FLORIDA POWER AND LIGHT COMPANY
ST. LUCIE NUCLEAR POWER PLANT
UNIT 2

DOCKET NO. 50-389

LICENSE NO. NPF-16

STARTUP TEST REPORT

SEPTEMBER, 1983

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

This report fulfills the requirement of Technical Specification 6.9.1.3 which states that a Startup Test Report will be submitted to the NRC within,

	COMPLETION DATE	+ 90 DAYS
1) 90 days after completion of the Startup Test Program	8-9-83	11-7-83
	COMMERCIAL DATE	+ 90 DAYS
2) 90 days following commencement of commercial power operation	8-8-83	11-6-83
	INITIAL CRITICALLITY	+ 9 MONTHS
3) 9 months following Initical Criticality	6-2-83	3-2-84

whichever is earliest.

This report is required to be submitted prior to 11-6-83.

The Startup Test Program was organized and administered by FP&L personnel. The NSSS vendor (Combustion Engineering) and the Architect Engineer (Ebasco) reviewed the program prior to its inception and participated in the field testing and review of test results. The program was based on Regulatory Guide 1.68 Rev. 2 with exceptions noted in the FSAR Section 14.2.7.

The Technical Specifications (Section 6.9.1.2) dictate that the Startup Report shall address each test identified in the FSAR. For this reason, Chapter 14 was used as a guideline in preparing the test summaries. Wherever possible, this report follows the test description sequence from Table 14.2-2 of the FSAR.

The Startup Test Program consisted of several phases:

1. Initial Fuel Load
2. Post Core Load Hot Functional Tests
3. Initial Criticality
4. Low Power Physics Tests
5. Power Ascension Tests
    a. 20% Plateau
    b. 50% Plateau
    c. 80% Plateau
    d. 100% Plateau

The Startup Test Program began on April 6, 1983 with the loading of the first fuel assembly into the reactor vessel. It terminated on August 8, 1983 with the declaration of commercial operation. Total test duration was 4 months, 2 days. Figure 1.1 lists the milestone dates during the test program.

SUMMARY

INITIAL FUEL LOAD

Fuel loading commenced on April 6, 1983 at 1909 hours and was completed on April 10, 1983. The Initial Fuel Load and Core Verification was planned for completion in 14 days. Eight to eleven day loadings were typical for preceeding CE plants. The actual fuel loading duration was 3 days 23 hours and 45 minutes with the core verification lasting approximately 8 hours and 30 minutes. The total duration of fuel load and core verification was 4 days 8 hours and 15 minutes. The Unit #2 Initial Core Load was completed at 1854 hours on April 10, 1983

POST CORE LOAD HOT FUNCTIONAL TESTING

Post Core Load Hot Functional Testing began with the plant heatup of April 27, 1983. Testing was completed on May 30, 1983. Total duration was 33 days. In addition to the testing described in Chapter 14 of the FSAR, several other tests were performed primarily due to retesting requirements. These tests were:

- RCS and Piping Thermal Expansion
- RCS Heat Loss
- Pressurizer Controls Test

All of the above tests met the required acceptance criteria.

INITIAL CRITICALITY

The reactor was initially brought to a critical state on June 2, 1983. A slow dilution followed CEA withdrawal lowering the boron concentration from 1783 ppm to 715 ppm. Measured RCS soluble boron concentration at criticality was in close agreement with predicted values and well within the acceptance critieria.

LOW POWER PHYSICS TESTS

The Low Power Physics Tests began on June 2, 1983 following the approach to criticality. These physics tests were completed on June 5, 1983. All acceptance criteria were met.

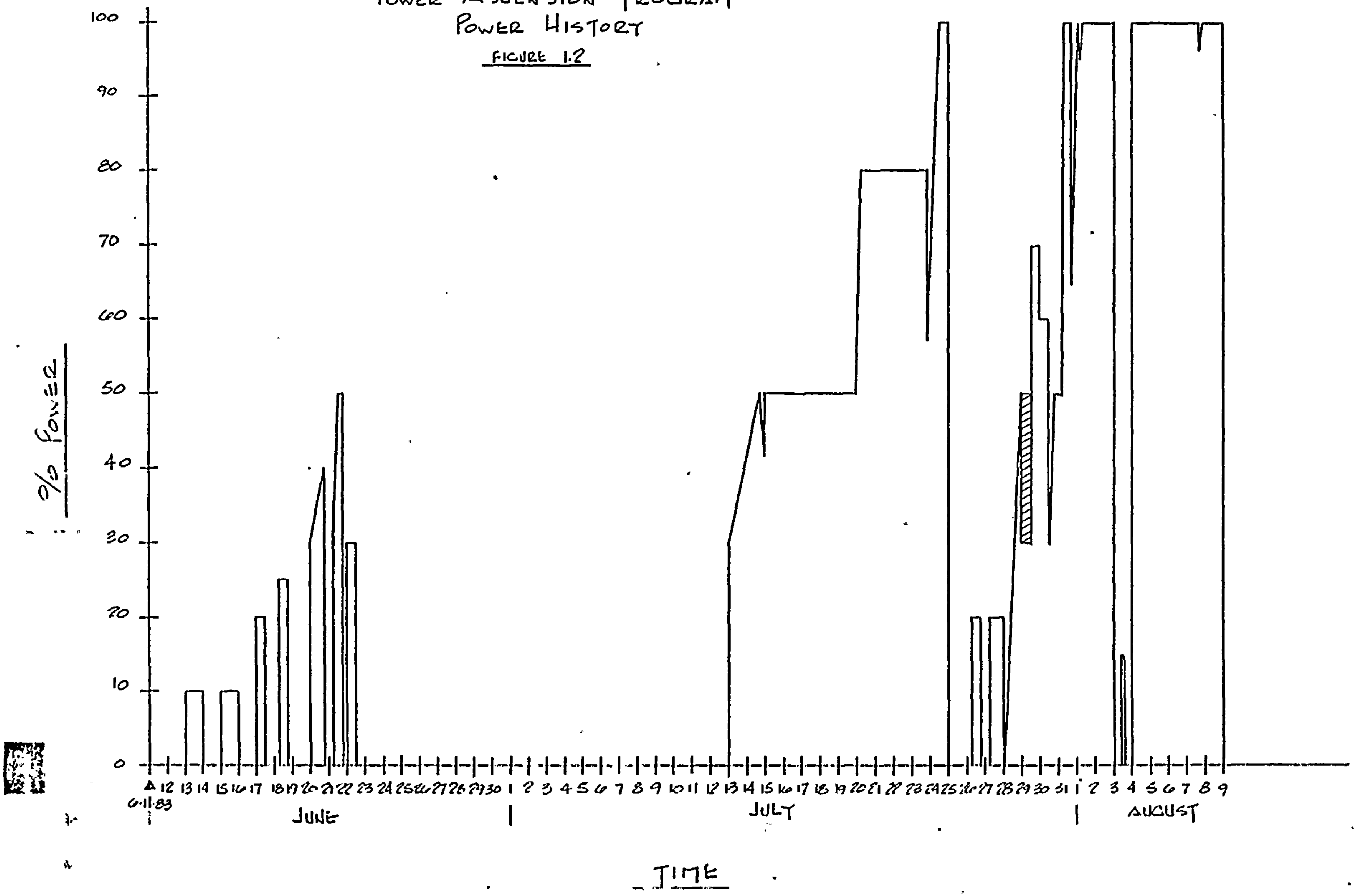
POWER ASCENSION

Power Ascension testing preparations began on June 10, 1983. The main generator was synchornized with the grid on June 13 and the 20% power plateau testing was started on June 16. After a brief time at 50% power, the plant underwent a 21 day outage to repair RCP seals, secondary chemistry and condenser cleaning, and a visual inspection of the secondary side of the steam generator for loose parts. 50% power plateau testing went on from July 14 through 19. 80% power testing was from July 20 through 24. 100% power was initially achieved on July 24 and the unit was decared commercial on August 8. Figure 1.2 gives a presentation of power history. Total elapsed power ascension test time was 59 days.

FIGURE 1.1
ST. LUCIE UNIT 2
STARTUP MILESTONE DATES

MILESTONE	1983 DATE
Core Load Start	April 6
Core Load End	April 9
Post Core Load Hot Functionals Started Heatup	April 27
Post Core Load Hot Functionals End Testing	May 30
Initial Criticality	June 2
Low Power Physics Test Start	June 2
Low Power Physics Test End	June 5
Full Power License Received	June 10
Start Power Ascension Testing	June 10
Reached 20% Plateau	June 16
Reached 50% Plateau	July 14
Reached 80% Plateau	July 20
Reached 100% Plateau	July 24
Commercial Operation Start	August 8

POWER ASCENSION PROGRAM
POWER HISTORY
FIGURE 1.2



2.0 INITIAL CORE LOAD

Fuel loading commenced on April 6, 1983 at 1909 hours and was completed on April 10, 1983. The Initial Fuel Load and Core Verification was planned for completion in 14 days. Eight to eleven day loadings were typical for preceding CE plants. The actual fuel loading duration was 3 days, 23 hours and 45 minutes with the core verification lasting approximately 8 hours and 30 minutes. The total duration of fuel load and core verification was 4 days, 8 hours and 15 minutes. The Unit #2 Initial Core Load was completed at 1854 hours on April 10, 1983.

Initial fuel loading was performed in accordance with a step-by-step procedure prepared by Florida Power and Light Company Operations Organization reviewed by Combustion Engineering, the Facility Review Group and approved by the Plant Manager. Florida Power and Light Company and Combustion Engineering provided continuous coverage for the fuel loading operation to ensure that nuclear safety was adequately safe-guarded.

The detailed procedure that was used for initial fuel loading included:

a) Defined personnel authorities and responsibilities.

b) Communication requirements between the control room, refueling machine, fuel storage area, and the neutron monitoring station.

c) Requirements for personnel and radiation monitoring.

d) Requirements to ensure proper Reactor Coolant System flow and level and that Technical Specifications for fuel loading are being met.

e) Requirements to verify serial numbers, orientations, and core locations of fuel assemblies, control element assemblies, source assemblies and temporary detectors.

f) Inverse multiplication plot requirements to assure a safe fuel loading.

g) An inverse multiplication criticality estimate for fuel loading following the seating of each fuel element.

h) Requirements for boron concentration, sampling frequency, boron injection flow path, and borated water sources.

i) Provisions for ensuring proper response of the startup and temporary neutron detectors to neutron sources installed in the core.

At 1934 hours on April 6, 1983, fuel assembly No. 1, containing neutron source No. 1, was loaded into core location Y-12. The Initial Core Load was completed at 1854 hours on April 10, 1983, when fuel assembly No. 217 was loaded into core location Y-7.

Figure 2-1 shows the fuel loading sequence. Figures 2-2 and 2-3 show fuel assembly and CEA locations by their respective serial numbers.

The neutron count rate was monitored during loading on four separate detector channels, Temporary Detector A in location V-7 and Temporary Detector B in location V-15, were installed prior to fuel loading and Startup Channels 1 and 2. Following the completion of step 140, Temporary Detector B was moved to location D-15.

Previous to fuel loading, a background countrate with no fuel or neutron sources in the core was taken. The acceptance criteria was upheld in that the background signals for each plant startup channel and temporary fuel loading channel were determined prior to the introduction of the source into the vessel and initial fuel loading. The dummy fuel assembly containing the first neutron source was positioned near both temporary and startup detectors to provide a response check prior to loading fuel. As was observed, the temporary fuel loading channels and startup channels responded with a signal that showed an increase above background, thereby, meeting the acceptance criterion for the detectors.

The source was then loaded into the first fuel assembly, and initially the core was loaded by placing the first fuel assemblies on the west side of the core. Succeeding assemblies were inserted in a manner to provide for a compact well coupled partial core. The loading generated a partial core, nine assemblies wide, on the west side of the reactor. As the loading progressed, the nine assembly wide slab was extended across the reactor to the east side. Once the slab was complete from west to east, the loading then proceeded to fill the south portion of the core. When the south portion of the core was finished, the loading progressed to the north side to complete the core.

Independent plots of inverse count rate versus the number of fuel assemblies loaded were maintained to ensure the reactor remained subcritical at all times during loading. The inverse count rate ratio plots remained level when geometric effects were discounted.

No major problems were encountered during fuel loading. All problem areas were corrected.

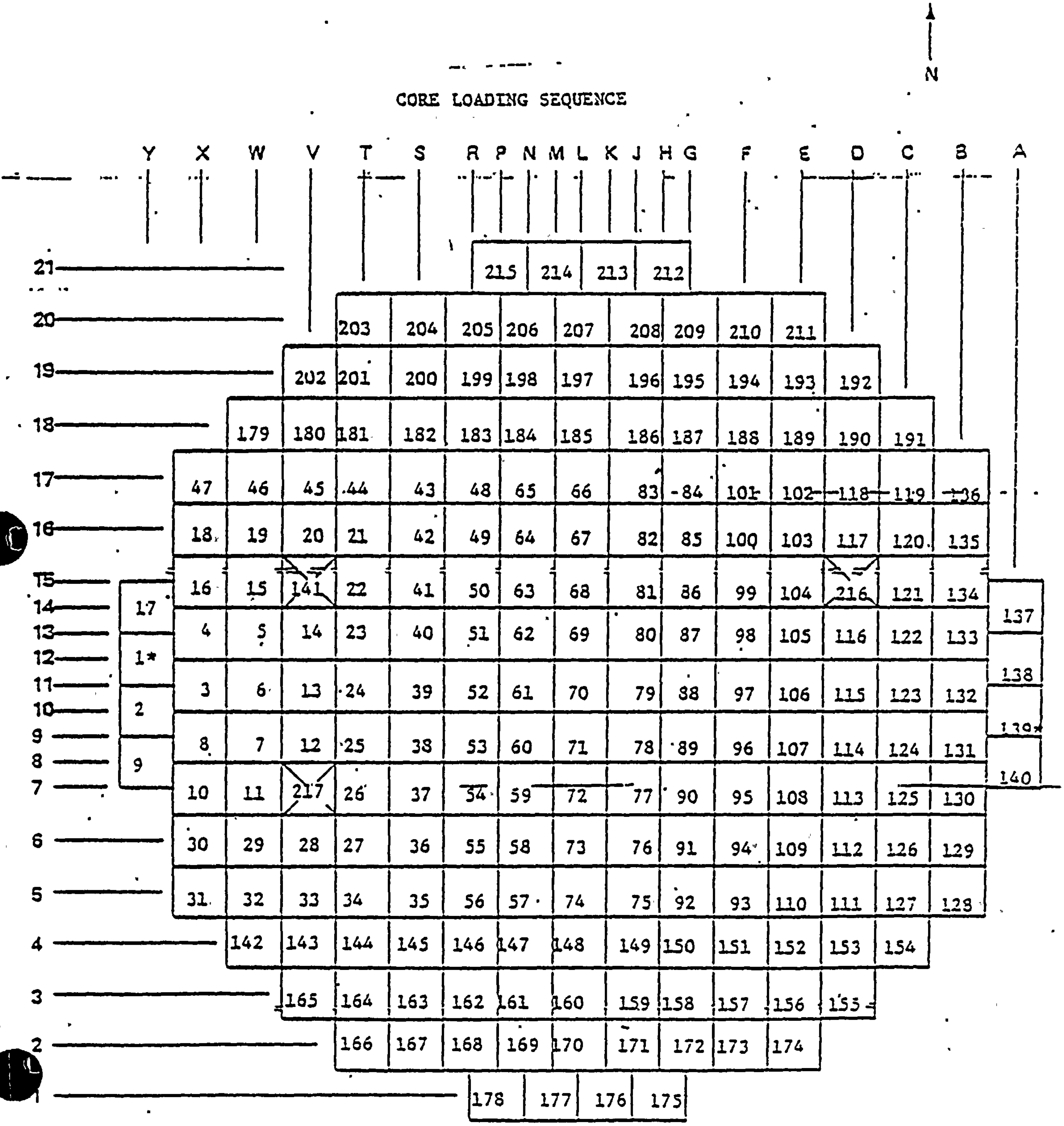
Fuel loading was conducted with the spent fuel pool dry, refueling cavity full to the top of the fuel transfer tube flange and the reactor vessel filled to above the vessel nozzles but below the internals support ledge. A refueling boron concentration of $\geq$ 1720 ppm boron was maintained with shutdown cooling flow through the core in accordance with the Technical Specifications at all times.

The location, serial number and orientation of all fuel assemblies, CEA's (not including four fingered CEA's) and neutron sources were visually verified and Appendix B (Fuel Loading Verification Check) of Preoperational Test Procedure 2-1600021, Unit 2 Initial Core Loading, was satisfactorily completed.

FIGURE 2-1

UNIT NO. 2 INITIAL CORE LOADING

CORE LOADING SEQUENCE



						215	214	213	212							
				203	204	205	206	207	208	209	210	211				
			202	201	200	199	198	197	196	195	194	193	192			
		179	180	181	182	183	184	185	186	187	188	189	190	191		
	47	46	45	44	43	48	65	66	83	84	101	102	118	119	136	
	18	19	20	21	42	49	64	67	82	85	100	103	117	120	135	
17	16	15	141	22	41	50	63	68	81	86	99	104	216	121	134	137
1*	4	5	14	23	40	51	62	69	80	87	98	105	116	122	133	138
2	3	6	13	24	39	52	61	70	79	88	97	106	115	123	132	139*
9	8	7	12	25	38	53	60	71	78	89	96	107	114	124	131	140
	10	11	217	26	37	54	59	72	77	90	95	108	113	125	130	
	30	29	28	27	36	55	58	73	76	91	94	109	112	126	129	
	31	32	33	34	35	56	57	74	75	92	93	110	111	127	128	
		142	143	144	145	146	147	148	149	150	151	152	153	154		
			165	164	163	162	161	160	159	158	157	156	155			
				166	167	168	169	170	171	172	173	174				
						178	177	176	175							

*: Fuel Assembly Containing Neutron Source
X: Temporary Detector Location

FIGURE 2-2

UNIT NO. 2 INITIAL CORE LOADING

CYCLE 1 CORE MAP (FUEL)

N

Y X W V T S R P N M L K J H G F E D C B A

21 20 19 18 17 6 15 14 13 12 11 10 9 8 7 6 5 4 3 1

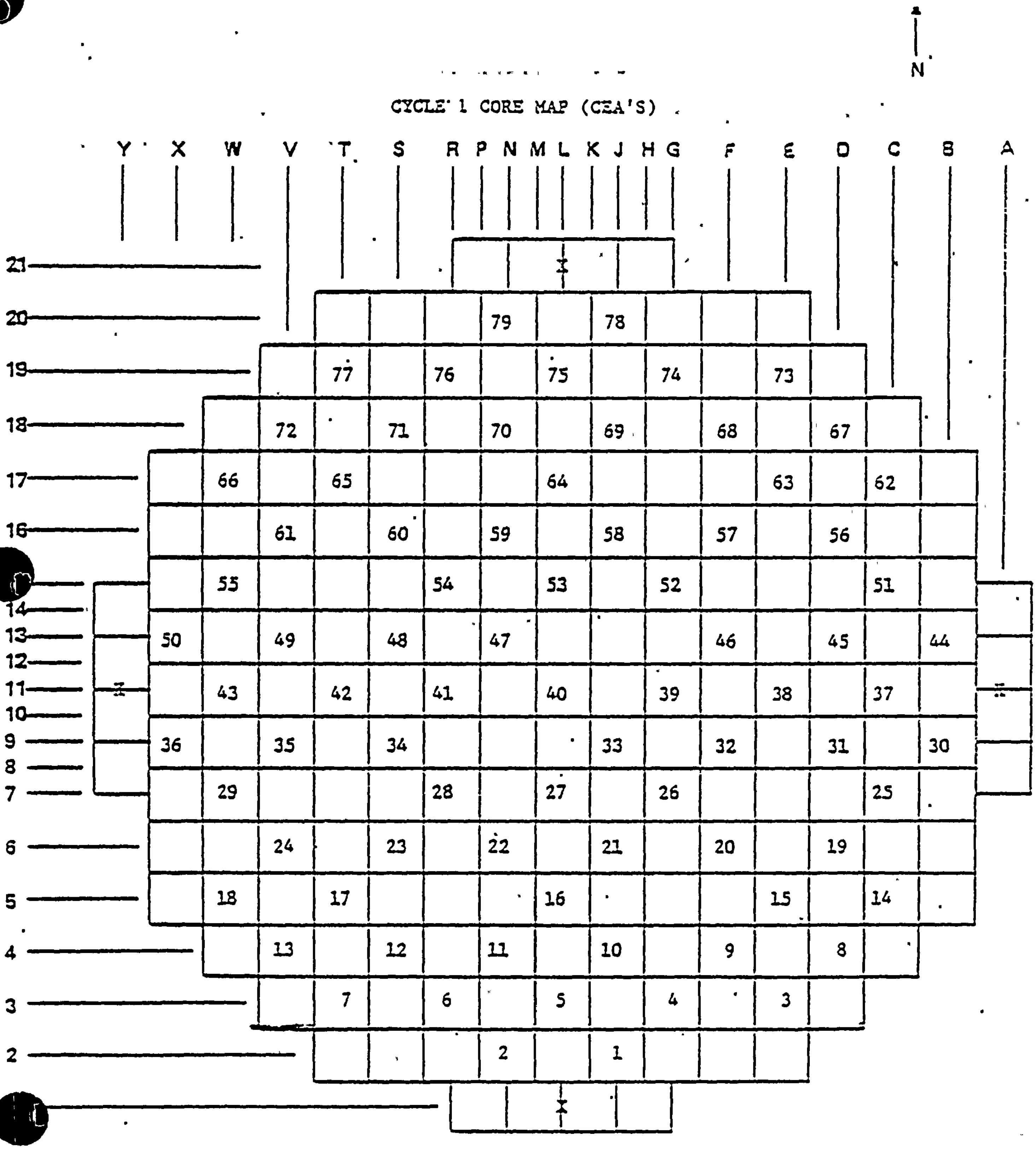
							C026	C005	C039	C027						
				C006	C015	C210	C201	B020	C202	C216	C008	C030				
			C038	C101	B017	A034	B055	A066	B010	A025	B063	C102	C032			
		C028	A057	B012	A026	B047	A058	B025	A046	B067	A049	B058	A050	C033		
	C029	C106	B006	A060	B066	A045	B019	A062	B036	A068	B056	A022	B064	C108	C011	
	C019	B062	A029	B061	A055	B033	A018	B074	A067	B041	A002	B068	A007	B069	C020	
	C203	A063	B050	A027	B043	A016	B076	A042	B039	A006	B042	A064	B065	A004	C209	
C036																
																C031
	C215	B049	A003	B022	A071	B054	A044	B029	A054	B035	A020	B038	A011	B078	C208	
C001																
																C002
	B051	A009	B040	A017	B030	A043	B028	A037	B031	A053	B037	A012	B015	A010	B071	
C003																
																C004
	C207	B046	A001	B026	A036	B018	A038	B032	A041	B023	A019	B053	A008	B072	C214	
C016																
																C040
	C213	A059	B057	A014	B079	A005	B034	A052	B027	A021	B045	A039	B077	A072	C212	
	C037	B009	A023	B060	A073	B014	A070	B080	A028	B021	A015	B048	A056	B001	C025	
	C010	C107	B005	A030	B013	A051	B044	A035	B073	A040	B011	A031	B008	C104	C014	
		C023	A065	B003	A033	B070	A013	B059	A061	B024	A032	B004	A047	C024		
			C022	C103	B002	A024	B052	A069	B016	A048	B007	C105	C018			
				C009	C017	C204	C211	B075	C205	C206	C021	C034				
							C012	C013	C035	C007						

NOTE: 1. Fuel assembly orientation: Serial number in SW corner.
2. All serial numbers are prefixed with "L2".

FIGURE 2-3

UNIT NO. 2 INITIAL CORE LOADING

CYCLE 1 CORE MAP (CEA'S)



NOTE: X 1. The four fingered CEA's (#'s 80, 81, 82, 83) will be installed as part of the upper guide structure following completion of fuel load.

2. CEA orientation: Serial # on SW web.

3.0 POST CORE LOAD HOT FUNCTIONAL TESTS (PCHF)

Several of the tests required prior to initial criticality require installation of the fuel and all reactor internals as a prerequisite. These tests (Post Core Hot Functional Tests) are conducted after initial fuel loading and complete the prerequisites for initial criticality. A list of the requird tests follows:

a) RCS Flow and Flow Coastdown
b) CEDM Performance
c) Incore Instrumentation Checkout
d) Pressurizer Spray Effectiveness
e) RCS Leak Tightness
f) Plant Chemical and Radio Chemical Analysis
g) Wide Range Nuclear Instrumentation Readings
h) Loose Parts Monitor
i) Reactor Protection System
j) Temporary Incore Instrument Channel Response
k) Safety Channel Pre-Critical Alignment Calibration
l) Start-Up/Control Channel Pre-Critical Alignment and Calibration
m) Auxiliary Feedwater System Automatic Actuation system
n) Natural Circulation

The above tests are described in Sections 3.a through 3.d. The instrumentation portion of many of the instrumentation and controls tests were performed as a prerequisite to either Core Load or PCHF testing.

In addition, those items or systems which require maintenance or had testing deferred from pre-core hot functional tests were tested during PCHF testing. This included:

a) RCS Heat Loss
b) RCS Component Expansion
c) Piping Thermal Expansion
d) Reactor Coolant Gas Vent System
e) Post Accident Monitoring System
f) Primary Sample System Retest
g) Shutdown Cooling Heat Exchanger Retest
h) Boron Flow Control Valve Retest
i) RTD Time Response Retest
j) Generator Vent System Retest

RCS heatup in preparation for Post Core Hot Functional (PCHF) testing began on April 27, 1983. However, an approximate one week delay in continued heatup resulted due to repairs on the 2A Auxiliary Feedwater pump. During the time Diesel Generator testing was completed and other PCHF prerequisite testing continued.

RCS heatup to 300°F and entry into Mode 4 (> 200°F) continued on May 7, 1983 where the plant entered into the Shutdown Cooling Mode and Shutdown Cooling Heat Exchanger retesting was completed. During this time a pressure boundary leak was detected and repaired on a Safety Injection drain line socket weld. RCS heatup to 532°F and entry into Mode 3 ($\geq$ 325°F) continued on May 13, 1983 where RTD Time Response and Reactor Heat vent testing was completed.

3.0 POST CORE LOAD HOT FUNCTIONAL TESTS (PCHF) (Cont.)

On May 14, 1983 abnormal pressures on the 2A2 Reactor Coolant Pump (RCP) seal were observed indicating partial RCP seal degradation. A subsequent plant cooldown and depressurization for 2A2 RCP seal change out took place resulting in a one week delay in the test program.

On May 22, 1983 RCS heatup to normal operating temperature and pressure commenced following which, the main core of the PCHF tests were conducted. All PCHF tests required as a prerequisite to initial criticality were complete on May 30, 1983. These tests were reviewed by the Facility Review Group and determined to have satisfactorily met their acceptance criteria.

3.a RCS FLOW COASTDOWN & MEASUREMENT

3.a.1 Purpose:

The objectives of this test were as follows:

(1) To measure the reactor coolant flow rate and core pressure drops.

(2) To obtain the reactor coolant pump flow coastdown characteristics.

3.a.2 Test Results

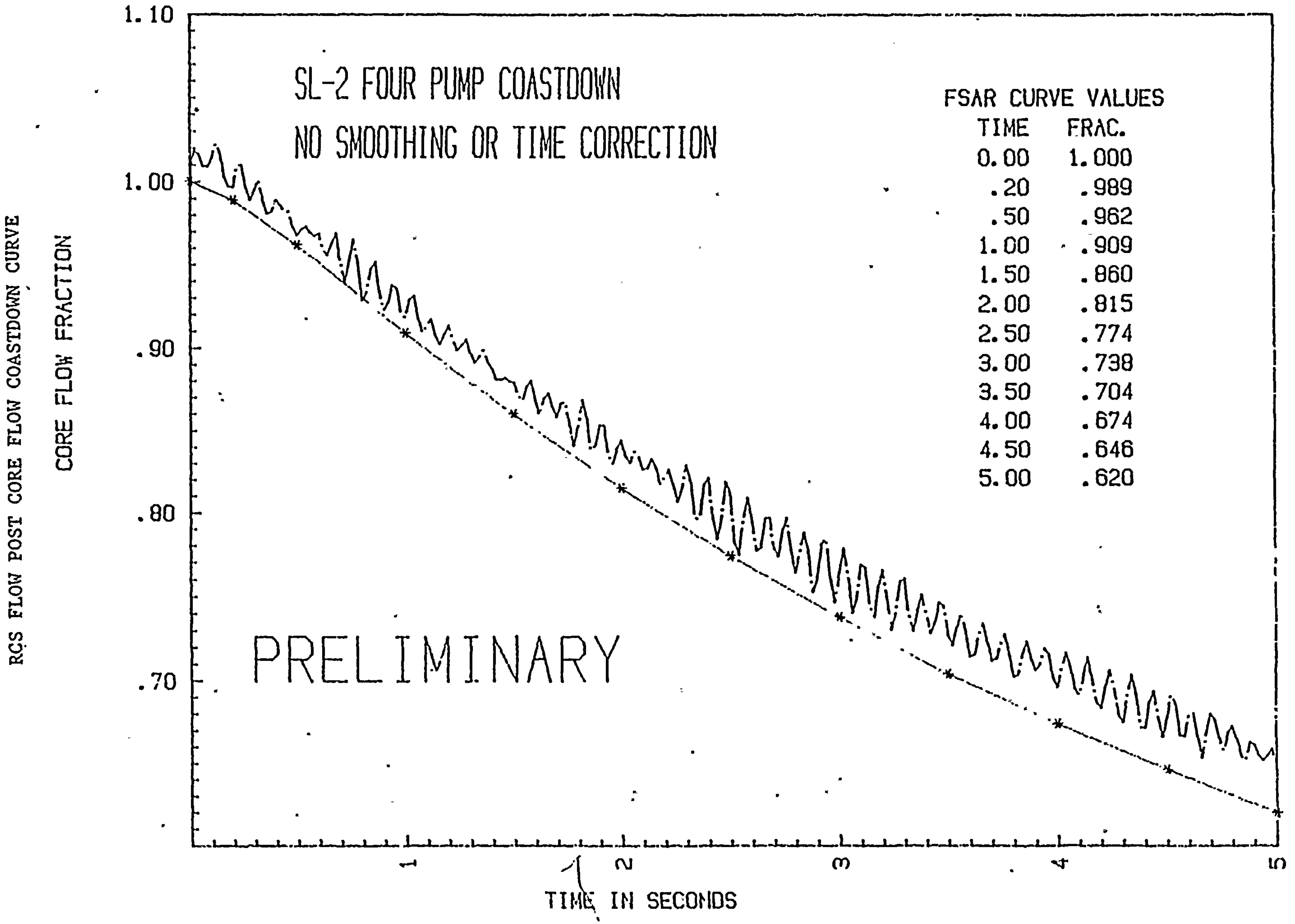
All possible 1, 2, 3 and 4 pump combinations of the reacotr coolant pumps were run with complete sets of hand and TDAS data of pump steam generator and vessel DP at design temperature and pressure were preformed for baseline data and no unusual pump oscillations were found that would effect present plant operating pumps confirurations.

The reactor coolant flow rate for 4 pump steady state operation at design temperature and pressure was determined using pump differential pressures and pump curves. This value of 396,502 gpm using the TDAS computor system method and calibration correcting all instruments was found to be well between the two required values of 388,400 gpm determined by CE. The flow coastdown characterics plot was found to exceed the predicted DNBR curve that was assumed in the safety analysis per CE preliminary on site study.

This coastdown plot (attached) shows the exceeding of the FSAR curve valves on all counts.

