE flow path capable of taking suction from the refueling water tank on a Safety Injection Actuation Signal and automatically transferring suction to the containment sump on a Recirculation Actuation Signal.

APPLICABILITY: MODES 1, 2 and 3*.

ACTION:

a. 1. With one ECCS subsystem inoperable only because its associated LPSI train is inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

2. With one ECCS subsystem inoperable for reasons other than condition a.1., restore the inoperable subsystem to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

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* With pressurizer pressure $\geq$ 1750 psia.

SURVEILLANCE REQUIREMENTS

4.5.2 Each ECCS subsystem shall be demonstrated OPERABLE:

a. At least once per 12 hours by verifying that the following valves are in the indicated positions with power to the valve operators removed:

Valve Number	Valve Function	Valve Position
1. V-3659	1. Mini-flow isolation	1. Open
2. V-3660	2. Mini-flow isolation	2. Open

b. At least once per 31 days by:

1. Verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

c. By a visual inspection which verifies that no loose debris (rags, trash, clothing, etc.) is present in the containment which could be transported to the containment sump and cause restriction of the pump suctions during LOCA conditions. This visual inspection shall be performed:

1. For all accessible areas of the containment prior to establishing CONTAINMENT INTEGRITY, and

2. At least once daily of the areas affected within containment by the containment entry and during the final entry when CONTAINMENT INTEGRITY is established.

d. At least once per 18 months by:

1. Verifying proper operation of the open permissive interlock (OPI) and the valve open/high SDCS pressure alarms for isolation valves V3651, V3652, V3480, V3481.

2. A visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or corrosion.

SURVEILLANCE REQUIREMENTS (continued)

e. At least once per 18 months, during shutdown, by:

   1. Verifying that each automatic valve in the flow path actuates to its correct position on a Safety Injection Actuation Signal.

   2. Verifying that each of the following pumps start automatically upon receipt of a Safety Injection Actuation Signal;

      a. High-Pressure Safety Injection Pump.

      b. Low-Pressure Safety Injection Pump.

   3. Verifying that upon receipt of an actual or simulated Recirculation Actuation Signal: each low-pressure safety injection pump stops, each containment sump isolation valve opens, each refueling water tank outlet valve closes, and each safety injection system recirculation valve to the refueling water tank closes.

f. By verifying that each of the following pumps develops the specified total developed head when tested pursuant to the Inservice Testing Program.

   1. High-Pressure Safety Injection pumps.

   2. Low-Pressure Safety Injection pumps.

SURVEILLANCE REQUIREMENTS (Continued)

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ECCS SUBSYSTEMS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.5.3 As a minimum, one ECCS subsystem comprised of the following shall be OPERABLE:

a. In MODES 3* and 4#, one ECCS subsystem composed of one OPERABLE high pressure safety injection pump and one OPERABLE flow path capable of taking suction from the refueling water storage tank on a safety injection actuation signal and automatically transferring suction to the containment sump on a sump recirculation actuation signal.

b. Prior to decreasing the reactor coolant system temperature below 270°F a maximum of only one high pressure safety injection pump shall be OPERABLE with its associated header stop valve open.

c. Prior to decreasing the reactor coolant system temperature below 236°F all high pressure safety injection pumps shall be disabled and their associated header stop valves closed except as allowed by Specifications 3.1.2.1 and 3.1.2.3.

APPLICABILITY: MODES 3* and 4.
MODES 5 and 6 when the Pressurizer manway cover is in place and the reactor vessel head is on.

ACTION:

a. With no ECCS subsystems OPERABLE in MODES 3* and 4#, immediately restore one ECCS subsystem to OPERABLE status or be in COLD SHUTDOWN within 20 hours.

b. With RCS temperature below 270°F and with more than the allowed high pressure safety injection pump OPERABLE or injection valves and header isolation valves open, immediately disable the high pressure safety injection pump(s) or close the header isolation valves.

c. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

SURVEILLANCE REQUIREMENTS

4.5.3.1 The ECCS subsystem shall be demonstrated OPERABLE per the applicable Surveillance Requirements of 4.5.2.

4.5.3.2 The high pressure safety injection pumps shall be verified inoperable and the associated header stop valves closed prior to decreasing below the above specified Reactor Coolant System temperature and once per month when the Reactor Coolant System is at refueling temperatures.

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* With pressurizer pressure < 1750 psia.

\# REACTOR COOLANT SYSTEM cold leg temperature above 250°F.

EMERGENCY CORE COOLING SYSTEMS

REFUELING WATER TANK

LIMITING CONDITION FOR OPERATION

3.5.4 The refueling water tank shall be OPERABLE with:

a. A minimum contained volume 477,360 gallons of borated water,

b. A minimum boron concentration of 1720 ppm,

c. A maximum water temperature of 100°F,

d. A minimum water temperature of 55°F when in MODES 1 and 2, and

e. A minimum water temperature of 40°F when in MODES 3 and 4

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the refueling water tank inoperable, restore the tank to OPERABLE status within 1 hour or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.5.4 The RWT shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1. Verifying the water level in the tank, and

2. Verifying the boron concentration of the water.

b. At least once per 24 hours by verifying the RWT temperature.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 CONTAINMENT VESSEL

CONTAINMENT VESSEL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 CONTAINMENT VESSEL INTEGRITY shall be maintained.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

Without CONTAINMENT VESSEL INTEGRITY, restore CONTAINMENT VESSEL INTEGRITY within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 CONTAINMENT VESSEL INTEGRITY shall be demonstrated:

a. At least once per 31 days by verifying that:

1. All containment vessel penetrations* not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in their positions, except for valves that are open on an intermittent basis under administrative control, and

2. All containment vessel equipment hatches are closed and sealed.

b. By verifying that each containment vessel air lock is OPERABLE per Specification 3.6.1.3.

* Except valves, blind flanges, and deactivated automatic valves which are located inside the containment and are locked, sealed or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except that such verification need not be performed more often than once per 92 days.

CONTAINMENT SYSTEMS

CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2 Containment leakage rates shall be limited in accordance with the Containment Leakage Rate Testing Program.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the containment leakage rate exceeding the acceptance criteria of the Containment Leakage Rate Testing Program, within 1 hour initiate action to be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore the overall leakage rate to less than that specified by the Containment Leakage Rate Testing Program prior to increasing the Reactor Coolant System temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.2 The containment leakage rates shall be demonstrated at the required test schedule and shall be determined in conformance with the criteria specified in the Containment Leakage Rate Testing Program.

Pages 3/4 6-4 through 3/4 6-9 have been DELETED.

Page 3/4 6-10 is the next valid page.

CONTAINMENT SYSTEMS

CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.1.3 Each containment air lock shall be OPERABLE with:

a. Both doors closed except when the air lock is being used for normal transit entry and exit through the containment, then at least one air lock door shall be closed, and

b. An overall air lock leakage rate in accordance with the Containment Leakage Rate Testing Program.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one containment air lock door inoperable*:

1. Maintain at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours or lock the OPERABLE air lock door closed.

2. Operation may then continue until performance of the next required overall air lock leakage test provided that the OPERABLE air lock door is verified to be closed at least once per 31 days.

3. Otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

4. The provisions of Specification 3.0.4 are not applicable.

b. With the containment air lock inoperable, except as the result of an inoperable air lock door, maintain at least one air lock door closed; restore the inoperable air lock to OPERABLE status within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE:

* If the inner air lock door is inoperable, passage through the OPERABLE outer air lock door is permitted to effect repairs to the inoperable inner air lock door. No more than one airlock door shall be open at any time.

SURVEILLANCE REQUIREMENTS (continued)

a. By verifying leakage rates and air lock door seals in accordance with the Containment Leakage Rate Testing Program; and

b. At least once per 6 months by verifying that only one door in each air lock can be opened at a time.

CONTAINMENT SYSTEMS

INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.4 Primary containment internal pressure shall be maintained between -0.7 and 2.4 PSIG.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the containment internal pressure outside of the limits above, restore the internal pressure to within the limits within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.4 The primary containment internal pressure shall be determined to be within the limits at least once per 12 hours.

AIR TEMPERATURE

LIMITING CONDITION FOR OPERATION

3.6.1.5 Primary containment average air temperature shall not exceed 120°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the containment average air temperature > 120°F, reduce the average air temperature to within the limit within 8 hours, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.5 The primary containment average air temperature shall be the arithmetical average of the temperatures at three of the following locations and shall be determined at least once per 24 hours:

Location

a. Containment fan cooler No. 1A air intake, elevation 45 feet.

b. Containment fan cooler No. 1B air intake, elevation 45 feet.

c. Containment fan cooler No. 1C air intake, elevation 62 feet.

d. Containment fan cooler No. 1D air intake, elevation 45 feet.

CONTAINMENT SYSTEMS

CONTAINMENT VESSEL STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.6 The structural integrity of the containment vessel shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.1.6.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the structural integrity of the containment vessel not conforming to the above requirements, restore the structural integrity to within the limits prior to increasing the Reactor Coolant System temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.6 The structural integrity of the containment vessel shall be determined, in accordance with the containment Leakage Rate Testing Program, by a visual inspection of the accessible interior and exterior surfaces of the vessel and verifying no apparent changes in appearance of the surfaces or other abnormal degradation.

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

CONTAINMENT SPRAY AND COOLING SYSTEMS

LIMITING CONDITION FOR OPERATION

3.6.2.1 Two containment spray trains and two containment cooling trains shall be OPERABLE.

APPLICABILITY: Containment Spray System: MODES 1, 2, and MODE 3 with Pressurizer Pressure ≥ 1750 psia.

Containment Cooling System: MODES 1,2, and 3.

ACTION:

1. Modes 1, 2, and 3 with Pressurizer Pressure ≥ 1750 psia:

   a. With one containment spray train inoperable, restore the inoperable spray train to OPERABLE status within 72 hours and within 10 days from initial discovery of failure to meet the LCO; otherwise be in MODE 3 within the next 6 hours and in MODE 4 within the following 54 hours.

   b. With one containment cooling train inoperable, restore the inoperable cooling train to OPERABLE status within 7 days and within 10 days from initial discovery of failure to meet the LCO; otherwise be in MODE 3 within the next 6 hours and in MODE 4 within the following 6 hours.

   c. With one containment spray train and one containment cooling train inoperable, concurrently implement ACTIONS a. and b. The completion intervals for ACTION a. and ACTION b. shall be tracked separately for each train starting from the time each train was discovered inoperable.

   d. With two containment cooling trains inoperable, restore one cooling train to OPERABLE status within 72 hours; otherwise be in MODE 3 within the next 6 hours and in MODE 4 within the following 6 hours.

   e. With two containment spray trains inoperable or any combination of three or more trains inoperable, enter LCO 3.0.3 immediately.

2. Mode 3 with Pressurizer Pressure < 1750 psia:

   a. With one containment cooling train inoperable, restore the inoperable cooling train to OPERABLE status within 72 hours; otherwise be in MODE 4 within the next 6 hours.

   b. With two containment cooling trains inoperable, enter LCO 3.0.3 immediately.

SURVEILLANCE REQUIREMENTS

4.6.2.1 Each containment spray system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is positioned to take suction from the RWT on a Containment Pressure -- High High test signal.

b. By verifying that each spray pump develops the specified discharge pressure when tested pursuant to the Inservice Testing Program.

SURVEILLANCE REQUIREMENTS (Continued)

c. At least once per 18 months, during shutdown, by:

1. Verifying that each automatic valve in the flow path actuates to its correct position on a CSAS test signal.

2. Verifying that each spray pump starts automatically on a CSAS test signal.

3. Verifying that upon a recirculation actuation signal, the containment sump isolation valves open and that a recirculation mode flow path via an OPERABLE shutdown cooling heat exchanger is established.

d. By verifying each spray nozzle is unobstructed following maintenance which could result in nozzle blockage.

4.6.2.1.1. Each containment cooling train shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Starting each cooling train fan unit from the control room and verifying that each unit operates for at least 15 minutes, and

2. Verifying a cooling water flow rate of greater than or equal to 1200 gpm to each cooling unit.

b. At least once per 18 months, during shutdown, by verifying that each containment cooling train starts automatically on an SIAS test signal.

SPRAY ADDITIVE SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.2.2 The spray additive system shall be OPERABLE with:

a. A spray additive tank containing a volume of between 4010 and 5000 gallons of between 28.5 and 30.5% by weight NaOH solution, and

b. Two spray additive eductors each capable of adding NaOH solution from the chemical additive tank to a containment spray system pump flow.

APPLICABILITY: MODES 1, 2 and 3.*

ACTION:

With the spray additive system inoperable, restore the system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours; restore the spray additive system to OPERABLE status within the next 48 hours or be in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.2.2 The spray additive system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 6 months by:

1. Verifying the contained solution volume in the tank, and

2. Verifying the concentration of the NaOH solution by chemical analysis.

c. At least once per 18 months, during shutdown, by verifying that each automatic valve in the flow path actuates to its correct position on a CSAS test signal.

*Applicable when pressurizer pressure is $\geq$ 1750 psia.

CONTAINMENT SYSTEMS

SPRAY ADDITIVE SYSTEM

SURVEILLANCE REQUIREMENTS (Continued)

d. At least once per 5 years by verifying a minimum sodium hydroxide (NaOH) flow-rate of 10.5 gpm from the spray additive tank to a drain connection immediately downstream of the tank outlet valve, and a demineralized water flow rate of 18 ± 1.5 gpm from that same drain connection to each containment spray pump.

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3/4.6.3 CONTAINMENT ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.6.3.1 The containment isolation valves shall be OPERABLE:

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one or more of the isolation valve(s) inoperable, either:

a. Restore the inoperable valve(s) to OPERABLE status within 4 hours, or

b. Isolate each affected penetration within 4 hours by use of at least one deactivated automatic valve secured in the isolation position, or

c. Isolate each affected penetration within 4 hours by use of at least one closed manual valve or blind flange; or

d. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.3.1.1 The isolation valves shall be demonstrated OPERABLE prior to returning the valve to service after maintenance, repair or replacement work is performed on the valve or its associated actuator, control or power circuit by performance of the cycling test, and verification of isolation time.

SURVEILLANCE REQUIREMENTS (continued)

4.6.3.1.2 Each containment isolation valve shall be demonstrated OPERABLE during the COLD SHUTDOWN or REFUELING MODE at least once per 18 months by:

a. Verifying that on a Containment Isolation test signal, and/or SIAS test signal, each isolation valve actuates to its isolation position.

4.6.3.1.3 The isolation time of each power operated or automatic containment isolation valve shall be determined to be within its limits when tested pursuant to the Inservice Testing Program.

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CONTAINMENT SYSTEMS

3/4.6.5 VACUUM RELIEF VALVES

LIMITING CONDITION FOR OPERATION

3.6.5.1 Two vacuum relief lines shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one vacuum relief line inoperable, restore the vacuum relief line to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.1 Verify each vacuum relief line OPERABLE in accordance with the Inservice Testing Program.

CONTAINMENT SYSTEMS

3/4.6.6 SECONDARY CONTAINMENT

SHIELD BUILDING VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.6.1 Two independent shield building ventilation systems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one shield building ventilation system inoperable, restore the inoperable system to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.1 Each shield building ventilation system shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by initiating, from the control room, flow through the HEPA filter and charcoal adsorber train and verifying that the train operates for at least 10 hours with the heaters on.

b. By performing required shield building ventilation system filter testing in accordance with the Ventilation Filter Testing Program.

c. At least once per 18 months by:

1. Verifying that the air flow distribution is uniform within 20% across HEPA filters and charcoal adsorbers when tested in accordance with ASME N510-1989.

2. Verifying that the filtration system starts automatically on a Containment Isolation Signal (CIS).

3. Verifying that the filter cooling makeup air and cross connection valves can be manually opened.

4. Verifying that each system produces a negative pressure of $\geq$ 2.0 inches W.G. in the annulus within 2 minutes after a Containment Isolation Signal (CIS).

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SHIELD BUILDING INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.6.2 SHIELD BUILDING INTEGRITY shall be maintained.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

Without SHIELD BUILDING INTEGRITY, restore SHIELD BUILDING INTEGRITY within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.6.2 SHIELD BUILDING INTEGRITY shall be demonstrated at least once per 31 days by verifying that the door in each access opening is closed except when the access opening is being used for normal transit entry and exit.

CONTAINMENT SYSTEMS

SHIELD BUILDING STRUCTURAL INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.6.3 The structural integrity of the shield building shall be maintained at a level consistent with the acceptance criteria in Specification 4.6.6.3.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the structural integrity of the shield building not conforming to the above requirements, restore the structural integrity to within the limits prior to increasing the Reactor Coolant System temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.6.3 The structural integrity of the shield building shall be determined, in accordance with the Containment Leakage Rate Testing Program, by a visual inspection of the accessible interior and exterior surfaces of the shield building and verifying no apparent changes in appearance of the concrete surfaces or other abnormal degradation.

3/4.7 PLANT SYSTEMS

3.4.7.1 TURBINE CYCLE

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line code safety valves shall be OPERABLE with lift settings as specified in Table 4.7-1.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With both reactor coolant loops and associated steam generators in operation and with one or more main steam line code safety valves inoperable, operation in MODES 1, 2 and 3 may proceed provided that within 4 hours, either the inoperable valve is restored to OPERABLE status or the Power Level-High trip setpoint is reduced per Table 3.7-1; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 Verify each main steam line code safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, as-left lift settings shall be within +/- 1% of 1000 psia for valves 8201 through 8208, and within +/- 1% of 1040 psia for valves 8209 through 8216 specified in Table 4.7-1.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER LEVEL-HIGH TRIP SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING OPERATION WITH BOTH STEAM GENERATORS

Maximum Number of Inoperable Safety Valves on Any Operating Steam Generator	Maximum Allowable Power Level-High Trip Setpoint (Percent of RATED THERMAL POWER)
1	93.2
2	79.8
3	66.5

TABLE 4.7-1

STEAM LINE SAFETY VALVES PER LOOP

	VALVE NUMBER		LIFT SETTING (+ 1% to - 3%)
	Header A	Header B	
a.	8201	8205	$\geq$ 955.3 psig and $\leq$ 995.3 psig
b.	8202	8206	$\geq$ 955.3 psig and $\leq$ 995.3 psig
c.	8203	8207	$\geq$ 955.3 psig and $\leq$ 995.3 psig
d.	8204	8208	$\geq$ 955.3 psig and $\leq$ 995.3 psig
e.	8209	8213	$\geq$ 994.1 psig and $\leq$ 1035.7 psig
f.	8210	8214	$\geq$ 994.1 psig and $\leq$ 1035.7 psig
g.	8211	8215	$\geq$ 994.1 psig and $\leq$ 1035.7 psig
h.	8212	8216	$\geq$ 994.1 psig and $\leq$ 1035.7 psig

PLANT SYSTEMS

AUXILIARY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 At least three independent steam generator auxiliary feedwater pumps and associated flow paths shall be OPERABLE with:

a. Two motor driven feedwater pumps, and

b. One feedwater pump capable of being powered from an OPERABLE steam supply system.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With one auxiliary feedwater pump inoperable, restore at least three auxiliary feedwater pumps (two motor driven pumps and one capable of being powered by an OPERABLE steam supply system) to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.2 Each auxiliary feedwater pump shall be demonstrated OPERABLE:

a. At least once per 31 days by:

SURVEILLANCE REQUIREMENTS (Continued)

1. Verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown by:

1. Verifying that each automatic valve in the flowpath actuates to its correct position upon receipt of the Auto Start actuation test signal.