3.a.3 Conclusions

Objective one of this test provides ample data for meeting the flow acceptance criteria along with suppling CE with much data on 1, 2, and 3 pump combinations which will be available for further studies and evaluation. Objective two provides data to meet the required coastdown acceptance criteria along with also providing data to CE for later review and studies of baseline information.



FSAR CURVE VALUES

TIME	FRAC.
0.00	1.000
.20	.989
.50	.962
1.00	.909
1.50	.860
2.00	.815
2.50	.774
3.00	.738
3.50	.704
4.00	.674
4.50	.646
5.00	.620

3.b. CONTROL ELEMENT DRIVE MECHANISM PERFORMANCE TEST

3.b.1 Purpose:

The objectives of this test were as follows:

1) To demonstrate the operation of the control element drive mechanism with extension shaft installed.

2) To measure the control element assembly withdraw and insertion speeds.

3) To demonstrate the operation of the control element assembly position indication systems.

4) To demonstrate the operation of the control element drive mechanism control system protective interlocks and alarms associated with individual CEA motion.

5) To measure the control element assembly drop times.

6) To demonstrate the operation of the control element assembly decelerating devices.

7) To demonstrate the operation of the manual trip function.

3.b.2 Test Results:

All of the objectives were satisfactorily completed. The mean drop time of the 5 finger CEA's was 2.36 seconds and of the 4 finger CEA's was 2.26 seconds. None of the CEA drop times were in excess of $\bar{x}$ + (2 ox) of 2.45 seconds for the 5 finger CEA's and 2.33 seconds for the 4 finger CEA's. Several CEDM's demonstrated sluggish operation of the gripper mechanism that resulted in the CEA slipping. This was corrected during testing by time and voltage adjustments. All CEA's moved at 30 inches/minute. CEA position indication displayed CEA position to within 2.50 inches of actual position and agreed with each control system interlocks and alarms actuated at their prescribed position. All CEA's decelerated just prior to reaching full insertion. Manual trip caused all CEA's to fully insert from a partially withdrawn position.

3.b.3 Conclusions:

No CEA drop time exceeded the Technical Specification 3.1.3.4 of 3.0 seconds to 90% insertion. The deceleration devices operated to slow CEA insertion prior to full insertion and CEA's operated at 30 in/min. CEA position is indicated to within 2.50 inches of actual position and with individual CEA motion operated. All CEA's full insert upon actuation of a Manual Trip.

3.c INCORE INSTRUMENTATION CHECKOUT

3.c.1 Purpose

The objectives of this test were as follows:

(1) To obtain incore thermocouple comparison data.

(2) To measure fixed incore detectors leakage resistance at normal operating temperature.

(3) To demonstrate the operation of the moveable incore detector system.

3.c.2 Test Results

Objectives 1 and 2 were satisfactorly completed. Objective 3 was not completed satisfactorly. The redundant path switch for the moveable incore switch could not be tested because of hardware malfunctions. A Plant Work Order has been prepared to correct the hardware malfunction during the first outage. The movalbe incore system is fully operational without the redundant path switch. A single drive machine or detector failure would limit operation to 50 percent of the available detector paths.

3.c.3 Conclusions

Objectives 2 and 3 were acceptance criteria for the test. Objective 2 was completed satisfactorily. Objective 3 wasn't completed satisfactorily as noted in the test results, however, the system is operational and will be completed during the first refueling outage.

3.d. PRESSURIZER SPRAY EFFECTIVENESS

3.d.1 Purpose:

The objectives of this test were as follows:

1) Establish setting of the pressurizer continuous spray values.

2) Verify that RCS pressure can be reduced at the design rate using.normal pressurizer spray flow.

3.d.2 Test Results:

The continuous spray valves were adjusted to provide respective spray line temperatures of 25 and 28°F lower than the average cold leg temperature. The observed rate of pressurizer pressure drop with full spray flow was 125 psi per minute.

3.d.3 Conclusions:

Both Continuous spray valves were satisfactorily adjusted to provide adequate flow for minimizing thermal shock to the spray nozzle without causing excessive pressurizer cooldown and pressure reduction. This was accomplished by adjusting the continuous spray valves to obtain spray line temperature 25°F to 30°F lower than the average cold leg temperature.

The second part of this test verified that full pressurizer spray flow was effective in reducing system pressure at a rate greater than 65 psi per minute. This was accomplished by establishing normal conditions for maximum spray line flow and recording pressurizer pressure drop on a strip chart recorder with spray valves full open. Pressurizer functional tests for pressure and level control were conducted during Pre-Core Hot Functional Testing. Retests for the following equipment realignments and modifications were satisfactorily completed as part of this test; pressurizer heater relay modification; backup mode operation of "C" charging pump, pressurizer high-low pressure alarm setpoint.

3.e REACTOR COOLANT SYSTEM LEAK TIGHTNESS

3.e.1 Purpose

The objective of this test is to verify that the reactor Coolant system operating leak integrity is within the required valves.

3.e.2 Results

This test was done in conjunction with the required weekly plant survillence procedure which isolates the make up water supply to the volume control tank and monitors its level drop over time. The level changes in various other containment located tanks (i.e. Safety injection, Reactor Drain, Quench) were also monitored to Determine increases/decreases in tank levels. Volume changes in these tanks were not observed so all leakage found fell in the unknown or system boundry leakage class.

The RCS leak integrity was found to be far below the 1 gpm unknown value acceptance criteria so no farther action was deemed procedurally necessary to located exact causes of leakage.

3.e.3 Conclusion

The objective of the procedure was accomplished satisfactory and the 1 gpm unknown leakage acceptance criteria was met easily with no notable problems in accomplishing it.

3.f PLANT CHEMICAL AND RADIO CHEMICAL ANALYSIS

3.f.1 Purpose:

1) To ensure that the primary and secondary systems water chemistry meet the criteria set forth in the St. Lucie Plant Chemistry Procedures Manual for system protection.

2) To correlate corrosion data and fission product buildup data to power evels.

3.f.2 Test Results:

Chemical and Radiochemical tests were performed as specified in the Chemistry Procedures Manual and Preoperational Test Procedures No. 2-3400081, which verified chemistry parameters and conformance to specifications for 200°F, 532°F, Startup Mode, 20, 50, 80 and 100% power.

3.f.2.1 Primary:

(1) All parameters were within limits for the specified modes. Hydrogen was not added to the system prior to initial criticality. Lithuim was maintained at the high end of the specification for a full 10 days during the preconditioning period (no boron) and also throughout the power ascention program. No abnormal isotopic mixes were noted for the perido of power ascention.

3.f.2.2 Secondary:

(1) Maximum steam generate blowdown was maintained as a primary objective for the major part of power testing.

(2) Condensate and feed systems were flushed to achieve as low as possible solids concentrations prior to initiation of feed to the steam generators.

(3) Hydrazine residuals were kept at 3 times the dissolved oxygen concentrations.

(4) Secondary Chemistry control was based upon the EPRI guidelines and specifications.

(5) Cation conductively remained high, resulting in power limitations during the ascention period. Samples were analyzed by both Combusion Engineering and Westinghouse. None of the know aggressive attack agents were identified. The apparent cause of the abnormal cation conductivity peaked at 14 umhos and was brought toward specification by limit power operation and maximum blowdown rates.

3.f PLANT CHEMICAL AND RADIO CHEMICAL ANALYSIS: (Cont.)

3.f.3 Conclusions:

Chemical testing, both primary & secondary, showed that the plant was in good condition. It showed that chemistry could be controlled within specified limits and that out of specification parameters could be remedied in a timely manner. It should be noted that the limits for S/G and condensate/feed cation conductivity are of recent development and were derived from operating plant experience, not startup of a new unit.

3.g WIDE RANGE NUCLEAR INSTRUMENTATION READINGS

3.g.1 Objective

To collect information regarding the temperature effects of neutron monitoring of the core by the wide range nuclear instrumentation. This test provides information to relate core loading count-rates to critical approach count-rates.

3.g.2 Test Results

The temperature effect on the neutron monitoring instrumentation was recorded at six temperatures plateaus. The count-rates were recorded from each source range detector.

3.g.3 Conclusions

It can be seen from the test results, that the count rates increased approximately 300% as temperature rose from ambient conditions to 532°F. This information explains the increase in count-rates from cold shutdown conditions to pre-critical hot standby.

3.h LOOSE PARTS MONITOR

3.h.1 Purpose:

The objective of this test was to obtain a set of baseline data that are used to set alarm setpoints and that are used in the future to analyze data provided by the Loose Parts Monitoring System during plant operation.

3.h.2 Test Results:

Twenty sets of baseline data was collected at various plant conditions including low, intermediate and full power acceleration (G) levels were calculated at 100% power. These were found to be well below the levels produced by a 0.5 ft. lb impact at 3 feet from the transducer.

Point	Background	0.5 ft lb Impact
1	0.36 G	5 G & 4 G
2	0.34 G	4 G & 4 G
3	0.22 G	1.1 G & 1.1 G
4	0.34 G	2.4 G & 1.9 G
5	0.18 G	2.7 G & 2.4 G
6	0.12 G	3.1 G & 2.4 G
7	0.14 G	3.8 G & 4.7 G
8	0.20 G	3.1 G & 3.6 G

3.h.3 Conclusions:

A complete set of baseline data was recorded and will be available for future reference. Minimum trigger setpoints were identified to allow setting of the alarm triggers.

3.i REACTOR PROTECTION SYSTEM (PRE-CRITICAL TEST)

3.i.1 Objective

a) To verify trip and pre-trip setpoint settings are in accordance with Chapter 16 (Technical Specifications).

b) To demonstrate operability of the by-pass logic and the trip logic circuitry.

c) To demonstrate operability of the manual reactor trip initiation circuit.

3.i.2 Test Results

The RPS setpoints were installed and verified by inputting test signals to trip each bistable. The by-pass and trip logic were exercised to verify setpoints and function. The manual trip logic was initiated and power interruption to CEDMCS power supplies was verified.

3.i.3 Conclusions

The RPS performs at the Tech Spec setpoints to meet the design specification.

3.j TEMPORARY INCORE INSTRUMENT CHANNEL RESPONSE

Temporary Incore Instrument Channel Response Test (Preoperational Test Procedure 2-1210082, Neutron Response of Temporary Fuel Loading Channels and Plant Startup Nuclear Channels).

Purpose

The two objectives of this test are to determine the background signal as measured by the temporary incore instrument channels prior to the introduction of a source and performance of a response check of these channels using a start-up source.

Test Results

A background determination for the temporary detectors was completed on April 6, 1983. The following background counts were obtained:

Temporary Detector A: .007 CPS
Temporary Detector B: .012 CPS

Following the background determination, the dummy assembly with startup source No. 1 was introduced into the vessel for a response determination of each channel. The following response counts were obtained:

Temporary Detector A: 1325.47 CPS
Temporary Detector B: 1799.15 CPS

The acceptance criterion was upheld in that the base count rates for the temporary fuel loading channels were determined prior to the introduction of the source into the vessel and initial core loading.

In addition, the temporary fuel loading channels responded with a signal that showed a significant increase above background*. Therefore the acceptance criterion for these detectors was upheld.

*CE Letter NST-82-348A

3.k SAFETY CHANNEL PRECRITICAL ALIGNMENT AND CALIBRATION

3.k.1 Objective

a) To perform final calibration and alignment of the safety channel drawers.

b) To verify associated alarms, protective functions and by-passes occur at the correct setpoints.

3.k.2 Test Results

The safety channels were calibrated in accordance with the Mfg's instruction manual. The alarms, protective functions, and by-passes were all demonstrated to function at the tech spec setpoints.

3.k.3 Conclusion

The safety channels have been demonstrated to satisfactoriuly meet their design limits.

3.1 START-UP/CONTROL CHANNEL PRECRITICAL ALIGNMENT AND CALIBRATION

3.1.1 Objection

To perform final calibration and alignment of the Start-up/Control channel drawers

3.1.2 Test Results

The Start-up/Control channel drawers were calibrated and aligned in accordance with the Mfg's tech manual.

3.1.3 Conclusions

The Start-up/Control channels provide source and power range neutron monitoring capability within the intended design limits.

4. INITIAL CRITICALITY

Initial criticality was achieved on June 2, 1983 at Reactor Coolant System (RCS) conditions of 533°F and 2240 psia. The RCS boron concentration prior to dilution was 1783 ppm. The approach to criticality began by withdrawing the Control Element Assembly's (CEA's) in specified increments with count rate data taken after each increment. During this withdrawal, CEA Sequencing and Inhibiting was verified to be functioning properly in accordance with FSAR test 14.2.12.3H. Criticality was subsequently achieved by deborating the RCS to a boron concentration of 715 ppm. Immediately prior to achieving criticality, one decade of nuclear instrumentation overlap was observed in accordance with FSAR test 14.2.12.3G.

Throughout the approach to criticality, two independent sets of inverse multiplication plots were maintained. Two plots of inverse count rate versus RCS dilution time were maintained during the dilution phase. Periodically, count rates were obtained from each Startup and Wide Range Logarithmic Channel. The ratio of initial average count rate to the count rate at the end of each time increment was the value plotted.

The CEA withdrawal sequence and intervals are shown in Table 4-1. The RCS dilution sequence and intervals are shown in Table 4-2. The inverse count rate versus CEA position points for the two Startup Channels are shown in Figures 4-1 and 4-2. The inverse count rate versus RCS dilution time is shown in Figures 4-3 and 4-4. The RCS boron concentration versus dilution time is shown in Figure 4-5.

After achieving initial criticality, CEA Group 6 was used to control neutron flux. Conditions were stabilized at 4×10^{-4}% power and the critical data shown in Table 4-3 was recorded and compared with predicted values.

In summary, initial criticality was achieved in a safe and orderly manner. There was good agreement between the measured and predicted boron concentrations.

TABLE 4-1
CEA WITHDRAWAL SEQUENCE

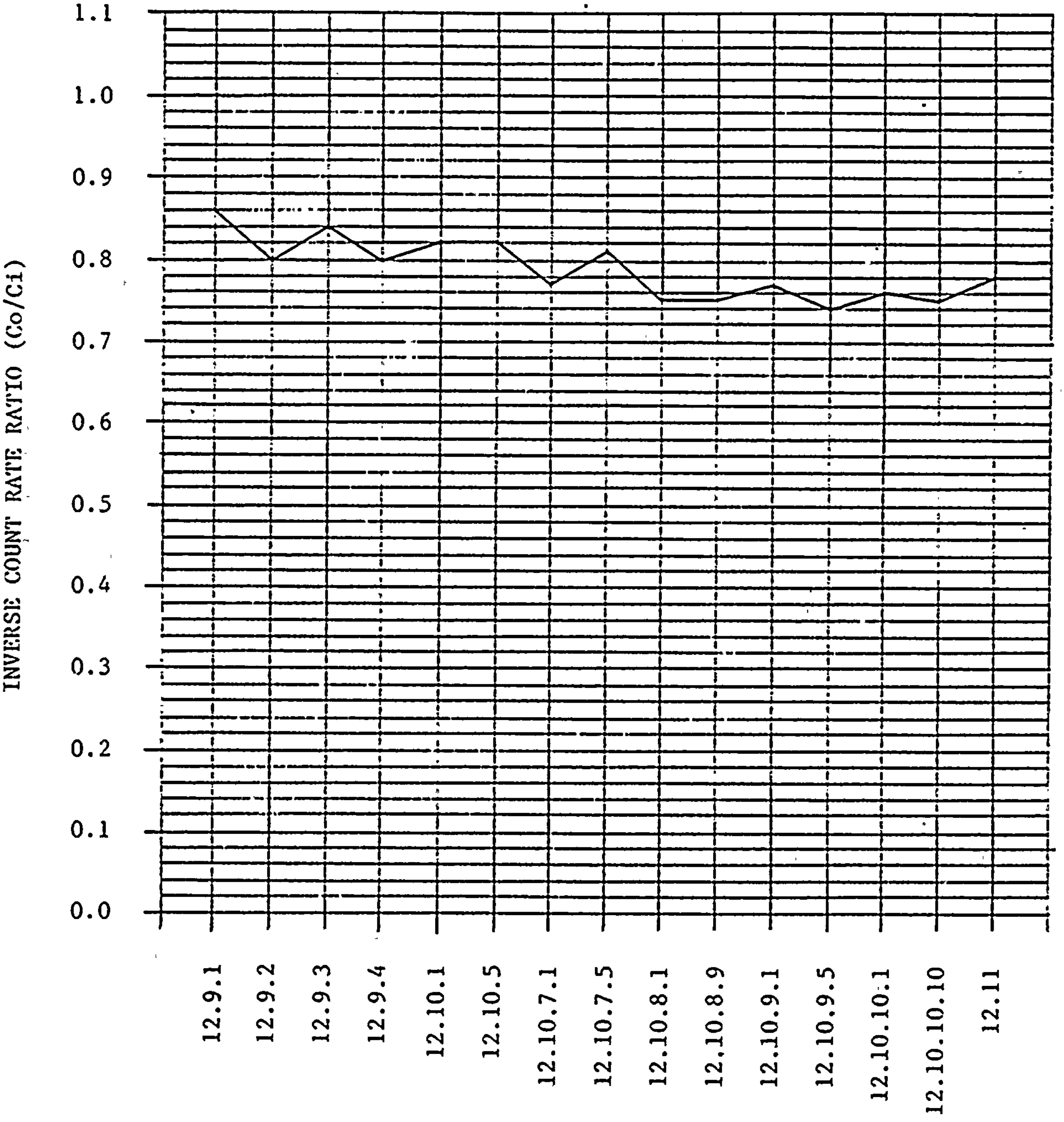
STEP *	CEA GROUP	INCHES WITHDRAWN	S/U 1 1/M	S/U 2 1/M
12.9.1	A	68	0.86	0.87
12.9.2	A	134	0.80	0.90
12.9.3	B	68	0.84	0.91
12.9.4	B	134	0.80	0.88
12.10.1	1	99	0.82	0.90
12.10.5	1	134	0.82	0.87
	2	≤ 55		
12.10.7.1	2	98	0.77	0.73
12.10.7.5	2	134	0.81	0.80
	3	≤ 55		
12.10.8.1	3	98	0.75	0.81
12.10.8.9	3	134	0.75	0.84
	4	≤ 55		
12.10.9.1	4	98	0.77	0.78
12.10.9.5	4	134	0.74	0.79
	5	≤ 55		
12.10.10.1	5	98	0.76	0.79
12.10.10.10	5	135	0.75	0.77
	6	≤ 55		
12.11	6	66	0.78	0.80

*Steps from Initial Criticality Procedure, Preop 2-0030221

TABLE 4-2
RCS DILUTION SEQUENCE

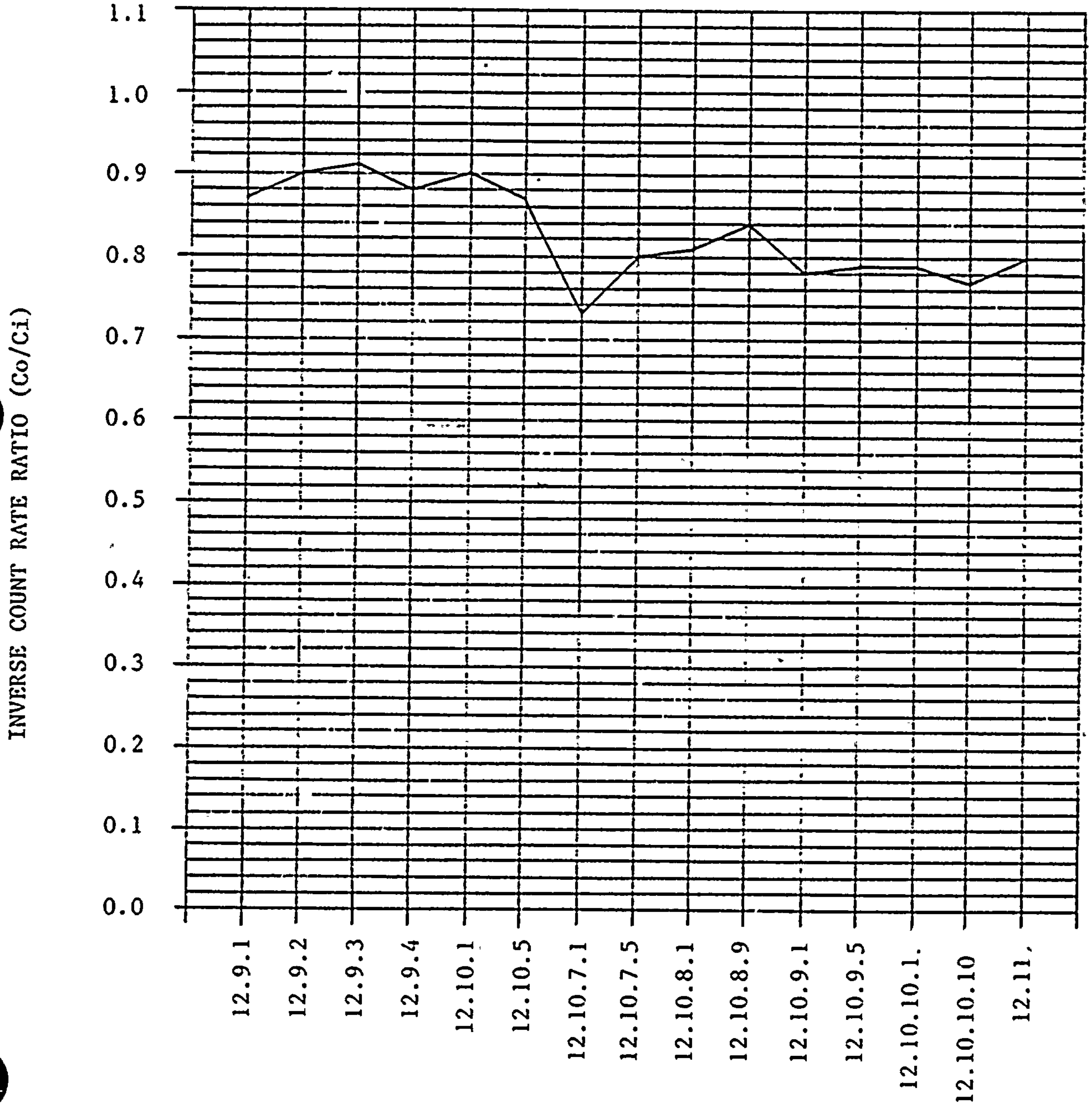
DILUTION TIME (MINUTES)	DILUTION TIME (HOURS)	DATE	TIME	RCS BORON CHEMICAL ANALYSIS	STARTUP CHANNEL 1 1/M	STARTUP CHANNEL 2 1/M
0	0	6-1-83	1945	1783	1.00	1.00
15	0.25		2000	1767	0.96	1.05
25	0.42		2010	1708	0.93	1.02
40	0.67		2100	1686	0.98	0.93
70	1.17		2130	1591	0.90	0.91
100	1.67		2200	1483	0.88	0.80
130	2.17		2230	1377	0.76	0.85
160	2.67		2300	1301	0.79	0.78
190	3.17		2330	1220	0.68	0.70
220	3.67	6-2-83	0000	1138	0.69	0.64
250	4.17		0030	1080	0.64	0.62
280	4.67		0100	991	0.57	0.59
310	5.17		0130	949	0.51	0.51
340	5.67		0200	890	0.44	0.43
369	6.15		0229	843	0.40	0.36
374	6.23		0330	889	0.40	0.43
389	6.48		0345	839	0.40	0.40
404	6.73		0400	826	0.36	0.40
419	6.98		0415	801	0.35	0.35
434	7.23		0430	784	0.30	0.29
449	7.48		0445	767	0.26	0.27
464	7.73		0500	754	0.23	0.25
479	7.98		0515	741	0.21	0.20
495	8.25		0530	737	0.16	0.16
509	8.48		0545		0.13	0.12
524	8.73		0551	716	0.02	0.02
530	8.83		0700	715	0	0

FIGURE 4-1
ST. LUCIE UNIT 2
ATTAINMENT OF INITIAL CRITICALITY
BOL, 1st CYCLE, 533°F, 2240 PSIA .
STARTUP CHANNEL NO. 1



STEPS FROM INITIAL CRITICALITY PROCEDURE PREOP 2-0030221

FIGURE 4-2
ST. LUCIE UNIT 2
ATTAINMENT OF INITIAL CRITICALITY
BOL, 1st CYCLE, 533°F, 2240 PSIA
STARTUP CHANNEL NO. 2



STEPS FROM INITIAL CRITICALITY PROCEDURE PREOP 2-0030221

FIGURE 4-3
ST. LUCIE UNIT 2
ATTAINMENT OF INITIAL CRITICALITY
BOL, 1st CYCLE, 533°F, 2240 PSIA
STARTUP CHANNEL NO. 1
ZERO POWER, CEA GROUP 6 AT 77 INCHES

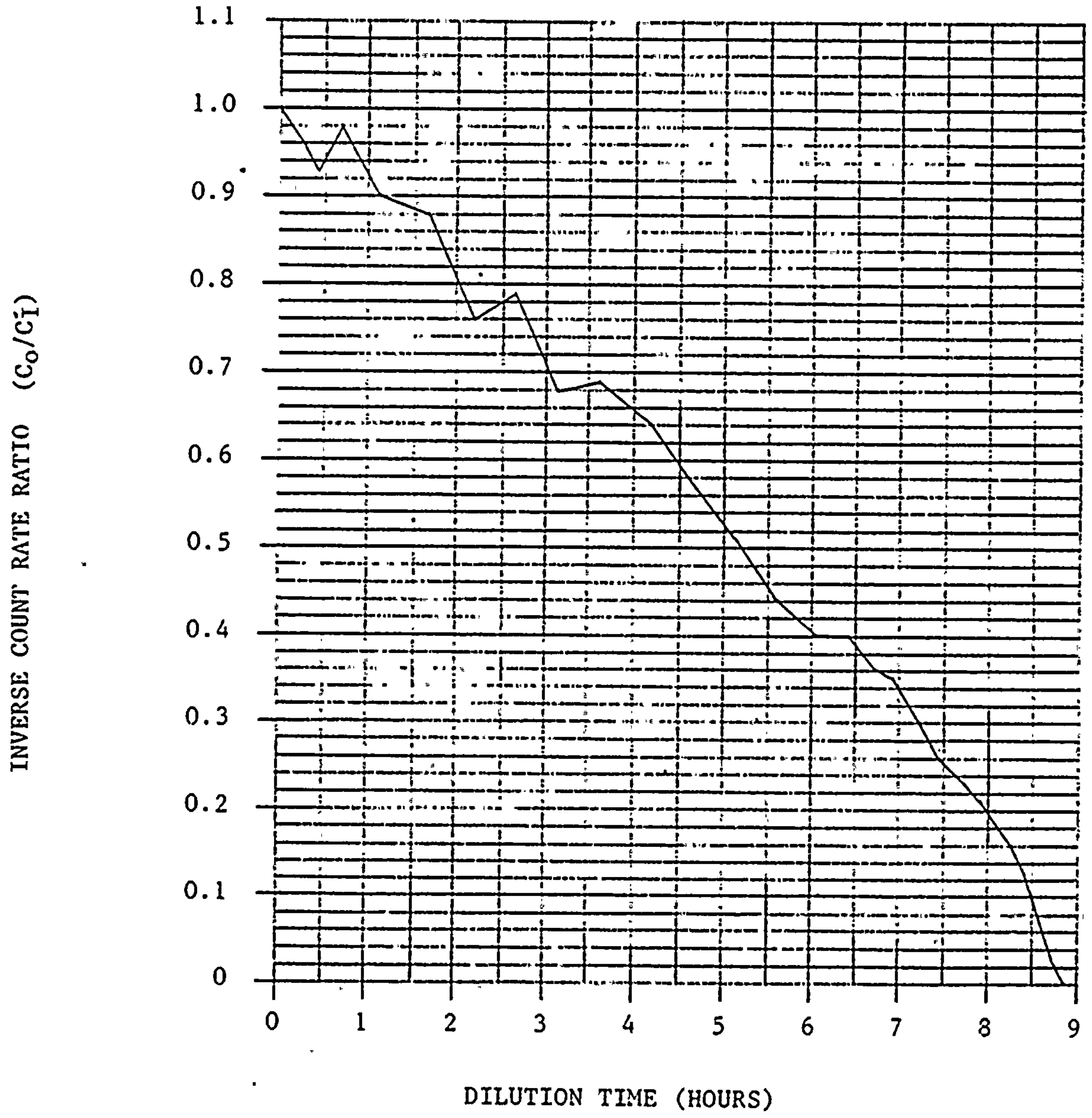


FIGURE 4-4
ST. LUCIE UNIT 2
ATTAINMENT OF INITIAL CRITICALITY
BOL, 1st CYCLE, 533°F, 2240 PSIA
STARTUP CHANNEL NO. 2
ZERO POWER, CEA GROUP 6 AT 77 INCHES