2. Verifying that each auxiliary feedwater pump starts automatically as designed upon receipt of the Auto Start actuation test signal.

c. By verifying the developed head of each AFW pump at the flow test point is greater than or equal to the required developed head when tested in accordance with the Inservice Testing Program. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 when testing the steam turbine-driven AFW pump and this Surveillance must be performed within 24 hours after entering MODE 3 and prior to entering MODE 2.

CONDENSATE STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.7.1.3 The condensate storage tank shall be OPERABLE with a minimum contained volume of 116,000 gallons.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With the condensate storage tank inoperable, restore the condensate storage tank to OPERABLE status within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.3 The condensate storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the water level.

PLANT SYSTEMS

ACTIVITY

LIMITING CONDITION FOR OPERATION

3.7.1.4 The specific activity of the secondary coolant system shall be $\leq$ 0.10 μCi/gram DOSE EQUIVALENT I-131.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With the specific activity of the secondary coolant system > 0.10 μCi/gram DOSE EQUIVALENT I-131, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.4 The specific activity of the secondary coolant system shall be determined to be within the limit by performance of the sampling and analysis program of Table 4.7-2.

TABLE 4.7-2

SECONDARY COOLANT SYSTEM SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM

TYPE OF MEASUREMENT AND ANALYSIS	MINIMUM FREQUENCY
1. Gross Activity Determination	3 times per 7 days with a maximum time of 72 hours between samples
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	a) 1 per 31 days, whenever the gross activity determination indicates iodine concentrations greater than 10% of the allowable limit.
	b) 1 per 6 months, whenever the gross activity determination indicates iodine concentrations below 10% of the allowable limit.

MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.5 Each main steam line isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

MODE 1 - With one main steam line isolation valve inoperable, POWER OPERATION may continue provided the inoperable valve is either restored to OPERABLE status or closed within 4 hours; otherwise, be in HOT STANDBY within the next 6 hours.

MODES 2 and 3 - With one or both main steam isolation valve(s) inoperable, subsequent operation in MODES 2 or 3 may proceed provided the isolation valve(s) is (are) maintained closed. Otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 24 hours.

The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.5 Each main steam line isolation valve that is open shall be demonstrated OPERABLE by verifying full closure within 6.0 seconds when tested pursuant to the Inservice Testing Program.

Pages 3/4 7-11 through 3/4 7-12 (Amendment No. 86) have been deleted from the Technical Specifications. The next page is 3/4 7-13.

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

LIMITING CONDITION FOR OPERATION

3.7.2.1 The temperatures of both the primary and secondary coolants in the steam generators shall be > 70°F when the pressure of either coolant in the steam generator is > 200 psig.

APPLICABILITY: ALL MODES.

ACTION:

With the requirements of the above specification not satisfied:

a. Reduce the steam generator pressure of the applicable side to ≤ 200 psig within 30 minutes, and

b. Perform an analysis to determine the effect of the overpressurization on the structural integrity of the steam generator. Determine that the steam generator remains acceptable for continued operation prior to increasing its temperatures above 200°F.

SURVEILLANCE REQUIREMENTS

4.7.2.1 The pressure in each side of the steam generators shall be determined to be < 200 psig at least once per hour when the temperature of either the primary or secondary coolant in the steam generators is < 70°F.

3/4.7.3 COMPONENT COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3.1 At least two independent component cooling water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one component cooling water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.3.1 At least two component cooling water loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) servicing safety related equipment that is not locked, sealed or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown by verifying that each automatic valve servicing safety related equipment actuates to its correct position on a Safety Injection Actuation Signal.

SURVEILLANCE REQUIREMENTS (Continued)

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3/4.7.4 INTAKE COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4.1 At least two independent intake cooling water loops shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one intake cooling water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4.1 At least two intake cooling water loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) servicing safety related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown by verifying that each automatic valve servicing safety related equipment actuates to its correct position on a Safety Injection Actuation signal.

SURVEILLANCE REQUIREMENTS (Continued)

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3/4.7.5 ULTIMATE HEAT SINK

LIMITING CONDITION FOR OPERATION

3.7.5.1 The ultimate heat sink shall be OPERABLE with:

a. Cooling water from the Atlantic Ocean providing a water level above -10.5 feet elevation, Mean Low Water, at the plant intake structure, and

b. Two OPERABLE valves in the barrier dam between Big Mud Creek and the intake structure.

APPLICABILITY: At all times.

ACTION:

a. With the water level requirement of the above Specification not satisfied, be in at least HOT STANDBY within six hours and provide cooling water from Big Mud Creek within the next 12 hours.

b. With one isolation valve in the barrier dam between Big Mud Creek and the intake structure inoperable, restore the inoperable valve to OPERABLE status within 72 hours or, within the next 24 hours, install a temporary flow barrier and open the barrier dam isolation valve. The availability of the onsite equipment capable of removing the barrier shall be verified at least once per seven days thereafter.

c. With both of the isolation valves in the barrier dam between the intake structure and Big Mud Creek inoperable, within 24 hours either:

   1) Install both temporary flow barriers and manually open both barrier dam isolation valves. The availability of the onsite equipment capable of removing the barriers shall be verified at least once per seven days thereafter, or

   2) Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.5.1.1 The ultimate heat sink shall be determined OPERABLE at least once per 24 hours by verifying the average water level to be within limits.

4.7.5.1.2 The isolation valves in the barrier dam between the intake structure and Big Mud Creek shall be demonstrated OPERABLE at least once per six months by cycling each valve through at least one complete cycle of full travel.

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PLANT SYSTEMS

3/4.7.7 CONTROL ROOM EMERGENCY VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7.1 The control room emergency ventilation system shall be OPERABLE with:

a. Two booster fans,

b. Two isolation valves in each outside air intake duct,

c. Two isolation valves in the toilet area air exhaust duct,

d. One filter train,

e. At least two air conditioning units, and

f. Two isolation valves in the kitchen area exhaust duct.

NOTE
The control room envelope boundary may be opened intermittently under administrative control.

APPLICABILITY: MODES 1, 2, 3, 4, 5 and 6 or during movement of irradiated fuel assemblies.

ACTION:

MODES 1, 2, 3 and 4:

a. With one booster fan inoperable, restore the inoperable fan to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one isolation valve per air duct inoperable, operation may continue provided the other isolation valve in the same duct is maintained closed; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With the filter train inoperable for reasons other than an inoperable Control Room Envelope boundary, restore the filter train to OPERABLE status within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

d. With only one air conditioning unit OPERABLE, restore at least two air conditioning units to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION: (continued)

MODES 1, 2, 3 and 4: (continued)

e. With the filter train inoperable due to an inoperable Control Room Envelope boundary:

   1. Immediately initiate actions to implement mitigating actions, and

   2. Within 24 hours, verify mitigating actions to ensure Control Room Envelope occupant exposures to radiological, chemical, and smoke hazards will not exceed limits, and

   3. Restore Control Room Envelope boundary to OPERABLE status within 90 days.

   With the above requirements not met, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION: (continued)

MODES 5 and 6 or during movement of irradiated fuel assemblies:

a. With one booster fan inoperable, restore the inoperable fan to OPERABLE status within 7 days or initiate and maintain operation of the remaining OPERABLE control room emergency ventilation system in the recirculation mode or suspend movement of irradiated fuel assemblies.

b. With one isolation valve in an air duct inoperable, maintain the other isolation valve in the same air duct closed or suspend movement of irradiated fuel assemblies.

c. With the filter train inoperable, suspend movement of irradiated fuel assemblies.

d. With only one air conditioning unit OPERABLE, restore at least two air conditioning units to OPERABLE status within 7 days or suspend movement of irradiated fuel assemblies.

SURVEILLANCE REQUIREMENTS

4.7.7.1 The control room emergency ventilation system shall be demonstrated OPERABLE:

a. At least once per 12 hours by verifying that the control room air temperature is ≤ 120°F.

b. At least once per 31 days by:

   1. Initiating flow through the HEPA filter and charcoal adsorber train and verifying that each booster fan operates for at least 15 minutes.

   2. Starting (unless already operating) each air conditioning unit and verifying that it operates for at least 8 hours.

c. By performing required control room emergency ventilation system filter testing in accordance with the Ventilation Filter Testing Program.

SURVEILLANCE REQUIREMENTS (Continued)

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PLANT SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

d. At least once per 18 months by verifying that on a containment isolation signal the system automatically isolates the control room within 35 seconds and switches into a recirculation mode of operation with flow through the HEPA filters and charcoal adsorber banks.

e. By performing required Control Room Envelope unfiltered air inleakage testing in accordance with the Control Room Envelope Habitability Program.

PLANT SYSTEMS

3/4.7.8 ECCS AREA VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.8.1 Two independent ECCS area exhaust air filter trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one ECCS area exhaust air filter train inoperable, restore the inoperable train to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.8.1 Each ECCS area exhaust air filter train shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by initiating, from the control room, flow through the HEPA filter and charcoal adsorber train and verifying that the train operates for at least 15 minutes.

b. By performing required ECCS area ventilation system filter testing in accordance with the Ventilation Filter Testing Program.

c. At least once per 18 months:

   1. Verifying that the air flow distribution is uniform within 20% across HEPA filters and charcoal adsorbers when tested in accordance with ASME N510-1989.

   2. Verifying that the filter train starts on a Safety Injection Actuation Signal.

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3/4.7.9 SEALED SOURCE CONTAMINATION

LIMITING CONDITION FOR OPERATION

3.7.9.1 Each sealed source containing radioactive material either in excess of 100 microcuries of beta and/or gamma emitting material or 5 microcuries of alpha emitting material shall be free of $\geq$ 0.005 microcuries of removable contamination.

APPLICABILITY: At all times.

ACTION:

a. Each sealed source with removable contamination in excess of the above limit shall be immediately withdrawn from use and:

1. Either decontaminated and repaired, or

2. Disposed of in accordance with Commission Regulations.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.9.1.1 Test Requirements - Each sealed source shall be tested for leakage and/or contamination by:

a. The licensee, or

b. Other persons specifically authorized by the Commission or an Agreement State.

The test method shall have a detection sensitivity of at least 0.005 microcuries per test sample.

4.7.9.1.2 Test Frequencies - Each category of sealed sources shall be tested at the frequencies described below.

a. Sources in use (excluding startup sources previously subjected to core flux) - At least once per six months for all sealed sources containing radioactive material:

SURVEILLANCE REQUIREMENTS (Continued)

1. With a half-life greater than 30 days (excluding Hydrogen 3), and

2. In any form other than gas.

b. Stored sources not in use - Each sealed source shall be tested prior to use or transfer to another licensee unless tested within the previous six months. Sealed sources transferred without a certificate indicating the last test date shall be tested prior to being placed into use.

c. Startup sources - Each sealed startup source shall be tested within 31 days prior to being subjected to core flux and following repair or maintenance to the source.

4.7.9.1.3 Reports - A Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days if source leakage tests reveal the presence of $\geq$ 0.005 microcuries of removable contamination.

3/4 7.10 SNUBBERS

LIMITING CONDITION FOR OPERATION

3.7.10 All safety related snubbers shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4. (MODES 5 and 6 for snubbers located on systems required OPERABLE in those MODES).

ACTION:

With one or more safety related snubbers inoperable, within 72 hours replace or restore the inoperable snubber(s) to OPERABLE status or declare the supported system inoperable and follow the appropriate ACTION statement for that system.

SURVEILLANCE REQUIREMENTS

4.7.10 Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

a. Inspection Types

As used in this specification, "type of snubber" shall mean snubbers of the same design and manufacturer, irrespective of capacity.

b. Visual Inspections

Snubbers are categorized as inaccessible or accessible during reactor operation. Each of these categories (inaccessible or accessible) may be inspected independently according to the schedule determined by Table 4.7-3. The visual inspection interval for each category of snubber shall be determined based upon the criteria provided in Table 4.7-3 and the first inspection interval determined using this criteria shall be based upon the previous inspection interval as established by the requirements in effect before Amendment

SURVEILLANCE REQUIREMENTS (Continued)

c. Visual Inspection Acceptance Criteria

Visual inspections shall verify that (1) the snubber has no visible indications of damage or impaired OPERABILITY, (2) attachments to the foundation or supporting structure are functional, and (3) fasteners for the attachment of the snubber to the component and to the snubber anchorage are functional. Snubbers which appear inoperable as a result of visual inspections shall be classified as unacceptable and may be reclassified acceptable for the purpose of establishing the next visual inspection interval, provided that (i) the cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers irrespective of type that may be generically susceptible; and (ii) the affected snubber is functionally tested in the as-found condition and determined OPERABLE per specifications 4.7.10.e and 4.7.10.f, as applicable. All snubbers found connected to an inoperable common hydraulic fluid reservoir shall be counted as unacceptable for determining the next inspection interval. A review and evaluation shall be performed and documented to justify continued operation with an unacceptable snubber. If continued operation cannot be justified, the snubber shall be declared inoperable and the ACTION requirements shall be met.

TABLE 4.7-3
SNUBBER VISUAL INSPECTION INTERVAL

	NUMBER OF UNACCEPTABLE SNUBBERS		
Population or Category (Notes 1 and 2)	Column A Extend Interval (Notes 3 and 6)	Column B Repeat Interval (Notes 4 and 6)	Column C Reduce Interval (Notes 5 and 6)
1	0	0	1
80	0	0	2
100	0	1	4
150	0	3	8
200	2	5	13
300	5	12	25
400	8	18	36
500	12	24	48
750	20	40	78
1000 or greater	29	56	109

SURVEILLANCE REQUIREMENTS (Continued)

Note 1: The next visual inspection interval for a snubber population or category size shall be determined based upon the previous inspection interval and the number of unacceptable snubbers found during that interval. Snubbers may be categorized, based upon their accessibility during power operation, as accessible or inaccessible. These categories may be examined separately or jointly. However, the licensee must make and document that decision before any inspection and shall use that decision as the basis upon which to determine the next inspection interval for that category.

Note 2: Interpolation between population or category sizes and the number of unacceptable snubbers is permissible. Use next lower integer for the value of the limit for Columns A, B, or C if that integer includes a fractional value of unacceptable snubbers as determined by interpolation.

Note 3: If the number of unacceptable snubbers is equal to or less than the number in Column A, the next inspection interval may be twice the previous interval but not greater than 48 months.

Note 4: If the number of unacceptable snubbers is equal to or less than the number in Column B but greater than the number in Column A, the next inspection interval shall be the same as the previous interval.

Note 5: If the number of unacceptable snubbers is equal to or greater than the number in Column C, the next inspection interval shall be two-thirds of the previous interval. However, if the number of unacceptable snubbers is less than the number in Column C but greater than the number in Column B, the next interval shall be reduced proportionally by interpolation, that is, the previous interval shall be reduced by a factor that is one-third of the ratio of the difference between the number of unacceptable snubbers found during the previous interval and the number in Column B to the difference in the numbers in Columns B and C.

Note 6: The provisions of Specification 4.0.2 are applicable for all inspection intervals up to and including 48 months.

SURVEILLANCE REQUIREMENTS (Continued)

d. Functional Tests

At least once per 18 months during shutdown, a representative sample (10% of the safety related snubbers) shall be functionally tested either in place or in a bench test. For each snubber that does not meet the functional test acceptance criteria of Specification 4.7.10.e or 4.7.10.f, an additional 10% of that type of snubber shall be functionally tested. Functional test shall continue until no additional snubbers are found inoperable or all safety related snubbers have been tested.

The representative sample selected for functional testing shall include the various configurations, operating environments and the range of size and capacity of snubbers.

Snubbers identified as "Especially Difficult to Remove" or in "High Exposure Zones During Shutdown" shall also be included in the representative sample.* Safety related hydraulic snubber listings and safety related mechanical snubber listings may be used jointly or separately as the basis for the sampling plan.

In addition to the regular sample, snubbers which failed the previous functional test shall be retested during the next test period. If a spare snubber has been installed in place of a failed snubber, then both the failed snubber (if it is repaired and installed in another position) and the spare snubber shall be retested. Test results of these snubbers shall not result in additional functional testing due to failure.

*Permanent or other exemptions from the functional testing for individual snubbers in these categories may be granted by the Commission only if justifiable basis for exemption is presented and/or snubber life destructive testing was performed to qualify snubber operability for all design conditions at either the completion of their fabrication or at a subsequent date.

If any snubber selected for functional testing either fails to lockup or fails to move, i.e., frozen in place, the cause will be evaluated and if caused by manufacturer or design deficiency, all snubbers of the same design subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated above for snubbers not meeting the functional test acceptance criteria.

e. Hydraulic Snubbers Functional Test Acceptance Criteria

The hydraulic snubber functional test shall verify that:

1. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

2. Snubber bleed, or release rate, where required, is within the specified range in compression or tension.

f. Mechanical Snubbers Functional Test Acceptance Criteria

The mechanical snubber functional test shall verify that:

1. The force that initiates free movement of the snubber rod in either tension or compression is less than the specified maximum drag force.

2. Activation (restraining action) is achieved in both tension and compression.

g. Snubber Service Life Monitoring

A record of the service life of each snubber, the date at which the designated service life commences and the installation and maintenance records on which the designed service life is based shall be maintained.

Concurrent with the first inservice visual inspection and at least once per 18 months thereafter, the installation and maintenance records for each safety related snubber shall be reviewed to verify that the indicated service life has not been exceeded or will not be exceeded by more than 10% prior to the next scheduled snubber service life review. If the indicated service life will be exceeded by more than 10% prior to the next scheduled snubber service life review, the snubber service life shall be reevaluated or the snubber shall be replaced or reconditioned so as to extend its service life beyond the date of the next scheduled service life review. The results of the reevaluation may be used to justify a change to the service life of the snubber. This reevaluation, replacement or reconditioning shall be indicated in the records.

TABLE 3.7-2a

DELETED

TABLE 3.7-2a (CONTINUED)

DELETED

TABLE 3.7-2a (CONTINUED)

DELETED

TABLE 3.7-2a (CONTINUED)

DELETED

TABLE 3.7-2b

DELETED

TABLE 3.7-2b (CONTINUED)

DELETED

TABLE 3.7-2b (CONTINUED)

DELETED

TABLE 3.7-2b (CONTINUED)

DELETED

TABLE 3.7-2b (CONTINUED)

DELETED

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Two separate and independent diesel generator sets each with:

1. Engine-mounted fuel tanks containing a minimum of 152 gallons of fuel,

2. A separate fuel storage system containing a minimum of 16,450 gallons of fuel, and

3. A separate fuel transfer pump.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one offsite circuit of 3.8.1.1.a inoperable, except as provided in Action f. below, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

b. With one diesel generator of 3.8.1.1.b inoperable, demonstrate the OPERABILITY of the A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and if the EDG became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventative maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE EDG by performing Surveillance Requirement 4.8.1.1.2.a.4 within 8 hours, unless it can be confirmed that the cause of the inoperable EDG does not exist on the remaining EDG*; restore the diesel generator to OPERABLE status within 14 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Additionally, within 4 hours from the discovery of concurrent inoperability of required redundant feature(s) (including the steam driven auxiliary feed pump in MODE 1, 2, and 3), declare required feature(s) supported by the inoperable EDG inoperable if its redundant required feature(s) is inoperable.

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* If the absence of any common-cause failure cannot be confirmed, this test shall be completed regardless of when the inoperable EDG is restored to OPERABILITY.

ACTION (continued)

c. With one offsite A.C. circuit and one diesel generator inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within one hour and at least once per 8 hours thereafter; and if the EDG became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventative maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE EDG by performing Surveillance Requirement 4.8.1.1.2.a.4 within 8 hours unless it can be confirmed that the cause of the inoperable EDG does not exist on the remaining EDG*. Restore at least one of the inoperable sources to OPERABLE status within 12 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore the other A.C. power source (offsite circuit or diesel generator) to OPERABLE status in accordance with the provisions of Section 3.8.1.1 ACTION Statement a or b, as appropriate, with the time requirement of that ACTION Statement based on the time of the initial loss of the remaining inoperable A.C. power source. Additionally, within 4 hours from the discovery of concurrent inoperability of required redundant feature(s) (including the steam driven auxiliary feed pump in MODE 1, 2, and 3), declare required feature(s) supported by the inoperable EDG inoperable if its redundant required feature(s) is inoperable.

d. With two of the required offsite A.C. circuits inoperable, restore one of the inoperable offsite sources to OPERABLE status within 24 hours or be in at least HOT STANDBY within the next 6 hours. Following restoration of one offsite source, follow ACTION Statement a. with the time requirement of that ACTION Statement based on the time of the initial loss of the remaining inoperable offsite A.C. circuit.

* If the absence of any common-cause failure cannot be confirmed, this test shall be completed regardless of when the inoperable EDG is restored to OPERABILITY.

ACTION (continued)

e. With two of the above required diesel generators inoperable, demonstrate the OPERABILITY of two offsite A.C. circuits by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; restore one of the inoperable diesel generators to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Following restoration of one diesel generator unit, follow ACTION Statement b. with the time requirement of that ACTION Statement based on the time of initial loss of the remaining inoperable diesel generator.

f. With one Unit 1 startup transformer (1A or 1B) inoperable and with a Unit 2 startup transformer (2A or 2B) connected to the same A or B offsite power circuit and administratively available to both units, then should Unit 2 require the use of the startup transformer administratively available to both units, Unit 1 shall demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the inoperable startup transformer to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be:

a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments, indicated power availability; and

b. Demonstrated OPERABLE at least once per 18 months by transferring (manually and automatically) unit power supply from the auxiliary transformer to the startup transformer.

4.8.1.1.2 Each diesel generator shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by:

1. Verifying fuel level in the engine-mounted fuel tank,

2. Verifying the fuel level in the fuel storage tank,

3. Verifying the fuel transfer pump can be started and transfers fuel from the storage system to the engine-mounted tank,

SURVEILLANCE REQUIREMENTS (continued)

4. Verifying the diesel starts from ambient condition and accelerates to approximately 900 rpm in less than or equal to 10 seconds**. The generator voltage and frequency shall be 4160 ± 420 volts and 60 ± 1.2 Hz within 10 seconds after the start signal**. The diesel generator shall be started for this test by using one of the following signals:

   a) Manual/Local

   b) Simulated loss-of-offsite power by itself.

   c) Simulated loss-of-offsite power in conjunction with an ESF actuation test signal.

   d) An ESF actuation test signal by itself.

5. Verifying the generator is synchronized, loaded to greater than or equal to 3500 kW in accordance with the manufacturer's recommendations and operates within a load band of 3300 to 3500 kW*** for at least an additional 60 minutes, and

6. Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

b. By removing accumulated water:

1. From the engine-mounted fuel tank at least once per 31 days and after each occasion when the diesel is operated for greater than 1 hour, and

2. From the storage tank at least once per 92 days.

** The diesel generator start (10 sec.) from ambient conditions shall be performed at least once per 184 days in these surveillance tests. All other diesel generator starts for the purposes of this surveillance testing may be preceded by an engine prelube period and may also include warmup procedures (e.g., gradual acceleration) as recommended by the manufacturer so that mechanical stress and wear on the diesel generator is minimized.

*** The indicated load band is meant as guidance to avoid routine overloading. Variations in loads in excess of the band due to changing bus loads shall not invalidate this test.

SURVEILLANCE REQUIREMENTS (Continued)

c. Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of the Diesel Fuel Oil Testing Program.

d. DELETED

e. At least once per 18 months during shutdown by:

   1. DELETED

   2. Verifying generator capability to reject a load of greater than or equal to 600 hp while maintaining voltage at 4160 $\pm$ 420 volts and frequency at 60 $\pm$ 1.2 Hz.

   3. Simulating a loss of offsite power by itself, and:

      a) Verifying deenergization of the emergency busses and load shedding from the emergency busses.

b) Verifying the diesel starts on the auto-start signal****, energizes the emergency busses with permanently connected loads within 10 seconds, energizes the auto-connected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at 4160 ± 420 volts and 60 ± 1.2 Hz during this test.

4. Verifying that on an ESF actuation test signal (without loss-of-offsite power) the diesel generator starts**** on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The steady state generator voltage and frequency shall be 4160 ± 420 volts and 60 ± 1.2 Hz within 10 seconds after the auto-start signal; the generator voltage and frequency shall be maintained within these limits during this test.

5. Simulating a loss-of-offsite power in conjunction with an ESF actuation test signal, and

   a) Verifying deenergization of the emergency busses and load shedding from the emergency busses.

   b) Verifying the diesel starts on the auto-start signal****, energizes the emergency busses with permanently connected loads within 10 seconds, energizes the auto-connected emergency (accident) loads through the auto-sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at 4160 ± 420 volts and 60 ± 1.2 Hz during this test.

   c) Verifying that all automatic diesel generator trips, except engine overspeed and generator differential, are automatically bypassed upon loss of voltage on the emergency bus concurrent with a safety injection signal.

****This test may be conducted in accordance with the manufacturer's recommendations concerning engine prelube period.

SURVEILLANCE REQUIREMENTS (Continued)

6. Verifying the diesel generator operates for at least 24 hours****. During the first 2 hours of this test, the diesel generator shall be loaded within a load band of 3800 to 3960 kW# and during the remaining 22 hours of this test, the diesel generator shall be loaded within a load band of 3300 to 3500 kW#. The generator voltage and frequency shall be 4160 ± 420 volts and 60 ± 1.2 Hz within 10 seconds after the start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

7. Verifying that the auto-connected loads do not exceed the 2000-hour rating of 3730 kW.

8. Verifying the diesel generator's capability to:

   a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power.

   b) Transfer its loads to the offsite power source, and

   c) Be restored to its standby status.

9. Verifying that with the diesel generator operating in a test mode (connected to its bus), a simulated safety injection signal overrides the test mode by (1) returning the diesel generator to standby operation and (2) automatically energizes the emergency loads with offsite power.

10. Verifying that the fuel transfer pump transfers fuel from each fuel storage tank to the engine-mounted tanks of each diesel via the installed cross connection lines.

11. Verifying that the automatic load sequence timers are operable with the interval between each load block within ± 1 second of its design interval.

f. At least once per ten years or after any modification which could affect diesel generator independence by starting**** the diesel generators simultaneously, during shutdown, and verifying that the diesel generators accelerate to approximately 900 rpm in less than or equal to 10 seconds.

#This band is meant as guidance to avoid routine overloading of the engine. Variations in load in excess of this band due to changing bus loads shall not invalidate this test.

****This test may be conducted in accordance with the manufacturer's recommendations concerning engine prelube period.

SURVEILLANCE REQUIREMENTS (continued)

g. At least once per ten years by:

1. Draining each fuel storage tank, removing the accumulated sediment and cleaning the tank using an appropriate cleaning compound, and

2. Performing a pressure test of those portions of the diesel fuel oil system designed to USAS B31.7 Class 3 requirements in accordance with the Inservice Inspection Program.

4.8.1.1.3 Reports -- (Not Used)

4.8.1.1.4 The Class 1E underground cable system shall be demonstrated OPERABLE within 30 days after the movement of any loads in excess of 80% of the ground surface design basis load over the cable ducts by pulling a mandrel with a diameter of at least 80% of the duct's inside diameter through a duct exposed to the maximum loading (duct nearest the ground's surface) and verifying that the duct has not been damaged.

TABLE 4.8-1

DIESEL GENERATOR TEST SCHEDULE

(NOT USED)

ELECTRICAL POWER SYSTEMS

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.1.2 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. One circuit between the offsite transmission network and the onsite Class 1E distribution system, and

b. One diesel generator set with:

1. Engine-mounted fuel tanks containing a minimum of 152 gallons of fuel,

2. A fuel storage system containing a minimum of 16,450 gallons of fuel, and

3. A fuel transfer pump.

APPLICABILITY: MODES 5 and 6.

ACTION:

With less than the above minimum required A.C. electrical power sources OPERABLE, immediately suspend all operations involving CORE ALTERATIONS, operations involving positive reactivity additions that could result in loss of required SHUTDOWN MARGIN or boron concentration, movement of irradiated fuel, or crane operation with loads over the fuel storage pool. In addition, when in MODE 5 with the reactor coolant loops not filled, or in MODE 6 with the water level less than 23 feet above the top of irradiated fuel assemblies seated within the reactor vessel, immediately initiate corrective action to restore the required sources to OPERABLE status as soon as possible.

SURVEILLANCE REQUIREMENTS

4.8.1.2.1 The above required A.C. electrical power sources shall be demonstrated OPERABLE by the performance of each of the Surveillance Requirements of 4.8.1.1.1 and 4.8.1.1.2 except for requirement 4.8.1.1.2a.5.

ELECTRICAL POWER SYSTEMS

3/4.8.2 ONSITE POWER DISTRIBUTION SYSTEMS

A.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 The following A.C. electrical busses shall be OPERABLE and energized from sources of power other than the diesel generator sets:

4160	volt Emergency Bus	1A3
4160	volt Emergency Bus	1B3
480	volt Emergency Bus	1A2
480	volt Emergency Bus	1B2
480	volt Emergency MCC Busses	1A5, 1A6, 1A7
480	volt Emergency MCC Busses	1B5, 1B6, 1B7
120	volt A.C. Instrument Bus	1MA
120	volt A.C. Instrument Bus	1MB
120	volt A.C. Instrument Bus	1MC
120	volt A.C. Instrument Bus	IMD

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With less than the above complement of A.C. busses OPERABLE, restore the inoperable bus to OPERABLE status within 8 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.1 The specified A.C. busses shall be determined OPERABLE and energized from A.C. sources other than the diesel generators at least once per 7 days by verifying indicated power availability.

ELECTRICAL POWER SYSTEMS

A.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.2 As a minimum, the following A.C. electrical busses shall be OPERABLE and energized from sources of power other than a diesel generator set but aligned to an OPERABLE diesel generator set:

1 - 4160 volt Emergency Bus

1 - 480 volt Emergency Bus

3 - 480 volt Emergency MCC Busses

2 - 120 volt A.C. Instrument Busses

APPLICABILITY: MODES 5 and 6

ACTION:

With less than the above complement of A.C. busses OPERABLE and energized, establish CONTAINMENT INTEGRITY within 8 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.2 The specified A.C. busses shall be determined OPERABLE and energized from A.C. sources other than the diesel generators at least once per 7 days by verifying indicated power availability.

D.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.3 As a minimum the following D.C. electrical sources shall be OPERABLE:

a. 125-volt D.C. bus No. 1A, 125-volt Battery bank No. 1A and a full capacity charger.

b. 125-volt D.C. bus No. 1B, 125-volt Battery bank No. 1B and a full capacity charger.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one of the required battery banks or busses inoperable, restore the inoperable battery bank or bus to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one of the required full capacity chargers inoperable, demonstrate the OPERABILITY of its associated battery banks by performing Surveillance Requirement 4.8.2.3.2.a.1 within 1 hour, and at least once per 8 hours thereafter. If any Category A limit in Table 4.8-2 is not met, declare the battery inoperable.

SURVEILLANCE REQUIREMENTS

4.8.2.3.1 Each D.C. bus train shall be determined OPERABLE and energized at least once per 7 days by verifying indicated power availability.

4.8.2.3.2 Each 125-volt battery bank and charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

1. The parameters in Table 4.8-2 meet the Category A limits, and

2. The total battery terminal voltage is greater than or equal to 129-volts on float charge.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 92 days and within 7 days after a battery discharge with battery terminal voltage below 110 volts, or battery overcharge with battery terminal voltage above 150 volts, by verifying that:

1. The parameters in Table 4.8-2 meet the Category B limits,

2. There is no visible corrosion at either terminals or connectors, or the connection resistance of these items is less than 150 x 10^{-6} ohms, and

3. The average electrolyte temperature of 10% (60 cells total) of connected cells is above 50°F.

c. At least once per 18 months by verifying that:

1. The cells, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration,

2. The cell-to-cell and terminal connections are clean, tight, and coated with anti-corrosion material,

3. The resistance of each cell-to-cell and terminal connection is less than or equal to 150 x 10^{-6} ohms, and

4. The battery charger will supply at least 300 amperes at 140 volts for at least 6 hours.

d. At least once per 18 months, during shutdown, by verifying that the battery capacity is adequate to supply and maintain in OPERABLE status all of the actual or simulated emergency loads for the design duty cycle when the battery is subjected to a battery service test.

e. At least once per 60 months, during shutdown, by verifying that the battery capacity is at least 80% of the manufacturer's rating when subjected to a performance discharge test. This performance discharge test may be performed in lieu of the battery service test required by Surveillance Requirement 4.8.2.3.2.d.

f. Annual performance discharge tests of battery capacity shall be given to any battery that shows signs of degradation or has reached 85% of the service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests, or is below 90% of the manufacturer's rating.

TABLE 4.8-2

BATTERY SURVEILLANCE REQUIREMENT

	CATEGORY A(1)	CATEGORY B(2)	
Parameter	Limits for each designated pilot cell	Limits for each connected cell	Allowable(3) value for each connected cell
Electrolyte Level	>Minimum level indication mark, and ≤ 1/4" above maximum level indication mark	>Minimum level indication mark, and ≤ 1/4" above maximum level indication mark	Above top of plates and not overflowing
Float Voltage	≥ 2.13 volts	≥ 2.13 volts(c)	> 2.07 volts
Specific Gravity(a)	≥ 1.195(b)	≥ 1.190 Average of all connected cells > 1.200	Not more than .020 below the average of all connected cells Average of all connected cells ≥ 1.190(b)

(a) Corrected for electrolyte temperature and level.

(b) Or battery charging current is less than 2 amps when on charge.

(c) Corrected for average electrolyte temperature.

(1) For any Category A parameter(s) outside the limit(s) shown, the battery may be considered OPERABLE provided that within 24 hours all the Category B measurements are taken and found to be within their allowable values, and provided all Category A and B parameter(s) are restored to within limits within the next 6 days.

(2) For any Category B parameter(s) outside the limit(s) shown, the battery may be considered OPERABLE provided that the Category B parameters are within their allowable values and provided the Category B parameter(s) are restored to within limits within 7 days.

(3) With any Category B parameter not within its allowable value, declare the battery inoperable.

D.C. DISTRIBUTION - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.8.2.4 As a minimum, the following D.C. electrical equipment and bus shall be energized and OPERABLE:

1 - 125-volt D.C. bus, and

1 - 125-volt battery bank and charger supplying the above D.C. bus.

APPLICABILITY: MODES 5 and 6.

ACTION:

With less than the above complement of D.C. equipment and bus OPERABLE, establish CONTAINMENT INTEGRITY within 8 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.4.1 The above required 125-volt D.C. bus shall be determined OPERABLE and energized at least once per 7 days by verifying indicated power availability.

4.8.2.4.2 The above required 125-volt battery bank and charger shall be demonstrated OPERABLE per Surveillance Requirement 4.8.2.3.2.

3/4.9 REFUELING OPERATIONS

BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.9.1 With the reactor vessel head unbolted or removed, the boron concentration of all filled portions of the Reactor Coolant System and the refueling cavity shall be maintained within the limit specified in the COLR.

APPLICABILITY: MODE 6*.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at $\geq$ 40 gpm of greater than or equal to 1720 ppm boron or its equivalent to restore boron concentration to within limits.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The boron concentration limit shall be determined prior to:

a. Removing or unbolting the reactor vessel head, and

b. Withdrawal of any full length CEA in excess of 3 feet from its fully inserted position.

4.9.1.2 The boron concentration of the refueling cavity shall be determined by chemical analysis at least 3 times per 7 days with a maximum time interval between samples of 72 hours.

* The reactor shall be maintained in MODE 6 when the reactor vessel head is unbolted or removed.

REFUELING OPERATIONS

INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.9.2 As a minimum, two wide range logarithmic neutron flux monitors shall be operating, each with continuous visual indication in the control room and one with audible indication in the containment.

APPLICABILITY: MODE 6.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or operations that would cause introduction into the RCS, coolant with boron concentration less than required to meet the boron concentration of Technical Specification 3.9.1. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.2 Each wide range logarithmic neutron flux monitor shall be demonstrated OPERABLE by performance of:

a. A CHANNEL FUNCTIONAL TEST at least once per 7 days.

b. A CHANNEL FUNCTIONAL TEST within 8 hours prior to the start of CORE ALTERATIONS, and

c. A CHANNEL CHECK at least once per 12 hours during CORE ALTERATIONS.

DECAY TIME

LIMITING CONDITION FOR OPERATION

3.9.3 The reactor shall be subcritical for a minimum of 72 hours.

APPLICABILITY: During movement of irradiated fuel in the reactor pressure vessel.

ACTION:

With the reactor subcritical for less than 72 hours, suspend all operations involving movement of irradiated fuel in the reactor pressure vessel. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.3 The reactor shall be determined to have been subcritical for at least 72 hours by verification of the date and time of subcriticality prior to movement of irradiated fuel in the reactor pressure vessel.

CONTAINMENT PENETRATIONS

LIMITING CONDITION FOR OPERATION

3.9.4 The containment penetrations shall be in the following status:

a. The equipment door closed and held in place by a minimum of four bolts.

b. A minimum of one door in each airlock is closed.

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere shall be either:

1. Closed by isolation valve, blind flange, or manual valve except for valves that are open on an intermittent basis under administrative control, or

2. Be capable of being closed by an OPERABLE automatic containment isolation valve, or

3. Be capable of being closed by an OPERABLE containment vacuum relief valve.

Note: Penetration flow path(s) providing direct access from the containment atmosphere to the outside atmosphere may be unisolated under administrative controls.