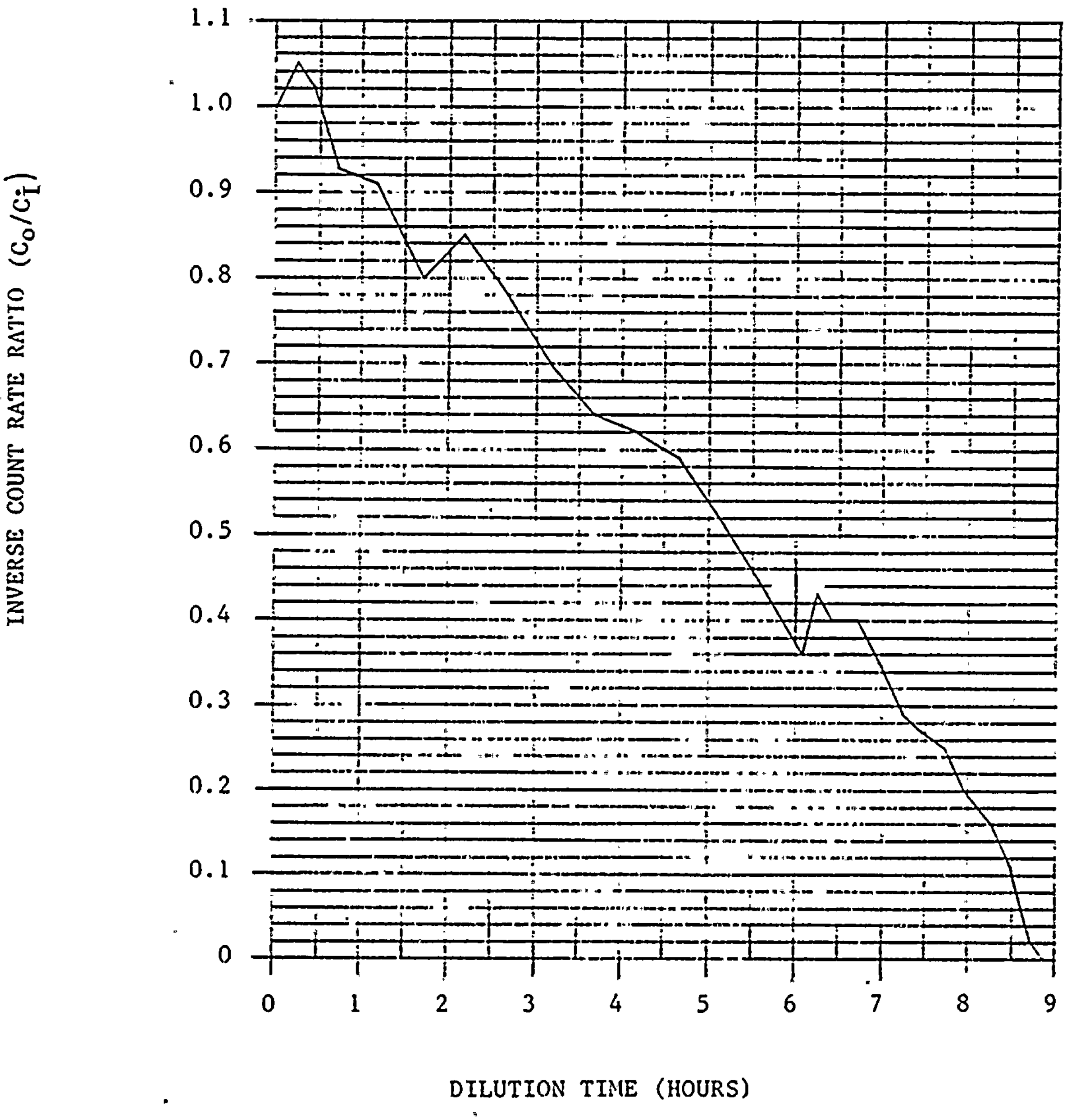
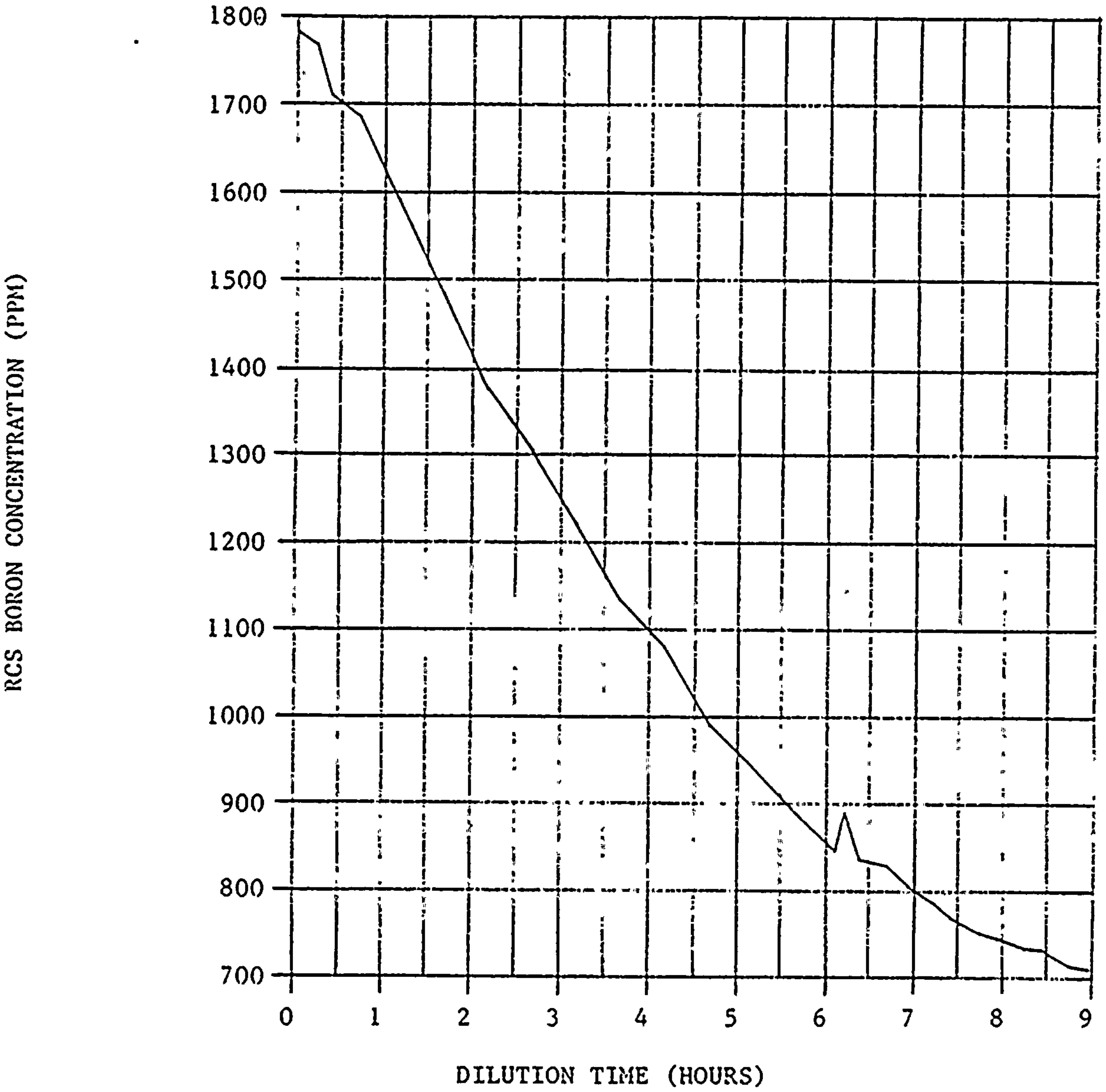


FIGURE 4-5
ST. LUCIE UNIT 2
BOL 1st CYCLE
REACTOR COOLANT SYSTEM BORON
CONCENTRATION VS DILUTION TIME



4-5

TABLE 4-3
CRITICAL CONDITIONS AND CEA CONFIGURATION

PARAMETER	PREDICTED CONDITION	MEASURED VALUE
RCS TEMPERATURE	532°F	533°F
RCS PRESSURE	2250 PSIA	2240 PSIA
RCP'S OPERATING	4	4
CEA GROUPS WITHDRAWN, IN INCHES		
A	UEL	UEL
B	UEL	UEL
1	UEL	UEL
2	UEL	UEL
3	UEL	UEL
4	UEL	UEL
5	UEL	UEL
6	77	77

RCS BORON CONCENTRATION (PPM)	693	715

NOTE: UEL = Upper Electrical Limit

5. LOW POWER PHYSICS TESTS (LPPT)

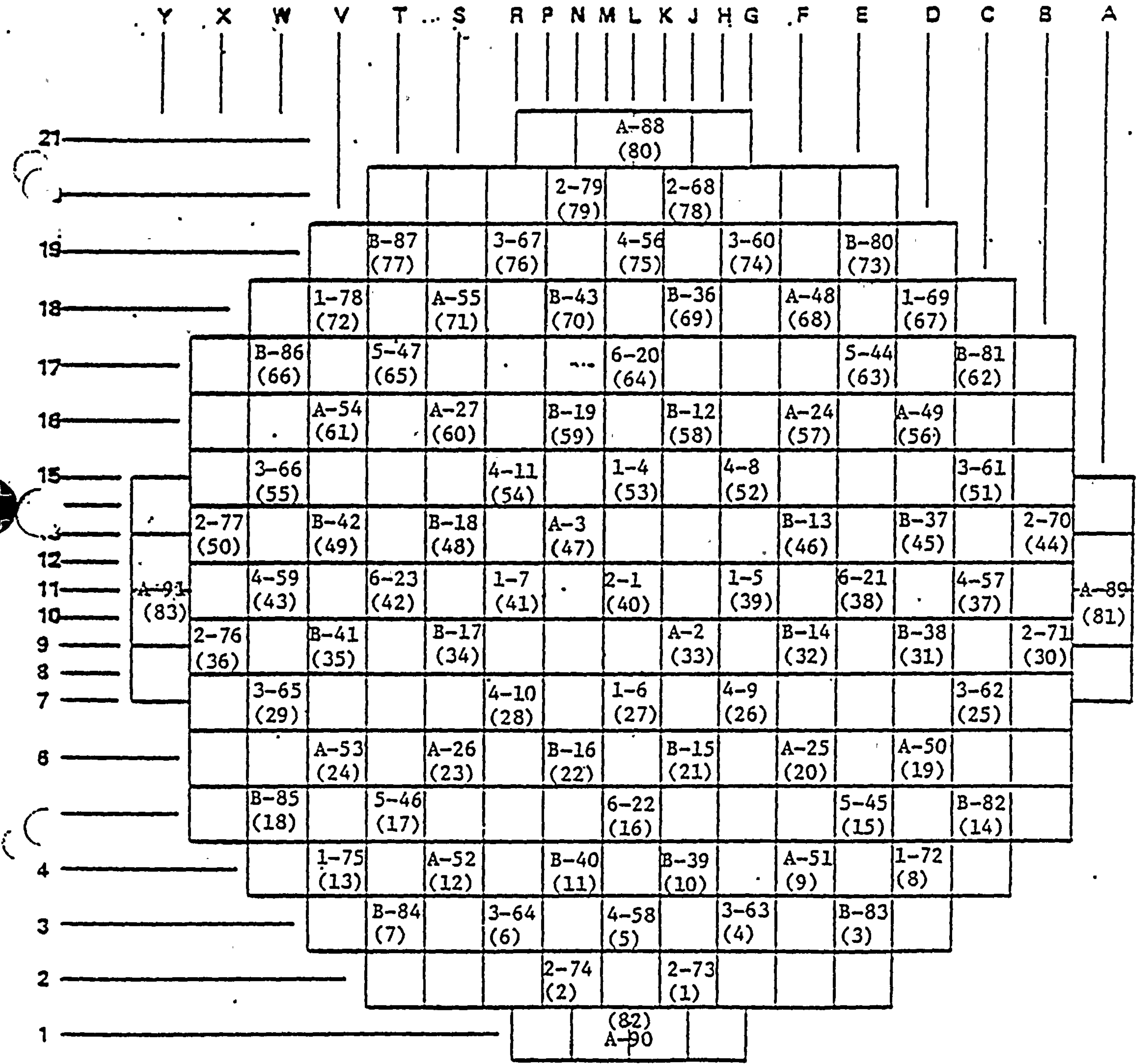
The St. Lucie Unit 2 initial core consists of two hundred seventeen (217) fuel assemblies each containing two hundred thirty six (236) fuel rods/burnable poison rods and five (5) Control Element Assembly (CEA) guide tubes. Fuel assemblies are divided into three (3) distinct groups by enrichment, Type A, B and C. Sixteen (16) fuel rods in all Type B and sixteen (16) Type C fuel assemblies are replaced with burnable poison rods. In addition, eight (8) Type C fuel assemblies have twelve (12) fuel rods replaced with burnable poison rods.

In addition to soluble boron in the Reactor Coolant System (RCS), reactivity control is provided by eighty-three (83) CEA's. CEA's are inserted into and withdrawn from the core by means of eight-three (83) Control Element Drive Mechanisms (CEDM's). Four (4) CEA's have only four (4) fingers and are placed into two (2) fuel assemblies on the four (4) core edges. Figure 5.0-1 shows the core locations of the CEA's. The CEDM's are arranged into eight (8) CEA Groups. Those groups are further defined by function. CEA Group A and B are Shutdown Groups. CEA Groups 1 through 6 are Regulating Groups. Figure 5.0-1 also displays the relative core location of the CEA Groups.

CEA Group movement is restricted as a function of power level in order to insure that CEA configurations not analyzed for in the safety analysis do not occur. The mechanism for this is the Power Dependent Insertion Limit (PDIL) of the Technical Specifications. Automatic control and alarm features as well as operator instructions and training prevent insertion of CEA groups into the core below the PDIL. The lower the reactor power, the greater the CEA insertion allowed.

LPPT consists primarily of the measurement of reactivity worths of components which can vary the critical condition of the core. To speed the collection of this data, as well as to enhance its accuracy, a digital computer which solves the kinetic equation for reactivity was used. All raw data was collected, reduced and analyzed onsite by both FP&L and CE personnel. In all cases, measured data met applicable acceptance criteria.

FIGURE 5.0-1
ST. LUCIE PLANT UNIT NO. 2
CEA/CEDM LOCATIONS



LEGEND

Group - CEDM No. 1.
CEA NO. (X) 2.

5.a RADIATION SHIELDING EVALUATION TEST

5.a.1 Purpose

1) Measure neutron and gamma radiation dose rates during startup testing as a function of reactor power level.

2) Establish baseline radiation levels for future comparisons

3) Compare the measured radiation levels as a function of reactor power levels to predicted design radiation levles in chapter 12 of the FSAR.

5.a.2 Test Results

A comprehensive series of radiation survey's were conducted during the power escalation phase of start-up testing. Surveys were taken at the 3-5%, 20%, 50%, 80% and 100% reactor power levels at selected locations in the REactor Containment Building, REactor Auxiliary Building, Fuel Handling Building, Control Room Controlled area. Measurements were taken at mechnical and electrical penetreations of the reactor auxiliary and the escape funnel in the spent fuel pool area to determine if radiation streaming (principally neutron) from the reactor containment building was occuring. Additional measurements of neutron radiation in the reactor containment building to determine the neutron energy spectrum were performed by the Baltele Pacific Northwest Labs.

5.a.3 Conclusions

The survey's performed within the reactor auxiliary building were compared to the predicted radiation dose rates in chapter 12.3 of the FSAR and were found to be in good agreement with the FSAR. Passageways, laboratories, locker rooms and offices ere below the predicted gamma dose rate of 0.25 mrem/hr. No neutrons were found at the penetration areas during any of the survey's. The control room, turbine building, out of doors radiation controlled area and fuel handling building were less than 0.25 mrem/hr gamma radiation and no neutron radiation was detected in these areas with streaming was detected at the personnel excape tunnel on the 62' elevation of the spent fuel pool area. At 100% reactor power the dose rates at the excape tunnel that are attributable to the streaming are 4 mrem/hr neutron and 2 mrem/hr gamma.

5.a RADIATION SHIELDING EVALUATION TEST (continued)

5.a.3 Conclusions (continued)

At the 20% reactor power level, the 62' elevation of the reactor containment building was above FSAR predicted dose rates (2.5 mrem/hr - 15 mrem/hr). The principle contribution to the dose rate was from neutrons. The area affected the most was to the west of the reactor. Neutron dose rates west of the steam generator cubicles ranged from 10 mrem/hr to 100 mrem/hr. Gamma dose rates ranged from 1.5 mr/hr to 30 mr/hr. At the 100% reactor power level all elevations within the building were in excess of FSAR predictions. The principle contributor to the dose rates were due to neutrons. Gamma radiation levels on the 23' and 45' elevations were essentially within predicted valves with general area dose rates ranges of 4-14 mr/hr. The 62' elevation gamma dose rates exceed FSAR predicted values for combined neutron and gamma dose rates. Gamma general area radiation levels ranged to 400 mrem/hr. Areas of highest dose rates are in the vicinity of the neutron shield wall attachments to the reactor refueling cavity and west of the steam generators to the containment building wall. The primary reason for the higher dose rates (neutron and gamma) is the streaming of neutrons between the reactor missle shield and part height shield walls west of the refueling cavity. Scattering of the neutrons from the containment wall and air appear to affect the entire 62' elevation.

Upon conclusion of the Battele neutron energy spectral analysis the neutron data will be reviewed and any necessary neutron dose rate corrections will be made as indicated by the study. It is expected that significant reductions in neutron dose-rates will be indicated based on neutron energy. After dose rate corrections have been made a final conclusion as to the adequacy of the containment building shielding will be made.

5.b Temperature Coefficient of Reactivity Measurement

5.b.1 Purpose

The moderator temperature coefficient of reactivity can be either negative or positive, depending upon the magnitude of the Reactor Coolant System boron concentration. The moderator temperature coefficient cannot be measured directly but it can be derived from a measurement of the isothermal temperature coefficient.

5.b.2 Test Results

The isothermal temperature coefficient of reactivity measurement was made with CEA Groups 5-B fully withdrawn and CEA Group 6 at 113 inches withdrawn. The measured isothermal temperature coefficient is the result of the average coefficient measured by several plant heatups and cooldowns. Throughout the measurements, reactor power was maintained below the point of adding nuclear heat to minimize reactivity effects of doppler feedback. Reactor Coolant System ramp temperature changes were affected by proper positioning of atmospheric dump valves. The measured moderator temperature coefficient was - .265 x 10^{-4} Delta rho/°F.

5.b.3 Conclusions

The measured moderator temperature coefficient was in satisfactory agreement with the predicted value of -.157 x 10^{-4} Delta rho/°F and met all of the following test acceptance criteria:

The moderator temperature coefficient is less positive than + 0.5 x 10^{-4} Delta rho/°F in accordance with Technical Specifications.

The moderator temperature coefficient is less positive than + 0.1 x 10^{-4} Delta rho/°F and less negative than -2.10 x 10^{-4} Delta rho/°F in accordance with the Safety Analysis.

The measured moderator temperature coefficient is within ± 0.3 x 10^{-4} Delta rho/°F of the predicted value.

5.c DIFFERENTIAL BORON WORTH MEASUREMENTS

5.c.1 Purpose

Soluble boron in the form of dissolved boric acid in the Reactor Coolant System provides variable reactivity control over the life of a core. It can supplement the reactivity control provided by CEA Groups. However, its principle function is to compensate for burnup of excess reactivity as core depletion proceeds. The critical boron concentrations were measured for various CEA configurations as presented in Section 5.e. The CEA Group worths were measured as described in Section 5.d. Using these measurements, the boron effect on reactivity was determined.

5.c.2 Test Results

CEA Group integral reactivity worths were measured using the soluble boron swap technique described in Section 5.d. In addition, as presented in Section 5.e, the soluble boron concentrations associated with steady state endpoints were measured during the CEA Group worth measurements. A comparison of measured and predicted inverse boron worth for the various endpoints is presented in Table 5.c-1.

5.c.3 Conclusions

Results indicate that measured boron worths were in satisfactory agreement with predictions and well within the acceptance criterion of ± 10 PPM/% Delta rho.

TABLE 5.c-1
INVERSE BORON WORTH SUMMARY

COLUMN 1	COLUMN 2	COLUMN 3	COLUMN 4	COLUMN 5	COLUMN 6
MEASURED CRITICAL BORON CONCENTRATION (PPM)	CEA CONFIGURATION	CHANGE IN CBC FROM ARO CRITICAL VALUE (DELTA PPM)	NON-OVERLAP CEA WORTH (%DELTA RHO)	MEASURED SOLUBLE INSERTED INVERSE BORON WORTH (DELTA PPM/% DELTA RHO) (COLUMN 3/COLUMN 4)	DESIGN SOLUBLE INSERTED INVERSE BORON WORTH (PPM/% DELTA RHO)
599	6-4 @ LEL 3-A @ UEL	125	1.5827	78.979	72.517
416	6-1 @ LEL A,B @ UEL	308	4.42325	69.632	69.008
207	6-B @ LEL A @ UEL	517	7.40685	69.800	68.767

5.d CEA GROUP WORTH MEASUREMENTS

5.d.1 Purpose

During reactor operation, nearly all excess reactivity is held down by soluble boron concentration in the Reactor Coolant System and burnable poison shim rods in the fuel assemblies. Additional hold down and reactivity control is provided by moveable Control Element Assemblies (CEA's). These CEA's are arrayed in symmetrical groups about the core (see Figure 5.0-1). The number of CEA's in each Regulating and Shutdown CEA group and the function of each group is described in Table 5.d-1. All CEA Group measured worths displayed in the Table are non-overlapping over the full range of CEA movement at various Reactor Coolant System boron concentrations.

5.d.2 Test Results

All CEA Group reactivity worths were measured using a soluble boron swap method, either dilution or boration, to maintain criticality while inserting or withdrawing CEA Groups in increments. The reactivity trace generated on the reactivity computer by this evolution was then analyzed to obtain the relationship between CEA Group positions from full in to full out and integral reactivity worth at these positions.

After the most reactive CEA, CEA B-83, was swapped with CEA Group A, the net integral worth of CEA Group A was measured using the standard boron swap technique.

The integral worths of all Shutdown and Regulating CEA Groups were measured at 532 ± 2°F and are compared with predicted values in Table 5.d-1. The integral reactivity worth curves are displayed in Figures 5.d-1 through 5.d-8.

5.d.3 Conclusions

The measured CEA Group integral reactivity worths are in satisfactory agreement with predicted values as shown in Table 5.d-2. The total measured CEA worth for CEA Groups 6 through B was within the acceptance criteria of ± 10% of design predictions to assure shutdown margin, consistent with accident analysis assumptions, throughout core life.

TABLE 5.d-1

CEA WORTH SUMMARY

CEA GROUP	NUMBER OF CEA's	FUNCTION OF CEA's	MEASURED WORTH (% Delta rho)	DESIGN WORTH (% Delta rho)	ACCEPTABLE RANGE (% Delta rho)	
6	4	Regulating	0.3653	0.3728	To	0.4228
					From	0.3228
5	4	Regulating	0.3725	0.3745	To	0.4245
					From	0.3245
4	8	Regulating	0.8449	0.8799	To	0.9679
					From	0.7919
3	8	Regulating	1.0360	1.0738	To	1.1812
					From	0.9664
2	9	Regulating	0.6433	0.6399	To	0.7039
					From	0.5759
1	8	Regulating	1.1613	1.1948	To	1.3143
					From	1.0753
B	24	Shutdown	2.9836	2.9824	To	3.2806
					From	2.6842
A*	18	Shutdown	1.7840	1.7260	To	1.8986
					From	1.5534
Net CEA Shutdown Worth:			9.1909			

*Net worth measurement made while most reactive CEA (CEA B-83) fully withdrawn in accordance with Technical Specification 3.10.1.

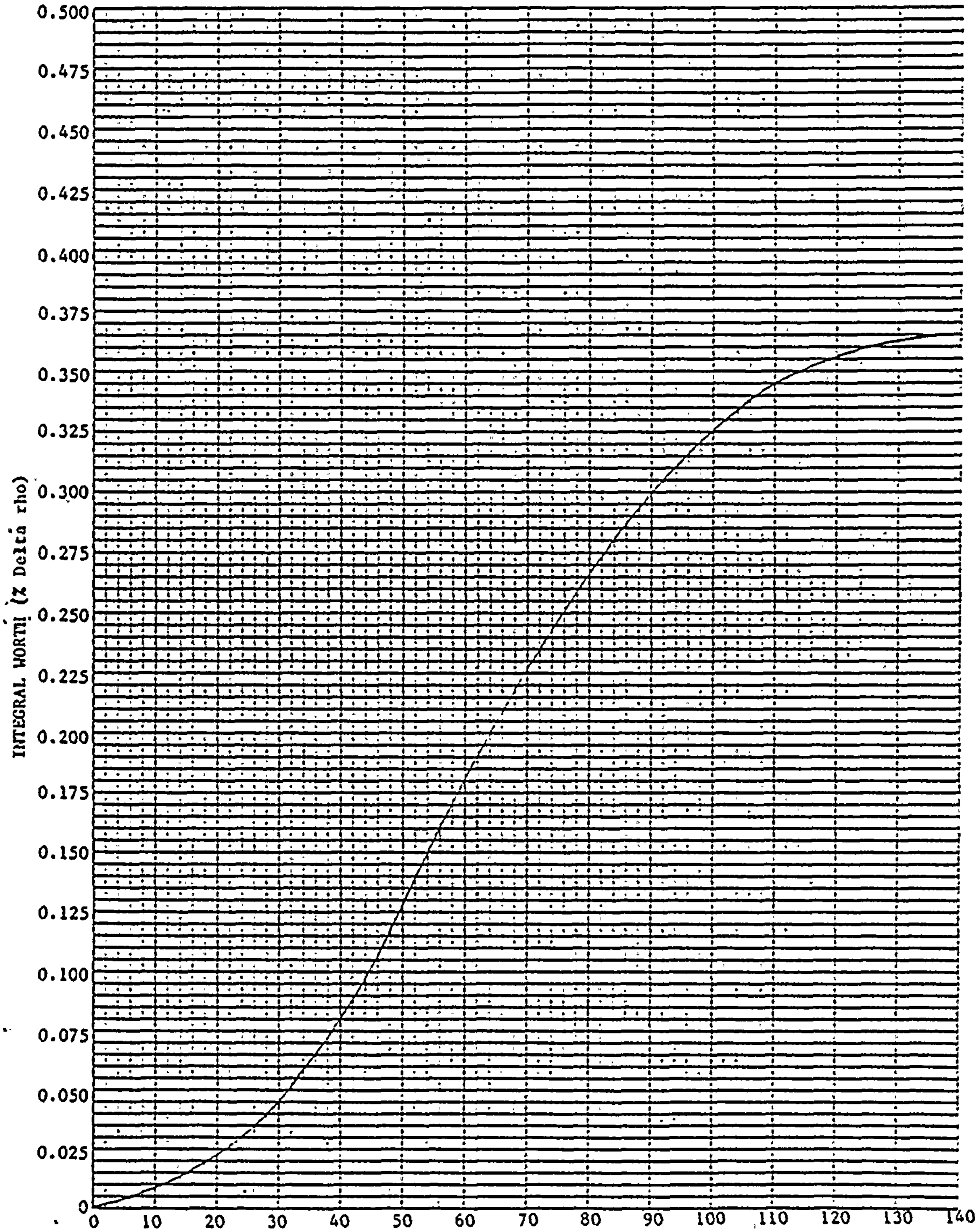
TABLE 5.d-2

CEA SHUTDOWN MARGIN SUMMARY

CEA GROUPS	MEASURED % Delta rho	DESIGN % Delta Rho	PERCENT DIFFERENCE
6 thru B	7.4069	7.5181	1.4798%

FIGURE 5.d-1
ST. LUCIE UNIT 2
INTEGRAL CEA GROUP WORTH
CYCLE 1, 0 EFPH, 532 ± 2°F, 2250 ± 15 psia

CEA GROUP 6



CEA WITHDRAWAL (INCHES)

FIGURE 5.d-2
ST. LUCIE UNIT 2
INTEGRAL CEA GROUP WORTH
CYCLE 1, 0 EFPH, 532 ± 2°F, 2250 ± 15 psia

CEA GROUP 5

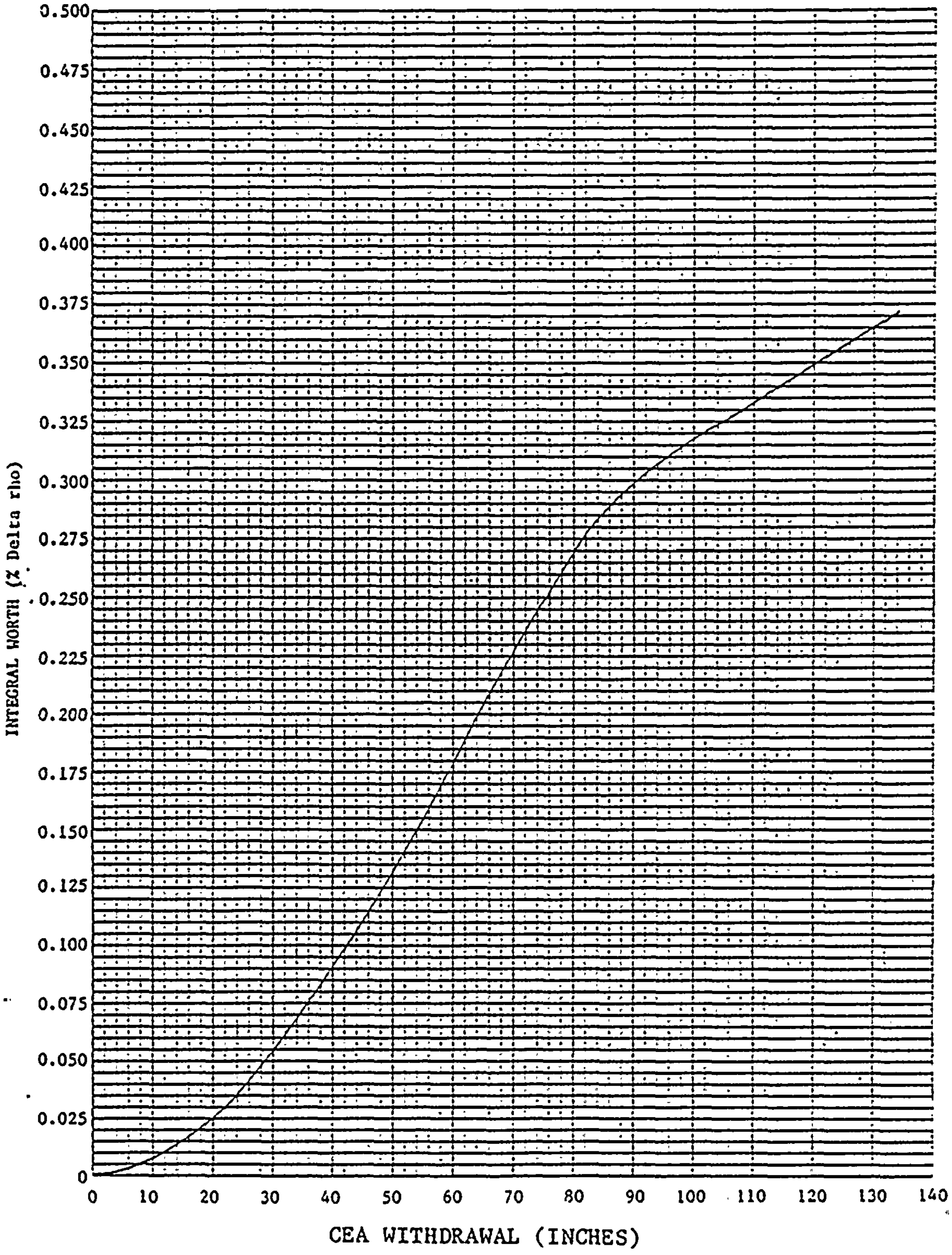


FIGURE 5.d-3
ST. LUCIE UNIT 2
INTEGRAL CEA GROUP WORTH
CYCLE 1, 0 EFPH, 532 ± 2°F, 2250 ± 15 psia

CEA GROUP 4

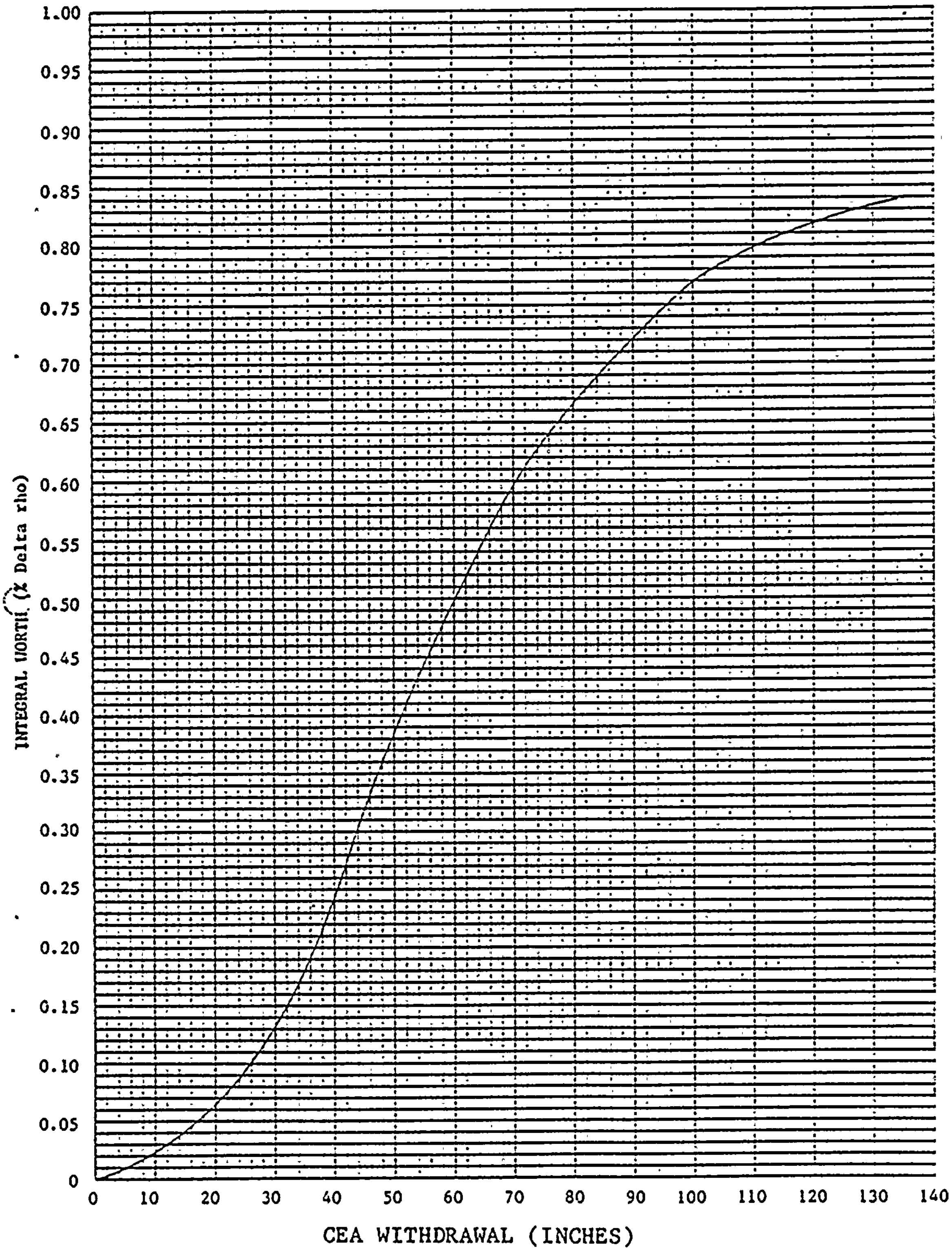


FIGURE 5.d-4
ST. LUCIE UNIT 2
INTEGRAL CEA GROUP WORTH
CYCLE 1, 0 EFPH, 532 ± 2°F, 2250 ± 15 psia

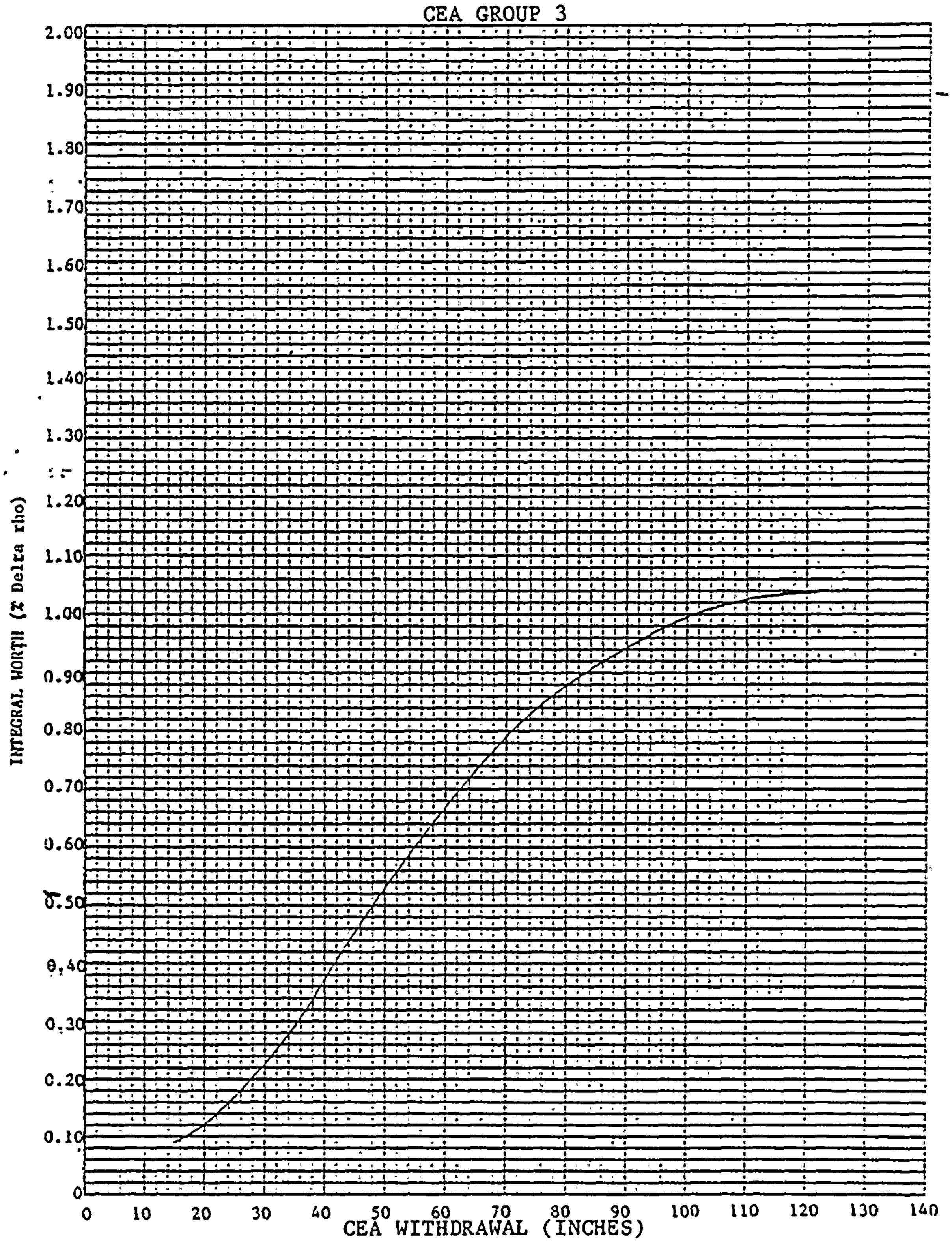


FIGURE 5.d-5
ST. LUCIE UNIT 2
INTEGRAL CEA GROUP WORTH
CYCLE 1, 0 EFPH, 532 ± 2°F, 2250 ± 15 psia

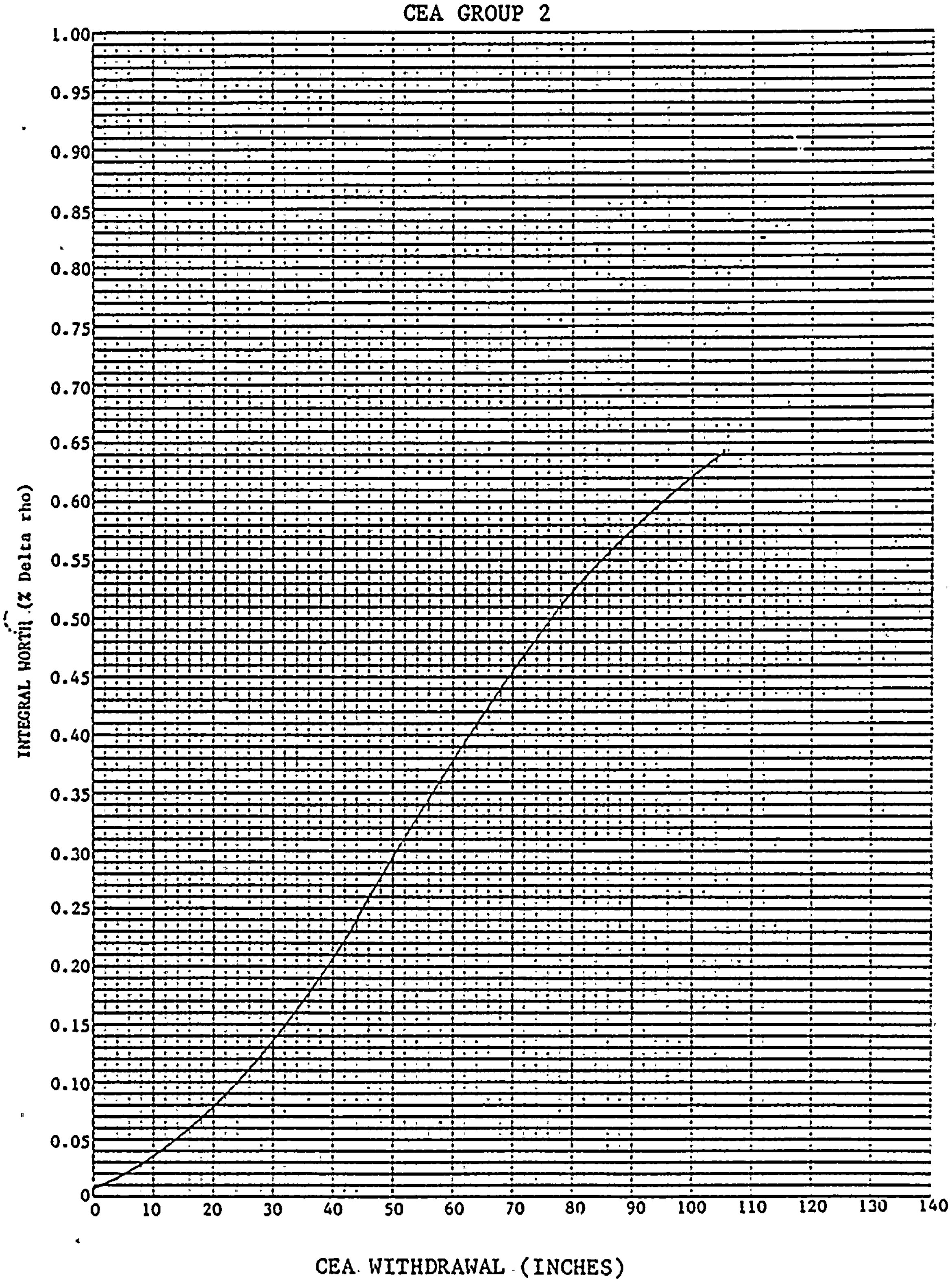


FIGURE 5.d-6
ST. LUCIE UNIT 2
INTEGRAL CEA GROUP WORTH
CYCLE 1, 0 EFPH, 532 ± 2^{o}F, 2250 ± 15 psia

CEA GROUP 1

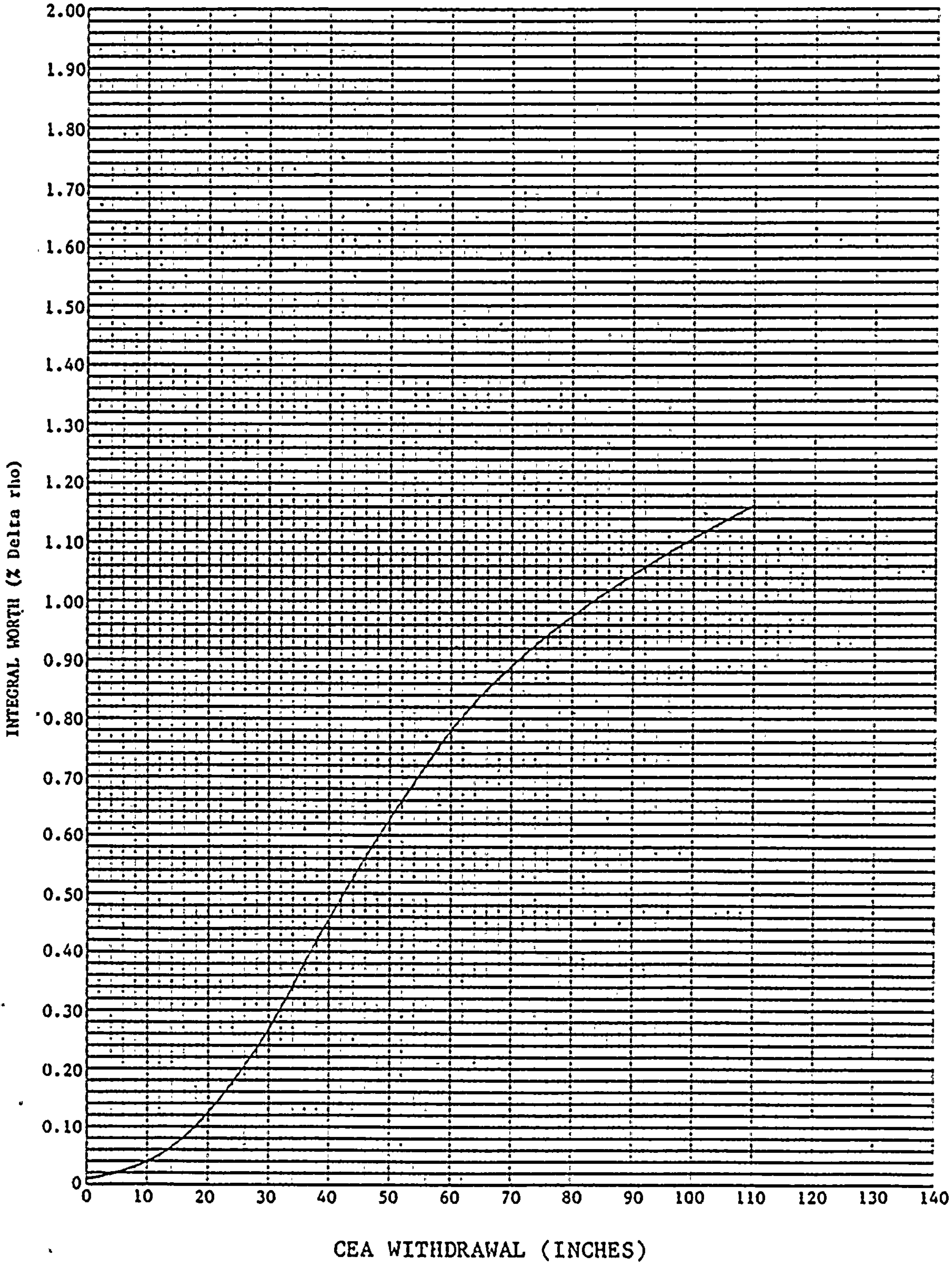
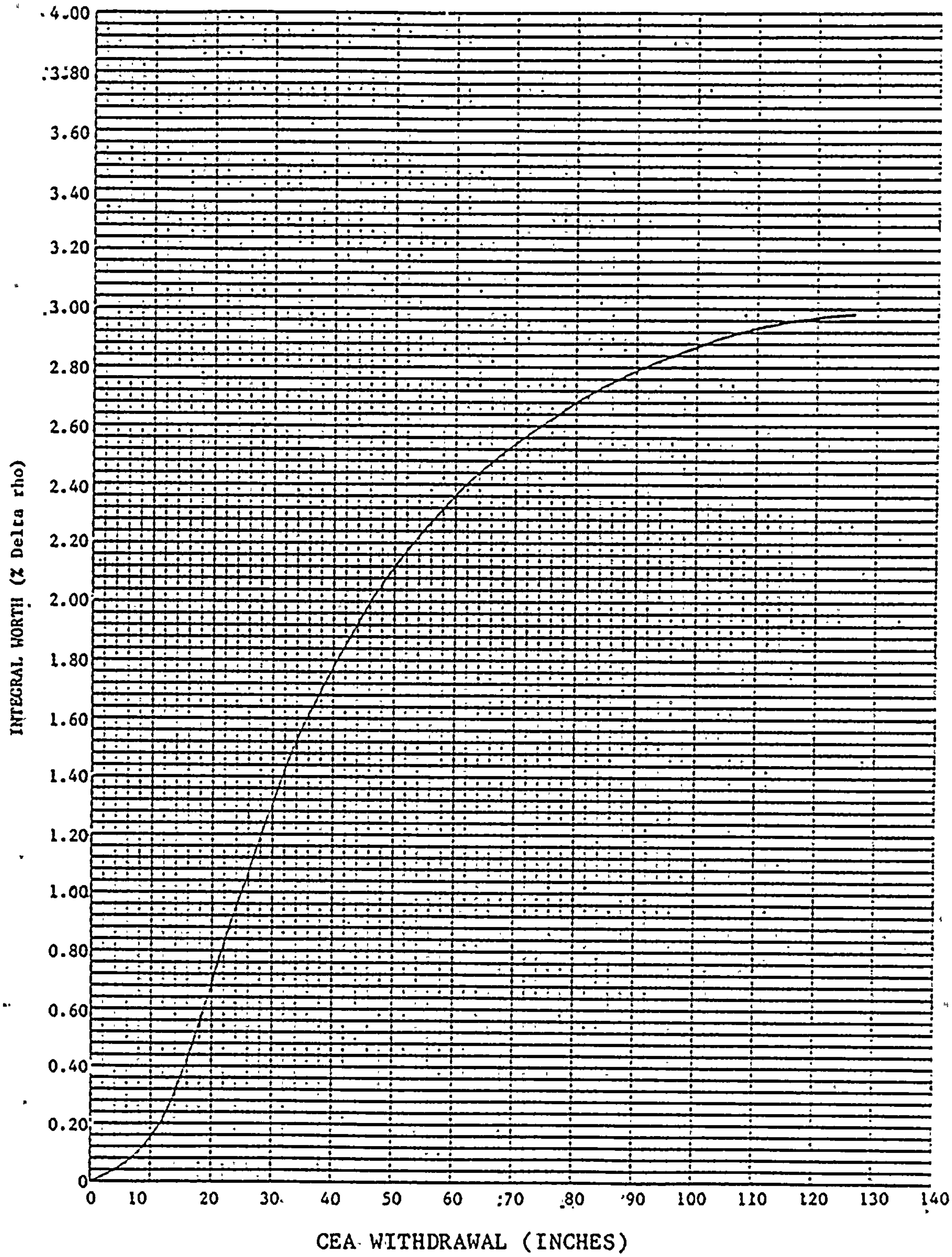


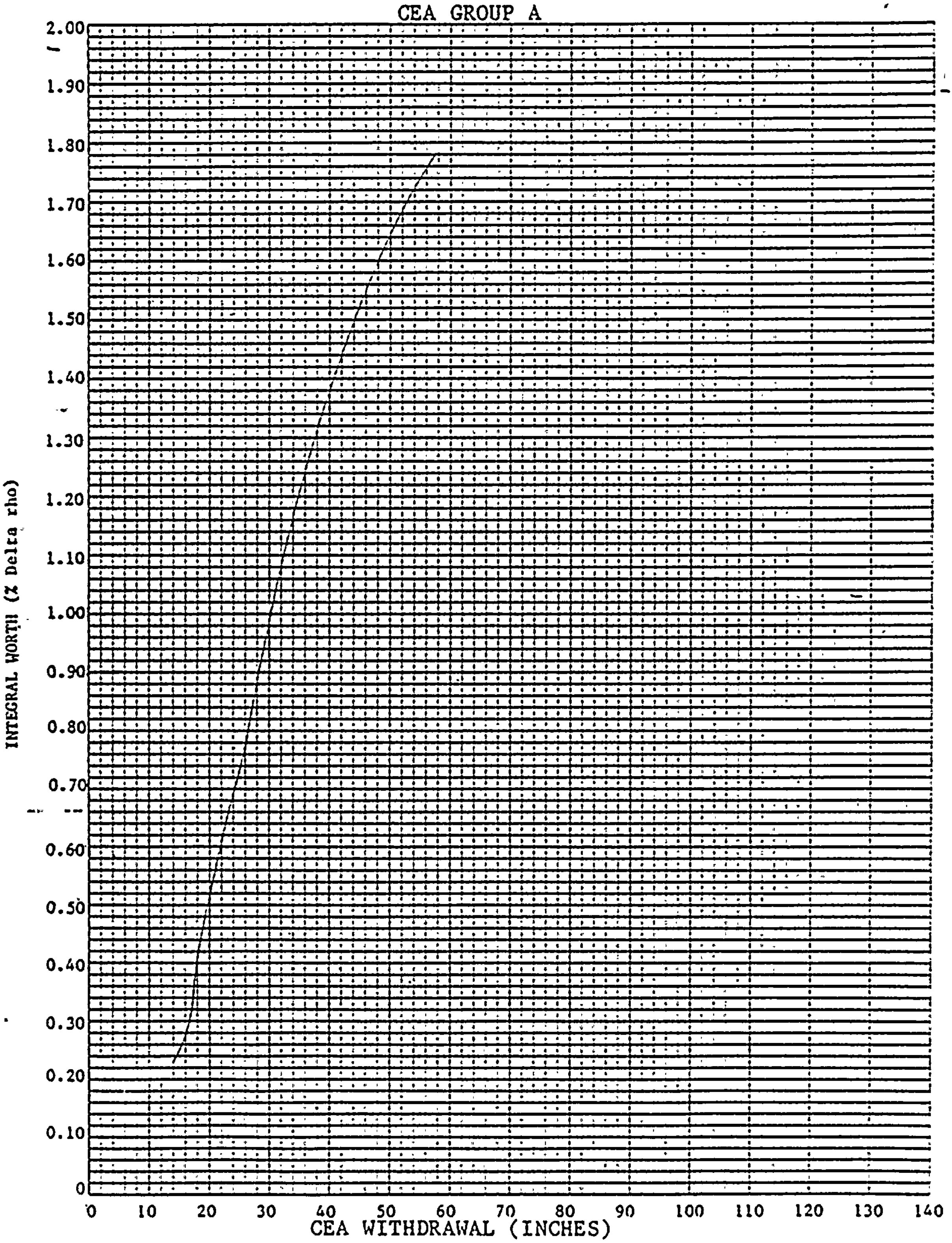
FIGURE 5.d-7
ST. LUCIE UNIT 2
INTEGRAL CEA GROUP WORTH
CYCLE 1, 0 EFPH, 532 ± 2°F, 2250 ± 15 psia

CEA GROUP B



CEA WITHDRAWAL (INCHES)

FIGRUE 5.d-8
ST. LUCIE UNIT 2
INTEGRAL CEA GROUP NET WORTH
CYCLE 1, 0 EFPH, 532 $\pm$ 2°F, 2250 $\pm$ 15 psia



5.e CRITICAL BORON CONCENTRATION MEASUREMENTS

5.e.1 Purpose

Critical boron concentration measurements were performed at various CEA configurations at relatively constant RCS temperature and pressure. The purpose of these measurements was to obtain an as-built value for the excess reactivity loaded into the core and to provide a basis for verification of predicted CEA Group reactivity worths.

5.e.2 Test Results

Boron concentration values were the stabilized averages of multiple chemical analysis measurements made of the Reactor Coolant System (RCS). Boron endpoint techniques were used when required. This technique borates (dilutes) CEA's out near UEL* (in near LEL**). After RCS conditions stabilize and the RCS boron concentration has been analyzed, the CEA's are quickly moved to UEL (to LEL), reactivity stabilized and CEA's quickly moved back in (out) to their bite position. The reactivity change (reactivity being plotted on a recorder of the reactivity computer) is measured. The amount of reactivity added (subtracted) is converted, via boron worth, to an equivalent Delta PPM. This Delta PPM is added to (subtracted from) the measured boron concentration. This technique gives a safe, fast and accurate method of determining critical boron concentrations at hard to achieve CEA positions (relatively low reactivity worths at UEL's and LEL's).

5.e.3 Conclusions

As Table 5.e-1 illustrates, the results indicate that measured critical boron concentrations were in satisfactory agreement with predictions and well within the acceptance criteria of ± 50 PPM.

* UEL = Upper Electrical Limit
**LEL = Lower Electrical Limit

TABLE 5.e-1

BORON ENDPOINT SUMMARY

CEA CONFIGURATION	MEASURED	DESIGN	ACCEPTABLE RANGE (PPM)
ARO	724	711	To Design + 50 PPM = 761 From Design - 50 PPM = 661
6-4 @ LEL 3-A @ UEL	599	593	To Design + 50 PPM = 643 From Design - 50 PPM = 543
6-1 @ LEL A,B @ UEL	416	398	To Design + 50 PPM = 448 From Design - 50 PPM = 348
6-B @ LEL A @ UEL	207	194	To Design + 50 PPM = 244 From Design - 50 PPM = 144

5.f CEA Symmetry Measurements

5.f.1 Purpose

The reactivity differences of symmetric CEA's were measured as one of numerous verification tests on both fuel and CEA manufacture and as designed placement into the reactor vessel. The measurement was performed by alternately swapping in and out all regulating and shutdown individual CEA's with their symmetric neighbors*. All CEA's were verified coupled to their Control Element Drive Mechanism (CEDM) extension shafts to verify CEA reactivity control of the core. This measurement was made by observing a reactivity change associated with individual CEA motion.

5.f.2 Test Results

The measured reactivity differences of symmetric CEA's were small with the average and worst case by symmetric inter-groups displayed in Table 5.f-1. All CEA's, including the center CEA, were verified coupled to their CEDM extension shafts.

5.f.3 Conclusions

Results indicate that the relative reactivity differences of symmetric CEA's were within the acceptance criteria value of 1 1/2 ¢ and all CEA's were coupled.

*Regulating center CEA 2-1 by design has no symmetric equivalent and as a result had no symmetry test performed; CEA 2-1, as with all other CEA's, was verified individually coupled to its CEDM extension shaft.

TABLE 5.f-1

CEA SYMMETRY SUMMARY

CEA Group	CEA Symmetry Subgroup	Number of Symmetric CEA's Measured and Verified Coupled	Average Symmetric Reactivity Difference (¢)	Worst Symmetric Reactivity Difference (¢)
A	6	4	-0.61	-1.08
	12,13	8	-0.74	-1.10
	22	4	-0.32	-0.59
	23	2	-1.10	-1.26
B	3,4	8	-0.28	-0.66
	9,10	8	-0.68	-1.08
	20,21	8	-0.45	-0.77
1	1	4	-0.28	-0.53
	18	4	-0.09	+0.24
2	17,19	8	-0.42	-0.90
3	15,16	8	-0.33	-0.93
4	2	4	-0.67	-0.89
	14	4	-0.53	-0.91
5	11	4	-0.52	-0.84
6	5	4	-0.03	-0.16

5.g SOURCE AND INTERMEDIATE RANGE NEUTRON INSTRUMENTATION OVERLAP VERIFICATION

5.g.1 Objective

Demonstration of adequate overlap of the source and intermediate neutron instrumentation.

5.g.2 Test Results

The overlap between the soruce range and intermediate range detectors was recorded during power ascension.

5.g.3 Conclusion

The data recorded in this test demonstrates this system exceeds the design limit of one decade overlap.

5.h CEA SEQUENCING 7 INHIBIT TEST

5.h.1 Purpose:

The objectives of this test were as follows:

1) To demonstrate that the CEA withdrawal sequence while operating in sequential mode was as specificed in the Technical Specifications, Section 3/4.1.3.

2) To demonstrate the operation of the CEA Motion Inhibits initiated by the Analog Display System (ADS).

5.h.2 Test Results:

The CEA's operated in the sequence specified by the Technical Specifications Section 3/4.1.3 while operating in Sequential Mode.

Regulating Group	Group Position at which next group begins motion
1	99"
2	97.5"
3	97.5"
4	97.5"
5	97.5"
6	N/A

CEA Motion is inhibited by the ADS signals resulting from the following:

1) A CEA in any group out of group position by 6, +1 -2.5 inches.

2) Adjacent Regulating Group positions within 82 inches of each other.

Groups	Overlap
1 & 2	86 inches
2 & 3	87 inches
3 & 4	86 inches
4 & 5	86 inches
5 & 6	86 inches

3) Groups 3, 4, 5 or 6 exceeding its Power Dependent Insertion Limit Regulating Group withdrawal is inhibited when all Shutdown Group CEA's are not at their UEL Shutdown Group insertion is inhibited when all Regulating Group CEA's are not at their LEL. Power Depent Insertion Linits meet the requirements of Technical Specification 3.1.3.6.

5.h.3 Conclusions:

Regulating CEA's withdraw in the specified sequence. CEA motion is inhibited by the limiting CEA position configuration as detected by the ADS.

6. POWER ASCENSION TESTING

The purpose of the Power Ascension program was to provide a safe and efficient frame work for the performance of initial plant startup tests and routine plant startup tests. Power Ascension officially began on June 11, 1983 and was completed on August 9, 1983, a total of 60 days. Included in this 60 days was a 21 day outage which was caused, in the most part, by failed 2A2 Reactor Coolant pump seals and secondary chemistry cation high conductivity.

Power Ascension testing can be broken down into three major categories. Firstly is "Reactor Physics" FSAR Chapter 14 testing such as Nuclear and Delta T Power Calibration, Moderator Temperature and Power Coefficient test, Peaking Factor and Flux Tilt Verification, etc. Secondly is the completion of Chapter 14 "System Testing" such as Generator Trip with Shutdown Outside the Control Room, Loss of Offsite Power, Turbine Overspeed, etc. The final category could be labeled "Miscellaneous", which would include Chemical and Radiochemical Analysis, Radiation Shielding Evaluation, Digital Data Processor Instrument Correlation, etc.

Power Ascension immediately followed Low Power Physics Testing. The first Power Ascension milestone was on June 13, 1983 when the main generator was synchronized to the grid at 8:55 a.m. Testing continued until June 22, 1983 when it was decided to cooldown and partially drain the RCS for 2A2 reactor coolant pump seal changeout in coincidence with a complete secondary flush, 2A steam generator loose parts internal inspection and condensate pump strainer cleanout. RCS heatup and pressurization commenced on July 3, 1983 and again the 2A2 reactor coolant pump seal exhibited problems. Cooldown and subsequent 2A2 reactor coolant pump changeout began on July 4, 1983. This time the entire seal cartridge was replaced. Heatup and pressurization began on July 12, 1983 and the 2A2 pump seal functioned properly. Fifty percent plateau testing started on July 15, 1983 and was completed on July 19. Power increase to the eighty percent plateau immediately followed completion of the fifty percent plateau and eighty percent testing began at 10:35 a.m. on July 20, 1983.

RCS flow measurement "delta T technique" results did not agree well with steam generator or pump power methods. Reactor power was maintained at the 80% plateau until this situation was resolved. The vendor recommends determining RCS flow based on stem generator delta P. Measurements using this technique yielded expected results. As a backup, reactor coolant pump motor input power readings were taken and the RCS flow calculated using this method agreed with the steam generator delta P method. After close scrutiny it was noted that T cold RTD's used to calculate RCS delta T were reading higher than two other RTD's located nearby. It was determined that an increased temperature statification factor was needed for RCS T cold RTD's. The RTD's were compensated and acceptable RCS flow using the delta T method was obtained.

Condensate pump strainers forced a power decrease to fifty percent at the end of the eighty percent plateau on July 24, 1983.

6. POWER ASCENSION TESTING (Cont.)

The Power Ascension Test Sequence was modified in an effort to shorten the time to continous 100% power operation. The one hundred percent generator trip test was moved from being the last one hundred percent test to the first. Physics tests were shuffled and dove tailed with vendor approval and yielded good results.

Power was increased to one hundred percent at 11:10 a.m. on July 24, 1983 followed by the generator trip test at 2:45 a.m. July 25, 1983. An immediate return to twenty percent power in preparation for Loss of Offsite Power (LOOP) test took place. The twenty percent power LOOP test was performed after an inadvertant trip on high steam generator level while controlling manually, on July 27, 1983.

Load swing testing was performed on July 29, 1983, after returning to fifty percent power and immediately followed with the Turbine Runback test. Power was decreased to thirty percent for secondary high cation conductivity (maximum blowdown and secondary feed and bleed).

One hundred percent power was again acheived at 7:10 p.m. on July 31, 1983. While plateau testing was in progress, oil level in the 2B2 reactor coolant pump motor was noticed to be decreasing. Immediately prior to coming off-line for repair of the 2B2 reactor coolant pump, the hot full power moderator temperature coefficient test was performed. The unit came off the line at 11:43 p.m. on August 3, 1983.

Repairs to 2B2 reactor coolant pump (cracked oil system oil pipe fitting) were completed and startup began at 10:46 a.m. on August 4, 1983. Axial shape index forced a power reduction to 10^{-3}%. The one hundred percent power moderator temperature coefficient test was performed. Immediately prior to shutdown, an attempt to restart during peak Xenon conditions combined with tight ASI LCO's caused the axial shape index problem.

On August 5, 1983 at 2:40 a.m., the plant was again at one hundred percent power and testing continued. Unit commercialization was declared on August 7, 1983 (midnight) with the initial testing program and Power Ascension program concluded at the completion of the NSSS and Turbine Generator Acceptance Run on August 9, 1983, 11:10 a.m.