APPLICABILITY: During movement of recently irradiated fuel within the containment.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving movement of recently irradiated fuel in the containment. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.4 Each of the above required containment penetrations shall be determined to be either in its closed/isolated condition or capable of being closed by an OPERABLE automatic containment isolation valve within 72 hours prior to the start of and at least once per 7 days during movement of recently irradiated fuel in the containment by:

a. Verifying the penetrations are in their closed/isolated condition, or

b. Testing of containment isolation valves per the applicable portions of Specifications 4.6.3.1.1. and 4.6.3.1.2.

REFUELING OPERATIONS

COMMUNICATIONS

LIMITING CONDITION FOR OPERATION

3.9.5 Direct communications shall be maintained between the control room and personnel at the refueling station.

APPLICABILITY: During CORE ALTERATIONS.

ACTION:

When direct communications between the control room and personnel at the refueling station cannot be maintained, suspend all CORE ALTERATIONS. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.5 Direct communications between the control room and personnel at the refueling station shall be demonstrated within one hour prior to the start of and at least once per 12 hours during CORE ALTERATIONS.

MANIPULATOR CRANE OPERABILITY

LIMITING CONDITION FOR OPERATION

3.9.6 The manipulator crane shall be used for movement of CEAs or fuel assemblies and shall be OPERABLE with:

a. A minimum capacity of 2000 pounds, and

b. An overload cut off limit of $\leq$ 3000 pounds.

APPLICABILITY: During movement of CEAs or fuel assemblies within the reactor pressure vessel.

ACTION:

With the requirements for crane OPERABILITY not satisfied, suspend use of any inoperable manipulator crane from operations involving the movement of CEAs and fuel assemblies within the reactor pressure vessel.

SURVEILLANCE REQUIREMENTS

4.9.6 The manipulator crane used for movement of CEAs or fuel assemblies within the reactor pressure vessel shall be demonstrated OPERABLE within 72 hours prior to the start of such operations by performing a load test of at least 2500 pounds and demonstrating an automatic load cut off before the crane load exceeds 3000 pounds.

INTENTIONALLY DELETED

REFUELING OPERATIONS

SHUTDOWN COOLING AND COOLANT CIRCULATION

HIGH WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.8.1 At least one shutdown cooling loop shall be OPERABLE and in operation*.

APPLICABILITY: MODE 6 when the water level above the top of irradiated fuel assemblies seated within the reactor pressure vessel is greater than or equal to 23 feet.

ACTION:

a. With less than one shutdown cooling loop in operation, suspend all operations involving an increase in reactor decay heat load or operations that would cause introduction into the RCS, coolant with boron concentration less than required to meet the boron concentration of Technical Specification 3.9.1. Close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere within 4 hours.

b. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.8.1 At least one shutdown cooling loop shall be verified to be in operation and circulating reactor coolant at a flow rate of greater than or equal to 3000 gpm at least once per 12 hours.

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* The shutdown cooling loop may be removed from operation for up to 1 hour per 8 hour period during the performance of CORE ALTERATIONS in the vicinity of reactor pressure vessel hot legs, provided no operations are permitted that would cause introduction into the RCS, coolant with boron concentration less than required to meet the SHUTDOWN MARGIN of Technical Specification 3.9.1.

LOW WATER LEVEL

LIMITING CONDITION FOR OPERATION

3.9.8.2 Two independent shutdown cooling loops shall be OPERABLE and at least one shutdown cooling loop shall be in operation.*

APPLICABILITY: MODE 6 when the water level above the top of irradiated fuel assemblies seated within the reactor pressure vessel is less than 23 feet.

ACTION:

a. With less than the required shutdown cooling loops OPERABLE, within one (1) hour 1) initiate corrective action to return the required loops to OPERABLE status, or 2) establish greater than or equal to 23 feet of water above irradiated fuel assemblies seated within the reactor pressure vessel.

b. With no shutdown cooling loop in operation, suspend operations that would cause introduction into the RCS, coolant with boron concentration less than required to meet the boron concentration of Technical Specification 3.9.1. and within one (1) hour initiate corrective action to return the required shutdown cooling loop to operation. Close all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere within 4 hours.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.8.2 At least one shutdown cooling loop shall be verified to be in operation and circulating reactor coolant at a flow rate of greater than or equal to 3000 gpm at least once per 12 hours.

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* One required shutdown cooling loop may be inoperable for up to 2 hours for surveillance testing, provided that the other shutdown cooling loop is OPERABLE and in operation.

REFUELING OPERATIONS

CONTAINMENT ISOLATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.9.9 The containment isolation system shall be OPERABLE.

APPLICABILITY: During movement of recently irradiated fuel assemblies within containment.

ACTION:

With the containment isolation system inoperable, either suspend all operations involving movement of recently irradiated fuel assemblies within containment or close each of the penetrations providing direct access from the containment atmosphere to the outside atmosphere.

SURVEILLANCE REQUIREMENTS

4.9.9 The containment isolation system shall be demonstrated OPERABLE within 72 hours prior to the start of and at least once per 7 days during movement of recently irradiated fuel assemblies by verifying that containment isolation occurs on manual initiation and on a high radiation signal from two of the containment radiation monitoring instrumentation channels.

REFUELING OPERATIONS

WATER LEVEL - REACTOR VESSEL

LIMITING CONDITION FOR OPERATION

3.9.10 At least 23 feet of water shall be maintained over the top of irradiated fuel assemblies seated within the reactor pressure vessel.

APPLICABILITY: During CORE ALTERATIONS.
During movement of irradiated fuel assemblies within containment.

ACTION:

With the requirements of the above specifications not satisfied, immediately suspend CORE ALTERATIONS and movement of irradiated fuel assemblies within containment, and immediately initiate action to restore refueling cavity water level to within limits.

SURVEILLANCE REQUIREMENTS

4.9.10 The water level shall be determined to be at least its minimum required depth within 2 hours prior to the start of and at least once per 24 hours thereafter during CORE ALTERATIONS and during movement of irradiated fuel assemblies within containment.

SPENT FUEL STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.11 The Spent Fuel Pool shall be maintained with:

a. The fuel storage pool water level greater than or equal to 23 ft over the top of irradiated fuel assemblies seated in the storage racks, and

b. The fuel storage pool boron concentration greater than or equal to 1720 ppm.

APPLICABILITY: Whenever irradiated fuel assemblies are in the spent fuel storage pool.

ACTION:

a. With the water level requirement not satisfied, immediately suspend all movement of fuel assemblies and crane operations with loads in the fuel storage areas and restore the water level to within its limit within 4 hours.

b. With the boron concentration requirement not satisfied, immediately suspend all movement of fuel assemblies in the fuel storage pool and initiate action to restore the fuel storage pool boron concentration to within the required limit.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.11 The water level in the spent fuel storage pool shall be determined to be at least its minimum required depth at least once per 7 days when irradiated fuel assemblies are in the fuel storage pool.

4.9.11.1 Verify the fuel storage pool boron concentration is within limit at least once per 7 days.

FUEL POOL VENTILATION SYSTEM – FUEL STORAGE

LIMITING CONDITION FOR OPERATION

3.9.12 At least one fuel pool ventilation system shall be OPERABLE.

APPLICABILITY: Whenever recently irradiated fuel is in the spent fuel pool.

ACTION:

a. With no fuel pool ventilation system OPERABLE, suspend all operations involving movement of recently irradiated fuel within the spent fuel pool or crane operation with loads over the recently irradiated spent fuel until at least one fuel pool ventilation system is restored to OPERABLE status.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.12 The above required fuel pool ventilation system shall be demonstrated OPERABLE:

a. At least once per 31 days by initiating flow through the HEPA filter and charcoal adsorber train and verifying that the train operates for at least 15 minutes.

b. At least once per 18 months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire or chemical release in any ventilation zone communicating with the system by:

SURVEILLANCE REQUIREMENTS (Continued)

1. Verifying that the charcoal adsorbers remove ≥ 99% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place in accordance with ANSI N510-1975 while operating the ventilation system at a flow rate of 10,350 cfm ± 10%.

2. Verifying that the HEPA filter banks remove ≥ 99% of the DOP when they are tested in-place in accordance with ANSI N510-1975 while operating the ventilation system at a flow rate of 10,350 cfm ± 10%.

3. Verifying that a laboratory analysis of a carbon sample from either at least one test canister or at least two carbon samples removed from one of the charcoal adsorbers demonstrates a removal efficiency of ≥ 85% for radioactive methyl iodide when the sample is tested in accordance with ASTM D3803-1989 (30°C, 95% RH). The carbon samples not obtained from test canisters shall be prepared by either:

    a) Emptying one entire bed from a removed adsorber tray, mixing the adsorbent thoroughly, and obtaining samples at least two inches in diameter and with a length equal to the thickness of the bed, or

    b) Emptying a longitudinal sample from an adsorber tray, mixing the adsorbent thoroughly, and obtaining samples at least two inches in diameter and with a length equal to the thickness of the bed.

4. Verifying a system flow rate of 10,350 cfm ± 10% during system operation when tested in accordance with ANSI N510-1975.

SURVEILLANCE REQUIREMENTS (Continued)

c. At least once per 18 months by:

   1. Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is < 4.15 inches Water Gauge while operating the ventilation system at a flow rate of 10,350 cfm ± 10%.

   2. Verifying that the air flow distribution is uniform within 20% across HEPA filters and charcoal adsorbers when tested in accordance with ANSI N510-1975.

   3. Verifying that the ventilation system maintains the spent fuel storage pool area at a negative pressure of ≥ 1/8 inches Water Gauge relative to the outside atmosphere during system operation.

d. After each complete or partial replacement of a HEPA filter bank by verifying that the HEPA filter banks remove ≥ 99% of the DOP when they are tested in-place in accordance with ANSI N510-1975 while operating the ventilation system at a flow rate of 10,350 cfm ± 10%.

e. After each complete or partial replacement of a charcoal adsorber bank by verifying that the charcoal adsorbers remove ≥ 99% of a halogenated hydrocarbon refrigerant test gas when they are tested in-place in accordance with ANSI N510-1975 while operating the ventilation system at a flow rate of 10,350 cfm ± 10%.

INTENTIONALLY DELETED

3/4.9.14 DECAY TIME - STORAGE POOL

LIMITING CONDITION FOR OPERATION

3.9.14 The irradiated fuel assemblies in the fuel storage pool shall have decayed for at least 1180 hours, unless more than one-third core is placed into the pool, in which case the irradiated fuel assemblies shall have decayed for 1490 hours.

APPLICABILITY: Prior to movement of the spent fuel cask into the fuel cask compartment.

ACTION:

With irradiated fuel assemblies having a decay time of less than 1180 hours, or 1490 hours in the case of more than one-third core discharge, suspend all activities involving movement of the spent fuel cask into the fuel cask compartment. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.14. The irradiated fuel assemblies in the fuel storage pool shall have been determined to have decayed for at least 1180 hours, or 1490 hours in the case of more than one-third core discharge, by verification of the date and time from the most recent subcriticality prior to movement of the spent fuel cask into the fuel cask compartment.

SHUTDOWN MARGIN

LIMITING CONDITION FOR OPERATION

3.10.1 The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 may be suspended for measurement of CEA worth and shutdown margin provided reactivity equivalent to at least the highest estimated CEA worth is available for trip insertion from OPERABLE CEA(s).

APPLICABILITY: MODE 2.

ACTION:

a. With any full length CEA not fully inserted and with less than the above reactivity equivalent available for trip insertion, immediately initiate and continue boration at $\geq$ 40 gpm of 1720 ppm boric acid solution or its equivalent until the SHUTDOWN MARGIN required by Specification 3.1.1.1 is restored.

b. With all full length CEAs inserted and the reactor subcritical by less than the above reactivity equivalent, immediately initiate and continue boration at $\geq$ 40 gpm of 1720 ppm boric acid solution or its equivalent until the SHUTDOWN MARGIN required by Specification 3.1.1.1 is restored.

SURVEILLANCE REQUIREMENTS

4.10.1.1 The position of each full length CEA required either partially or fully withdrawn shall be determined at least once per 2 hours.

4.10.1.2 Each CEA not fully inserted shall be demonstrated capable of full insertion when tripped from at least the 50% withdrawn position within 7 days prior to reducing the SHUTDOWN MARGIN to less than the limits of Specification 3.1.1.1.

SPECIAL TEST EXCEPTIONS

GROUP HEIGHT, INSERTION AND POWER DISTRIBUTION LIMITS

LIMITING CONDITION FOR OPERATION

3.10.2 The group height, insertion and power distribution limits of Specifications 3.1.1.4, 3.1.3.1, 3.1.3.5, 3.1.3.6, 3.2.3 and 3.2.4 may be suspended during the performance of PHYSICS TESTS provided:

a. The THERMAL POWER is restricted to the test power plateau which shall not exceed 85% of RATED THERMAL POWER, and

b. The limits of Specification 3.2.1 are maintained and determined as specified in Specification 4.10.2.2 below.

APPLICABILITY: MODES 1 and 2.

ACTION:

With any of the limits of Specification 3.2.1 being exceeded while the requirements of Specifications 3.1.1.4, 3.1.3.1, 3.1.3.5, 3.1.3.6, 3.2.3 and 3.2.4 are suspended, either:

a. Reduce THERMAL POWER sufficiently to satisfy the requirements of Specification 3.2.1, or

b. Be in HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.10.2.1 The THERMAL POWER shall be determined at least once per hour during PHYSICS TESTS in which the requirements of Specifications 3.1.1.4, 3.1.3.1, 3.1.3.5, 3.1.3.6, 3.2.3, or 3.2.4 are suspended and shall be verified to be within the test power plateau.

4.10.2.2 The linear heat rate shall be determined to be within the limits of Specification 3.2.1 by monitoring it continuously with the Incore Detector Monitoring System pursuant to the requirements of Specifications 4.2.1.4 during PHYSICS TESTS above 5% of RATED THERMAL POWER in which the requirements of Specifications 3.1.1.4, 3.1.3.1, 3.1.3.5, 3.1.3.6, 3.2.3, or 3.2.4 are suspended.

SPECIAL TEST EXCEPTIONS

PRESSURE/TEMPERATURE LIMITATION - REACTOR CRITICALITY

LIMITING CONDITION FOR OPERATION

3.10.3 This specification deleted.

SURVEILLANCE REQUIREMENTS

4.10.3 This specification deleted.

SPECIAL TEST EXCEPTIONS

PHYSICS TESTS

LIMITING CONDITION FOR OPERATION

3.10.4 This specification deleted.

SURVEILLANCE REQUIREMENTS

4.10.4 This specification deleted.

SPECIAL TEST EXCEPTIONS

CENTER CEA MISALIGNMENT

LIMITING CONDITION FOR OPERATION

3.10.5 The requirements of Specifications 3.1.3.1 and 3.1.3.6 may be suspended during the performance of PHYSICS TESTS to determine the isothermal temperature coefficient and power coefficient provided:

a. Only the center CEA (CEA #1) is misaligned, and

b. The limits of Specification 3.2.1 are maintained and determined as specified in Specification 4.10.5.2 below.

APPLICABILITY: MODES 1 and 2.

ACTION:

With any of the limits of Specification 3.2.1 being exceeded while the requirements of Specifications 3.1.3.1 and 3.1.3.6 are suspended, either:

a. Reduce THERMAL POWER sufficiently to satisfy the requirements of Specification 3.2.1, or

b. Be in HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.10.5.1 The THERMAL POWER shall be determined at least once per hour during PHYSICS TESTS in which the requirements of Specifications 3.1.3.1 and/or 3.1.3.6 are suspended and shall be verified to be within the test power plateau.

4.10.5.2 The linear heat rate shall be determined to be within the limits of Specification 3.2.1 by monitoring it continuously with the Incore Detector Monitoring System pursuant to the requirements of Specification 4.2.1.4 during PHYSICS TESTS above 5% of RATED THERMAL POWER in which the requirements of Specifications 3.1.3.1 and/or 3.1.3.6 are suspended.

Pages 3/4 11-2 through 3/4 11-13 (Amendment No. 123) have been deleted from the Technical Specifications. The next page is 3/4 11-14.

RADIOACTIVE EFFLUENTS

EXPLOSIVE GAS MIXTURE

LIMITING CONDITION FOR OPERATION

3.11.2.5 The concentration of oxygen in the waste gas decay tanks shall be limited to less than or equal to 2% by volume whenever the hydrogen concentration exceeds 4% by volume.

APPLICABILITY: At all times.

ACTION:

a. With the concentration of oxygen in the waste gas decay tank greater than 2% by volume but less than or equal to 4% by volume, reduce the oxygen concentration to the above limits within 48 hours.

b. With the concentration of oxygen in the waste gas decay tank greater than 4% by volume and the hydrogen concentration greater than 2% by volume, immediately suspend all additions of waste gases to the system and immediately commence reduction of the concentration of oxygen to less than or equal to 2% by volume.

c. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.5.1 The concentration of oxygen in the waste gas decay tank shall be determined to be within the above limits by continuously* monitoring the waste gases in the on service waste gas decay tank.

4.11.2.5.2 With the oxygen concentration in the on service waste gas decay tank greater than 2% by volume as determined by Specification 4.11.2.5.1, the concentration of hydrogen in the waste gas decay tank shall be determined to be within the above limits by gas partitioner sample at least once per 24 hours.

* When continuous monitoring capability is inoperable, waste gases shall be monitored in accordance with the actions specified for the Waste Gas Decay Tanks Explosive Gas Monitoring System in Chapter 13 of the Updated Final Safety Analysis Report.

RADIOACTIVE EFFLUENTS

GAS STORAGE TANKS

LIMITING CONDITION FOR OPERATION

3.11.2.6 The quantity of radioactivity contained in each gas storage tank shall be limited to less than or equal to 285,000 curies noble gases (considered as Xe-133).

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any gas storage tank exceeding the above limit, immediately suspend all additions of radioactive material to the tank.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.6 The quantity of radioactive material contained in each gas storage tank shall be determined to be within the above limit at least once per 24 hours when radioactive materials are being added to the tank when reactor coolant system activity exceeds $\frac{100}{\bar{E}}$.

SECTION 5.0

DESIGN FEATURES

5.0 DESIGN FEATURES

5.1 SITE

EXCLUSION AREA

5.1.1 The exclusion area is shown on Figure 5.1-1.

LOW POPULATION ZONE

5.1.2 The low population zone is shown on Figure 5.1-1.

5.2 CONTAINMENT

CONFIGURATION

5.2.1 The containment structure is comprised of a steel containment vessel, having the shape of a right circular cylinder with a hemispherical dome and ellipisoidal bottom, surrounded by a reinforced concrete shield building. The radius of the shield building is at least 4 feet greater than the radius of circular cylinder portion of the containment vessel at any point.

5.2.1.1. CONTAINMENT VESSEL

a. Nominal inside diameter = 140 feet.