6.a AUTOMATIC CONTROL SYSTEM AND LOAD SWING TEST

Purpose

This test verified that system automatic controls were capable of maintaining plant parameters with allowable tolerances during steady state and design load change conditions. Data was also obtained via the Transient Data Acquisition System (TDAS) to verify Combustion Engineering System Excursion Code (CESEC) used in the safety analysis.

Test Results

Initial testing at the 20% power plateau resulted in some adjustment to main feedwater controllers. This was expected since low flow throttling of the main feedwater regulating valves inherently induces instability. However, at subsequent plateaus no adjustments were necessary.

Load swings of 5%/min decrease, 10% step decrease, 10% step increase, and 10% ramp increase were performed on July 29, 1983. All automatic systems functioned properly and all Single Valve Acceptance Criteria (SVAC) were met for each test except for 10% step decrease. The turbine control system overshot approximately 3% on the 10% step decrease (i.e. 13% step decrease). After correcting for the overshoot, the SVAC were met.

Conclusions

All acceptance criteria were met for this test. The TDAS allowed for immediate feedback thereby shortening post test analysis and the determination of acceptable results.

6.b LOSS OF OFFSITE POWER TEST

6.b.1 Purpose

The objectives of this test were as follows:

1) Demonstrate the plant's response during a load rejection from 20% reactor power to station auxilliary load by opening thge oil circuit breakers to the distribution system.

2) Demonstrate the plant's response to a total loss of offsite power by inducing a turbine generator trip with the plant carrying station auxilliary load and automatic closure of breakers to provide offsite power disabled.

3) Verify that the diesel generators start and provide power to plant vital loads for at least 30 minutes following the turbine generator trip.

4) Collect data for use by Combustion Engineering for quallification of the CE System Excursion Code (CESEC) NSSS simulation.

6.b.2 Test Results

All of the above were satisfactorily completed. The load reduction to station auxilliary load portion of the test was performed with no unexpected events. All plant equipment functioned to maintain pressurizer pressure, pressurizer water level, reactor coolant temperature and steam generator pressure within prescribed limits and no plant technical specificaiton parameters were violated. When the turbine generator trip was initiated to perform the loss of offsite power portion of the test both diesel generators started, however, the B diesel generator breaker failed to remain closed. The test, was continued with the A diesel generator only. Pressurizer pressure, water level, reactor coolant temperature and steam generator pressure were maintained within prescribed linits for a 30 minute period without offsite power. The B diesel generator breaker failure was found to be caused by a broken terminal lug on the bus differential current relay. The broken terminal lug was repaired and a loss of offsite power test for the B train only was performed. The B diesel generator started and its breaker closed satisfactorily.

6.b.3 Conclusions

Items 1, 2 and 3 of the test objections listed above were acceptance criteria of the Preoperational Test Procedure and were satisfactorily met. Item 4 was for use by Combustion Engineering. The desired data was obtained and provided to CE.

6.c 10% LOAD REDUCTION - TURBINE RUNBACK

6.c.1 Purpose

The objectives of this test were:

1) Verify operation of the turbine DEH controller runback circuit.

2) Record the turbine generator response to an automatic load reduction of approximately 10%.

6.c.2 Test Results

A turbine runback was initiated by simulating loss of a single main reedwater pump. Runback occurred without incident. Turbine generator response in shown in Figures 6.c-1 and 6.c-2. Due to the fast ramp rate of the runback circuit (200% load per minute), some overshoot in turbine first stage prssure and generator gross megawatts resulted as a was anticipated. In addition, first stage pressure before, during, and after the transient did not agree with the theoretical calibration curve (Figure 6.c-3). This disagreement is due to actual secondary plant efficiency at the time of the test being different from that which is assumed for the theoretical calibration curve.

6.c.3 Conclusions

The DEH runback circuit functioned as required upon initiation of a runback signal. Turbine first stage pressure at the end of the transient was lower than predicted. However, when corrected for overshoot and plant conditions as described above, the test was successful.

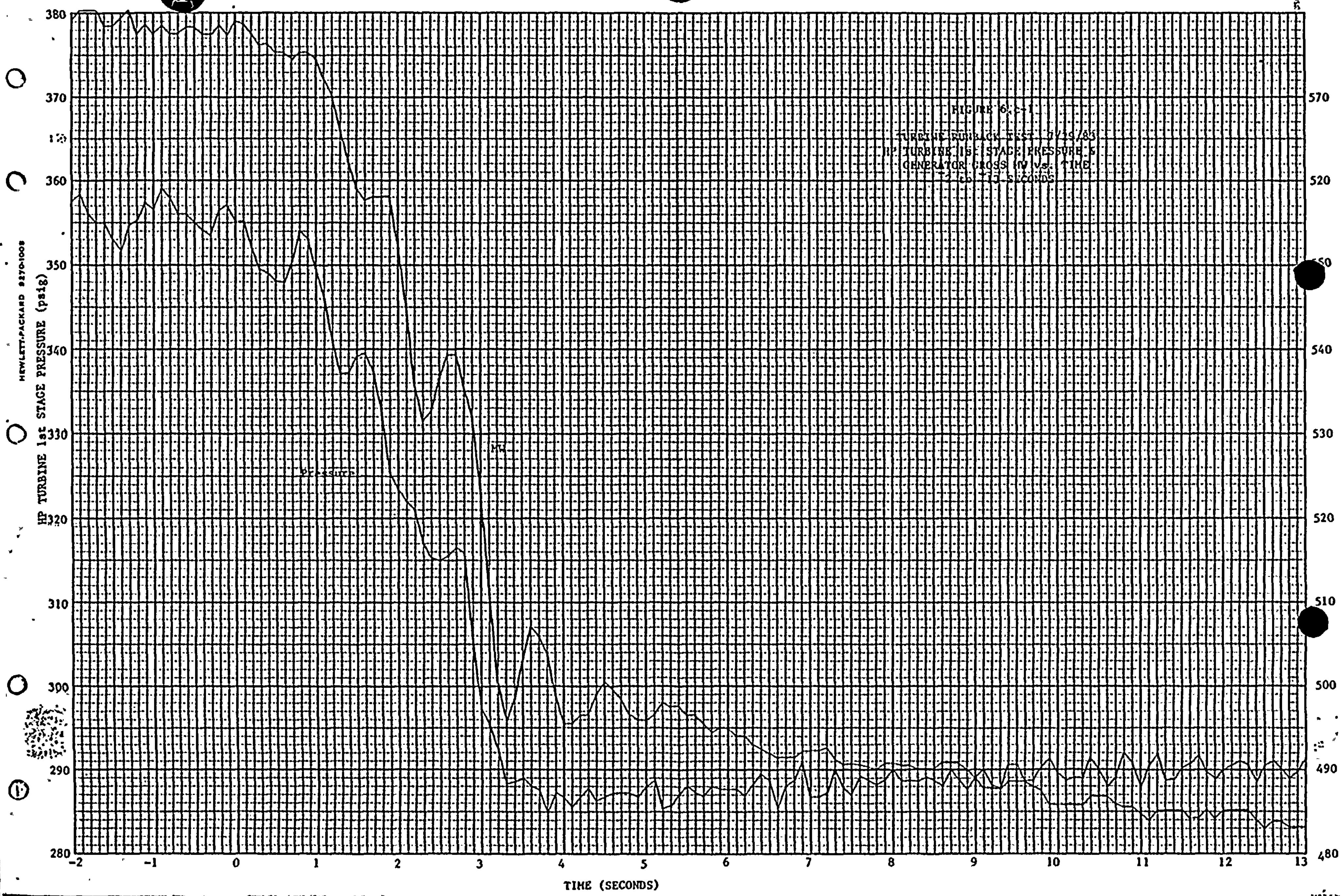


FIGURE 6.c-1

TURBINE RUNBACK TEST 7/19/85
HP TURBINE 1st STAGE PRESSURE &
GENERATOR GROSS MW vs. TIME
-2 to +13 SECONDS

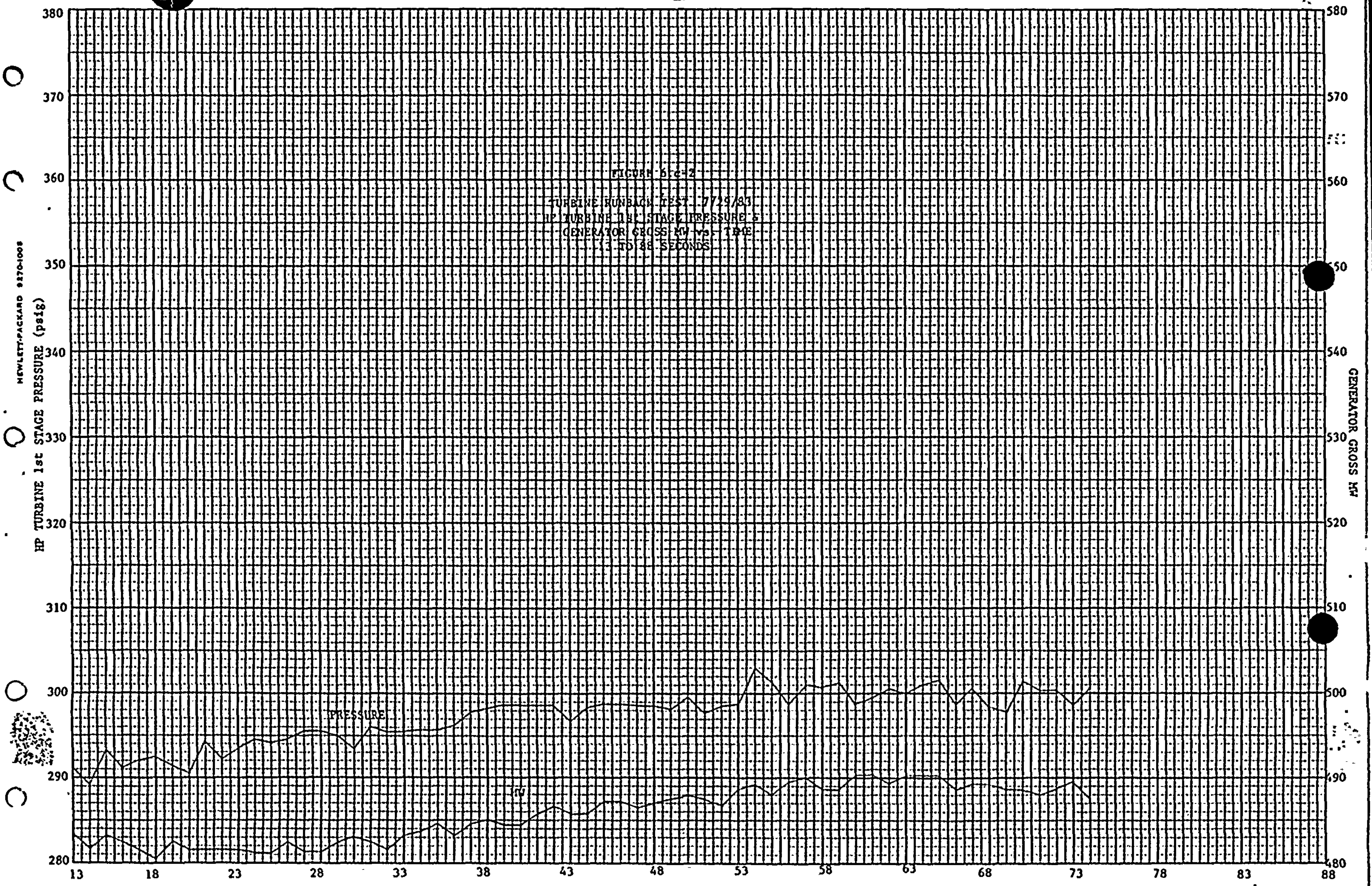


FIGURE 6-c-2

TURBINE RUNBACK TEST 7/29/83
HP TURBINE 1st STAGE PRESSURE &
GENERATOR GROSS MW vs. TIME
13 TO 88 SECONDS

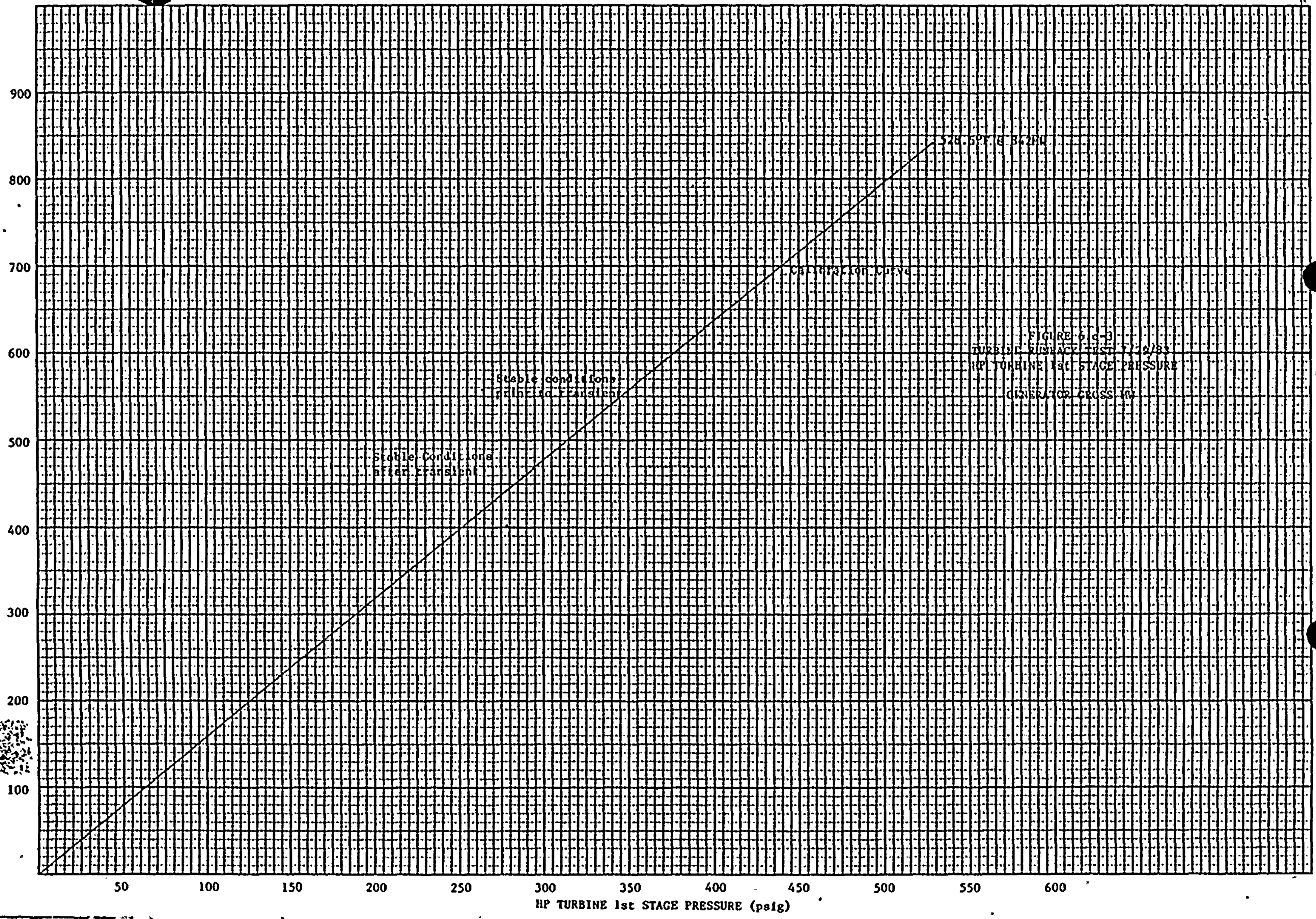


FIGURE 6.c-3
TURBINE RUNBACK TEST 7/19/83
HP TURBINE 1st STAGE PRESSURE

GENERATOR GROSS KW

6.d GENERATOR TRIP WITH SHUTDOWN OUTSIDE CONTROL ROOM

6.d.1 Purpose:

The objectives of this test were as follows:

a) Verify the reactor could be tripped from outside the control room.

b) Establish stable hot shutdown conditions with minimum shift crew.

c) Maintain Reactor Coolent System (RCS) temperature and pressure at 523°F ± 5°F and 2100 psia ± 100 psia respectively.

d) Maintain steam generator levels at 65% ± 15%.

e) Verify RCS boron concentration can be increased by at least 10 ppm from outside the control room.

6.d.2 Test Results

A brush recorder was connected to monitor some of the above parameters in addition to the permanent strip chart recorders in the Control Room. All the above were satisfactorily completed from outside the Control Room, either via the Hot Shutdown Panel or locally.

Boration was performed by a manual operation of the boric acid gravity feed valves. Backup personnel were stationed in the Control Room to ensure the plant was under control at all times. No intervention by the Control Room personnel was necessary

6.d.3 Conclusions

Controlling the plant from outside the Control Room requires good coordination and communciation between operational personnel. This was present during the test as evidenced in the overall performance and expedious completion (less than 2 hours) of the test. Performing this type of test also identifies key areas of design improvement or the need for modification/classification of procedures.

6.e GENERATOR TRIP AT 100% POWER

6.e.1 Purpose

The objective of this test was to verify that the dynamic response of plant systems and controls for a generator trip transient were in accordance with design requirements and as predicted by the CE System Excursion Code NSSS simulation (CESEC).

6.e.2 Test Results

The required initial plant conditions were satisfactorly achieved prior to the generator trip. All Single Value Acceptance Criteria (SVAC) parameters were satisfactorily recorded on the Transient Data Acquisition System Computor at 10 scans per second throughout the trip transient. No operator actions were required or taken during the first 60 second after the trip.

The following tables lists the SVAC parameters, the actual values observed during the transient and the acceptable SVAC values.

Parameter	Observed Value	SVAC Value
2A S/G Pressure	951.74 psia (max.)	$\leq$ 990 psia
2B S/G Pressure	943.59 psia (max.)	$\leq$ 990 psia
Pressurizer Pressure	2266.66 psia (max.)	$\leq$ 2340 psia
Pressurizer Level	39.14% (min.)	$\geq$ 34%
2A Hot Leg Temperature	543.51°F (min.)	$\geq$ 538°F
2B Hot Leg Temperature	542.38°F (min.)	$\geq$ 538°F

6.e.3 Conclusions

The generator trip test was successfully completed and satisfactory results were achieved. All SVAC parameters remained well within their respective limits and plant conditions required no operator actions in the initial 60 seconds of the transient. Plant systems and controls responded as predicted and recovery from the transient was without incident.

6.f EVALUATION OF CORE PERFORMANCE

6.f.1 Purpose

The objective of the core performance record is to verify steady state equilibrium xenon core power distributions and peaking factors are within acceptable limits at various power levels.

NOTE: Equilibrium xenon was established as per the guidelines of the Power Ascension Document. The specific acceptance criteria applied to the measured core power distributions are listed below:

1) CECOR calculates an axially integrated core radial power distribution and relative power density for each of the 217 fuel bundles in the core from incore detector signals. A core radial power distribution prediction for 50%, 80% and 100% power has been supplied by Combustion Engineering. The Root Mean Square (RMS) difference between the actual calculated radial power and the predicted radial power distribution shall be less than 3.0%.

2) Similarly, CECOR calculates a 51 point core average axial power distribution. The RMS difference between the CECOR calculated and the CE predicted axial power distribution shall be less than 3.0%.

3) The CECOR code also has the capability of calculating peaking factors and azimuthal power tilt. The measured peaking factors and tilt shall be less than allowed by applicable Technical Specifications. For the peaking factors listed below, the CECOR calculated values shall be within 7.5% of the CE predicted values for the 50%, 80% and 100% power levels:

F_{xy}: Core maximum unrodded planar radial peaking factor
F_r: Core maximum unrodded integrated radial peaking factor
F_z: Core average axial power peaking factor
F_q: Core 3-D power peaking factor

6.f.2 Test Results

The power distribution summary for 50%, 80%, and 100% power is given in Table 6.f-1. Tables 6.f-2, 6.f-3, and 6.f-4 represent the radial power distribution comparison for the various power levels. Figure 6.f-1 is provided for correlation of the information in Tables 6.f-2, 6.f-3 and 6.f-4. Table 6.f-5 represents the axial power distribution for the various power levels. Table 6.f-6 is the peaking factor and tilt summary with respect to applicable Technical Specifications for the 20%, 50%, 80% and 100% power levels.

6.f EVALUATION OF CORE PERFORMANCE (Cont.)

6.f.3 Conclusions:

At steady state equilibrium xenon, the measured peaking factors and tilts determined from incore detector flux maps are less than allowed by the applicable Technical Specifications at the 20%, 50%, 80% and 100% power plateaus. The axial and radial core power distributions are in satisfactory agreement with the predictions. The measured peaking factors are in satisfactory agreement with the predictions.

TABLE 6.f-1

POWER DISTRIBUTION SUMMARY - 50%, 80% AND 100% POWER

PARAMETER	Acceptance Criteria	Results at Power Level		
		50%	80%	100%
RMS Difference - Radial Power Distribution	≤ 3.0%	(7/17/83) 1.665%	(7/22/83) 2.705%	(8-9-83) 2.75%
RMS Difference - Axial Power Distribution	≤3.0%	1.850%	2.953%	1.61%

50% Power Date 7/7/83

PARAMETER	Measured	Predicted	% Difference	Acceptance Criteria
F_{xy}: Core Maximum Unrodded Planar Radial Peaking Factor	1.462	1.388	5.33%	< ± 7.5%
F_r: Core Maximum Unrodded Integrated Radial Peaking Factor	1.398	1.352	3.40%	< ± 7.5%
F_z: Core Average Axial Power Peaking Factor	1.272	1.256	1.27%	< ± 7.5%
F_q: Core 3-D Power Peaking Factor	1.769	1.693	4.49%	< ± 7.5%

80% Power Date 7/22/83

PARAMETER	Measured	Predicted	% Difference	Acceptance Criteria
F_{xy}: Core Maximum Unrodded Planar Radial Peaking Factor	1.4203	1.386	2.47%	< ± 7.5%
F_r: Core Maximum Unrodded Integrated Radial Peaking Factor	1.3704	1.367	0.25%	< ± 7.5%
F_z: Core Average Axial Power Peaking Factor	1.2644	1.280	-1.22%	< ± 7.5%
Fq: Core 3-D Power Peaking Factor	1.7299	1.745	-0.87%	< + 7.5%

TABLE 6.f-1
POWER DISTRIBUTION SUMMARY - 50%, 80% AND 100% POWER
-continued-

100% Power

Date 8/2/83

PARAMETER	Measured	Predicted	% Difference	Acceptance Criteria
F_{xy}: Core Maximum Unrodded Planar Radial Peaking Factor	1.447	1.415	2.26%	< ± 7.5%
F_r: Core Maximum Unrodded Integrated Radial Peaking Factor	1.372	1.397	-1.79%	< ± 7.5%
F_z: Core Average Axial Power Peaking Factor	1.289	1.290	-0.08%	< ± 7.5%
F_q: Core 3-D Power Peaking Factor	1.798	1.796	0.11%	< ± 7.5%

FIGURE 6.f-1
CEPOST NUMBERING SYSTEM

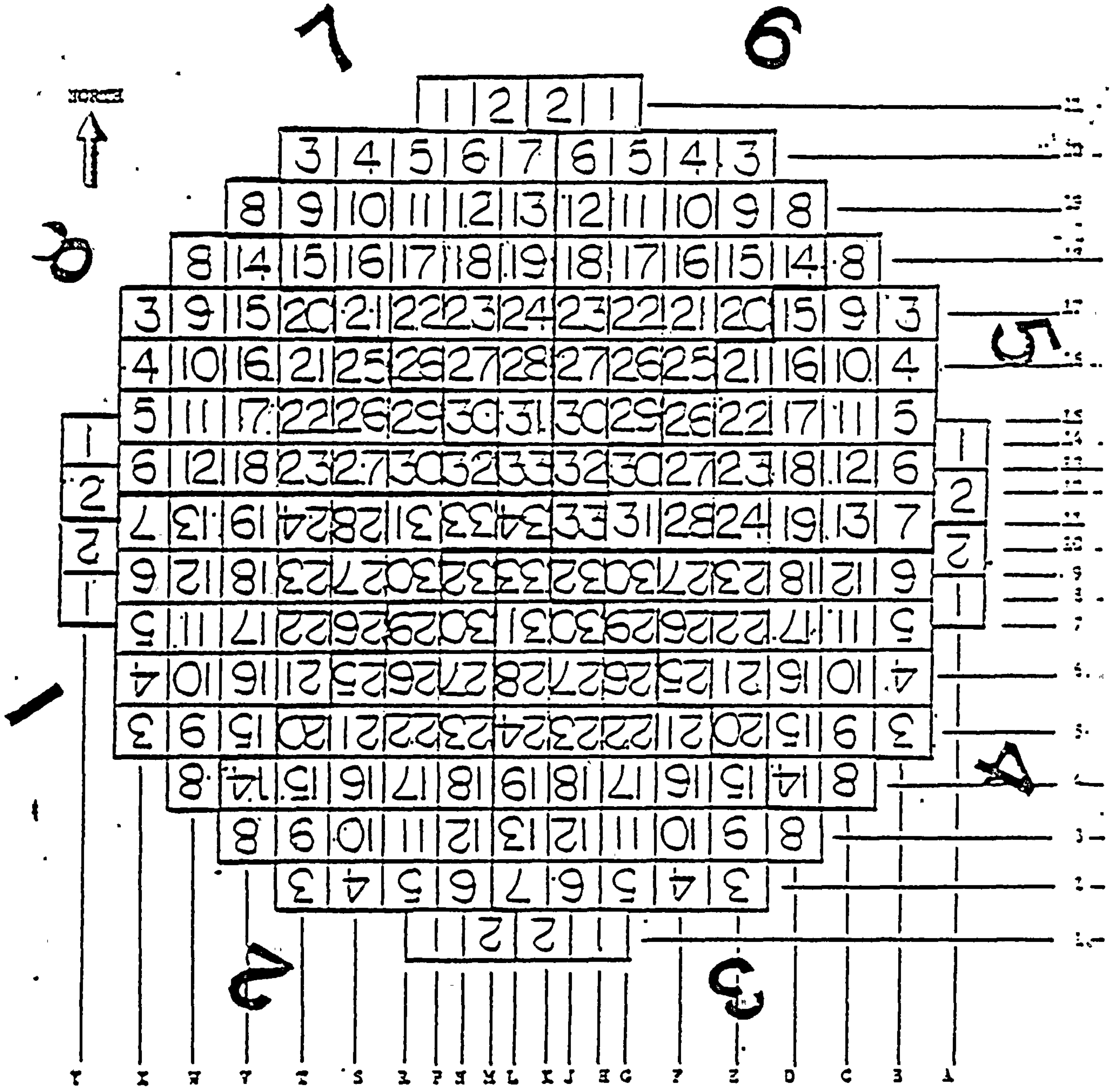


TABLE 6.f-2
RADIAL POWER DISTRIBUTION COMPARISON
50% POWER

Date 7/17/83

BOX NO.	OCTANT 1		OCTANT 2		OCTANT 3		OCTANT 4	
	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN
1	.725	.681	.680	.681	.679	.681	.7	.681
2	.950	.912	.917	.912	.917	.912	.933	.912
3	.638	.629	.659	.629	.656	.629	.617	.629
4	.879	.863	.881	.863	.880	.863	.854	.863
5	1.013	.985	.992	.985	.991	.985	.987	.985
6	1.183	1.146	1.156	1.146	1.155	1.146	1.159	1.146
7	1.077	1.053	----	----	1.043	1.053	----	----
8	.758	.686	.705	.686	.697	.686	.711	.686
9	1.022	.986	1.007	.986	1.004	.986	.987	.986
10	1.012	.999	1.016	.999	1.015	.999	.981	.999
11	1.010	1.005	1.004	1.005	1.004	1.005	.988	1.005
12	1.078	1.089	1.101	1.089	1.101	1.089	1.063	1.089
13	1.033	1.039	----	----	1.041	1.039	----	----
14	----	----	.860	.831	----	----	.842	.831
15	1.025	.992	1.002	.992	1.003	.992	1.007	.992
16	1.002	.997	.995	.997	.996	.997	.998	.997
17	1.117	1.096	1.085	1.096	1.09	1.096	1.099	1.096
18	1.047	1.05	1.05	1.05	1.051	1.05	1.028	1.05
19	1.130	1.116	----	----	1.139	1.116	----	----
20	----	----	.994	.989	----	----	.991	.989
21	1.088	1.092	1.112	1.092	1.107	1.092	1.095	1.092
22	1.049	1.051	1.052	1.051	1.046	1.051	1.039	1.051
23	1.132	1.124	1.145	1.124	1.141	1.124	1.109	1.124
24	1.065	1.064	----	----	1.070	1.064	----	----
25	----	----	1.052	1.051	----	----	1.044	1.051
26	1.142	1.127	1.151	1.127	1.127	1.127	1.131	1.127
27	1.066	1.071	1.075	1.071	1.067	1.071	1.053	1.071
28	1.149	1.138	----	----	1.147	1.138	----	----
29	----	----	1.072	1.073	----	----	1.06	1.073
30	1.137	1.144	1.158	1.144	1.152	1.144	1.130	1.144
31	1.07	1.081	----	----	1.078	1.081	----	----
32	----	----	1.074	1.084	----	----	1.071	1.084
33	1.153	1.151	----	----	1.151	1.151	----	----
34	1.071	1.087	----	----	----	----	----	----

TABLE 6.f-2
RADIAL POWER DISTRIBUTION COMPARISON
50% POWER
-continued-

Date 7/17/83

BOX NO.	OCTANT 5		OCTANT 6		OCTANT 7		OCTANT 8	
	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN
1	.713	.681	.663	.681	.668	.681	.703	.681
2	.936	.912	.879	.912	.899	.912	.942	.912
3	.616	.629	.632	.629	.655	.629	.622	.629
4	.853	.863	.855	.963	.873	.863	.859	.863
5	.989	.985	.964	.985	.977	.985	.993	.985
6	1.161	1.146	1.128	1.146	1.134	1.146	1.168	1.146
7	1.063	1.053	----	----	1.021	1.053	----	----
8	.718	.686	.682	.686	.699	.686	.725	.686
9	.984	.986	.976	.986	1.003	.986	.995	.986
10	.977	.999	.991	.999	1.010	.999	.986	.999
11	.982	1.005	.983	1.005	.994	1.005	.993	1.005
12	1.051	1.089	1.076	1.089	1.081	1.089	1.065	1.089
13	1.018	1.039	----	----	1.015	1.039	----	----
14	----	----	.830	.831	----	----	.846	.831
15	.993	.992	.975	.992	1.005	.992	1.008	.992
16	.974	.997	.976	.997	.992	.997	.986	.997
17	1.088	1.096	1.079	1.096	1.087	1.096	1.105	1.096
18	1.021	1.05	1.028	1.05	1.032	1.05	1.043	1.05
19	1.109	1.116	----	----	1.098	1.116	----	----
20	----	----	.969	.989	----	----	.985	.989
21	1.065	1.092	1.087	1.092	1.099	1.092	1.077	1.092
22	1.024	1.051	1.03	1.051	1.035	1.051	1.042	1.051
23	1.099	1.124	1.121	1.124	1.124	1.124	1.138	1.124
24	1.043	1.064	----	----	1.049	1.064	----	----
25	----	----	1.026	1.051	----	----	1.034	1.051
26	1.122	1.127	1.110	1.127	1.111	1.127	1.131	1.127
27	1.054	1.071	1.055	1.071	1.055	1.071	1.064	1.071
28	1.137	1.138	----	----	1.138	1.138	----	----
29	----	----	1.058	1.073	----	----	1.056	1.073
30	1.153	1.144	1.145	1.144	1.143	1.144	1.135	1.144
31	1.07	1.081	----	----	1.066	1.081	----	----
32	----	----	1.07	1.084	----	----	1.065	1.084
33	1.154	1.151	----	----	1.132	1.151	----	----
34	----	----	----	----	----	----	----	----

TABLE 6.f-3
RADIAL POWER DISTRIBUTION COMPARISON
80% POWER

Date 7/22/83

BOX NO.	OCTANT 1		OCTANT 2		OCTANT 3		OCTANT 4	
	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN
1	.6975	.644	.6648	.644	.6636	.644	.6745	.644
2	.9273	.857	.8967	.857	.8962	.857	.9098	.857
3	.6287	.6	.6426	.6	.6386	.6	.6087	.6
4	.8656	.825	.865	.825	.8618	.825	.8402	.825
5	.9935	.951	.9692	.951	.9656	.951	.9679	.951
6	1.1601	1.103	1.1324	1.103	1.131	1.103	1.1354	1.103
7	1.0578	1.017	-----	----	1.0165	1.017	-----	----
8	.7423	.66	.689	.66	.6896	.66	.6975	.66
9	1.0092	.952	.9954	.952	.9913	.952	.9746	.952
10	.9988	.977	1.0066	.977	1.0046	.977	.9676	.977
11	1.0013	.993	.9951	.993	.9946	.993	.9788	.993
12	1.074	1.079	1.0914	1.079	1.0911	1.079	1.0556	1.079
13	1.0263	1.032	-----	-----	1.032	1.032	-----	----
14	-----	----	.8518	.813	-----	----	.834	.813
15	1.0202	.981	.9973	.981	.9986	.981	1.0014	.981
16	1.001	.997	.9948	.997	.9947	.997	.9857	.997
17	1.1182	1.103	1.0914	1.103	1.0952	1.103	1.0994	1.103
18	1.0514	1.062	1.0541	1.062	1.0545	1.062	1.0317	1.062
19	1.1336	1.13	-----	----	1.1478	1.13	-----	----
20	-----	----	.9964	.994	-----	----	.9924	.994
21	1.1013	1.108	1.1171	1.108	1.1135	1.108	1.1052	1.108
22	1.06	1.075	1.0597	1.075	1.0562	1.075	1.0485	1.075
23	1.1488	1.154	1.1554	1.154	1.1533	1.154	1.1248	1.154
24	1.0788	1.094	-----	----	1.0831	1.094	-----	-----
25	-----	----	1.0624	1.078	-----	----	1.057	1.078
26	1.1581	1.164	1.161	1.164	1.1479	1.164	1.1475	1.164
27	1.0848	1.111	1.0905	1.111	1.0859	1.111	1.0715	1.111
28	1.1704	1.182	-----	-----	1.1704	1.182	-----	----
29	-----	----	1.09	1.116	-----	-----	1.0812	1.116
30	1.1666	1.194	1.1812	1.194	1.1767	1.194	1.157	1.194
31	1.0949	1.13	-----	----	1.102	1.13	-----	----
32	-----	----	1.1005	1.136	-----	----	1.0973	1.136
33	1.1824	1.207	-----	----	1.1839	1.207	-----	----
34	1.1006	1.142	-----	----	-----	----	-----	----

TABLE 6.f-3
RADIAL POWER DISTRIBUTION COMPARISON
80% POWER
-continued-

Date 7/22/83

BOX NO.	OCTANT 5		OCTANT 6		OCTANT 7		OCTANT 8	
	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN
1	.6862	.644	.649	.644	.6532	.644	.6801	.644
2	.9132	.857	.8783	.857	.8801	.857	.9212	.857
3	.6078	.6	.615	.6	.639	.6	.6135	.6
4	.84	.825	.8385	.825	.8565	.825	.8461	.825
5	.9695	.951	.9418	.951	.9535	.951	.9751	.951
6	1.1358	1.103	1.1068	1.103	1.1124	1.103	1.1456	1.103
7	1.0418	1.017	------	----	.9973	1.017	-----	----
8	.7033	.66	.6755	.66	.6915	.66	.7125	.66
9	.9722	.952	.9653	.952	.9615	.952	.9831	.952
10	.9664	.977	.9817	.977	.9999	.977	.9736	.977
11	.9727	.993	.9752	.993	.9855	.993	.9839	.993
12	1.0409	1.079	1.0677	1.079	1.0727	1.079	1.0573	1.079
13	1.0088	1.032	-----	------	1.0075	1.032	-----	----
14	------	----	.8224	.813	-----	----	.8392	.813
15	.9888	.981	.9781	.981	1.0002	.981	1.0034	.981
16	.9729	.997	.9759	.997	.9916	.997	.9849	.997
17	1.0881	1.103	1.0841	1.103	1.0925	1.103	1.1058	1.103
18	1.023	1.062	1.0323	1.062	1.036	1.062	1.0462	1.062
19	1.1109	1.13	-----	----	1.1059	1.13	-----	----
20	-----	----	.9781	.994	-----	----	.9874	.994
21	1.0763	1.108	1.0945	1.108	1.1062	1.108	1.0876	1.108
22	1.0346	1.075	1.0418	1.075	1.0466	1.075	1.0533	1.075
23	1.1136	1.154	1.1358	1.154	1.1379	1.154	1.1556	1.154
24	1.055	1.094	-----	----	1.064	1.094	-----	-----
25	-----	----	1.0408	1.078	-----	----	1.0477	1.078
26	1.1397	1.164	1.1344	1.164	1.1324	1.164	1.1484	1.164
27	1.0729	1.111	1.0763	1.111	1.0758	1.111	1.0832	1.111
28	1.1575	1.182	-----	-----	1.1657	1.182	-----	----
29	-----	----	1.0809	1.116	-----	-----	1.0773	1.116
30	1.182	1.194	1.1717	1.194	1.1691	1.194	1.1624	1.194
31	1.0943	1.13	-----	----	1.0927	1.13	-----	----
32	-----	----	1.0978	1.136	-----	----	1.0925	1.136
33	1.1828	1.207	-----	----	1.166	1.207	-----	----

TABLE 6.f-4

RADIAL POWER DISTRIBUTION COMPARISON

100% POWER

Date 8/2/83

BOX NO.	OCTANT 1		OCTANT 2		OCTANT 3		OCTANT 4	
	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN
1	.674	.625	.65	.625	.648	.625	.654	.625
2	.902	.828	.874	.828	.873	.828	.888	.828
3	.615	.584	.622	.584	.617	.584	.596	.584
4	.848	.805	.844	.805	.84	.805	.825	.805
5	.98	.936	.952	.936	.948	.936	.957	.936
6	1.147	1.085	1.119	1.085	1.118	1.085	1.125	1.085
7	1.046	1.002	----	----	1.001	1.002	----	----
8	.72	.645	.683	.645	.675	.645	.679	.645
9	.993	.936	.98	.936	.977	.936	.961	.936
10	.988	.968	.996	.968	.995	.968	.958	.968
11	.995	.987	.988	.987	.989	.987	.975	.987
12	1.074	1.076	1.089	1.076	1.089	1.076	1.058	1.076
13	1.024	1.029	----	----	1.029	1.029	----	----
14	----	----	.838	.803	----	----	.823	.803
15	1.013	.976	.991	.976	.994	.976	.996	.976
16	.999	.997	.993	.997	.994	.997	.985	.997
17	1.121	1.108	1.096	1.108	1.103	1.108	1.104	1.108
18	1.056	1.068	1.059	1.068	1.06	1.068	1.038	1.068
19	1.14	1.138	----	----	1.158	1.138	----	----
20	----	----	.996	.996	----	----	.993	.996
21	1.11	1.117	1.123	1.117	1.12	1.117	1.116	1.117
22	1.069	1.086	1.069	1.086	1.066	1.086	1.059	1.086
23	1.164	1.169	1.169	1.169	1.167	1.169	1.14	1.169
24	1.092	1.108	----	----	1.096	1.108	----	----
25	----	----	1.073	1.091	----	----	1.069	1.091
26	1.175	1.182	1.18	1.182	1.166	1.182	1.165	1.182
27	1.103	1.13	1.108	1.13	1.103	1.13	1.089	1.13
28	1.191	1.204	----	----	1.192	1.204	----	----
29	----	----	1.11	1.136	----	----	1.1	1.136
30	1.194	1.219	1.205	1.219	1.2	1.219	1.183	1.219
31	1.118	1.153	----	----	1.124	1.153	----	----
32	----	----	1.125	1.16	----	----	1.121	1.16
33	1.21	1.235	----	----	1.212	1.235	----	----
34	1.126	1.168	----	----	----	----	----	----

TABLE 6.f-4
RADIAL POWER DISTRIBUTION COMPARISON
100% POWER
-continued-

Date 8/2/83

BOX NO.	OCTANT 5		OCTANT 6		OCTANT 7		OCTANT 8	
	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN	MEASURED	DESIGN
1	.665	.625	.633	.625	.637	.625	.66	.625
2	.89	.828	.854	.828	.856	.828	.897	.828
3	.596	.584	.596	.584	.62	.584	.599	.584
4	.825	.805	.818	.805	.836	.805	.829	.805
5	.958	.936	.923	.936	.935	.936	.962	.936
6	1.125	1.085	1.092	1.085	1.097	1.085	1.133	1.085
7	1.032	1.002	----	----	.98	1.002	----	----
8	.683	.645	.661	.645	.677	.645	.691	.645
9	.959	.936	.951	.936	.976	.936	.967	.936
10	.958	.968	.972	.968	.989	.968	.962	.968
11	.968	.987	.968	.987	.978	.987	.977	.987
12	1.041	1.076	1.064	1.076	1.069	1.076	1.055	1.076
13	1.009	1.029	----	----	1.003	1.029	----	----
14	----	----	.81	.803	----	----	.826	.803
15	.983	.976	.966	.976	.993	.976	.995	.976
16	.972	.997	.975	.997	.989	.997	.982	.997
17	1.092	1.108	1.091	1.108	1.098	1.108	1.108	1.108
18	1.029	1.068	1.037	1.068	1.04	1.068	1.051	1.068
19	1.119	1.138	----	----	1.114	1.138	----	----
20	----	----	.972	.996	----	----	.986	.996
21	1.086	1.117	1.101	1.117	1.112	1.117	1.095	1.117
22	1.045	1.086	1.053	1.086	1.056	1.086	1.063	1.086
23	1.13	1.169	1.149	1.169	1.151	1.169	1.172	1.169
24	1.068	1.108	----	----	1.076	1.108	----	----
25	----	----	1.053	1.091	----	----	1.059	1.091
26	1.157	1.182	1.156	1.182	1.153	1.182	1.166	1.182
27	1.091	1.13	1.095	1.13	1.094	1.13	1.101	1.13
28	1.178	1.204	----	----	1.187	1.204	----	----
29	----	----	1.101	1.136	----	----	1.097	1.136
30	1.208	1.219	1.196	1.219	1.193	1.219	1.189	1.219
31	1.117	1.153	----	----	1.115	1.153	----	----
32	----	----	1.122	1.16	----	----	1.117	1.16
33	1.21	1.235	----	----	1.196	1.235	----	----

TABLE 6.f-5
AXIAL POWER DISTRIBUTION COMPARISON

PERCENT CORE *HEIGHT	50% POWER (7/17/83)		80% POWER (7/22/83)		100% POWER (8/9/83)	
	MEASURED	PREDICTED	MEASURED	PREDICTED	MEASURED	PREDICTED
0	.370	.379	.373	.383	.371	.385
2	.463	.482	.457	.486	.46	.490
4	.534	.573	.538	.578	.545	.583
6	.611	.654	.616	.660	.627	.667
8	.685	.727	.690	.734	.705	.743
10	.755	.792	.760	.801	.779	.812
12	.820	.851	.825	.862	.847	.874
14	.881	.904	.886	.918	.911	.932
16	.937	.953	.941	.969	.970	.984
18	.989	.997	.992	1.015	1.024	1.031
20	1.035	1.037	1.038	1.057	1.072	1.074
22	1.077	1.072	1.079	1.095	1.115	1.112
24	1.114	1.105	1.115	1.129	1.153	1.147
26	1.146	1.133	1.147	1.159	1.186	1.177
28	1.175	1.158	1.174	1.186	1.214	1.203
30	1.198	1.180	1.197	1.208	1.238	1.225
32	1.218	1.199	1.216	1.228	1.257	1.244
34	1.235	1.215	1.231	1.244	1.272	1.259
36	1.248	1.228	1.243	1.256	1.284	1.271
38	1.258	1.238	1.252	1.266	1.292	1.280
40	1.265	1.246	1.259	1.273	1.297	1.286
42	1.269	1.251	1.263	1.278	1.299	1.289
44	1.272	1.255	1.264	1.280	1.298	1.290
46	1.272	1.256	1.264	1.280	1.296	1.289
48	1.271	1.256	1.263	1.278	1.291	1.285
50	1.267	1.254	1.259	1.273	1.284	1.279
52	1.263	1.251	1.255	1.267	1.275	1.271
54	1.256	1.246	1.249	1.259	1.265	1.262
56	1.248	1.239	1.241	1.249	1.252	1.250
58	1.239	1.231	1.232	1.237	1.238	1.236
60	1.227	1.221	1.222	1.223	1.222	1.220
62	1.214	1.208	1.209	1.206	1.205	1.202
64	1.199	1.194	1.195	1.188	1.185	1.182
66	1.182	1.177	1.179	1.167	1.162	1.159
68	1.162	1.157	1.160	1.143	1.138	1.133
70	1.139	1.134	1.139	1.116	1.111	1.104
72	1.114	1.108	1.114	1.086	1.081	1.073
74	1.085	1.079	1.086	1.053	1.048	1.038
76	1.052	1.047	1.055	1.017	1.012	1.001
78	1.016	1.011	1.019	.978	.972	.961
80	.976	.972	.980	.936	.929	.917
82	.931	.929	.936	.891	.883	.871
84	.883	.883	.888	.843	.833	.822
86	.830	.833	.836	.792	.779	.770
88	.773	.779	.779	.737	.722	.715
90	.711	.721	.718	.679	.661	.657
92	.646	.657	.652	.617	.597	.594
94	.577	.586	.583	.548	.530	.527
96	.504	.505	.509	.471	.459	.452
98	.428	.411	.433	.383	.387	.367
100	.349	.296	.353	.279	.312	.268

TABLE 6.F-6
PEAKING FACTOR AND TILT COMPLIANCE WITH TECHNICAL SPECIFICATIONS FOR 20%, 50%, 80% AND 100% POWER LEVELS

F_{xy}^{-T}: Total Planar Radial Peaking Factor

F_r^{-T}: Total Integrated Radial Peaking Factor

T_q: Azimuthal Power Tilt

PARAMETER	20% POWER MEASURED	50% POWER MEASURED	80% POWER MEASURED	100% POWER MEASURED	TECHNICIAL SPECIFICATION LIMIT
Date	6-15-83	7-17-83	7-22-83	8-2-83	N/A
F_{xy}^{-T}	1.581	1.444	1.409	1.418	1.60
F_r^{-T}	1.485	1.416	1.388	1.390	1.60
T_q	0.021	0.015	0.016	0.016	0.03

6.g AT POWER MODERATOR TEMPERATURE COEFFICIENT AND POWER COEFFICIENT TEST

6.g.1 PURPOSE

The purpose of this test was to measure the Power Coefficient and the Isothermal Temperature Coefficient (ITC) and derive the Moderator Temperature Coefficient at 50%, 80%, and 100% reactor power. The measured coefficients shall be in satisfactory agreement with the predictions and are conservative with respect to the Technical Specifications.

6.g.2 TEST RESULTS

Variable T_{avg} tests were conducted at the 50%, 80% and 100% power plateaus with the lead bank of CEAs, Group 6, at approximately 110 inches withdrawn and equilibrium xenon and boron conditions established as per the guidelines of the Power Ascension Document. The 50% test was conducted with the ITC and Power Coefficient as separate tests. During the ITC test, Delta T power was held constant and Reactor Coolant System (RCS) T_{avg} was varied. T_{avg} was decreased approximately 5°F below the original temperature and CEA Group 6 was moved. to maintain constant power. Conditions were stabilized, data recorded and T_{avg} was increased to the original temperature. Conditions were again stabilized and data recorded. This cycle was repeated.

The Power Coefficient Test was conducted by maintaining T_{avg} constant and varying Delta T power. Delta T power was decreased approximately 5% and CEA Group 6 was moved to maintain constant temperature (T_{avg}). Conditions were stabilized, data recorded and power was increased to the original value. Conditions were again stabilized and data recorded. This cycle was repeated.

The final ITC and Power Coefficient values were the average value of the runs conducted. This test was performed similarly for the 80% and 100% plateaus. The Moderator Temperature Coefficient (MTC) is calculated by subtracting the Fuel Temperature Coefficient from the ITC. The Fuel Temperature Coefficient is pre-calculated by CE. The measured values and limits for the ITC, MTC and Power Coefficient for the 50%, 80% and 100% power plateaus are given in Table 6.g.1.

6.g.3 Conclusions

The measured Isothermal Temperature Coefficients are in satisfactory agreement with CE predictions. The Moderator Temperature Coefficients determined at the 50%, 80% and 100% power plateau are conservative with respect to the Technical Specifications and are in satisfactory agreement with CE predictions. The measured Power Coefficients are in satisfactory agreement with CE predictions.

TABLE 6.g-1
MEASURED ISOTHERMAL TEMPERATURE COEFFICIENT (ITC), POWER COEFFICENTS (PC) AND DERIVED MODERATOR TEMPERATURE COEFFICIENT (MTC) AT 50%, 80%, AND 100% POWER LEVELS

Parameter	DATE	POWER LEVEL	Measured Value	Acceptance Criteria*
	7-15-83	50%		
ITC			-0.720×10^{-4} $\Delta K/K/{}^{o}F$	$(-0.700 \pm 0.3) \times 10^{-4}$ $\Delta K/K/{}^{o}F$
PC			-0.862×10^{-4} $\Delta K/K/\%$ pwr	$(-0.888 \pm 0.2) \times 10^{-4}$ $\Delta K/K/\%$ pwr
MTC			-0.576×10^{-4} $\Delta K/K/{}^{o}F$	$(-.556 \pm 0.3) \times 10^{-4}$ $\Delta K/K/{}^{o}F$
				MTC $< +0.5 \times 10^{-4}$ $\Delta K/K/{}^{o}F$
	7-21-83	80%		
ITC			-0.752×10^{-4} $\Delta K/K/{}^{o}F$	$(-0.848 \pm 0.3) \times 10^{-4}$ $\Delta K/K/{}^{o}F$
PC			-0.760×10^{-4} $\Delta K/K/\%$ pwr	$(-.793 \pm 0.2) \times 10^{-4}$ $\Delta K/K/\%$ pwr
MTC			-0.6155×10^{-4} $\Delta K/K/{}^{o}F$	$(-.712 \pm 0.3) \times 10^{-4}$ $\Delta K/K/{}^{o}F$
				MTC $< +0.0 \times 10^{-4}$ $\Delta K/K/{}^{o}F$
	8-3-83	100%		
ITC			-0.860×10^{-4} $\Delta K/K/{}^{o}F$	$(-0.937 \pm 0.3) \times 10^{-4}$ $\Delta K/K/{}^{o}F$
PC			-0.764×10^{-4} $\Delta K/K/\%$ pwr	$(-0.736 \pm 0.2) \times 10^{-4}$ $\Delta K/K/\%$ pwr
MTC			-0.728×10^{-4} $\Delta K/K/{}^{o}F$	$(-.805 \pm 0.3) \times 10^{-4}$ $\Delta K/K/{}^{o}F$
				MTC $> -2.7 \times 10^{-4}$ $\Delta K/K/{}^{o}F$

*Represents CE predictions with acceptance criteria applied (FSAR Table 14.2-3)

6.h NUCLEAR POWER AND DELTA T POWER CORRELATION

6.h.1 Purpose

The purpose of this test was to:

(1) Determine the core thermal power by a primary plant heat balance (20% power plateau) and by the Digital Data Processing System (DDPS) for the 50%, 80% and 100% power plateaus.

(2) Adjust the Power Range Safety Channels and Delta T Power reference calculators to agree with the primary plant heat balance at the 20% power plateau.

(3) Adjust the Power Range Safety Channels and Delta T Power reference calculators to agree with the primary thermal energy balance calculations as calculated by the DDPS at the 50%, 80% and 100% power plateaus.

6.h.2 Test Results

At the 20% power plateau, Nuclear Power and Delta T Power were adjusted to agree with the primary manual calorimetric within 0.5 percent. These values are given in Table 6.h-1.

At the 50%, 80% and 100% power plateaus, Nuclear Power and Delta T Power were adjusted to agree with the DDPS thermal calorimetric within 0.5 percent. These values are given in Table 6.h-2.

6.h.3 Conclusions

The Nuclear Power and Delta T Power calibrations were performed at the 20%, 50%, 80% and 100% power plateaus and all results were within acceptable limits.

TABLE 6.h-1
NUCLEAR AND DELTA T POWER CALIBRATION

20% Power

Date 6/15/83

Primary Calorimetric Power = 19.195%

Channel	A	B	C	D
a) Nuclear Power (%)	19.19	19.19	19.19	19.19
b) Delta T Power (%)	19.17	19.16	19.42	19.25
c) (Primary Calorimetric Power) minus (Nuclear Power) (%)	.005	.005	.005	.005
d) (Primary Calorimetric Power) minus (Delta T Power) (%)	0.025	0.035	-.225	-.055

TABLE 6.h-2

NUCLEAR AND DELTA T POWER CALIBRATION

50% Power

Date 7/15/83

DDPS Calorimetric Power (PID 31) = 50.43%

Channel	A	B	C	D
a) Nuclear Power (%)	51.20	51.53	51.55	50.36
b) Delta T Power (%)	51.21	51.28	51.76	51.52
c) (Primary Calorimetric Power) minus (Nuclear Power) (%)	-0.10	-0.10	-0.12	+0.07
d) (DDPS Calorimetric Power) minus (Delta T Power) (%)	+0.23	+0.15	-0.33	-0.09

80% Power

Date 7/20/83

DDPS Calorimetric Power (PID 31)= 80.58%

Channel	A	B	C	D
a) Nuclear Power (%)	80.73	80.65	80.52	80.50
b) Delta T Power (%)	80.63	80.72	80.71	80.42
c) (Primary Calorimetric Power) minus (Nuclear Power) (%)	-.15	-.07	+.06	+.08
d) (Primary Calorimetric Power) minus (Delta T Power) (%)	-.05	-.14	-.13	+.16

TABLE 6.h-2
-continued-

100% Power

Date 8/3/83

DDPS Calorimetric Power (PID 31) = 99.58%

Channel	A	B	C	D
a) Nuclear Power (%)	99.57	99.57	99.61	99.68
b) Delta T Power (%)	99.32	99.56	99.73	99.99
c) (DDPS Calorimetric Power) minus (Nuclear Power) (%)	+.01	+.01	-.03	-.10
d) (DDPS Calorimetric Power) minus (Delta T Power) (%)	+.26	+.02	-.15	-.41

6.i NATURAL CIRCULA[illegible]N

6.i.1 Purpose

The purpose of this test was to:

a) Provide operator training for the natural circulation mode of cooling the Reactor Coolant System (RCS) and to

b) Monitor key RCS and secondary parameters to better define and identify plant transition into the natural circulation totally utilized both steam generators. Depressurization and cooldown rates and subcooled margin were easily maintained at all times without any uncontrolled ocillation of primary or secondary temperatures, pressures or levels.

All available licensed operators particapated in at least one of the natural circulation tests performed on two different shifts.

6.i.3 Conclusions

Performing natural circulation training by this method provides meaningful operation training. However, it is not intended to verify that the basic RCS design configuration is adequate to support natural circulation, which was verified earilier on an identical RCS (St. Lucie Unit 1)

All the acceptance criteria for this test were met. However, performing natural circulation training on a unit in the Startup phase in unnecessory. Simulators available today offer equivalent or even better training in the natural circulation mode.

6.j. DIGITAL DATA PROCESSOR INSTRUMENT CORRELATION

6.j.1 Purpose

The objective of this test was to demonstrate the operation of the Digital Data Processor.

6.j.2 Test Results

At the test plateaus of 0, 20, 50, 80 and 100% power, the Digital Data Processor inputs were compared with related process instrumentation. The safety related channel correltion were within the loop accuracies specified by the NSSS Vendor. The objective was satisfactorily completed.

6.j.3 Conclusion

The Digital Data Processor is capable of accumately monitoring certain process parameters as demonstrated by meeting the acceptance criteria.

6.k VENTILATION AND [illegible]R CONDITIONING SYSTEM CAPABILI[illegible]ES

6.k.1 Purpose

To demonstrate that the heating, ventilating, and air conditioning (HVAC) systems for the containment, and areas housing Engineered Safety Features (ESF) maintain design temperatures, at 50% power, 100% power and during Shutdown Cooling in the ECCS pump and heat exchanger areas.

6.k.2 Test Results

All of the above were satisfactorily completed. The temperature reading at the 50% power level were all within the acceptable limit as on Data Sheets NBo. 1, No. 2 and No. 3. Also, the reading at the 100% power level were within the acceptable limit as on Data Sheets No. 4, No. 5 and No. 6. All of the temperaturee reading taken while on Shutdown Cooling were within the 104°F acceptance limit as seen on Table 6.k.7.

6.k.3 Conclusions

The temperature conditions within the Containment, the ESF areas, and the Fuel Handling Building were all maintained within the acceptable limits as indicated on Tables 6.k.1 through 7. The above limits were not exceeded during the 50% or 100% power levels or during the periods Shutdown Cooling was in service.

TABLE 6.k.1, NO. 1
REMOTE TEMPERATURE READINGS AT APPROXIMATELY 50%

Page 2 of 2

LOCATION	TEMP. READING IN DEGREES °F	ACCEPTABLE TEMP. LIMIT
TE-07-3A Containment Temp.	105°F	≤ 120°F
TE-07-5A Cont. Sump. Temp.	90°F	≤ 120°F
TE-07-3A Containment Temp.	110°F	≤ 120°F
TE-07-5BA Containment Sump. Temp.	87°F	≤ 120°F
TE-25-14 CEDM Cooling 130°F Coil Inlet	≤ 150°F	

TABLE 6.k.2
RAB LOCAL TEMPERATURE READING AT APPROXIMATELY 50% POWER

LOCATION		TEMP. READING IN DEGREES °F	ACCEPTABLE TEMP. LIMIT
Between 2HVE 6A and			≤ 104°F
2HVE-6B SBVS Filter Trains		90°F	≤ 104°F
Iodine Removal System Hydrazine Tank and Pumps		88°F	≤ 104°F
2A Shutdown Heat Exchanger		88°F	≤ 104°F
2B Shutdown Heat Exchanger		89°F	≤ 104°F
Refer to Figure #1 for Sample Location Points	#1	90°F	≤ 104°F
	#2	91°F	≤ 104°F
	#3	89°F	≤ 104°F
	#4	88°F	≤ 104°F
Refer to Figure #2 for Sample Location Points	#5	87°F	≤ 104°F
	#6	88°F	≤ 104°F
	#7	88°F	≤ 104°F
	#8	88°F	≤ 104°F
	#9	88°F	≤ 104°F
	#10	89°F	≤ 104°F
Refer to Figure #3 For Samp. Loc. Points	#11	89°F	≤ 104°F
	#12	92°F	≤ 104°F

TABLE 6.k.2
RAB LOCAL TEMPERATURE READING AT APPROXIMATELY 50% POWER

LOCATION		TEMP. READING IN DEGREES °F	ACCEPTABLE TEMP. LIMIT
Between 2HVE 6A and 2HVE-6B SBVS Filter Trains		90°F 91°F	≤ 104°F ≤ 104°F
Iodine Removal System Hydrazine Tank and Pumps		90°F	≤ 104°F
2A Shutdown Heat Exchanger		90°F	≤ 104°F
2B Shutdown Heat Exchanger		90°F	≤ 104°F
Refer to Figure	#1	90°F	< 104°F
#1 for Sample	#2	90°F	< 104°F
Location Points	#3	72°F	≤ 104°F
	#4	88°F	≤ 104°F
Refer to Figure	#5	86°F	< 104°F
#2 for Sample	#	88°F	< 104°F
Location Points	#7	88°F	< 104°F
	#8	85°	< 104°F
	#9	86°F	< 104°F
	#10	84°F	< 104°F
Refer to Figure #3	#11	92°F	< 104°F
For Samp. Loc. Points	#12	94°F	< 104°F
Unit #2 Control Room		72°F	75°F ± 5°F

TABLE 6.k-3

FUEL HANDLING BUILDING LOCAL TEMPERATURE READINGS AT APPROXIMATELY 50% POWER

LOCATION	TEMP. READING IN DEGREES °F	ACCEPTABLE TEMP. LIMIT
Spent Fuel Pool	92°F	≤ 104°F
Fuel Handling	92°F	≤ 104°F
Building Motor	92°F	≤ 104°F
Operated Vent.	88°F	≤ 104°F
Dampers	88°F	≤ 104°F
H & V Equipment Room	89°F	≤ 104°F

TABLE 6.k-4
REMOTE TEMPERATURE READINGS AT APPROXIMATELY 100% POWER

Page 1 of 2

INSTRUMENT NOMENCLATURE	LOCATION	TEMP. READING IN DEGREES °F	ACCEPTABLE TEMP. LIMIT
	TE-25-1 Cont. Cooling Fan 2HVS 1A Cooling Coil Inlet	95°F	≤ 120°F
	TE-25-3 Cont. Cooling Fan 2HVS 1B Cooling Coil Inlet	100°F	≤ 120°F
	TE-25-17 Reactor Cavity Cooling Sysem	105°F	≤ 140°F
	TE-25-11A Reactor Support Cooling System	106°F	≤ 150°F
	TE-25-12A Reactor Support Cooling System	108°F	≤ 150°F
	TE-25-13A Reactor Support Cooling System	108°F	≤ 150°F
	TE-25-13A ESSC Pump Room A	94°F	≤ 104°F
TEMPERATURE RECORDER TR-25-1B	TE-25-5 Cont. Cooling Fan 2HVS 1C Cooling Coil Inlet	106°F	≤ 120°F
	TE-25-7 Cont. Cooling Fan 2HVS 1D Cooling Coil Inlet	104°F	≤ 120°F
	TE-25-16 Reactor Cavity Cooling System	104°F	≤ 140°F
	TE-25-11B Reactor Support Cooling System	106°F	≤ 150°F
	TE-25-12B Reactor Support Cooling	106°F	≤ 150°F
	TE-25-13B Reactor Cavity Cooling System	107°F	≤ 150°F
	TE-25-23 ECCS Pump Room B	94°F	≤ 104°F

TABLE 6.k-5
REMOTE TEMPERATURE READINGS AT APPROXIMATELY 100%

Page 2 of 2

LOCATION	TEMP. READING IN DEGREES °F	ACCEPTABLE TEMP. LIMIT
TE-07-3A Containment Temp.	110°F	≤ 120°F
TE-07-5A Cont. Sump. Temp.	90°F	≤ 120°F
TE-07-3A Containment Temp.	110°F	≤ 120°F
TE-07-5BA Containment Sump. Temp.	67°F	≤ 120°F
TE-25-14 CEDM Cooling Coil Inlet	132°F	≤ 150°F

TABLE 6.k-6

FUEL HANDLING BUILDING LOCAL TEMPERATURE READINGS AT APPROXIMATELY 100% POWER

ATMOSPHERIC SAMPLE LOCATION	TEMP. READING IN DEGREES °F	ACCEPTABLE TEMP. LIMIT
Spent Fuel Pool	84°F	≤ 104°F
Fuel Handling D29, D30	85°F	≤ 104°F
Building Motor D31, D32	85°F	≤ 104°F
Operated Vent. D33, D34	85°F	≤ 104°F
Dampers D35, D36	85°F	≤ 104°F
H & V Equipment Room	85°F	≤ 104°F

TABLE 6.k-7
TEMPERATURE READINGS DURING SHUTDOWN COOLING

LOCATION	TEMP. READING IN DEGREES °F	ACCEPTABLE TEMP. LIMIT (*)
ECCS Pump Room A	89°F	$\leq$ 104°F
ECCS Pump Room B	78°F	$\leq$ 104°F
2A Shutdown Heat Exchanger Room	78°F	$\leq$ 104°F
2B Shutdown Heat Exchanger Room	78°F	$\leq$ 104°F

6.1 FORCED XENON OSCILLATION TEST

6.1.1 Purpose

The purpose of this test was to obtain transient test data by inducing an axial xenon oscillation in the core at the 50% power plateau in order to determine the Shape Annealing Factors (SAF) for each Power Range Safety Channel and Power Range Control Channel.