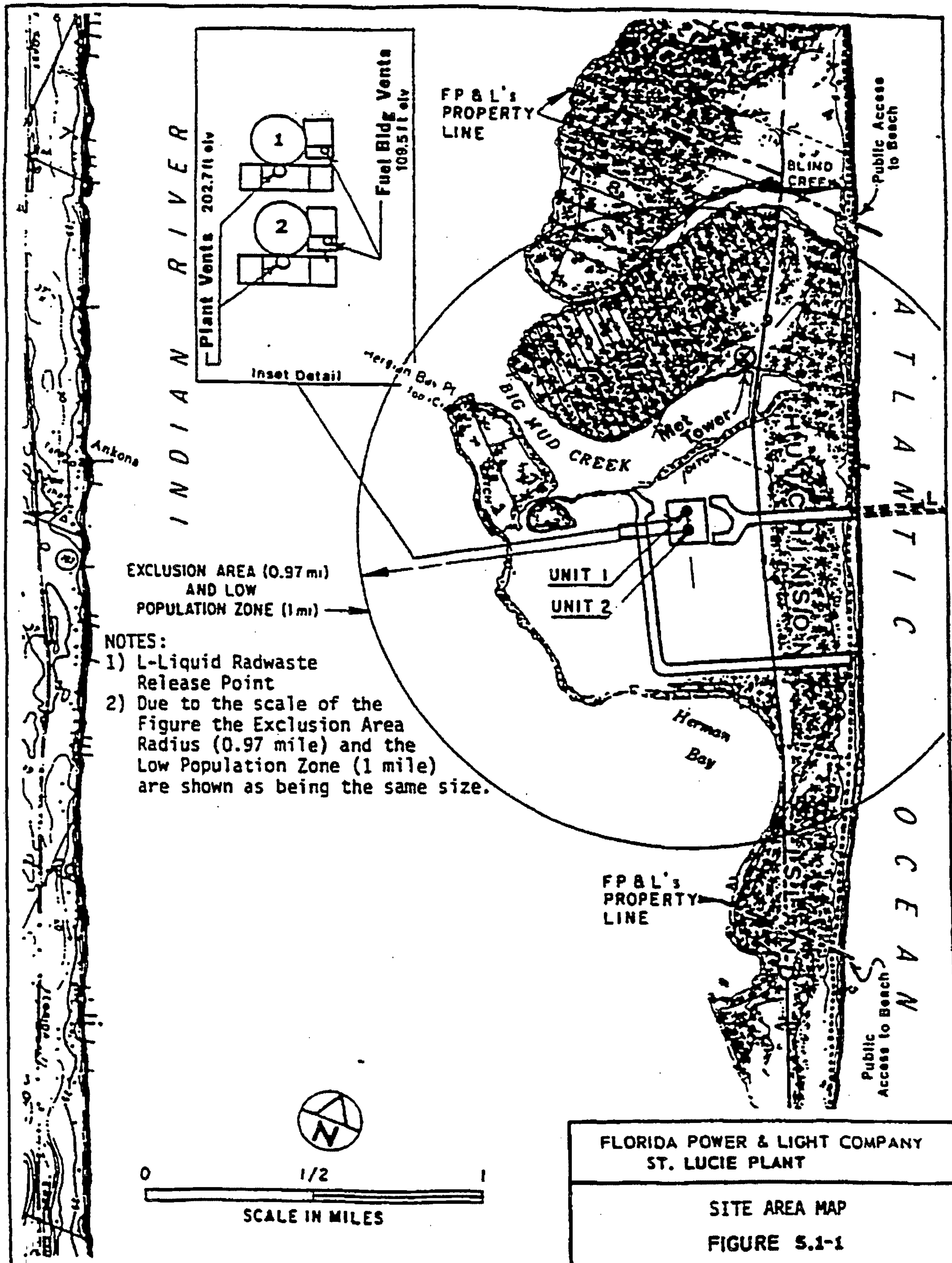
b. Nominal inside height = 232 feet.

c. Net free volume = 2.5×10^6 cubic feet.

d. Nominal thickness of vessel walls = 2 inches.

e. Nominal thickness of vessel dome = 1 inch.

f. Nominal thickness of vessel bottom = 2 inches.



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT

SITE AREA MAP

FIGURE 5.1-1

FIGURE 5.1-2

(Deleted)

2.1.2 SHIELD BUILDING

a. Minimum annular space = 4 feet

b. Annulus nominal volume = 543,000 cubic feet

c. Nominal outside height (measured from top of foundation base to the top of the dome) = 230.5 feet

d. Nominal inside diameter = 148 feet

e. Cylinder wall minimum thickness = 3 feet

f. Dome minimum thickness = 2.5 feet

g. Dome inside radius - 112 feet

DESIGN PRESSURE AND TEMPERATURE

5.2.2 The containment vessel is designed and shall be maintained for a maximum internal pressure of 44 psig and a temperature of 264°F.

PENETRATIONS

5.2.3 Penetrations through the containment structure are designed and shall be maintained in accordance with the original design provisions contained in Sections 3.8.2.1.10 and 6.2.4 of the FSAR with allowance for normal degradation pursuant to the applicable Surveillance Requirements.

5.3 REACTOR CORE

FUEL ASSEMBLIES

5.3.1 The reactor core shall contain 217 fuel assemblies with each fuel assembly containing a maximum of 176 fuel rods clad with Zircaloy-4. Each fuel rod shall have a nominal active fuel length of between 134.1 and 136.7 inches. Individual fuel assemblies shall contain fuel rods of the same nominal active fuel length. Fuel assemblies shall be limited to those designs that have been analyzed using NRC approved methodology and shown by tests or analyses to comply with fuel design and safety criteria. The initial core loading shall have a maximum enrichment of 2.83 weight percent U-235. Reload fuel shall be similar in physical design to the initial core loading.

5.3.1.1 Except for special test as authorized by the NRC, all fuel assemblies under control element assemblies shall be sleeved with a sleeve design previously approved by the NRC.

CONTROL ELEMENT ASSEMBLIES

5.3.2 The reactor core shall contain 73 full length and no part length control element assemblies. The control element assemblies shall be designed and maintained in accordance with the original design provisions contained in Section 4.2.3.2 of the FSAR with allowance for normal degradation pursuant to the applicable Surveillance Requirements.

5.4 REACTOR COOLANT SYSTEM

DESIGN PRESSURE AND TEMPERATURE

5.4.1 The reactor coolant system is designed and shall be maintained:

a. In accordance with the code requirements specified in Section 5.2 of the FSAR with allowance for normal degradation pursuant to the applicable Surveillance Requirements,

b. For a pressure of 2485 psig, and

c. For a temperature of 650°F, except for the pressurizer which is 700°F.

VOLUME

5.4.2 The total water and steam volume of the reactor coolant system is 11,100 ± 180 cubic feet at a nominal T_{avg} of 567°F, when not accounting for steam generator tube plugging.

5.5 EMERGENCY CORE COOLING SYSTEMS

5.5.1 The emergency core cooling systems are designed and shall be maintained in accordance with the original design provisions contained in Section 6.3 of the FSAR with allowance for normal degradation pursuant to the applicable Surveillance Requirements.

5.6 FUEL STORAGE

CRITICALITY

5.6.1.a The spent fuel pool and spent fuel storage racks shall be maintained with:

1. k_{eff} less than 1.0 when fully flooded with unborated water, which includes an allowance for biases and uncertainties as described in Section 9.1 of the Updated Final Safety Analysis Report.

2. A nominal 10.12 inches center to center distance between fuel assemblies in Region 1 of the spent fuel pool storage racks, a nominal 10.30 inches center to center distance between fuel assemblies in the Region 1 cask pit storage rack, and a nominal 8.86 inches center to center distance between fuel assemblies in Region 2 of the spent fuel pool storage racks.

CRITICALITY (Continued)

3. A k_{eff} less than or equal to 0.95 when flooded with water containing 500 ppm boron, including an allowance for biases and uncertainties as described in Section 9.1 of the Updated Final Safety Analysis Report.

4. For storage of enriched fuel assemblies, requirements of Criteria 1 and 3 shall be met by positioning fuel in the spent fuel storage racks consistent with the requirements of Specification 5.6.1.c.

5. Vessel Flux Reduction Assemblies (VFRAs), as defined in Section 9.1 of the Updated Final Safety Analysis Report, may be placed in any allowable fuel storage location.

6. Fissile material, not contained in a fuel assembly lattice, shall be stored in accordance with the requirements of Criteria 1 and 3.

b. The Region 1 cask pit storage rack shall contain neutron absorbing material (Boral) between stored fuel assemblies when installed in the spent fuel pool.

c. Loading of spent fuel storage racks shall be controlled as described below. Criteria 2 and 3 do not apply to the Region 1 cask pit storage rack.

1. The maximum initial planar average U-235 enrichment of any fuel assembly inserted in a spent fuel storage rack shall be less than or equal to 4.5 weight percent.

2. Fuel placed in Region 1 of the spent fuel pool storage racks shall comply with the storage patterns and alignment restrictions of Figure 5.6-1 and the minimum burnup requirements of Table 5.6-1 and Table 5.6-2.

3. Fuel placed in Region 2 of the spent fuel pool storage racks shall comply with the storage patterns or allowed special arrangements of Figure 5.6-2 and the minimum burnup requirements of Table 5.6-1 and Table 5.6-2. The allowed special arrangement for fresh fuel may be repeated, provided the applicable interface requirements specified by the safety analysis are met.

4. Any fuel satisfying criteria 5.6.1.c.1, including fresh fuel, may be placed in the Region 1 cask pit storage rack.

d. The new fuel storage racks are designed for dry storage of unirradiated fuel assemblies having a U-235 enrichment less than or equal to 4.5 weight percent, while maintaining a k_{eff} of less than or equal to 0.98 under the most reactive condition.

DRAINAGE

5.6.2 The fuel pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 56 feet.

CAPACITY

5.6.3 The spent fuel pool storage racks are designed and shall be maintained with a storage capacity limited to no more than 1706 fuel assemblies, and the cask pit storage rack is designed and shall be maintained with a storage capacity limited to no more than 143 fuel assemblies. The total Unit 1 spent fuel pool and cask pit storage capacity is limited to no more than 1849 fuel assemblies.

5.7 SEISMIC CLASSIFICATION

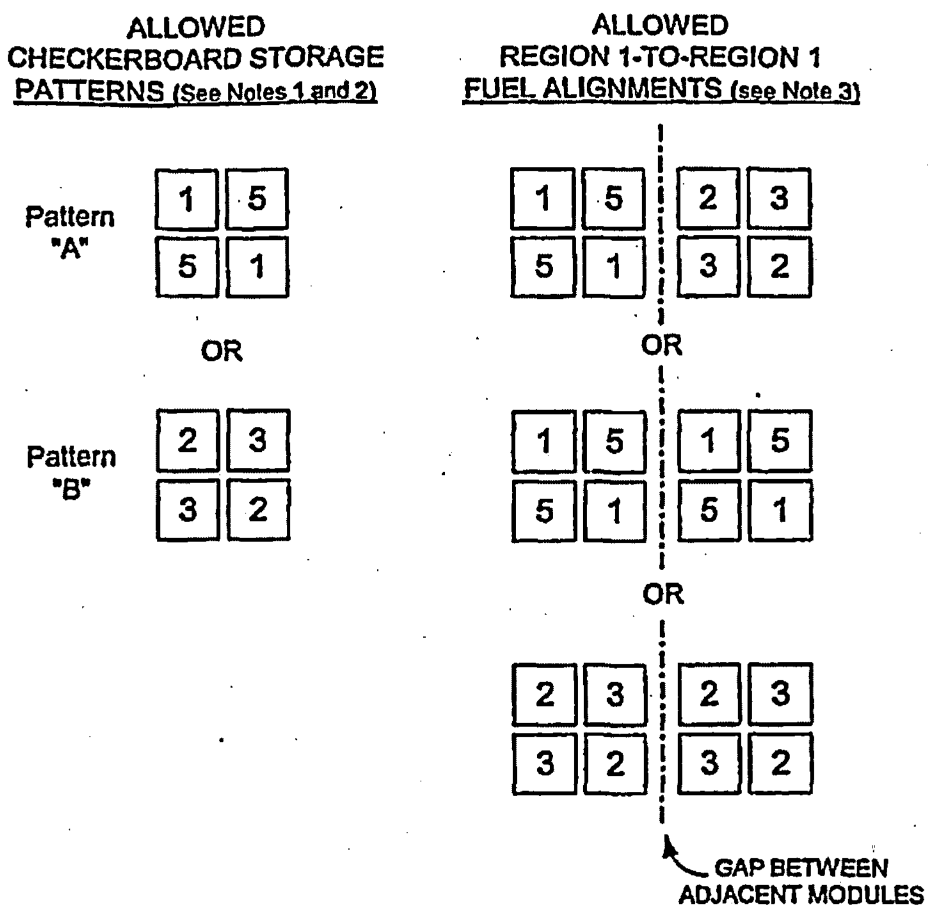
5.7.1 Those structures, systems and components identified as seismic Class I in Section 3.2.1 of the FSAR shall be designed and maintained to the original design provisions contained in Section 3.7 of the FSAR with allowance for normal degradation pursuant to the applicable Surveillance Requirement.

5.8 METEOROLOGICAL TOWER LOCATION

5.8.1 The meteorological tower location shall be as shown on Figure 5.1-1.

5.9 COMPONENT CYCLE OR TRANSIENT LIMITS

5.9.1 The components identified in Table 5.9-1 are designed and shall be maintained within the cyclic or transient limits of Table 5.9-1.



NOTES:

1. Numbering denotes fuel assembly type. Minimum burnup requirements for fuel assembly types 1, 2, 3, and 5 are defined in Tables 5.6-1 and 5.6-2.

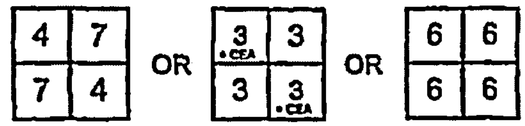
2. The storage arrangement of fuel within a rack module may contain more than one pattern. Different fuel storage patterns within a rack module must be separated by an empty row of cells.

3. Interface restrictions on fuel placement apply between adjacent Region 1 rack modules. No interface restrictions apply between Region 1 racks and adjacent Region 2 racks.

4. Open cells within any checkerboard pattern are acceptable.

FIGURE 5.6-1
Allowable Region 1 Storage Patterns and Fuel Alignments

ALLOWED
CHECKERBOARD STORAGE
PATTERNS (See Notes 1 and 2)

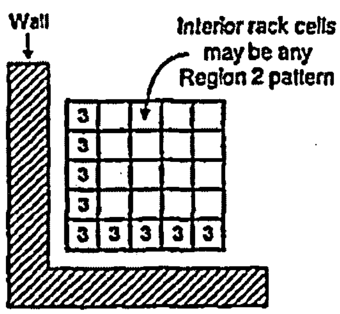


Pattern "C" Pattern "D" Pattern "E"

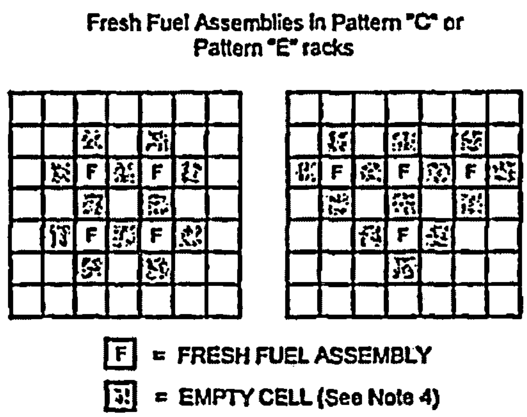
RACK INTERFACE
RESTRICTIONS

NONE

ALLOWED SPECIAL
ARRANGEMENTS:



(See Note 3)



NOTES:

1. *Numbering denotes fuel assembly type. Minimum burnup requirements for fuel* assembly types 3, 4, 6, and 7 are defined in Tables 5.6-1 and 5.6-2.

2. The storage arrangement within a rack module may contain more than one checkerboard pattern (patterns "C," "D," or "E") provided an empty row of cells separates the patterns.

3. Fuel in peripheral cells need not contain CEAs. An empty row of cells separating these peripheral cells from the interior pattern is not required. Cells on the Region 2 periphery that form interior corners do not qualify for this arrangement.

4. Cells required to be empty as part of an allowed special arrangement may contain non-actinide material, such as an empty fuel assembly skeleton, as long as the material occupies no more than 75% of the cell volume.

5. Open cells within any checkerboard pattern are acceptable.

FIGURE 5.6-2
Allowable Region 2 Storage Patterns and Arrangements

TABLE 5.6-1
Minimum Burnup as a Function of Enrichment for Non-Blanketed Assemblies

Fuel Type	Cooling Time	Coefficients			Minimum Burnup (GWd/MTU) for Initial Enrichment			
		A	B	C	1.9 w/o	2.5 w/o	3.0 w/o	3.8 w/o
1	0 years	0.00	9.31	-24.39	0.00	0.00	3.54	10.99
2	0 years	0.00	10.51	-22.35	0.00	3.93	9.18	17.59
3	0 years	0.00	10.97	-14.71	6.13	12.72	18.20	26.98
4	0 years	-0.41	17.00	-21.39	9.43	18.55	25.92	37.29
	12 years	-0.54	16.22	-20.63	8.24	16.55	23.17	33.21
	15 years	-0.53	15.86	-20.07	8.15	16.27	22.74	32.54
	20 years	-0.46	15.11	-18.80	8.25	16.10	22.39	31.98
5	0 years	-0.74	17.49	-19.72	10.84	19.38	26.09	36.06
	5 years	-0.56	15.64	-17.65	10.04	17.95	24.23	33.70
6	0 years	-0.41	17.70	-17.97	14.18	23.72	31.44	43.37
	12 years	0.04	13.10	-12.56	12.47	20.44	27.10	37.80
	15 years	0.13	12.38	-11.83	12.16	19.93	26.48	37.09
	20 years	0.26	11.56	-11.16	11.74	19.37	25.86	36.52
7	0 years	-0.65	20.08	-16.52	19.29	29.62	37.87	50.40
	12 years	-0.65	17.76	-15.58	15.82	24.76	31.85	42.52
	15 years	-0.43	16.25	-13.84	15.48	24.10	31.04	41.70
	20 years	0.12	12.90	-9.61	15.33	23.39	30.17	41.14

NOTES:

1. Enter this table for a "non-blanketed assembly"; defined as a fuel assembly without any designed axial variation in uranium-235 enrichment to control the axial burnup distribution.