6.1.2 Test Results

During the 50% test plateau, an axial oscillation was induced in the core. This oscillation was monitored by the Combustion Engineering supplied incore analysis code CECOR and by the excore detectors; Power Range Safety Channels A, B, C, and D and Power Range Control Channels 9 and 10. The SAF corrects the excore detector signal to account for the distance from the excore detector to the reactor core and corrects for the signal received by the upper detector from neutrons generated in the bottom of the core and the signal received by the lower detector from neutrons generated in the upper part of the core. Basically, the SAF is determined by plotting CECOR ASI versus the excore ASI as determined from the Power Range Safety and Control Channels during a xenon oscillation with all CEA's full out. The slope of the function depicted by this plot is the Shape Annealing Factor. Axial Shape Index (ASI) is defined as a ratio of the difference in power generated in the lower and upper halves of the core to total core power. Table 6.1-1 summarizes the SAF measurements. Figure 6.1-1 illustrates CECOR ASI (incore) versus time for the test.

6.1.3 Conslusions

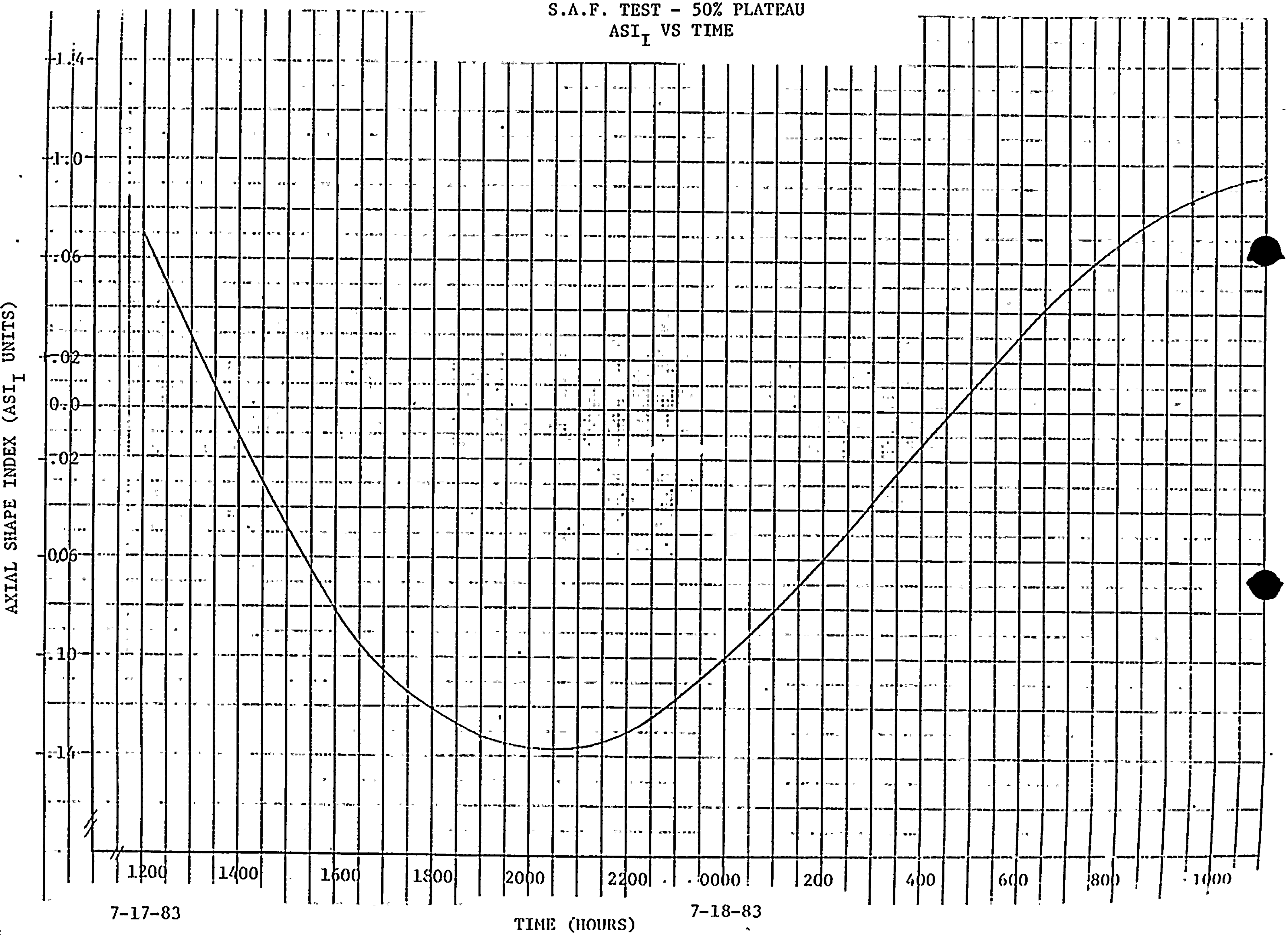
The Shape Annealing Factor (SAF) values were measured, input and all in use by the Power Range Safety Channels and Power Range Control Channels as input for calculation of the axial shape indices.

TABLE 6.1-1
SHAPE ANNEALING FACTOR SUMMARY

Date 7/18/83

CHANNEL	SHAPE ANNEALING FACTOR (SAF) (MEASURED)	Y-INTERCEPT (MEASURED)
A	3.72434	-0.00310
B	4.16947	+0.00217
C	4.11225	-0.01083
D	3.52241	-0.01145
9	3.51525	-0.01565
10	4.19326	-0.01711

FI[illegible] 6.1-1
ST. LUCIE UNIT 2 CYCLE 1
S.A.F. TEST - 50% PLATEAU
ASI$_I$ VS TIME



AB-623

FLORIDA POWER & LIGHT COMPANY

ST. LUCIE UNIT 2

ANNUAL ENVIRONMENTAL OPERATING REPORT

1992

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FLORIDA POWER & LIGHT COMPANY
JUNO BEACH, FLORIDA

APPLIED BIOLOGY, INC.
DECATUR, GEORGIA

ENVIRONMENTAL OPERATING REPORT

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TABLE OF CONVERSION FACTORS FOR METRIC UNITS

To convert	Multiply by	To obtain
centigrade (degrees)	(^oC x 1.8) + 32	fahrenheit (degrees)
centigrade (degrees)	^oC + 273.18	kelvin (degrees)
centimeters (cm)	3.937×10^{-1}	inches
centimeters (cm)	3.281×10^{-2}	feet
centimeters/second (cm/sec)	3.281×10^{-2}	feet per second
cubic centimeters (cm^3)	1.0×10^{-3}	liters
grams (g)	2.205×10^{-3}	pounds
grams (g)	3.527×10^{-2}	ounces (avoirdupois)
hectares (ha)	2.471	acres
kilograms (kg)	1.0×10^{3}	grams
kilograms (kg)	2.2046	pounds
kilograms (kg)	3.5274×10^{1}	ounces (avoirdupois)
kilometers (km)	6.214×10^{-1}	miles (statute)
kilometers (km)	1.0×10^{6}	millimeters
liters (l)	1.0×10^{3}	cubic centimeters (cm^3)
liters (l)	2.642×10^{-1}	gallons (US liquid)
meters (m)	3.281	feet
meters (m)	3.937×10^{1}	inches
meters (m)	1.094	yards
milligrams (mg)	1.0×10^{-3}	grams
milligrams/liters (mg/l)	1.0	parts per million
milliliters (ml)	1.0×10^{-3}	liters (US liquid)
millimeters (mm)	3.937×10^{-2}	inches
millimeters (mm)	3.281×10^{-3}	feet
square centimeters (cm^2)	1.550×10^{-1}	square inches
square meters (m^2)	1.076×10^{1}	square feet
square millimeters (mm^2)	1.55×10^{3}	square inches

EXECUTIVE SUMMARY

INTRODUCTION

The St. Lucie Plant is an electric generating station on Hutchinson Island in St. Lucie County, Florida. The plant consists of two nuclear-fueled 850-MW units; Unit 1 was placed on-line in March 1976 and Unit 2 in May 1983. This document has been prepared to satisfy the requirements contained in the United States Nuclear Regulatory Commission's Appendix B Environmental Protection Plan (EPP) to St. Lucie Unit 2 Facility Operating License No. NPF-16. This report discusses environmental protection activities related to sea turtles as required by Subsection 4.2 of the EPP. Other routine annual reporting requirements are addressed in Volume 2, also entitled "St. Lucie Unit 2 Annual Environmental Operating Report".

TURTLE NESTING SURVEY

Since monitoring began in 1971, there have been considerable year-to-year fluctuations in sea turtle nesting activity on Hutchinson Island. However, data collected through 1992 have shown no long-term reductions in nesting on the island. Relatively high nesting during recent years may actually reflect an increase in the number of nesting females in the study area. On a smaller scale, power plant operation has had no significant effect on nesting near the plant. Low nesting activity in 1975 and again in 1981 - 1983 in the vicinity of the plant was attributed to nighttime construction activities associated with installation of plant intake and discharge structures. Nesting returned to normal or above normal levels following both periods of construction. During 1991,

daytime construction activities associated with velocity cap repairs had no apparent effect on nesting. Formal requirements to conduct nesting surveys expired in 1986 but this program was voluntarily continued through 1992 with agreement from federal and state agencies.

INTAKE CANAL MONITORING

Since plant operation began in 1976, 2,501 sea turtles (including 124 recaptures) representing five different species have been removed from the intake canal. Eighty-two percent of these were loggerheads. Differences in the numbers of turtles found during different months and years have been attributed primarily to natural variation in the occurrences of turtles in the vicinity of the plant, rather than to operational influences of the plant itself. The majority of turtles removed from the intake canal (about 93 percent) were captured alive and released back into the ocean. Ongoing evaluations and improvements to the canal capture program have substantially reduced mortalities of entrapped sea turtles during recent years. Turtles confined between the A1A 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.

OTHER RELATED ACTIVITIES

Studies to evaluate various intake deterrent systems, as required by the NRC's Unit 2 Environmental Protection Plan, were conducted during 1982 and 1983. Results and evaluations of those studies were presented to regulatory agencies during 1984, and the requirement is now considered completed.

INTRODUCTION

BACKGROUND

This document has been prepared to satisfy the requirements contained in the United States Nuclear Regulatory Commission's (NRC) Appendix B Environmental Protection Plan to St. Lucie Unit 2 Facility Operating License No. NPF-16.

In 1970, Florida Power & Light Company (FPL) was issued Permit No. CPPR-74 by the United States Atomic Energy Commission, now the Nuclear Regulatory Commission, that allowed construction of Unit 1 of the St. Lucie Plant, an 850-MW nuclear-powered electric generating station on Hutchinson Island in St. Lucie County, Florida. St Lucie Plant Unit 1 was placed on-line in March 1976. In May 1977, FPL was issued Permit No. CPPR-144 by the NRC for the construction of a second 850-MW nuclear-powered unit. Unit 2 was placed on-line in May 1983 and began commercial operation in August of that year.

St. Lucie Plant Units 1 and 2 use the Atlantic Ocean as a source of water for once-through condenser cooling. Since 1971, the potential environmental effects resulting from the intake and discharge of this water have been the subject of FPL-sponsored biotic studies at the site.

Baseline environmental studies of the marine environment adjacent to the St. Lucie Plant were described in a series of reports published by the Florida Department of Natural Resources (Camp et al., 1977; Futch and Dwinell, 1977; Gallagher, 1977; Gallagher and Hollinger, 1977; Worth and Hollinger, 1977; Moffler and Van Breedveld,

1979; Tester and Steidinger, 1979; Walker, 1979; Walker et al., 1979; Walker and Steidinger, 1979; Lyons, 1989). The results of Unit 1 operational and Unit 2 preoperational biotic monitoring at the St. Lucie Plant were presented in six annual reports (ABI, 1977, 1978, 1979, 1980a, 1981b, 1982). In January 1982, a National Pollutant Discharge Elimination System (NPDES) permit was issued to FPL by the US Environmental Protection Agency (EPA). The EPA guidelines for the St. Lucie site biological studies were based on the document entitled "Proposed St. Lucie Plant Preoperational and Operational Biological Monitoring Program - August 1981" (ABI, 1981c). Findings from these studies were reported in three annual reports (ABI, 1983, 1984a, 1985a). The EPA biotic monitoring requirements were deleted from the NPDES permit in 1985.

Jurisdiction for sea turtle studies is with the NRC, which is considered to be the lead federal agency relative to consultation under the Endangered Species Act. Previous results dealing exclusively with sea turtle studies are contained in nine annual environmental operating reports covering the period from 1983 through 1991 (ABI 1984b, 1985b, 1986, 1987, 1988, 1989, 1990, 1991, 1992). This report describes the 1992 environmental protection activities related to sea turtles, as required by Subsection 4.2 of the St. Lucie Plant Unit 2 Environmental Protection Plan.

AREA DESCRIPTION

The St. Lucie Plant is located on a 457-ha site on Hutchinson Island on Florida's east coast (Figures 1 and 2). The plant is approximately midway between the Ft. Pierce and St. Lucie Inlets. It is bounded on its east side by the Atlantic Ocean and on its west side by the Indian River Lagoon.

Hutchinson Island is a barrier island that extends 36 km between inlets and obtains its maximum width of 2 km at the plant site. Elevations approach 5 m atop dunes bordering the beach and decrease to sea level in the mangrove swamps that are common on much of the western side. Island vegetation is typical of southeastern Florida coastal areas; dense stands of Australian pine, palmetto, sea grape and Spanish bayonet are present at the higher elevations, and mangroves abound at the lower elevations. Large stands of black mangroves, including some on the plant site, have been killed by flooding for mosquito control over past decades.

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 unstable substrate limits the establishment of rooted macrophytes.

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 offshore. Oceanic water associated with the western boundary of the current periodically meanders over the inner shelf, especially during summer months.

PLANT DESCRIPTION

The St. Lucie Plant consists of two 850-MW nuclear-fueled electric generating units that use nearshore ocean waters for the plant's once-through condenser cooling

water system. Water for the plant enters through three submerged intake structures located about 365 m offshore (Figure 2). Each of the intake structures is equipped with a velocity cap to minimize fish entrainment. Horizontal intake velocities are less than 30 cm/sec. From the intake structures, the water passes through submerged pipes (two 3.7 m and one 4.9 m in diameter) under the beach and dunes that lead to a 1,500-m long intake canal. This canal transports the water to the plant. After passing through the plant, the heated water is discharged into a 670-m long canal that leads to two buried discharge pipelines. These pass underneath the dunes and beach and along the ocean floor to the submerged discharges, the first of which is approximately 365 m offshore and 730 m north of the intake.

Heated water leaves the first discharge line from a Y-shaped nozzle (diffuser) at a design velocity of 396 cm/sec. This high-momentum jet entrains ambient water, resulting in rapid heat dissipation. The ocean depth in the area of the first discharge is about 6 m. Heated water leaves the second discharge line through a series of 48 equally spaced high velocity jets along a 323-m manifold (multiport diffuser). This diffuser starts 168 m beyond the first discharge and terminates 856 m from shore. The ocean depth at discharge along this diffuser is from about 10 to 12 m. As with the first diffuser, the purpose of the second diffuser is to entrain ambient water and rapidly dissipate heat. From the points of discharge at both diffusers, the warmer water rises to the surface and forms a surface plume of heated water. The plume then spreads out on the surface of the ocean under the influence of wind and currents and the heat dissipates to the atmosphere.

TURTLES

The NRC's St. Lucie Unit 2 Appendix B Environmental Protection Plan issued April 1983 contains the following technical specifications:

4.2 Terrestrial/Aquatic Issues

Issues on endangered or threatened sea turtles raised in the Unit 2 FES-OL [NRC, 1982] and in the Endangered Species Biological Assessment (March 1982) [Bellmund et al., 1982] will be addressed by programs as follows:

4.2.1 Beach Nesting Surveys

Beach nesting surveys for all species of sea turtles will be conducted on a yearly basis for the period of 1982 through 1986. These surveys will be conducted during the nesting season from approximately mid-April through August.

The Hutchinson Island beach will be divided into 36 one-km-long survey areas. In addition, the nine 1.25-km-long survey areas used in previous studies (1971-1979) will be maintained for comparison purposes. Survey areas will be marked with numbered wooden plaques and/or existing landmarks.

The entire beach will be surveyed seven days a week. All new nests and false crawls will be counted and recorded in each area. After counting, all crawl tracks will be obliterated to avoid recounting. Predation on nests by raccoons or other predators will be recorded as it occurs. Records will be kept of any seasonal changes in beach topography that may affect the suitability of the beach for nesting.

4.2.2 Studies to Evaluate and/or Mitigate Intake Entrapment

A program that employs light and/or sound to deter turtles from the intake structure will be conducted. The study will determine with laboratory and field experiments if sound and/or light will result in a reduction of total turtle entrapment rate.

The study shall be implemented no later than after the final removal from the ocean of equipment and structures associated with construction of the third intake structure and the experiments shall terminate 18 months later. Four months after the conclusion of the experimental period, a report on the results of the study will be submitted to NRC, EPA, National Marine Fisheries Service (NMFS), and the US Fish and Wildlife Service (USFWS) for their evaluation. If a statistically significant reduction in annual total turtle entrapment rate of 80 percent or greater can be demonstrated, using the developed technology and upon FPL receiving written concurrence by NRC, EPA, NMFS, and USFWS then permanent installation of the deterrent system shall be completed and functioning no later than 18 months after the agencies' concurrence. The design of this study needs to take into account the significant annual variation in turtle entrapment observed in the past.

If an 80 percent reduction of turtle entrapment cannot be projected to all three intake structures, then an interagency task force composed of NRC, EPA, NMFS, USFWS, and FPL shall convene 18 months after completion of the third intake and determine if other courses of action to mitigate and/or reduce turtle entrapment are warranted (such as physical barrier, emergence of new technology or methods to deter turtles).

4.2.3 Studies to Evaluate and/or Mitigate Intake Canal Mortality

Alternative methods or procedures for the capture of sea turtles entrapped in the intake canal will be evaluated. If a method or procedure is considered feasible and cost effective and may reduce capture mortality rates, it will be field tested in the intake canal.

4.2.5 Capture and Release Program

Sea turtle removal from the intake canal will be conducted on a continuing basis. The turtles will be captured with large mesh nets, or other suitable nondestructive device(s), if deemed appropriate. A formalized daily inspection, from the shoreline, of the capture device(s) will be made by a qualified individual when the device(s) are deployed. The turtles will be identified to species, measured, weighed (if appropriate), tagged and released back into the ocean. Records of wounds, fresh or old, and a subjective judgement on the condition of the turtle (e.g., barnacle coverage, underweight) will be maintained. Methods of obtaining additional biological/physiological data, such as blood analyses and parasite loads, from captured

sea turtles will be pursued. Dead sea turtles will be subjected to a gross necropsy, if found in fresh condition.

INTRODUCTION

Hutchinson Island, Florida, is an important rookery for the loggerhead turtle, Caretta caretta, and also supports some nesting of the green turtle, Chelonia mydas, and the leatherback turtle, Dermochelys coriacea (Caldwell et al., 1959; Routa, 1968; Gallagher et al., 1972; Worth and Smith, 1976; Williams-Walls et al., 1983). All three species are protected by state and federal statutes. The federal government classified the loggerhead turtle as a threatened species. The leatherback turtle and the Florida nesting population of the green turtle are listed by the federal government as endangered species. Because of reductions in world populations of marine turtles resulting from coastal development and fishing pressure (NMFS, 1978), maintaining the vitality of the Hutchinson Island rookery is important.

It has been a prime concern of FPL that the construction and subsequent operation of the St. Lucie Plant would not adversely affect the Hutchinson Island rookery. Because of this concern, FPL has sponsored monitoring of marine turtle nesting activity on the island since 1971.

Daytime surveys to quantify nesting, as well as nighttime turtle tagging programs, were conducted in odd numbered years from 1971 through 1979. During daytime nesting surveys, nine 1.25-km-long survey areas were monitored five days per week (Figure 3). The St. Lucie Plant began operation in 1976; therefore, the first three survey years (1971, 1973 and 1975) were preoperational. Though the power plant was not operating during 1975, St. Lucie Plant Unit No. 1 ocean intake and discharge structures were installed during that year. Installation of these structures included nighttime construction activities conducted offshore from and perpendicular to the beach. Construction had been completed and the plant was in full operation during the 1977 and 1979 surveys.

A modified daytime nesting survey was conducted in 1980 during the preliminary construction of the ocean discharge structure for St. Lucie Plant Unit 2. During this study, four of the previously established 1.25-km-long survey areas were monitored. Additionally, eggs from turtle nests potentially endangered by construction activities were relocated.

Every year from 1981 through 1992, 36 1-km-long survey areas comprising the entire island were monitored seven days a week during the nesting season (Figure 3). The St. Lucie Plant Unit 2 discharge structure was installed during the 1981 nesting season. Offshore and beach construction of the Unit 2 intake structure proceeded throughout the 1982 nesting season and was completed near the end of the 1983 season. Construction activities associated with installation of both structures were similar to those conducted when Unit 1 intake and discharge structures were installed. Eggs from turtle nests potentially endangered by construction activities were relocated during all three years.

During 1991, another major offshore construction project was undertaken to replace damaged velocity caps on the three intake structures. A large elevated platform, from which repair activities were conducted, was erected around the three structures. Construction occurred throughout the nesting season. However, in contrast to

previous offshore projects, work was restricted almost entirely to daylight hours, nighttime lighting of the work area was minimal, and no equipment or materials were used on the beach. A sea turtle protection plan implemented in support of the project included caging of nests along a 1,500 m section of beach west of the platform and release of hatchlings to unaffected areas to the north and south. This plan was intended to mitigate any negative effects potentially resulting from required safety and navigational lighting on and near the platform.

Requirement 4.2.1 of the NRC's St. Lucie Unit 2 Appendix B Environmental Protection Plan was completed with submission of the 1986 nesting survey data (ABI, 1987). The nesting survey was continued voluntarily through 1992 with agreement from federal and state agencies. Results are presented in this report and discussed in relation to previous findings.

In addition to monitoring sea turtle nesting activities and relocating nests away from plant construction areas, removal of turtles from the intake canal has been an integral part of the St. Lucie Plant environmental monitoring program. Turtles entering the ocean intake structures are entrained with cooling water and rapidly transported through the intake pipes into an enclosed canal system where they must be manually captured and returned to the ocean. Since the plant became operational in 1976, turtles entrapped in the intake canal have been systematically captured, measured, weighed, tagged and released.

Previous publications and technical reports have presented findings of the nesting surveys, nest relocation activities and canal capture program (Gallagher et al., 1972;

Worth and Smith, 1976; ABI, 1978, 1980a, 1981a, 1982, 1983, 1984b, 1985b, 1986, 1987, 1988, 1989, 1990, 1991; Williams-Walls et al., 1983; Proffitt et al., 1986; Ernest et al., 1988, 1989; Martin et al., 1989a, 1989b; Wibbels et al., 1991). Results of studies to assess the effects of thermal discharges on hatchling swimming speed have also been reported (ABI, 1978; O'Hara, 1980). The purpose of this report is to 1) present 1992 sea turtle nesting survey data and summarize observed spatial and temporal nesting patterns since 1971, 2) document and summarize predation on turtle nests since 1971, and 3) present 1992 canal capture data and summarize comparable data collected since 1976.

MATERIALS AND METHODS

Nesting Survey

Methodologies used during previous turtle nesting surveys on Hutchinson Island were described by Gallagher et al. (1972), Worth and Smith (1976) and ABI (1978, 1981a, 1982, 1987, 1988, 1989). Methods used during the 1992 survey were designed to allow comparisons with these previous studies.

On 13 April 1992, a preliminary nest survey was conducted along Hutchinson Island from the Ft. Pierce Inlet south to the St. Lucie Inlet. From 15 April through 4 September, nest surveys were conducted on a daily basis. To confirm that nesting had ceased, additional surveys were conducted on 8, 9, 10, 11 and 14 September. Biologists used small off-road motorcycles to survey the island each morning. New nests, non-nesting emergences (false crawls), and nests destroyed by predators were recorded for each of the 36 1-km-long survey areas comprising the entire island (Figure

3). The nine 1.25-km-long survey areas established by Gallagher et al. (1972) also were monitored so comparisons could be made with previous studies.

During the daily nest monitoring, any major changes in topography that may have affected the beach's suitability for nesting were recorded. In addition, each of the 36 1-km-long survey areas has been systematically analyzed and categorized based on beach slope (steep, moderate, etc.), width from high tide line to the dune, presence of benches (areas of abrupt vertical relief) and miscellaneous characteristics (packed sand, scattered rock, vegetation on the beach, exposed roots on the primary dune, etc.).

In a cooperative effort, data from stranded turtles found during beach surveys were routinely provided to the National Marine Fisheries Service (NMFS) through the Sea Turtle Stranding and Salvage Network.

Intake Canal Monitoring

Most turtles entrapped in the St. Lucie Plant intake canal were removed by means of large-mesh tangle nets fished between the intake headwalls and a barrier net located at the Highway A1A bridge (Figure 2). Nets used during 1992 were from 30 to 40 m in length, 3 to 4 m deep and composed of 40 cm stretch mesh nylon twine. Large floats were attached to the surface, and unweighted lines used along the bottom. Turtles entangled in the nets generally remained at the water's surface until removed.

Since its inception in 1976, ABI's canal capture program has been under continual review and refinement in an attempt to minimize both entrapment times and injuries/mortalities to entrapped sea turtles. Prior to April 1990, turtle nets were usually deployed on Monday mornings and retrieved on Friday afternoons. During periods of deployment, the nets were inspected for captures by ABI personnel at least twice each day (mornings and afternoons). Additionally, St. Lucie Plant personnel checked the nets periodically, and ABI was notified immediately if a capture was observed. ABI's sea turtle specialists were on call 24 hours a day to retrieve captured turtles from the plant.

Beginning April 1990, after consultation with NMFS, net deployment was scaled back to daylight hours only. Concurrently, surveillance of the intake canal was increased and ABI personnel remained on site for the duration of each day's netting activities. This measure decreased response time for removal of entangled turtles from nets and provided an opportunity to improve daily assessments of turtle levels within the canal. Records of daily canal observations were compared with capture data to assess capture efficiencies.

The A1A barrier net is used to confine turtles to the easternmost section of the intake canal, where capture techniques have been most effective. This net is constructed of large diameter polypropylene rope and has a mesh size of 20.3 cm x 20.3 cm. A cable and series of large floats are used to keep the top of the net above the water's surface, and the bottom is anchored by a series of heavy blocks. The net is inclined at a slope of 3:1, with the bottom positioned upstream of the surface cable. This reduces bowing in the center and minimizes the risk of a weak or injured turtle being pinned underwater by strong currents.

In the past, the integrity of the barrier net was occasionally compromised, and turtles were able to move west of A1A. These turtles were further constrained downstream by an underwater intrusion detection system (UIDS) consisting, in part, of a large barrier positioned perpendicular to the north-south arm of the canal (Figure 2). The UIDS security barrier also consists of 20.3 cm x 20.3 cm mesh.

Prior to completion of the UIDS in December 1986, turtles uncontained by the A1A barrier net were usually removed from the canal at the intake wells of Units 1 and 2 (Figure 2). There they were retrieved by means of large mechanical rakes or specially designed nets. Following construction of the UIDS barrier, all but the smallest individuals were unable to reach the intake wells. Thus, as required, tangle nets were also deployed west of A1A. Improvements made to the A1A barrier net during 1990 have effectively confined all turtles larger than 32.5 cm to the eastern end of the canal.

Formal daily inspections of the intake canal were made to determine the numbers, locations and species of turtles present. Surface observations were augmented with periodic underwater inspections using SCUBA, particularly in and around the A1A barrier net. Because of the reduction in total netting hours since April 1990, increased effort has been directed toward hand capture of turtles. This effort, accomplished by diving and use of dip nets, has proved very effective during periods of good water clarity.

Regardless of capture method, all turtles removed from the canal were identified to species, measured, weighed, tagged, and examined for overall condition (wounds, abnormalities, parasites, etc.). Healthy turtles were released into the ocean the same day of capture. Sick or injured turtles were treated and occasionally held for observation prior to release. When treatment was warranted, injections of antibiotics and vitamins were administered by permitted veterinarians. Resuscitation techniques were used if a turtle was found that appeared to have died recently. Beginning in 1982, necropsies were conducted on dead turtles found in fresh condition; one necropsy was performed during 1992.

Since 1982, blood samples have been collected and analyzed to determine the sex of immature turtles. Blood was removed from the paired dorsal cervical sinuses of subject turtles using the technique described by Owens and Ruiz (1980). The samples were maintained on ice and later centrifuged for 15 minutes to separate cells and serum. Sex determinations were subsequently made by researchers at Texas A & M University using radioimmunoassay for serum testosterone (Owens et al., 1978).

Florida Power & Light Company and Applied Biology, Inc. continued to assist other sea turtle researchers in 1992. Since the program began, data, specimens and/or assistance have been given to the Florida Department of Natural Resources, National Marine Fisheries Service, US Fish and Wildlife Service, US Army Corps of Engineers, Smithsonian Institution, South Carolina Wildlife and Marine Resources Division, Center for Sea Turtle Research (University of Florida), Florida Atlantic University, University of Central Florida, Texas A & M University, University of Rhode Island, University of South Carolina, University of Illinois, University of Georgia, Virginia Institute of Marine Science and the Western Atlantic Turtle Symposium.

Studies to Evaluate and/or Mitigate Intake Entrapment

A program that assessed the feasibility of using light and/or sound to deter turtles from entering the St. Lucie Plant intake structures was conducted in 1982 and 1983 and completed in January 1984. As required, test results and evaluations were written up and a presentation was made to the NRC, National Marine Fisheries Service and the Florida Department of Natural Resources on 11 April 1984. Requirement 4.2.2 of the NRC's St. Lucie Unit 2 Appendix B Environmental Protection Plan is considered completed with submission of deterrent study findings.

RESULTS AND DISCUSSION

Nesting Survey

Spatial Distribution of Loggerhead Turtle Nests

Since 1981, 36 1-km-long segments comprising the island's coastline have been surveyed. The distribution of nests among these 36 survey areas has shown an increase in nesting from north to south along the northern half of the island (Figure 4; ABI, 1987, 1992). Along the southern half of the island there has either been no gradient or a gradient of decreasing nesting from north to south.

Though beach dynamics may sometimes affect the selection of nesting sites by loggerhead turtles (Worth and Smith, 1976; Williams-Walls et al., 1983), no consistent relationship was apparent when field observations of beach widths were compared to the spatial distribution of nests along the island (ABI, 1987). Therefore other factors must also contribute to the selection process. Offshore bottom contours, spatial distribution of nearshore reefs, type and extent of dune vegetation, and degree of human activity on the beach at night have been identified as some of the factors affecting nesting (Caldwell, 1962; Hendrickson and Balasingam, 1966; Bustard, 1968; Bustard and Greenham, 1968; Hughes, 1974; Davis and Whiting, 1977; Mortimer, 1982). Relationships between spatial nesting patterns and specific environmental conditions are often difficult to establish because of the interrelationship of the factors involved.