2. To qualify in a fuel type, the calculated burnup of a fuel assembly must exceed the "minimum burnup" given in the table for the "cooling time" and "initial enrichment" of the fuel assembly. Alternatively, for fuel assembly characteristics between the increments depicted in the table, "minimum burnup" may be calculated by inserting the "coefficients" for the associated "type" and "cooling time" into the polynomial function:

   $BU = A^*E^2 + B^*E + C$ where:

   BU = Minimum Burnup (GWD/MTU)

   E = Initial Maximum Planar Average Enrichment (weight percent uranium-235)

   A, B, C = Coefficients

3. Interpolation between values of cooling time is not permitted.

TABLE 5.6-2
Minimum Burnup as a Function of Enrichment for Blanketed Assemblies

Fuel Type	Cooling Time	Coefficients			Minimum Burnup (GWd/MTU) for Initial Enrichment				
		A	B	C	2.5 w/o	3.0 w/o	3.5 w/o	4.0 w/o	4.5 w/o
1	0 years	0.00	9.31	-24.39	0.00	3.54	8.20	12.85	17.51
2	0 years	0.00	10.51	-22.35	3.93	9.18	14.44	19.69	24.95
3	0 years	0.00	10.97	-14.71	12.72	18.20	23.69	29.17	34.66
4	0 years	-0.98	18.97	-22.54	18.76	25.55	31.85	37.66	42.98
	5 years	-0.74	16.54	-19.10	17.63	23.86	29.73	35.22	40.35
	10 years	-0.57	14.73	-16.49	16.77	22.57	28.08	33.31	38.25
	15 years	-0.46	13.54	-14.70	16.28	21.78	27.06	32.10	36.92
	20 years	-0.41	12.98	-13.74	16.15	21.51	26.67	31.62	36.37
5	0 years	-0.74	17.49	-19.72	19.38	26.09	32.43	38.40	44.00
	5 years	-0.56	15.64	-17.65	17.95	24.23	30.23	35.95	41.39
6	0 years	-0.24	14.23	-10.38	23.70	30.15	36.49	42.70	48.80
	5 years	-0.20	13.10	-9.24	22.26	28.26	34.16	39.96	45.66
	10 years	-0.23	12.70	-9.27	21.04	26.76	32.36	37.85	43.22
	15 years	-0.32	13.02	-10.48	20.07	25.70	31.17	36.48	41.63
	20 years	-0.47	14.08	-12.85	19.41	25.16	30.67	35.95	40.99
7	0 years	-0.84	19.25	-13.42	29.46	36.77	43.67	50.14	56.20
	5 years	-0.72	17.40	-12.03	26.97	33.69	40.05	46.05	51.69
	10 years	-0.66	16.32	-11.46	25.22	31.56	37.58	43.26	48.62
	15 years	-0.67	16.00	-11.73	24.08	30.24	36.06	41.55	46.70
	20 years	-0.76	16.45	-12.81	23.57	29.70	35.46	40.83	45.83

NOTES:

1. Enter this table for a "blanketed assembly"; defined as a fuel assembly with designed axial variation in uranium-235 enrichment to control the axial burnup distribution. Use Table 5.6-1 to characterize blanketed assemblies having a central zone initial planar average enrichment of less than 2.5 w/o.

2. To qualify in a fuel type, the calculated burnup of a fuel assembly must exceed the "minimum burnup" given in the table for the "cooling time" and "initial enrichment" of the fuel assembly. Alternatively, for fuel assembly characteristics between the increments depicted in the table, "minimum burnup" may be calculated by inserting the "coefficients" for the associated "type" and "cooling time" into the polynomial function:

   $BU = A*E^2 + B*E + C$ where:

   BU = Minimum Burnup (GWD/MTU)

   E = Initial Maximum Planar Average Enrichment (weight percent uranium-235)

   A, B, C = Coefficients

3. Interpolation between values of cooling time is not permitted

TABLE 5.9-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMITS	DESIGN CYCLE OR TRANSIENT
Reactor Coolant System	40 Cycles of loss of load without immediate reactor trip	100% to 0% RATED THERMAL POWER
	40 cycles of loss of offsite A.C. electrical power	100% to 0% RATED THERMAL POWER
	400 reactor trips	100% to 0% RATED THERMAL POWER
	16 inadvertent auxiliary spray cycles	Spray line 650°F to 120°F in 1.5 seconds
	200 leak tests	Pressure $\geq$ 2235 psig
	10 hydrostatic pressure tests	Pressure $\geq$ 3110 psig
Secondary System	5 steam line breaks	Complete loss of secondary pressure
	200 leak tests	Pressure $\geq$ 985 psig
	10 hydrostatic pressure tests	Pressure $\geq$ 1235 psig

6.0 ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1 The plant manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

6.1.2 The Shift Supervisor, or during his absence from the control room a designated individual, shall be responsible for the control room command function. A management directive to this effect, signed by the corporate officer with direct responsibility for the plant, shall be reissued to all station personnel on an annual basis.

6.2 ORGANIZATION

ONSITE AND OFFSITE ORGANIZATION

6.2.1 An onsite and an offsite organization shall be established for unit operation and corporate management. This onsite and offsite organization shall include the positions for activities affecting the safety of the nuclear power plant.

a. Lines of authority, responsibility and communication shall be established and defined from the highest management levels through intermediate levels to and including all operating organization positions. Those relationships shall be documented and updated, as appropriate, in the form of organizational charts. These organizational charts will be documented in the Quality Assurance Topical Report and updated in accordance with 10 CFR 50.54(a)(3). The plant-specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications shall be documented in the UFSAR or the Quality Assurance Topical Report.

b. A specified corporate officer shall be responsible for overall plant nuclear safety. This individual shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support in the plant so that continued nuclear safety is assured.

c. The plant manager shall be responsible for overall safe operation and shall have control over those onsite resources necessary for safe operation and maintenance of the plant.

d. Although the individuals who train the operating staff and those who carry out the quality assurance functions may report to the appropriate manager onsite, they shall have sufficient organizational freedom to be independent from operating pressures.

e. Although health physics individuals may report to any appropriate manager onsite, for matters relating to radiological health and safety of employees and the public, the radiation protection manager shall have direct access to that onsite individual having responsibility for overall unit management. Health physics personnel shall have the authority to cease any work activity when worker safety is jeopardized or in the event of unnecessary personnel radiation exposures.

6.2 ORGANIZATION (continued)

UNIT STAFF

6.2.2 The unit organization shall be subject to the following:

a. Each on duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2-1.

b. Deleted.

c. A health physics technician# shall be on site when fuel is in the reactor.

d. Either a licensed SRO or licensed SRO limited to fuel handling who has no concurrent responsibilities during this operation shall be present during fuel handling and shall directly supervise all CORE ALTERATIONS.

e. Deleted.

The health physics technician may be less than the minimum requirement for a period of time not to exceed 2 hours, in order to accommodate unexpected absence, provided immediate action is taken to fill the required positions.

DELETED

TABLE 6.2-1

MINIMUM SHIFT CREW COMPOSITION

TWO UNITS WITH TWO SEPARATE CONTROL ROOMS

WITH UNIT 2 IN MODE 5 OR 6 OR DEFUELED		
POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	MODE 1, 2, 3 or 4	MODE 5 or 6
SS (SRO)	1[a]	1[a]
SRO	1	None
RO	2	1
AO	2	2[b]
STA *	1	None

WITH UNIT 2 IN MODE 1, 2, 3, or 4		
POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	MODE 1, 2, 3 or 4	MODE 5 or 6
SS (SRO)	1[a]	1[a]
SRO	1	None
RO	2	1
AO	2	1
STA *	1[c]	None

SS - Shift Supervisor with a Senior Reactor Operator's License on Unit 1
SRO - Individual with a Senior Reactor Operator's License on Unit 1
STA - Shift Technical Advisor
RO - Individual with a Reactor Operator's License on Unit 1
AO - Auxiliary Operator

Except for the Shift Supervisor, the Shift Crew Composition may be one less than the minimum requirements of Table 6.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the Shift Crew Composition to within the minimum requirements of Table 6.2-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

During any absence of the Shift Supervisor from the Control Room while the unit is in MODE 1, 2, 3 or 4, an individual (other than the Shift Technical Advisor) with a valid SRO license shall be designated to assume the Control Room command function. During any absence of the Shift Supervisor from the Control Room while the unit is in MODE 5 or 6, an individual with a valid SRO or RO license shall be designated to assume the Control Room command function.

a/ Individual may fill the same position on Unit 2.
b/ One of the two required individuals may fill the same position on Unit 2.
c/ If STA position is filled by an STA qualified Shift Supervisor or dedicated STA, then the individual may fill the same position on Unit 2.
* A single, onsite STA position shall be manned in Mode 1, 2, 3, and 4 unless the Shift Supervisor meets the qualifications for the STA as required by Technical Specification 6.3.1 or an individual on each unit with a Senior Reactor Operator's license meets the qualifications for the STA as required by Technical Specification 6.3.1.

f. DELETED

g. The operations supervisor shall hold a Senior Reactor Operator license.

SHIFT TECHNICAL ADVISOR FUNCTION

6.2.3 An individual shall provide advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This individual shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

6.3 UNIT STAFF QUALIFICATIONS

6.3.1 Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI / ANS-3.1-1978 for comparable positions, except for:

(1) the radiation protection manager who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975,

(2) the Shift Technical Advisor who shall have specific training in plant design and plant operating characteristics, including transients and accidents, and any of the following educational requirements:

- Bachelor's degree in engineering from an accredited institution; or

- Professional Engineer's (PE) license obtained by successful completion of the PE examination; or

- Bachelor's degree in engineering technology from an accredited institution, including course work in the physical, mathematical, or engineering sciences, or

- Bachelor's degree in physical science from an accredited institution, including course work in the physical, mathematical, or engineering sciences.

(3) the Multi-Discipline Supervisors who shall meet or exceed the following requirements:

a. Education: Minimum of a high school diploma or equivalent.

b. Experience: Minimum of four years of related technical experience, which shall include three years power plant experience of which one year is at a nuclear power plant.

c. Training: Complete the Multi-Discipline Supervisor training program.

6.3.2 For the purpose of 10 CFR 55.4, a licensed senior reactor operator and a licensed reactor operator are those individuals who, in addition to meeting the requirements of 6.3.1, perform the functions described in 10 CFR 50.54(m).

6.4 DELETED

6.5 DELETED

DELETED

DELETED

DELETED

DELETED

DELETED

6.6 DELETED

6.7 DELETED

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978, and those required for implementing the requirements of NUREG 0737.

b. Refueling operations.

c. Surveillance and test activities of safety-related equipment.

d. Not Used.

e. Not Used.

f. Fire Protection Program implementation.

g. PROCESS CONTROL PROGRAM implementation.

h. OFFSITE DOSE CALCULATION MANUAL implementation.

i. Quality Control Program for effluent monitoring, using the guidance in Regulatory Guide 1.21, Revision 1, June 1974.

j. Quality Control Program for environmental monitoring using the guidance in Regulatory Guide 4.1, Revision 1, April 1975.

6.8.2 DELETED

6.8.3 DELETED

6.8.4 The following programs shall be established, implemented, and maintained.

a. Primary Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include the Shutdown Cooling System, High Pressure Safety Injection System, Containment Spray System, and RCS Sampling. The program shall include the following:

(i) Preventive maintenance and periodic visual inspection requirements, and

(ii) Integrated leak test requirements for each system at least once per 18 months.

The provisions of Specification 4.0.2 are applicable.

b. In-Plant Radioiodine Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentration in vital areas under accident conditions. This program shall include the following:

(i) Training of personnel,

(ii) Procedures for monitoring, and

(iii) Provisions for maintenance of sampling and analysis equipment.

c. Secondary Water Chemistry

A program for monitoring of secondary water chemistry to inhibit steam generator tube degradation. This program shall include:

(i) Identification of a sampling schedule for the critical variables and control points for these variables,

(ii) Identification of the procedures used to measure the values of the critical variables,

(iii) Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in-leakage,

(iv) Procedures for the recording and management of data,

(v) Procedures defining corrective actions for all off-control point chemistry conditions, and

(vi) A procedure identifying (a) the authority responsible for the interpretation of the data, and (b) the sequence and timing of administrative events required to initiate corrective action.

d. Backup Method for Determining Subcooling Margin

A program which will ensure the capability to accurately monitor the Reactor Coolant System subcooling margin. This program shall include the following:

(i) Training of personnel, and

(ii) Procedures for monitoring.

e. DELETED

f. Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBERS OF THE PUBLIC from radioactive effluents as low as reasonably achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by operating procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

1) Limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM,

2) Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to ten times the concentration values in 10 CFR 20.1001 - 20.2401, Appendix B, Table 2, Column 2.

3) Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM,

4) Limitations on the annual and quarterly doses or dose commitment on a MEMBER OF THE PUBLIC from radioactive materials in liquid effluents released from each unit to UNRESTRICTED AREAS conforming to Appendix I to 10 CFR Part 50,

5) Determination of cumulative dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days. Determination of projected dose contributions from radioactive effluents in accordance with the methodology in the ODCM at least every 31 days.

6) Limitations on the operability and use of the liquid and gaseous effluent treatment systems to ensure that the appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a 31-day period would exceed 2 percent of the guidelines for the annual dose or dose commitment conforming to Appendix I to 10 CFR Part 50,

7) Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas at or beyond the SITE BOUNDARY shall be limited to the following:

   a) For noble gases: Less than or equal to 500 mrem/yr to the total body and less than or equal to 3000 mrem/yr to the skin, and

   b) For Iodine-131, for Iodine-133, for tritium, and for all radionuclides in particulate form with half-lives greater than 8 days: Less than or equal to 1500 mrem/yr to any organ;

8) Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

9) Limitations on the annual and quarterly doses to a MEMBER OF THE PUBLIC from Iodine-131, Iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents released from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50,

10) Limitations on the annual dose or dose commitment to any MEMBER OF THE PUBLIC, beyond the site boundary, due to releases of radioactivity and to radiation from uranium fuel cycle sources conforming to 40 CFR Part 190.

The provisions of Specifications 4.0.2 and 4.0.3 are applicable to the Radioactive Effluent Controls Program surveillance frequency.

g. Radiological Environmental Monitoring Program

A program shall be provided to monitor the radiation and radio-nuclides in the environs of the plant. The program shall provide (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluent monitoring program and modeling of the environmental exposure pathways. The program shall (1) be contained in the ODCM,

(2) conform to the guidance of Appendix I to 10 CFR Part 50, and
(3) include the following:

1) Monitoring, sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM.

2) A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of this census, and

3) Participation in a Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

h. Containment Leakage Rate Testing Program

A program to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50 Appendix J, Option B, as modified by approved exemptions. This program is in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," as modified by the following exception(s):

a) Bechtel Topical Report, BN-TOP-1 or ANS 56.8-1994 (as recommended by R.G. 1.163) will be used for type A testing.

b) The first Type A test performed after the May 1993 Type A test shall be no later than May 2008.

The peak calculated containment internal pressure for the design basis loss of coolant accident P_a, is 39.6 psig. The containment design pressure is 44 psig.

The maximum allowed containment leakage rate, L_a, at P_a, shall be 0.50% of containment air weight per day.

Leakage rate acceptance criteria are:

a. Containment leakage rate acceptance criterion is $\leq$ 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are < 0.60 L_a for the Type B and C tests, $\leq$ 0.75 L_a for Type A tests, and $\leq$ 0.096 L_a for secondary containment bypass leakage paths.

b. Air lock testing acceptance criteria are:

   1) Overall air lock leakage rate is $\leq$ 0.05 L_a when tested at $\geq$ P_a.

   2) For the personnel air lock door seal, leakage rate is < 0.01 L_a when pressurized to $\geq$ 1.0 P_a.

   3) For the emergency air lock door seal, leakage rate is < 0.01 L_a when pressurized to $\geq$ 10 psig.

The provisions of T.S. 4.0.2 do not apply to test frequencies in the Containment Leak Rate Testing Program.

The provisions of T.S. 4.0.3 are applicable to the Containment Leak Rate Testing Program.

i. Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2 and 3 components (pumps and valves). The program shall include the following:

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code* and applicable addenda as follows:

ASME Boiler and Pressure Vessel Code* and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of Specification 4.0.2 are applicable to the above required frequencies for performing inservice testing activities;

c. The provisions of Specification 4.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code* shall be construed to supersede the requirements of any technical specification.

j. Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

1. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

2. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

   a. a change in the TS incorporated in the license; or

   b. a change to the updated UFSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

3. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

4. Proposed changes that meet the criteria of Specification 6.8.4.j.2.a or 6.8.4.j.2.b, above, shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

* Where ASME Boiler and Pressure Vessel Code is referenced it also refers to the applicable portions of ASME/ANSI OM-Code, "Operation and Maintenance of Nuclear Power Plants," with applicable addenda, to the extent it is referenced in the Code.

ADMINISTRATIVE CONTROLS (continued)

k. Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in Regulatory Guide 1.52, Revision 3.

1. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass less than the value specified below when tested in accordance with ASME N510-1989 at the system flowrate specified below.

ESF Ventilation System	**Penetration**	**Flowrate**
Control Room Emergency Ventilation	≤ 0.05%	2000 ± 200 cfm
Shield Building Ventilation System	≤ 0.05%	6000 ± 600 cfm
ECCS Area Ventilation System	≤ 0.05%	30,000 ± 3000 cfm

2. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass less than the value specified below when tested in accordance with ASME N510-1989 at the system flowrate specified below.

ESF Ventilation System	**Penetration**	**Flowrate**
Control Room Emergency Ventilation	≤ 0.05%	2000 ± 200 cfm
Shield Building Ventilation System	≤ 0.05%	6000 ± 600 cfm
ECCS Area Ventilation System	≤ 0.05%	30,000 ± 3000 cfm

3. Demonstrate for each of the ESF systems that a laboratory test of a sample of the charcoal adsorber, when obtained as described in Regulatory Guide 1.52, Revision 3, shows the methyl iodide penetration less than the value specified below when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and the relative humidity specified below.

ESF Ventilation System	**Penetration**	**RH**
Control Room Emergency Ventilation	≤ 2.5%	70%
Shield Building Ventilation System	≤ 2.5%	70%
ECCS Area Ventilation System	≤ 2.5%	70%

4. Demonstrate for each of the ESF systems that the pressure drop across the combined HEPA filters and charcoal adsorbers is less than the value specified below when tested at the system flowrate specified below.

ESF Ventilation System	**Delta P**	**Flowrate**
Control Room Emergency Ventilation	< 4.15" W.G.	2000 ± 200 cfm
Shield Building Ventilation System	≤ 6.15" W.G.	6000 ± 600 cfm
ECCS Area Ventilation System	< 4.15" W.G.	30,000 ± 3000 cfm

5. At least once per 18 months, demonstrate that the heaters for each of the ESF systems dissipate the value specified below when tested in accordance with ASME N510-1989.

ESF Ventilation System	**Wattage**
Shield Building Ventilation System	
Main Heaters	30 ± 3 kW
Auxiliary Heaters	1.5 ± 0.25 kW

The provisions of SR 4.0.2 and SR 4.0.3 are applicable to the VFTP test frequencies.

l. Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following provisions:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational leakage.

   1. Structural integrity performance criterion: All in-service SG tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cooldown and all anticipated transients included in the design specification) and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

   2. Accident induced leakage performance criterion: The primary-to-secondary accident induced leakage rate for any design basis accident, other than SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 0.5 gpm total through all SGs and 0.25 gpm through any one SG.

   3. The operational leakage performance criterion is specified in LCO 3.4.6.2.c, "Reactor Coolant System Operational Leakage."

c. Provisions for SG tube repair criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

l. Steam Generator (SG) Program (continued)

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube repair criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. An assessment of degradation shall be performed to determine the type and location of flaws to which the tube may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG replacement.

2. Inspect 100% of the tubes at sequential periods of 144, 108, 72, and, thereafter, 60 effective full power months. The first sequential period shall be considered to begin after the first inservice inspection of the SGs. In addition, inspect 50% of the tubes by the refueling outage nearest the midpoint of the period and the remaining 50% by the refueling outages nearest the end of the period. No SG shall operate for more than 72 effective full power months or three refueling outages (whichever is less) without being inspected.

3. If crack indications are found in any SG tube, then the next inspection for each SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever is less). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary-to-secondary leakage.

m. Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation System (CREVS), CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident.

The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

m. Control Room Envelope Habitability Program (continued)

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREVS, operating at the flow rate required by the VFTP, at a Frequency of 36 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 36 month assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 4.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

n. Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

(i) Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

1. An API gravity or an absolute specific gravity within limits,
2. A flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and
3. A clear and bright appearance with proper color or a water and sediment content within limits;

(ii) Other properties for ASTM 2D fuel oil are within limits within 31 days following sampling and addition to storage tanks; and

(iii) Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 31 days.

The provisions of SR 4.0.2 and SR 4.0.3 are applicable to the Diesel Fuel Oil Testing Program test frequencies.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS

6.9.1 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following reports shall be submitted to the NRC.

STARTUP REPORT

6.9.1.1 A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an operating license, (2) amendment of the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal or hydraulic performance of the plant.

6.9.1.2 The startup report shall address each of the tests identified in the FSAR and shall include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

6.9.1.3 Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commercial operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

ANNUAL REPORTS[1/]

6.9.1.4 Annual reports covering the activities of the unit as described below for the previous calendar year shall be submitted prior to March 1 of each year. The initial report shall be submitted prior to March 1 of the year following initial criticality.

6.9.1.5 Annual reports shall include the results of specific activity analysis in which the primary coolant exceeded the limits of Specification 3.4.8. The following information shall be included: (1) Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded; (2) Results of the last

1/ A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

isotopic analysis for radioiodine performed prior to exceeding the limit, results of analysis while the limit was exceeded and results of one analysis after the radioiodine activity was reduced to less than the limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Clean-up system flow history starting 48 hours prior to the first sample in which the limit was exceeded; (4) Graph of the I-131 concentration and one other radioiodine isotope concentration in microcuries per gram as a function of time for the duration of the specific activity above the steady-state level; and (5) The time duration when the specific activity of the primary coolant exceeded the radioiodine limit.

MONTHLY OPERATING REPORTS

6.9.1.6 Deleted

ANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT*

6.9.1.7 The Annual Radioactive Effluent Release Report covering the operation of the unit during the previous 12 months of operation shall be submitted within 60 days after January 1 of each year. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be (1) consistent with the objectives outlined in the ODCM and PCP and (2) in conformance with 10 CFR 50.36a and Section IV.B.1 of Appendix I to 10 CFR Part 50.

*A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT**

6.9.1.8 The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted before May 1 of each year. The report shall include summaries, interpretations, and analysis of trends of the results of the Radiological Environmental Monitoring Program for the reporting period. The material provided shall be consistent with the objectives outlined in (1) the ODCM and (2) Sections IV.B.2, IV.B.3, and IV.C of Appendix I to 10 CFR Part 50.

**A single submittal may be made for a multiple unit station.

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT (continued)

6.9.1.9 At least once every 5 years, an estimate of the actual population within 10 miles of the plant shall be prepared and submitted to the NRC.

6.9.1.10 At least once every 10 years, an estimate of the actual population within 50 miles of the plant shall be prepared and submitted to the NRC.

6.9.1.11 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

Specification 3.1.1.1	Shutdown Margin – T_{avg} Greater Than 200°F
Specification 3.1.1.2	Shutdown Margin – T_{avg} Less Than or Equal to 200°F
Specification 3.1.1.4	Moderator Temperature Coefficient
Specification 3.1.3.1	Full Length CEA Position – Misalignment > 15 inches
Specification 3.1.3.6	Regulating CEA Insertion Limits
Specification 3.2.1	Linear Heat Rate
Specification 3.2.3	Total Integrated Radial Peaking Factor – F_r^T
Specification 3.2.5	DNB Parameters
Specification 3.9.1	Refueling Operations – Boron Concentration

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, as described in the following documents, approved Revisions and Supplements as specified in the COLR.

1. WCAP-11596-P-A, "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," June 1988 (Westinghouse Proprietary)

2. NF-TR-95-01, "Nuclear Physics Methodology for Reload Design of Turkey Point & St. Lucie Nuclear Plants," Florida Power & Light Company, January 1995.

3. XN-75-27(A) [also issued as XN-NF-75-27(A)], "Exxon Nuclear Neutronic(s) Design Methods for Pressurized Water Reactors"

4. ANF-84-73(P)(A), "Advanced Nuclear Fuels Methodology for Pressurized Water Reactors: Analysis of Chapter 15 Events"

5. XN-NF-82-21(P)(A), "Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations"

CORE OPERATING LIMITS REPORT (continued)

6. EMF-84-093(P)(A), "Steam Line Break Methodology for PWRs"

7. XN-75-32(P)(A), "Computational Procedure for Evaluating Fuel Rod Bowing"

8. XN-NF-82-49(P)(A), "Exxon Nuclear Company Evaluation Model Revised EXEM PWR Small Break Model"

9. XN-NF-78-44(NP)(A), "A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors"

10. XN-NF-621(P)(A), " Exxon Nuclear DNB Correlation for PWR Fuel Designs"

11. EMF-2087(P)(A), "SEM/PWR-98: ECCS Evaluation Model for PWR LBLOCA Applications"

12. XN-NF-82-06(P)(A), "Qualification of Exxon Nuclear Fuel for Extended Burnup"

13. ANF-88-133(P)(A), "Qualification of Advanced Nuclear Fuels' PWR Design Methodology for Rod Burnups of 62 GWd/MTU"

14. XN-NF-85-92 (P)(A), "Exxon Nuclear Uranium Dioxide/Gadolinia Irradiation Examination and Thermal Conductivity Results"

15. ANF-89-151(P)(A), "ANF-RELAP Methodology for Pressurized Water Reactors: Analysis of Non-LOCA Chapter 15 Events"

16. DELETED

17. EMF-92-116(P)(A), "Generic Mechanial Design Criteria for PWR Fuel Design"

18. EMF-92-153(P)(A), "HTP: Departure from Nucleate Boiling Correlation for High Thermal Performance Fuel"

19. EMF-96-029(P)(A), Volumes 1 and 2, "Reactor Analysis System for PWRs Volume 1 – Methodology Description, Volume 2 – Benchmarking Results"

CORE OPERATING LIMITS REPORT (continued)

20. EMF-1961(P)(A), "Statistical Setpoint/Transient Methodology for Combustion Engineering Type Reactors"

21. EMF-2310(P)(A), "SRP Chapter 15 Non-LOCA Methodology for Pressurizer Water Reactors"

22. EMF-2328(P)(A), "PWR Small Break LOCA Evaluation Model, S-RELAP5 Based"

CORE OPERATING LIMITS REPORT (continued)

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SHUTDOWN MARGIN, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any mid cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

STEAM GENERATOR TUBE INSPECTION REPORT

6.9.1.12 A report shall be submitted within 180 days after the initial entry into HOT SHUTDOWN following completion of an inspection performed in accordance with Specification 6.8.4.l, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Active degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each active degradation mechanism,

f. Total number and percentage of tubes plugged to date,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing, and

h. The effective plugging percentage for all plugging in each SG.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the NRC within the time period specified for each report.

6.10 DELETED

6.11 RADIATION PROTECTION PROGRAM

Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure.

6.12 HIGH RADIATION AREA

6.12.1 In lieu of the "control device" or "alarm signal" required by paragraph 20.1601(a) of 10 CFR Part 20, each high radiation area in which the intensity of radiation is greater than 100 mrem/hr but less than 1000 mrem/hr measured at a distance of 30 cm (12 in) shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP)*. Any individual or group of individuals permitted to enter such areas shall be 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 rate level in the area has been established and personnel have been made knowledgeable of them.

c. A health physics qualified individual (i.e., 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 facility Health Physicist in the RWP.

6.12.2 In addition to the requirements of Specification 6.12.1, areas accessible to personnel with radiation levels in excess of 1000 mrem/hr at 30 cm (12 in) and less than 500 rads/hr at 1 meter shall be provided with locked doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of the Shift Foreman on duty and/or health physics supervision. Doors shall remain locked except during periods of access by personnel under an approved RWP which shall specify the dose rate levels in the immediate work area and the maximum allowable stay time for individuals in that area. For individual areas accessible to personnel with radiation levels in excess of 1000 mrem/hr at 30 cm (12 in) and less than 500 rads/hr at 1 meter that are located within large areas, such as PWR containment, where no enclosure exists for purposes of locking, and no enclosure can be reasonably constructed around the individual areas, then that area shall be roped off, conspicuously posted and a flashing light shall be activated as a warning device. In lieu of the stay time specification of the RWP, direct or remote (such as use of closed circuit TV cameras) continuous surveillance may be made by personnel qualified in radiation protection procedures to provide positive exposure control over the activities within the area.

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* Health Physics personnel or personnel escorted by Health Physics personnel shall be exempt from the RWP issuance requirement during the performance of their assigned radiation protection duties, provided they are otherwise following plant radiation protection procedures for entry into high radiation areas.

6.13 PROCESS CONTROL PROGRAM (PCP)

Changes to the PCP:

1. Shall be documented and this documentation shall contain:

    a) Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

    b. A determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

2. Shall become effective after the approval of the plant manager.

6.14 OFFSITE DOSE CALCULATION MANUAL (ODCM)

Changes to the ODCM:

1. Shall be documented and this documentation shall contain:

    a) Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s) and

    b. A determination that the change will maintain the level of radioactive effluent control required by 10 CFR 20.1302, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I to 10 CFR Part 50 and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations.

2. Shall become effective after the approval of the plant manager.

3. Shall be submitted to the Commission in the form of a complete, legible copy of the entire ODCM as part of or concurrent with the Annual Radioactive Effluent Release Report for the period of the report in which any change to the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (e.g., month/year) the change was implemented.

DELETED

APPENDIX B - PART I

DELETED

APPENDIX B - PART II

ENVIRONMENTAL PROTECTION PLAN

(NON-RADIOLOGICAL)

TECHNICAL SPECIFICATIONS

FLORIDA POWER & LIGHT COMPANY

ST. LUCIE UNIT NO. 1

OPERATING LICENSE NO. DPR-67

Docket No. 50-335

1.0 Objectives of the Environmental Protection Plan

The Environmental Protection Plan (EPP) is to provide for protection of the local area environment of the St. Lucie Nuclear Plant during construction and operation.

The principle objectives of the EPP are to:

1. Verify that the plant is operated in an environmentally acceptable manner as established by the FES and other NRC environmental impact assessments

2. Coordinate NRC requirements and maintain consistency with other Federal, State and local requirements for environmental protection

3. Keep NRC informed of the environmental effects of facility construction and operation and of actions taken to control those effects

Environmental concerns identified in the Unit 1 FES which relate to water quality matters are to be regulated by way of the licensee's Wastewater permit

2.0 Environmental Protection Issues

In the FES-OL dated June 1973, NRC staff considered the environmental impacts associated with the operation of the St. Lucie Plant Unit 1. Certain environmental issues were identified which required study or license conditions for resolution of environmental concerns and to assure adequate environmental protection. The Unit 1 Appendix B Environmental Technical Specifications accompanying license DPR-67 included discharge restrictions and monitoring

programs to resolve the issues. Prior to issuance of this EPP, ETS requirements related to non-radiological environmental activities have included the following programs:

2.1 Aquatic monitoring programs to insure:

1. Protection of the local aquatic communities by limiting thermal stress to aquatic organisms

2. Minimization of cooling system organism entrainment and impingement levels

3. Protection of local aquatic biota by minimizing the release of chlorine used to control cooling system biofouling to that necessary to maintain plant efficiency and integrity

4. That the local aquatic environment is protected from potential discharges of heavy metals, discharge of water with unacceptable pH from the plant and insuring that no significant dissolved oxygen alteration due to plant operation occurred

To insure that the issues identified in items 1, 2, 3 and 4 above have and are being satisfied, extensive chemical, thermal and biotic monitoring has been performed since plant operation began in 1976.

With assumption of aquatic monitoring programs by EPA through the NPDES program, as delineated in NPDES Permit FL0002208 effective January 29,

1982, NRC will rely on EPA for resolution of issues involving the monitoring of water quality and aquatic biota.

On May 1, 1995, the FDEP was granted authority by the U.S. Environmental Protection Agency (EPA) to administer the NPDES permitting programs. Pursuant to the Florida Administrative Code (FAC) 62-620.105(10), the EPA-issued NPDES permit and the State-issued wastewater permit for each facility were to be combined into one document. The resulting single document, Wastewater Permit No. FL0002208, combines the NPDES Permit FL0002208 and the State Wastewater Permit IO56-194945.

2.2 Terrestrial issues raised have led to programs on sea turtles that:

1. Document the nesting at the site and vicinity; determine effects of the discharge thermal plume on nesting patterns and hatchling migration; and investigate thermal stress on hatching and rearing factors by using turtle eggs from displaced nests

2. Minimize turtle hatchling disorientation by planting a light screen along the beach

The above programs specifically addressed as conditions in the Unit 1 FES, Operating License and Technical Specifications have been completed and the requirements have been satisfied.

3.0 Consistency Requirements

3.1 Plant Design and Operation

The licensee may make changes in station design or operation or perform tests or experiments affecting the environment provided such changes, tests or experiments do not involve an unreviewed environmental question. Changes in plant design or operation or performance of tests or experiments which do not affect the environment are not subject to this requirement.

Before engaging in unauthorized construction or operational activities which may affect the environment, the licensee shall perform an environmental evaluation of such activity.* When the evaluation indicates that such activity involves an unreviewed environmental question, the licensee shall provide a written evaluation of such activities and obtain prior approval from the NRC.

A proposed change, test or experiment shall be deemed to involve an unreviewed environmental question if it concerns (1) a matter which may result in a significant increase in any adverse environmental impact previously evaluated in the final environmental statement (FES) as modified by staff's testimony to the Atomic Safety and Licensing Board, supplements to the FES, environmental impact appraisals, or in any decisions of the Atomic Safety and Licensing Board; or (2) a significant change in effluents or power level (in accordance with 10 CFR Part 51.5(b)(2) or (3) a matter not previously reviewed and evaluated in the documents specified in (1) of this Subsection, which may have a significant adverse environmental impact.

The licensee shall maintain records of changes in facility design or operation and of tests and experiments carried out pursuant to this Subsection. These records shall include a written evaluation which provides bases for the determination that the change, test, or experiment does not involve an unreviewed environmental question.

*Activities are excluded from this requirement if all measurable nonradiological effects are confined to the on-site areas previously disturbed during site preparation and plant construction.

Activities governed by Section 3.3 of this EPP are not subject to the requirements of this section.

3.2 Reporting related to the Wastewater Permit and State Certification (pursuant to Section 401 of the Clean Water Act)

1. Violations of the Wastewater Permit or the State 401 Certification Conditions shall be reported to the NRC by submittal of copies of the reports required by the Wastewater Permit or State 401 Certification.

2. The licensee shall provide the NRC with a copy of any 316(b) studies and/or related documentation at the same time it is submitted to the permitting agency.

3. Changes and additions to the Wastewater Permit or the State 401 Certification shall be reported to the NRC within 30 days following the date the change is approved. If a permit or certification, in part or in its entirety, is appealed and stayed, the NRC shall be notified within 30 days following the date the stay is granted.

4. The NRC shall be notified of changes to the effective Wastewater Permit proposed by the licensee by providing NRC with a copy of the proposed change at the same time it is submitted to the permitting agency. The licensee shall provide the NRC a copy of the application for renewal of the Wastewater Permit at the same time the application is submitted to the permitting agency.

3.3 Changes Required for Compliance with Other Environmental Regulations

Changes in plant design or operation and performance of tests or experiments which are required to achieve compliance with or approval from other Federal, State, or local environmental regulations are not subject to the requirements of Section 3.1.

4.0 Environmental Conditions

4.1 Unusual or Important Environmental Events

Any occurrence of an unusual or important event the indicates or could result in significant environmental impact causally related to station operation shall be recorded and promptly reported to the NRC Operations Center within 72 hours via Emergency Notification System described in 10 CFR 50.72. In addition, the reporting requirement time frame shall be consistent with 10 CFR 50.72 for environmental protection issues. The initial report shall be followed by a written report as described in Section 5.4.2. No routine monitoring programs are required to implement this condition. Events covered by Section 3.2 of this EPP will be subject to reporting requirements as defined in that section and not subject to these requirements.

The following are examples of unusual or important events: excessive bird impaction events; onsite plant or animal disease outbreaks; mortality (causally related to station operation), or unusual occurrence of any species protected by the Endangered Species Act of 1973; unusual fish kills; increase in nuisance organisms or conditions; and unanticipated or emergency discharge of waste water or chemical substances.

4.2 Terrestrial/Aquatic Issues

The certifications and permits required under the Clean Water Act provide mechanisms for protecting water quality and indirectly, aquatic biota. The NRC will rely on the decisions made by the State of Florida under the authority of the Clean Water Act and, in the case of sea turtles, decisions made by the NMFS under the authority of the Endangered Species Act, for any requirements pertaining to terrestrial and aquatic monitoring.

In accordance with Section 7(a) of the Endangered Species Act, on May 4, 2001, the NMFS issued a revised Biological Opinion that revised the ITS and modified some of the terms and conditions of the previous Opinion. After discussions among the NRC, NMFS, and FPL and in response to an NRC letter dated June 8, 2001, the NMFS issued a clarification of the issues in the new Biological Opinion and the ITS on October 8, 2001. The revised Biological Opinion concludes that continued operation of the St. Lucie Plant circulating seawater cooling system is not likely to jeopardize the continued existence of the listed species. No critical habitat has been designated for the specified species in the action area; therefore, none will be affected.

FPL shall adhere to the specific requirements within the ITS in the Biological Opinion as clarified by the NMFS and NRC. Changes to the ITS or the terms and conditions must be preceded by consultation between the NRC, as the authorizing agency, and NMFS.

4.2.1 DELETED

4.2.2 DELETED

INTENTIONALLY DELETED

INTENTIONALLY DELETED

4.2.3 Light Screen to Minimize Turtle Disorientation

Suitable plants (i.e., native vegetation such as live oak, native figs, wild tamarind, and others) shall be planted and maintained as a light screen along the beach dune line bordering the plant property to minimize turtle disorientation. In addition, FPL owner controlled area lighting shall be shielded so that none of the light is diverted skyward.

4.3 General Exceptions

The environmental conditions of the EPP Section 4 are contingent upon licensee or its contractors being able to obtain the necessary FDEP endangered species permits to take, handle, and experiment with sea turtles. If licensee is unable to obtain the necessary permits, then NRC shall be notified of alternatives by the licensee.

5.0 Administrative Procedures

5.1 Review and Audit

The licensee shall provide for review and audit of compliance with the Environmental Protection Plan. The audits shall be conducted independently of the individual or groups responsible for performing the specific activity. A description of the organization structure utilized to achieve the independent review and audit function and results of the audit activities shall be maintained and made available for inspection.

5.2 Records Retention

Records and logs relative to the environmental aspects of plant operation shall be made and retained in a manner convenient for review and inspection. These records and logs shall be made available to NRC on request.

Records of modifications to plant structures, systems and components determined to potentially affect the continued protection of the environment shall be retained for the life of the plant. All other records, data and logs relating to this EPP shall be retained for five years or, where applicable, in accordance with the requirements of other agencies.

5.3 Changes in Environmental Protection Plan

Request for change in the Environmental Protection Plan shall include an assessment of the environmental impact of the proposed change and a supporting justification. Implementation of such changes in the EPP shall not commence prior to NRC approval of the proposed changes in the form of a license amendment incorporating the appropriate revision to the Environmental Protection Plan.

5.4 Plant Reporting Requirements

5.4.1 Routine Reports

5.4.1.1Monthly Reports

Copies of monthly reports covering sea turtle entrapment, capture, rehabilitation, and sea turtle mortalities shall be furnished to NMFS.

5.4.1.2Annual Environmental Operating Report

An Annual Environmental Operating Report describing implementation of this EPP for the previous calendar year shall be submitted to the NRC prior to May 1 of each year.

The report shall include summaries and analyses of the results of the environmental protection activities required by Section 4.2 of this Environmental Protection Plan for the report period, including a comparison with preoperational studies, operational controls (as appropriate), and previous non-radiological environmental monitoring reports, and an assessment of the observed impacts of the plant operation on the environment. If harmful effects or evidence of trends towards irreversible damage to the environment are

observed, the licensee shall provide a detailed analysis of the data and a proposed course of action to alleviate the problem.

The Annual Environmental Operating Report shall also include:

(a) A list of EPP noncompliances and the corrective actions taken to remedy them.

(b) A list of all changes in station design or operation, tests, and experiments made in accordance with Subsection 3.1 which involved a potentially significant unreviewed environmental issue.

(c) A list of nonroutine reports submitted in accordance with Subsection 5.4.2.

(d) A discussion of the sea turtle entrapment, capture efforts, turtle mortalities, available information on barrier net inspections and maintenance, and the Taprogge condenser tube cleaning system operation including sponge ball loss at St. Lucie Plant

In the event that some results are not available by the report due date, the report shall be submitted noting and explaining the missing results. The missing data shall be submitted as soon as possible in a supplementary report.

5.4.2 Nonroutine Reports

A written report shall be submitted to the NRC in accordance with 10 CFR 50.4 within 30 days of occurrence of a nonroutine event. The report shall (a) describe, analyze, and evaluate the event, including extent and magnitude of the impact and plant operating characteristics, (b) describe the probable cause of the event, (c) indicate the action taken to correct the reported event, (d) indicate the corrective action taken to preclude repetition of the event and to prevent similar occurrences involving similar components or systems, and (e) indicate the agencies notified and their preliminary responses.

Events reportable under this subsection which also require reports to other Federal, State, or local agencies shall be reported in accordance with those reporting requirements in lieu of the requirements of this subsection. The NRC shall be provided a copy of such reports within 30 days of the date they submitted to the other agency.

From:	Wong, Melanie
To:	shelley.norton@noaa.gov; stephania.bolden@noaa.gov
Cc:	Balsam, Briana; Logan, Dennis
Subject:	Kind Request: St. Lucie Nuclear Power Plant Section 7 Consultation
Date:	Tuesday, December 11, 2012 8:14:56 AM

Dear Ms. Norton and Ms. Bolden,

I am the new Chief of the Environmental Review and Guidance Update Branch (RERB). As you may be aware based on interactions with Dennis and Briana, our branch performs, among other things, work related to the Endangered Species Act (ESA) during the regulatory review of nuclear power plants.

I am writing to you regarding the delay of the draft biological opinion from the consultation that we reinitiated with NMFS in 2005 and 2006 for the St. Lucie Nuclear Power Plant in Florida.

Both the NRC and the licensee, Florida Power and Light (FPL), have been waiting for the draft biological opinion on sea turtles and smalltooth sawfish. A take of a smalltooth sawfish at the St. Lucie Nuclear Power Plant in May of 2005 resulted in the NRC requesting reinitiation of Section 7 consultation. In addition, when the plant exceeded the annual incidental take limit for sea turtles in 2006, sea turtles were added to the consultation. Although FPL initiated some of the projects that they and the NRC understood would be required in the biological opinion, because of the delay, FPL has terminated that work until they receive the new biological opinion from NMFS.

Both the NRC and FPL are committed to cooperating with NMFS in protecting endangered species under the ESA. We would greatly appreciate it if you could please let us know when the biological opinion would be finalized.

Would it be possible for me to give you a call this week to discuss further?

Thank you for your kind consideration.

Sincerely,
Melanie

Melanie Wong, Chief
Environmental Review & Guidance Update Branch
Division of License Renewal
Office of Nuclear Reactor Regulation
Loc: O-11E20
301-415-2432

From: Wong, Melanie
To: Shelley Norton - NOAA Federal
Cc: Logan, Dennis
Subject: RE: Kind Request: St. Lucie Nuclear Power Plant Section 7 Consultation
Date: Tuesday, December 11, 2012 4:21:50 PM

Dear Shelly,

That is wonderful news. May we call you at 9:15am tomorrow?

Best regards,
Melanie

From: Shelley Norton - NOAA Federal [mailto:shelley.norton@noaa.gov]
Sent: Tuesday, December 11, 2012 1:11 PM
To: Wong, Melanie
Subject: Re: Kind Request: St. Lucie Nuclear Power Plant Section 7 Consultation

Hi Melanie, I would be happy to set up a meeting. What days and times work best for you? My office hours are 7-3:30. My schedule is open accept tomorrow from 10-11 and Friday from 11-2.

Thanks,
Shelley

On Tue, Dec 11, 2012 at 8:14 AM, Wong, Melanie <Melanie.Wong@nrc.gov> wrote:
Dear Ms. Norton and Ms. Bolden,

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Sincerely,
Melanie

Melanie Wong, Chief
Environmental Review & Guidance Update Branch
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Office of Nuclear Reactor Regulation
Loc: O-11E20
301-415-2432

--
Shelley Norton
Sawfish and Johnson's Seagrass Coordinator
National Marine Fisheries Service
NOAA Southeast Regional Office
Protected Resources Division
263 13th Avenue South
St. Petersburg, Florida 33701
PH: (727) 551-5781
FX: (727) 824-5309
Email: shelley.norton@noaa.gov
Web: http://sero.nmfs.noaa.gov/pr/pr.htm

From:	Wong, Melanie
To:	Shelley Norton - NOAA Federal
Cc:	Logan, Dennis
Subject:	RE: Kind Request: St. Lucie Nuclear Power Plant Section 7 Consultation
Date:	Wednesday, December 12, 2012 7:51:07 AM

Hello Shelley,

10:30 on this Friday is perfect. I will send a scheduler.

Thank you again.

Best regards,
Melanie

Melanie Wong, Chief
Environmental Review & Guidance Update Branch
Division of License Renewal
Office of Nuclear Reactor Regulation
Loc: O-11E20
301-415-2432

From: Shelley Norton - NOAA Federal [mailto:shelley.norton@noaa.gov]
Sent: Wednesday, December 12, 2012 7:28 AM
To: Wong, Melanie
Cc: Logan, Dennis
Subject: Re: Kind Request: St. Lucie Nuclear Power Plant Section 7 Consultation

Hi Melanie, can we talk at 10:30 on Friday? I am including our section 7 supervisor on the call and Friday is her only available time this week.

Thanks,
Shelley

On Tue, Dec 11, 2012 at 4:21 PM, Wong, Melanie <Melanie.Wong@nrc.gov> wrote:
Dear Shelly,

That is wonderful news. May we call you at 9:15am tomorrow?

Best regards,
Melanie

From: Shelley Norton - NOAA Federal [mailto:shelley.norton@noaa.gov]
Sent: Tuesday, December 11, 2012 1:11 PM
To: Wong, Melanie
Subject: Re: Kind Request: St. Lucie Nuclear Power Plant Section 7 Consultation

Hi Melanie, I would be happy to set up a meeting. What days and times work best for you? My office hours are 7-3:30. My schedule is open accept tomorrow from 10-11 and Friday from 11-2.

Thanks,
Shelley

On Tue, Dec 11, 2012 at 8:14 AM, Wong, Melanie <Melanie.Wong@nrc.gov> wrote:
Dear Ms. Norton and Ms. Bolden,

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Would it be possible for me to give you a call this week to discuss further?

Thank you for your kind consideration.

Sincerely,
Melanie

Melanie Wong, Chief
Environmental Review & Guidance Update Branch
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Shelley Norton
Sawfish and Johnson's Seagrass Coordinator
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From:	Wong, Melanie
To:	Shelley Norton - NOAA Federal; Logan, Dennis; Gless, Jodie
Subject:	RE: Design Specifications of the Turtle Excluder Device/Velocity Caps for the St. Lucie Nuclear Power Plant
Date:	Wednesday, March 20, 2013 10:58:20 AM

Hello Shelley,

Thank you for providing the request for information.

We appreciate your consideration and commitment to keeping the consultation process progressing.

Best regards,
MelanieW

Melanie Wong, Chief
Environmental Review & Guidance Update Branch
Division of License Renewal
Office of Nuclear Reactor Regulation
Loc: O-11E20
301-415-2432

-----Original Message-----
From: Shelley Norton - NOAA Federal [mailto:shelley.norton@noaa.gov]
Sent: Tuesday, March 19, 2013 4:02 PM
To: Wong, Melanie; Logan, Dennis; Gless, Jodie
Subject: Design Specifications of the Turtle Excluder Device/Velocity Caps for the St. Lucie Nuclear Power Plant

Good afternoon Melanie, I wanted to send this email so that we can keep the consultation process moving on the BO for the continued operation of the St. Lucie Nuclear Power Plant. I will follow-up this email with a formal letter. During our conference call in December of 2012, we discussed our request for additional information on the turtle excluder device/velocity caps that are proposed for the St. Lucie Nuclear Power Plant. FP&L has designed an excluder device to prevent large marine organisms, such as sea turtles and smalltooth sawfish, from entering the intake structure. The proposed excluder/velocity cap is currently designed to exclude approximately
23 percent of the turtles captured in the intake pipe. Can you please provide verification from your NRC engineering staff that explains why FP&L cannot design a turtle excluder device/velocity cap that excludes more than 23 percent of the turtles that currently enter the plant? I am out of the office tomorrow and Thursday but will be on our call Friday to discuss any questions you may have on the consultation.

Thanks,
Shelley

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Shelley Norton
Sawfish and Johnson's Seagrass Coordinator National Marine Fisheries Service NOAA Southeast Regional Office Protected Resources Division
263 13th Avenue South
St. Petersburg, Florida 33701

PH: (727) 551-5781
FX: (727) 824-5309
Email: shelley.norton@noaa.gov
Web: http://sero.nmfs.noaa.gov/pr/pr.htm

From: Logan, Dennis
To: Gless, Jodie
Cc: Shelley Norton - NOAA Federal
Subject: St. Lucie: Contact information for NRC staff new to project
Date: Friday, April 19, 2013 8:21:12 AM

Jodie,

Rafael's and Siva's contact information is below:

Rafael Rodriquez, Project Manager (DORL)
Phone 301-415 1558
Email Rafael.Rodriguez@nrc.gov

Siva Lingam, Project Manager (DORL)
Phone 301-415-1564
Email Siva.Lingam@nrc.gov

DORL stands for Division of Operating Reactor Licensing.

As we discussed, Rafael will be replacing Tracy Orf and Siva will be assisting in the engineering review of the turtle excluder.

Dennis

From:	Logan, Dennis
To:	Shelley Norton - NOAA Federal; Gless, Jodie
Cc:	Audra Livergood - NOAA Federal
Subject:	RE: St. Lucie Biop POC
Date:	Monday, April 29, 2013 7:43:13 AM

Shelley, Jodie, and Audra,

If a call will help, I would be available this week, although I have a number of other obligations so we'd have to work out a time.

Dennis

From: Shelley Norton - NOAA Federal [mailto:shelley.norton@noaa.gov]
Sent: Monday, April 29, 2013 7:39 AM
To: Gless, Jodie; Logan, Dennis
Cc: Audra Livergood - NOAA Federal
Subject: St. Lucie Biop POC

Hi Dennis and Jodie, Audra Livergood will be taking over the writing of the BO for the continute operation of the St. Lucie Nuclear Power Plant. I will work closely with Audra during the rewriting of the document. I am sending the file to Audra this week. Do you want ot schedule a call with the four of us to get everyone up to speed on where we are in the process? Also, do you have electronic copies of the annual operating reports?

Thanks,
Shelley

--

Shelley Norton
Sawfish and Johnson's Seagrass Coordinator
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NOAA Southeast Regional Office
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263 13th Avenue South
St. Petersburg, Florida 33701
PH: (727) 551-5781
FX: (727) 824-5309
Email: shelley.norton@noaa.gov
Web. http://sero.nmfs.noaa.gov/pr/pr.htm

From:	Logan, Dennis
To:	Shelley Norton - NOAA Federal
Subject:	RE: St. Lucie Biop POC
Date:	Monday, April 29, 2013 10:22:35 AM

OK here. Thanks Shelley.

From: Shelley Norton - NOAA Federal [mailto:shelley.norton@noaa.gov]
Sent: Monday, April 29, 2013 10:21 AM
To: Logan, Dennis
Subject: Re: St. Lucie Biop POC

Hi Dennis, it looks like Jodie is out of the office. We can wait for Jodie to return next week.

Shelley

On Mon, Apr 29, 2013 at 7:43 AM, Logan, Dennis <Dennis.Logan@nrc.gov> wrote:
Shelley, Jodie, and Audra,

If a call will help, I would be available this week, although I have a number of other obligations so we'd have to work out a time.

Dennis

From: Shelley Norton - NOAA Federal [mailto:shelley.norton@noaa.gov]
Sent: Monday, April 29, 2013 7:39 AM
To: Gless, Jodie; Logan, Dennis
Cc: Audra Livergood - NOAA Federal
Subject: St. Lucie Biop POC

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Thanks,
Shelley

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Email: shelley.norton@noaa.gov
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From:	Logan, Dennis
To:	Audra Livergood - NOAA Federal
Cc:	Shelley Norton - NOAA Federal
Subject:	St Lucie BiOp question
Date:	Tuesday, May 21, 2013 2:13:31 PM

Audra,

This is Dennis Logan at the US Nuclear Regulatory Commission. I am writing about the Section 7 consultation for St. Lucie plant. I know that we will take this up when you have more free time, but I was wondering if you had a quick answer to this question. I tried to call, but the number I found is no longer in service.

Some of NRC's engineers are reviewing the design for the turtle excluding device proposed for the St. Lucie intake structure. The question posed by NMFS is whether the openings could be made smaller—but we are trying to better understand the question before us. There are trade-offs, such as smaller openings would tend to clog more easily with displaced seaweed during storms or be more subject to fouling. The present design would already exclude almost all pregnant female turtles, which I understood was the objective of the excluder. The engineers have to understand these tradeoffs, and we have few actual data. So if at some time you could help me more clearly understand the objective, I could help them better.

This is not an immediate concern, as the project is delayed until you have more time, but, at some point, we should discuss this. I am copying Shelley, as she is familiar with the consultation.

My contact information is below. Thank you for your time,

Dennis

Dennis Logan, Ph.D.
Ecologist
U.S. Nuclear Regulatory Commission
One White Flint North, Mail Stop O-11F1
11555 Rockville Pike
Rockville, MD 20852-2738

Phone: 301.415.0490
Fax: 301.415.2002

From: Logan, Dennis
To: Audra Livergood - NOAA Federal
Subject: RE: FPL St. Lucie
Date: Wednesday, August 06, 2014 3:03:55 PM

Audra:. Thank you for keeping me "in the loop." -Dennis

From: Audra Livergood - NOAA Federal [mailto:audra.livergood@noaa.gov]
Sent: Wednesday, August 06, 2014 3:01 PM
To: Gless, Jodie
Cc: Logan, Dennis
Subject: FPL St. Lucie

Hi Jodie,

I hope you are well. As per my voicemail message, I just had a good conversation with John Mitchell from our Pascagoula lab. I am cc'ing Dennis Logan to keep him in the loop.

John and his team have 25+ years experience testing TEDs, and after speaking with him, there are some valuable "lessons learned" that can also be applied in this case. I would like to set up a call with you, Dennis, Mike (Inwater Research), John, and myself. He has some good questions about the excluder, and there may be questions you want to ask him.

One question he has is whether the excluder can be scaled down so it can be towed behind a boat for testing.

Also, can you please email me a schematic of the excluder design? I would like to pass it on to John.

I will set up a Doodle poll. Jodie, can you please send me Mike's email address?

Thanks,
Audra

--
Audra (Livergood) Banks
NOAA National Marine Fisheries Service
SERO Protected Resources Division
8000 N. Ocean Drive, Suite 228
Dania Beach, FL 33004

Let us not lose heart in doing good, for in due time we will reap if we do not grow weary. (Galatians 6:9)

We are supposed to preach without preaching, not by words, but by our example, by our actions. All works of love are works of peace.
Mother Teresa

From:	Logan, Dennis
To:	"Audra Livergood - NOAA Federal"
Subject:	RE: St. Lucie
Date:	Monday, January 12, 2015 12:53:11 PM

Audra,

Thank you. We have been expecting something like this, but did not things would happen so quickly.

Best wishes to you.

Dennis

From: Audra Livergood - NOAA Federal [mailto:audra.livergood@noaa.gov]
Sent: Monday, January 12, 2015 11:52 AM
To: Gless, Jodie; Logan, Dennis
Subject: St. Lucie

Good morning Jodie and Dennis,

Happy New Year! I hope you are both well. I wanted to notify you that my supervisor, Rachel Sweeney, spoke with Cathy Tortorici (who is now in Silver Spring) and they decided it would be best if our Office of Protected Resources (OPR) in Silver Spring took on the responsibility of completing the biological opinion for St. Lucie. The project is being transferred to Debbie Spring. Her contact info is provided below:

Debbie Spring
debbie.spring@noaa.gov
301-427-8475

I'm sorry this project keeps getting passed around, but given their recent work in OPR on the ESA Section 7(a)(2) consultation on EPA's 316(b) regulations, this seems like a good fit for them.

I sent the file to Debbie via UPS on Friday. Please give her some time to familiarize herself and get up to speed. Also, please include her on the invitation list for upcoming conference calls for St. Lucie.

Jodie, can you please ask Steve Weege to remove my name from the email list and add Debbie's name for the monthly marine turtle removal reports?

It has been a pleasure to work with both of you. If you have questions, feel free to contact me by email or phone (786) 351-2225.

Thank you,
Audra

--
Audra (Livergood) Banks
NOAA National Marine Fisheries Service

SERO Protected Resources Division
8000 N. Ocean Drive, Suite 228
Dania Beach, FL 33004

Looking at them, Jesus said, "With people it is impossible, but not with God; for all things are possible with God." *(Mark 10:27)*

We are supposed to preach without preaching, not by words, but by our example, by our actions. All works of love are works of peace.
Mother Teresa