Not all ventures onto the beach by a female turtle culminate in successful nests. These "false crawls" (non-nesting emergences) may occur for many reasons and are commonly encountered at other rookeries (Baldwin and Lofton, 1959; Schulz, 1975; Davis and Whiting, 1977; Talbert et al., 1980; Raymond, 1984). Davis and Whiting (1977) suggested that relatively high percentages of false crawls may reflect disturbances or unsatisfactory nesting beach characteristics. Therefore, certain factors may affect a turtle's preference to emerge on a beach, while other factors may affect a turtle's tendency to nest after it has emerged. An index which relates the number of nests to the number of false crawls in an area is useful in estimating the post-emergence suitability of a beach for nesting. In the present study this index is termed "nesting success" and is defined as the percentage of total emergences that result in nests.

Historically, the pattern of loggerhead emergences on the island has generally paralleled the distribution of nests (ABI, 1987, 1992), and this same trend was apparent in 1992 (Figure 5). In contrast, nesting success by loggerheads along the island has typically lacked gradients (Figure 6; ABI, 1987, 1992). Thus, the relatively high numbers of loggerhead nests observed in certain areas are usually a result of more turtles coming ashore in those areas rather than of more preferable nesting conditions being encountered by the turtles after they emerged.

Any of the factors previously identified (i.e., offshore bottom contours, distribution of reefs, type and extent of dune vegetation, and human activity on the beach at night) may affect loggerhead turtle emergence patterns and several have been reported to affect emergence patterns on Hutchinson Island (ABI, 1988, 1989; Martin et al., 1989). Undoubtedly a combination of factors account for the overall distribution of emergences and therefore the overall nesting pattern on the island.

Nesting surveys on Hutchinson Island were initiated in response to concerns that the operation of the St. Lucie Plant might negatively impact the local sea turtle rookery. Previous analysis, using log-likelihood tests of independence (G-test; Sokal and Rohlf, 1981) demonstrated that the construction of the plant's offshore intake and discharge structures significantly reduced nesting at the plant site during construction years -- 1975, 1981, 1982 and 1983 (Proffitt et al., 1986; ABI, 1987). However, nesting at the plant consistently returned to levels similar to or greater than those at a control site in years following construction (Figure 7). During 1991 when offshore construction was restricted almost entirely to daylight hours, nests were more abundant at the plant site than at the control site. Data collected through 1992 have shown that power plant operation exclusive of nighttime intake/discharge construction has had no apparent effect on nesting.

Long-Term Trends in Loggerhead Turtle Nesting

Various methods were used during surveys prior to 1981 to estimate the total number of loggerhead nests on Hutchinson Island based on the number of nests found in the nine 1.25-km-long survey areas (Gallagher et al., 1972; Worth and Smith, 1976; ABI, 1980a). Each of these methods were subsequently found to consistently overestimate island totals (ABI, 1987). Since whole-island surveys began in 1981, it has been possible to determine the actual proportion of total nests deposited in the nine areas. This has then allowed extrapolation from the nine survey areas to the entire island for years prior to 1981.

From 1981 through 1992 the total number of nests in the nine areas varied from 32.5 to 35.6 percent of the total number of nests on the island (Table 1). This is slightly higher than the 31.3 percent which would be expected based strictly on the proportion of linear coastline comprised by the nine areas. Using the twelve-year mean of 33.91 percent, estimates of the total number of nests on Hutchinson Island can be calculated by multiplying the number of nests in the nine areas by 2.949. This technique, when applied to the nine survey areas during the twelve years in which the entire island was surveyed, produced whole-island estimates within 5.0 percent of the actual number of nests counted. Because the proportion of nests recorded in the nine survey areas remained relatively constant over the last twelve years, this extrapolation procedure should provide a fairly accurate estimate of total loggerhead nesting for years prior to 1981.

It is clear that loggerhead nesting activity on Hutchinson Island fluctuates considerably from year to year (Table 1; Figure 8). Annual variations in nest densities also are common at other rookeries (Hughes, 1976; Davis and Whiting, 1977; Ehrhart, 1980) and may result from non-annual reproductive behavior (Frazer, 1989). Nonetheless, data collected through 1992 suggest an overall increase in nesting on Hutchinson Island since surveys began in 1971. Total nesting activity was greatest during 1991 when 6,812 loggerhead nests were recorded. No relationships between total nesting activity and power plant operation or intake/discharge construction were indicated by year-to-year variations in total nesting on Hutchinson Island.

Seasonal Patterns of Loggerhead Turtle Nesting

The loggerhead turtle nesting season usually begins between mid-April and early May, attains a maximum during June or July, and ends by late August or early September (ABI, 1987). Nesting activity during 1992 followed this same pattern (Figure 9).

Cool water intrusions frequently occur over the continental shelf of southeast Florida during the summer (Taylor and Stewart, 1958; Smith, 1982). Worth and Smith (1976), Williams-Walls et al. (1983) and ABI (1992) suggested that these intrusions may have been responsible for the temporary declines in loggerhead turtle nesting activity previously observed on Hutchinson Island. Similarly, an intrusion of cool water from late June through early July 1992 may have contributed to the substantial decrease in nesting during that period (Figure 9).

Though natural fluctuations in temperature have been shown to affect temporal nesting patterns on Hutchinson Island, there has been no indication that power plant operation has affected these temporal patterns (ABI, 1988).

Predation on Loggerhead Turtle Nests

Since nest surveys began in 1971, raccoon predation has been a major cause of turtle nest destruction on Hutchinson Island. Researchers at other locations have reported raccoon predation levels as high as 70 to nearly 100 percent (Davis and Whiting, 1977; Ehrhart, 1979; Hopkins et al., 1979; Talbert et al., 1980). Raccoon predation of loggerhead turtle nests on Hutchinson Island has not approached this level during any study year, though levels for individual 1.25-km-long areas have been as high as 80 percent. Overall predation rates for survey years 1971 through 1977 were between 21 and 44 percent, with a high of 44 percent recorded in 1973. A pronounced decrease in raccoon predation occurred after 1977, and overall predation rates for the nine areas have not exceeded 10 percent since 1979. A decline in predation rates on Hutchinson Island has been variously attributed to trapping programs, construction activities, habitat loss and disease (Williams-Walls et al., 1983; ABI, 1987).

During 1992, four percent (255) of the loggerhead nests (n=6,459) on the island were depredated by raccoons. As in previous years (ABI, 1992), predation of turtle nests was primarily restricted to the most undeveloped portion of the island (i.e., Areas E through S; Figure 10).

Ghost crabs have been reported by numerous researchers as important predators of sea turtle nests (Baldwin and Lofton, 1959; Schulz, 1975; Diamond, 1976; Fowler,

1979; Hopkins et al., 1979; Stancyk, 1982). Though turtle nests on Hutchinson Island probably have been depredated by ghost crabs since nesting surveys began in 1971, this source of nest destruction did not become apparent until 1983. Quantification of ghost crab predation was initiated the same year.

Overall predation rates by ghost crabs have varied from 0.1 to 2.1 percent from 1983 - 1991 (ABI, 1992). During 1992, 0.1 percent (7) of the loggerhead nests (n=6,459) on the island were depredated by ghost crabs (Figure 10). Nests destroyed by a combination of raccoon and ghost crab predation have been included as raccoon predations in previous discussions. When these combination predations are included as crab predations, the overall predation rates by ghost crabs range from 0.4 to 3.2 percent. During 1992, 0.9 percent (57 nests) were destroyed by either ghost crabs or a combination of ghost crabs and raccoons.

Green and Leatherback Turtle Nesting

Green and leatherback turtles also nest on Hutchinson Island, but in fewer numbers than loggerhead turtles. Prior to 1981, both survey (nine 1.25-km-long sections) and inter-survey areas were monitored for the presence of green and leatherback nests. Thirty-one kilometers of beach from Area 1 south to the St. Lucie Inlet were included in that effort. During whole-island surveys from 1981 through 1992, only seven of 256 leatherback nests and only twelve of 794 green nests were recorded on the five kilometers of beach north of Area 1. Therefore, previous counts of green and leatherback nests within the 31 kilometers surveyed probably were not appreciably different from total densities for the entire island. Based on this assumption, green and leatherback nest densities may be compared among all survey years, except 1980, when less than 15 kilometers of beach were surveyed.

Prior to 1992, the number of nests observed on the island ranged from 5 to 132 for green turtles and from 1 to 44 for leatherbacks (Figure 11). During the 1992 survey, 146 green turtle and 30 leatherback turtle nests were recorded on Hutchinson Island.

Temporal nesting patterns for these species differ from the pattern for loggerhead turtles. Green turtles typically nest on Hutchinson Island from mid-June through the first or second week of September. During 1992, green turtles nested from 29 May through 9 September. Leatherback turtles usually nest on the island from mid-April through early to mid-July. During 1992 this species nested from 26 March through 8 June.

Considerable fluctuations in green turtle nesting on the island have occurred among survey years (Figure 11). This is not unusual since there are drastic year-to-year fluctuations in the numbers of green turtles nesting at other breeding grounds (Carr et al., 1982). Despite these fluctuations, data collected through 1992 suggest an overall increase in nesting since 1971 and may reflect an increase in the number of nesting females in the Hutchinson Island area. During 1992, green turtles nested most frequently along the southern half of the island. This is consistent with results of previous surveys.

Leatherback turtle nest densities have remained low on Hutchinson Island; however, increased nesting during recent years (Figure 11) may reflect an overall increase in the number of nesting females in the Hutchinson Island area. During 1992, leatherback turtles primarily nested on the southern half of the island.

Intake Canal Monitoring

Entrainment of sea turtles at the St. Lucie Plant has been attributed to the presumed physical attractiveness of the offshore structures housing the intake pipes rather than to plant operating characteristics (ABI, 1980b and 1986). The velocity caps supported above the openings to each intake pipe eliminate vertical water entrainment and substantially reduce current velocities near the structures by spreading horizontal draw over an arc of 360°. Even when both units are operating at full capacity, turtles must actively swim into the mouth of one of the intake pipes before they encounter current velocities sufficiently strong to effect entrainment. Consequently, a turtle's entrapment relates primarily to the probability that it will detect and subsequently enter one of the intake structures.

Relative Abundance and Temporal Distribution

During 1992, 187 sea turtles were captured in the intake canal of the St. Lucie Plant: 123 loggerheads, 61 green turtles, 1 leatherback and 2 hawksbills (Table 2). All but one of the five species of sea turtles inhabiting coastal waters of the southeastern United States were represented. Since intake canal monitoring began in May 1976, 2,083 loggerhead (including 121 recaptures), 379 green (including 3 recaptures), 10 leatherback, 11 hawksbill and 18 Kemp's ridley captures have taken place at the St. Lucie Plant. Annual catches for all species combined ranged from a low of 33 in 1976 (partial year of plant operation and monitoring) to 220 in both 1984 and 1986.

One of the potential uses of annual abundance data is to provide a gauge of change in the relative number of turtles occurring in the vicinity of the St. Lucie Plant. Assuming that the probability of entrainment (an individual's chance of detecting and entering one of the pipes) does not vary appreciably over time and that, within a species, a constant proportion of turtles are equally attracted to the structures, capture rates should vary in proportion to the size of the populations being sampled.

Since 1977, the first full year of plant operation, the number of loggerheads captured each year has ranged from 62 in 1981 to 195 in 1986 (Figure 12). Annual green turtle captures over the same period ranged from 3 in 1979 to 69 in 1984. Numbers for both species have exhibited considerable year-to-year fluctuations with no persistent trends evident. However, this analysis may be confounded by changes in the physical characteristics of the intake structures that have occurred since the plant began operating.

Two offshore intake structures were in place prior to Unit 1 start-up in 1976. The third and largest structure was not installed until 1982-1983. Even though all three structures are in relatively close proximity, the addition of another pipe may have increased the probability of a turtle's entrainment. Because this change cannot be quantified, data collected prior to 1982 may not be comparable with data collected after 1983. Additionally, in 1989 holes developed in the center of two of the three velocity caps. This damage, which was repaired during 1991-1992, added a strong vertical component to water entrainment. The degree to which modified entrainment characteristics and subsequent repair operations affected sea turtle entrapment is also unknown. With these considerations in mind, neither a long-term increase nor decrease

in the number of sea turtles inhabiting the nearshore environment adjacent to the St. Lucie Plant can be inferred from the canal capture data.

During 1992, the monthly catch of loggerheads ranged from 1 (May) to 19 (January), with a monthly mean of 10.3 (±5.2; Table 3). The numbers of captures during March, May and June were considerably below average, while captures in November and December were considerably higher than average. Over the entire monitoring period, monthly catches have ranged from 0 to 39, with the greatest number of captures occurring during January 1983.

When data from all full years of monitoring (1977-1992) are combined, the highest mean number of loggerhead captures (15.7) occurred in January; fewest average captures were recorded in November (5.8; Table 3). However, as evidenced by minimum and maximum values, monthly catches have shown considerable annual variability. Months having relatively low catches one year often have had relatively high catches in another.

Green turtles have been caught during every month of the year, with average monthly catches for all years combined ranging from 0.5 in July to 6.4 in January (Table 4). Seasonal abundance patterns of green turtles have been much more pronounced than for loggerheads, with 42 percent of all captures occurring between January and February. During 1992, the largest number of green turtles (18) were captured in October. The number of green turtles captured between October and December was the highest on record. The most ever caught in one month was 37 in January 1984.

Catches of leatherbacks, hawksbills and Kemp's ridleys have been infrequent and scattered throughout the 17 year study period (Table 2). Each species has shown rather pronounced seasonal occurrences; all but 2 of the 10 leatherbacks were collected between January and May, 9 of the 11 hawksbills were collected between June and October, and all but 2 of the 18 Kemp's ridleys were caught between November and April.

Size-Class Distributions

Although several straight-line and curved measurements were recorded for turtles removed from the intake canal, only one straight-line measurement has been used in analyses presented here. Straight-line carapace length (SLCL) was measured from the precentral scute to the notch between the postcentral scutes (minimum carapace length of Pritchard et al., 1983). To date, loggerheads removed from the intake canal have ranged in length (SLCL) from 40.2 to 112.0 cm ($\bar{x} = 66.4 \pm 13.6$ cm) and in weight from 10.7 kg to 169.6 kg ($\bar{x} = 48.2 \pm 30.6$ kg).

A carapace length of 70 cm approximates the smallest size of nesting loggerhead females observed along the Atlantic east coast (Hirth, 1980). However, adults can only be reliably sexed on external morphological characteristics (i.e., relative tail length) after attaining a somewhat larger size. Recent data suggest that some males may not mature, and thus might not be distinguishable from females, until they are about 85.0 cm long. Based on these divisions, data were segregated into three groups: juveniles ($\leq$70 cm), adults (>85 cm) and transitional (71-85 cm). The latter group probably includes both mature and immature individuals.

Of the 2,050 loggerhead captures between 1977 and 1992 for which length data were recorded, 69.6 percent were juveniles, the majority of these measuring between 50 and 70 cm SLCL (Figure 13; Table 5). The remaining individuals were nearly equally divided between adults and animals in the transitional size class. Similar size-frequency distributions, indicating a preponderance of juveniles, have been reported for loggerheads inhabiting the Mosquito/Indian River Lagoon (Mendonca and Ehrhart, 1982), the Canaveral ship channel (Henwood, 1987), and Georgia and South Carolina (Hillestad et al., 1982). These data suggest that coastal waters of the southeastern United States constitute an important developmental habitat for loggerhead sea turtles.

Seasonal patterns of abundance for various size classes indicated that juvenile loggerheads were slightly more abundant during the winter than at other times of the year (Table 5). About 47 percent of the juveniles were captured between January and April. Abundances decreased in spring and remained relatively constant during the summer and early fall before decreasing again to lowest levels in November and December. The seasonal distribution of adult loggerheads was much more pronounced, 75 percent of all captures occurring between May and August. This represents the major portion of the nesting season on Hutchinson Island.

Green turtles removed from the intake canal over the entire study period ranged in size from 20.0 to 108.0 cm SLCL ($\bar{x}$ = 36.4 ± 14.3 cm) and 0.9 kg to 177.8 kg ($\bar{x}$ = 9.9 ± 20.0 kg). Nearly all (97 percent) were juveniles, with over 75 percent 40 cm or less in length (Figure 14). Although these immature turtles exhibited distinct winter pulses, some small individuals were captured throughout the year (Table 4). To date, only

10 adult green turtles (SLCL >83 cm; Witherington and Ehrhart, 1989) have been removed from the canal; all were captured during or shortly after the nesting season.

The 11 hawksbills removed from the canal ranged in size from 34.0 to 83.4 cm SLCL ($\bar{x}$ = 49.3 ± 15.7 cm) and in weight from 6.4 to 86.6 kg ($\bar{x}$ = 23.1 ± 25.2 kg). All but two were juveniles (SLCL <63 cm; Witzell, 1983). Similarly, all but one of the 18 Kemp's ridleys captured at the St. Lucie Plant were juveniles (SLCL <60.0 cm; Hirth, 1980). Carapace lengths for the ridleys ranged from 27.0 to 62.0 cm SLCL ($\bar{x}$ = 37.0 ± 10.1 cm) and weights from 3.1 to 31.8 kg ($\bar{x}$ = 8.6 ± 8.2 kg). The 10 leatherbacks removed from the canal ranged in length from 112.5 to 150.0 cm, and at least 8 were adults (SLCL >121 cm; Hirth, 1980). The largest leatherback for which an accurate weight was obtained, a female with a curved carapace length of 158.5 cm, weighed 334.8 kg.

Sex Ratios

Since intake canal monitoring began in 1976, 299 adult loggerheads (SLCL >85.0 cm) have been sexed. Females predominated males by a ratio of 5.2:1.0, which significantly departs from a 1:1 ratio (X^2, $P \leq 0.05$). Consequently, temporal patterns in the number of adult loggerhead captures were heavily influenced by the numbers of females present. When sexes were separated, it was evident that males were relatively evenly distributed among months, whereas 88 percent of the females were taken during the nesting season (May through September; Figure 15).

The number of adult female loggerheads captured at the St. Lucie Plant has increased noticeably since 1983. From 1977 (first full year of plant operation) through

1983, an average of 4.6 adult females ($\pm$ 3.2; range = 1-10) were entrapped each year, whereas since then, an average of 24.4 females per year were captured ($\pm$ 6.9; range = 16-35). This increase corresponds to a general rise in loggerhead nesting activity near the plant (Figure 16). Increased nearshore movement associated with nesting increases the probability of a turtle detecting one of the intake structures and hence the probability of entrainment. The decline in adult loggerhead captures during 1991 and 1992 may be related to velocity cap repairs. Construction activities and/or the lack of biological fouling on the new caps may have reduced the attractiveness of the intake structures as a resting or staging area between successive nesting forays. Reduced association with the structures would decrease the likelihood of entrainment.

Since September 1982, 435 individual juvenile and sub-adult loggerhead turtles (SLCL $\leq$70.0 cm) captured in the canal were sexed by Texas A & M University researchers using a bioimmunoassay technique for blood serum testosterone. Females significantly (X^2; $P \leq 0.05$) outnumbered males by a ratio of 2.2:1.0. This female bias is consistent with findings of Wibbels et al. (1987) for other coastal loggerhead populations in the southeastern United States.

Of the 10 adult green turtles captured since monitoring began, six were males and four were females. Seventeen immature green turtles have been sexed through blood work: 11 females and 3 males. Of the six adult leatherback turtles for which sex was recorded, three were females and three were males. The two adult hawksbills and one Kemp's ridley were all females. No sex information exists for juveniles of any of these species.

Capture Efficiencies

Netting methodologies have been under continual review and refinement as net materials, configurations and placement have been varied in an effort to minimize sea turtle entrapment times. Additionally, alternative capture techniques have been evaluated and potential deterrent systems tested in the laboratory. Current capture procedures have proven to provide a safe, efficient and cost-effective program for removing entrapped turtles from the intake canal.

Formal daily inspections of the intake canal are conducted every day that capture nets are deployed (usually five days each week), and the number, location, and relative size of entrapped turtles are recorded on field observation forms. During 1992, about 65 percent of the turtles entering the canal were caught within 24 hours of first sighting. Because of differences in mean size, loggerheads typically resided in the canal for shorter periods than the smaller green turtles.

Since April 1990 when the current daytime netting program was implemented, 90 percent of all loggerheads have been captured within one week of first sighting, with a mean entrapment period of only 2.9 (± 4.5) days (Figure 17). Over that same period, green turtles, which are less easily entangled in the large mesh nets, had a mean entrapment time of 5.3 (± 9.8) days. Ninety percent of all green turtles were captured within two weeks of first sighting. Better utilization of currents and eddies, adjustments to tethering lines, multi-net deployments and increased efforts to hand capture turtles have contributed to reduced entrapment times during recent years.

Entrapment times may be extended for turtles swimming past the A1A barrier net (ABI, 1987). Prior to barrier net repairs in 1990, the top of the net was occasionally submerged or the anchor cable pulled free from the bottom, allowing turtles that would otherwise be restrained by the net to pass. Because capture efforts west of the A1A bridge were generally less effective than those near the intake headwalls, most turtles breaching the barrier net were not caught until they entered the intake wells of Units 1 and 2. Prior to installation of the UIDS barrier in 1986, about 15 percent of all turtles entrapped in the canal were removed from the intake wells. Because of their relatively small sizes, a much larger proportion of greens (51.6 percent) reached the plant than loggerheads (10.1 percent). Since 1986, the percentage of greens caught at the intake wells has decreased to 26.3 percent, while all loggerheads have been prevented from reaching the plant. During 1992, only 7 of the 61 green turtle captures (11.5 percent) occurred at the intake wells.

During 1992, 96 percent of all turtles entrapped in the canal were captured east of the A1A bridge, 137 by netting and 43 by hand. The effective confinement of turtles east of A1A has been a major contributor to the high capture efficiency achieved during recent years.

Relative Condition

Turtles captured alive in the intake canal of the St. Lucie Plant were assigned a relative condition based on weight, activity, parasite infestation, barnacle coverage, wounds, injuries and any other abnormalities which might have affected overall vitality. During 1992, 90.2 percent (111) of all loggerheads found in the canal were alive and

in good to excellent condition. Only 8.1 percent (10) of loggerhead captures involved individuals in fair or poor condition; two loggerheads were dead when removed from the canal. Of the 61 green turtles removed from the intake canal during 1992, 57 (93.4 percent) were in good to excellent condition, 2 (3.3 percent) were in fair condition, and 2 (3.3 percent) were dead.

Over the entire monitoring period, about 77 and 80 percent, respectively, of all loggerhead and green captures have involved turtles in good to excellent condition (Table 6). Captures of individuals in fair to poor condition have occurred about 15 percent of the time for loggerheads and 12 percent of the time for greens. All of the hawksbills and leatherbacks have been removed from the canal in good to excellent condition, while half of the Kemp's ridleys have fallen into these categories.

Relative condition ratings can be influenced by a number of factors, some related and others unrelated to entrainment and/or entrapment in the intake canal. Ratings of good to excellent indicate that turtles have not been negatively impacted by their entrapment in the canal, at least as evidenced by physical appearance. Although ratings of fair or poor imply reduced vitality, the extent to which entrainment/entrapment is responsible is often indeterminable. In some instances, conditions responsible for lower ratings, such as injuries, obviously were sustained prior to entrainment.

During 1992, only 3 of the 123 loggerhead captures (2.4 percent) involved individuals with noticeable injuries, such as missing appendages, broken or missing pieces of carapace and deep lacerations. Most of these were old, well-healed wounds,

and none were serious enough to require medical attention. None of the green turtles captured during 1992 had major injuries.

The majority of loggerheads rated as fair or poor during 1992 did not suffer from physical disabilities but rather appeared lethargic. Most were underweight and heavily infested with barnacles and leeches. This condition, referred to as "diseased turtle syndrome" (Ehrhart, 1987) has been reported from several other locales and is unrelated to a turtle's entrapment in the canal.

Mortalities

Sea turtle mortalities have been closely monitored throughout the life of the canal capture program in an attempt to assign probable causes and take appropriate remedial action to minimize future occurrences. Previous analyses of capture data identified drowning in nets (A1A barrier net, UIDS barrier, and tangle nets), drowning in the intake pipes during periods of reduced intake flow, injuries sustained from dredging operations and injuries sustained from the mechanical rakes used in the intake wells as probable mortality factors (ABI, 1987). Although difficult to quantify, the entrapment and subsequent demise of injured or sick turtles has probably accounted for a portion of observed mortalities.

Over the entire 17 year monitoring period, 130 (6.2 percent) of the 2,083 loggerheads and 23 (6.1 percent) of the 379 green turtles entrapped in the canal were found dead (Table 6). Mortalities spanned the range of size classes for loggerheads (SLCL = 47.5-103 cm), while all green turtle mortalities involved juveniles less than 42 cm in length. The four Kemp's ridley mortalities documented at the plant during 1987 and

1988 were the only deaths for this species to date; no leatherback or hawksbill mortalities have occurred at the St. Lucie Plant.

Modifications to capture procedures, improvements to the A1A barrier net and virtual elimination of low flow conditions within the canal have resulted in a substantial reduction in sea turtle mortalities over the life of the canal capture program. Mortality rate, expressed as the percentage of total captures involving dead animals, declined from 9.2 percent during the period 1976-1983 to 4.6 percent since 1983 (Table 2). During 1992, four mortalities (2.1 percent of all captures), two loggerheads and two green turtles, were documented.

Both dead loggerheads removed from the canal in 1992 were found east of the A1A barrier net. No apparent physical injuries were noted, and it is believed that these individuals may have been in poor health prior to their entrapment. The two green turtle mortalities occurred at the intake wells. Injuries to one suggested that it may have been impacted by the mechanical rakes used to remove debris from the wells. However, a necropsy failed to provide a definitive cause of death. The other green turtle was too decomposed to necropsy.

Recapture Incidents

Since the St. Lucie Plant capture program began, most turtles removed from the intake canal have been tagged and released into the ocean at various locations along Hutchinson Island. Consequently, individual turtles can be identified as long as they retain their tags. Over the 17 year history of turtle entrapment at the St. Lucie Plant, 73 individuals (70 loggerheads and 3 green turtles) have been removed from the canal

more than once. Several other turtles with tag scars have also been recovered, indicating that the actual number of recaptures may be higher.

Of the 70 individual loggerheads known to have been caught more than once, 46 were caught twice and 4 were caught three times. The remainder were captured on four or more separate occasions, with one individual being caught nine times. Release site did not appear to have any effect on a turtle's probability of being recaptured. Turtles released both north and south of the plant returned. Recaptures also did not appear to be related to size, as both juveniles and adults were captured more than once (range of SLCL = 47-89 cm). As for overall captures, the majority of recapture incidents involved juveniles (SLCL $\leq$70 cm).

Recapture intervals for loggerheads ranged from 1 to 858 days, with a mean of 151 days ($\pm$173 days). All three green turtles caught more than once were captured twice, with recapture intervals ranging from 38 to 75 days. About 58 percent of all loggerhead recapture incidents occurred within 90 days of previous capture and 89 percent within one year (Figure 18). The average interval between first and last capture was 263 days ($\pm$334 days). The longest period between first and last capture was 5.3 years. These data suggest that residency times of loggerheads within the nearshore habitat adjacent to the St. Lucie Plant are relatively short. Similar findings have been reported for loggerheads inhabiting the Mosquito/Indian River Lagoons of east-central Florida (Mendonca and Ehrhart, 1982).

SUMMARY

A gradient of increasing loggerhead turtle nest densities from north to south along the northern half of Hutchinson Island has been shown during most survey years. This gradient may result from variations in beach topography, offshore depth contours, distribution of nearshore reefs, onshore artificial lighting and human activity on the beach at night. Low nesting activity in the vicinity of the power plant during 1975 and from 1981 through 1983 was attributed to nighttime construction activities associated with installation of power plant intake and discharge structures. Nesting returned to normal or above normal levels following both periods of construction. During 1991, daytime construction activities associated with velocity cap repairs had no apparent effect on nesting. Statistical analyses indicate that power plant operation, exclusive of nighttime construction, has had no significant effect on nest densities near the plant.

There have been considerable year-to-year fluctuations in loggerhead nesting activity on Hutchinson Island from 1971 through 1992. Fluctuations are common at other rookeries and may result from non-annual reproductive behavior. Despite these fluctuations, loggerhead nesting activity has remained high during recent years and may reflect an overall increase in the number of nesting females in the Hutchinson Island area. No relationship between total nesting on the island and power plant operation or intake/discharge construction was indicated.

Temporary declines in loggerhead nesting activity have been attributed to cool water intrusions that frequently occur over the continental shelf of southeast Florida. Though temporal nesting patterns of the Hutchinson Island population may be in-

fluenced by natural fluctuations in water temperature, no significant effects due to power plant operation have been indicated.

Since nesting surveys began in 1971, raccoon predation was considered the major cause of turtle nest destruction on Hutchinson Island. From 1971 through 1977, overall predation rates in the nine survey areas were between 21 and 44 percent. However, a pronounced decrease in raccoon predation occurred after 1977, and overall predation rates in the nine survey areas have not exceeded ten percent since 1979. Decreased predation by raccoons probably reflects a decline in the raccoon population.

During 1992, 146 green turtle and 30 leatherback turtle nests were recorded on Hutchinson Island. Nesting activity by these two species exhibited considerable annual fluctuations, as has been recorded at other rookeries, but has remained relatively high during recent years. This may reflect an overall increase in the number of nesting green and leatherback turtles in the Hutchinson Island area.

During 1992, 187 loggerheads, 61 green turtles, 1 leatherback and 2 hawksbills were removed from the St. Lucie Plant intake canal. Since monitoring began in May 1976, 2,083 loggerhead, 379 green, 10 leatherback, 11 hawksbill and 18 Kemp's ridley turtles have been captured. Over the life of the monitoring program, annual catches for loggerhead turtles have ranged from 33 in 1976 (partial year of plant operation and monitoring) to a high of 195 in 1986. Yearly catches of green turtles have ranged from 0 in 1976 to 69 in 1984. Differences in the number of turtles entrapped during different years and months are attributed primarily to natural variation in the occurrence of turtles in the vicinity of the offshore intake structures, rather than to plant operating characteristics.

Size-class distributions of loggerhead turtles removed each year from the canal have consistently been predominated by juveniles between 50 and 70 cm in straight line carapace length. Over 75 percent of all green turtles entrapped in the canal were juveniles 40 cm or less in length. For both species, the largest number of captures for all years combined occurred during the winter, but these seasonal peaks were much more pronounced for green turtles. Sex ratios of both adult and immature loggerheads caught in the canal continued to be biased towards females.

During 1992, about 90 and 93 percent, respectively, of all loggerheads and green turtles removed from the canal were categorized by physical appearance as being in good to excellent condition. Over the entire 17 year monitoring period, 77 and 80 percent, respectively, of all loggerhead and green turtle captures have involved individuals in these categories; 15 percent of the loggerheads and 12 percent of the green turtles removed from the canal have been in fair or poor condition.

Only three turtles removed from the intake canal during 1992 had substantial injuries, and most of those were apparently sustained prior to entrapment. Once in the canal, turtles confined east of A1A typically had very brief residency times. Thus the relative condition of most turtles was not affected by their entrapment.

During 1992, two loggerhead and two green turtle mortalities were recorded in the intake canal. Cause of death could not be positively determined for any, but poor health is suspected in the case of the loggerheads. Program modifications, including

continual surveillance of tangle nets during periods of deployment, improvements to the integrity of the A1A barrier net and greater effort to hand capture turtles have contributed to a substantial decline in sea turtle mortalities during recent years.

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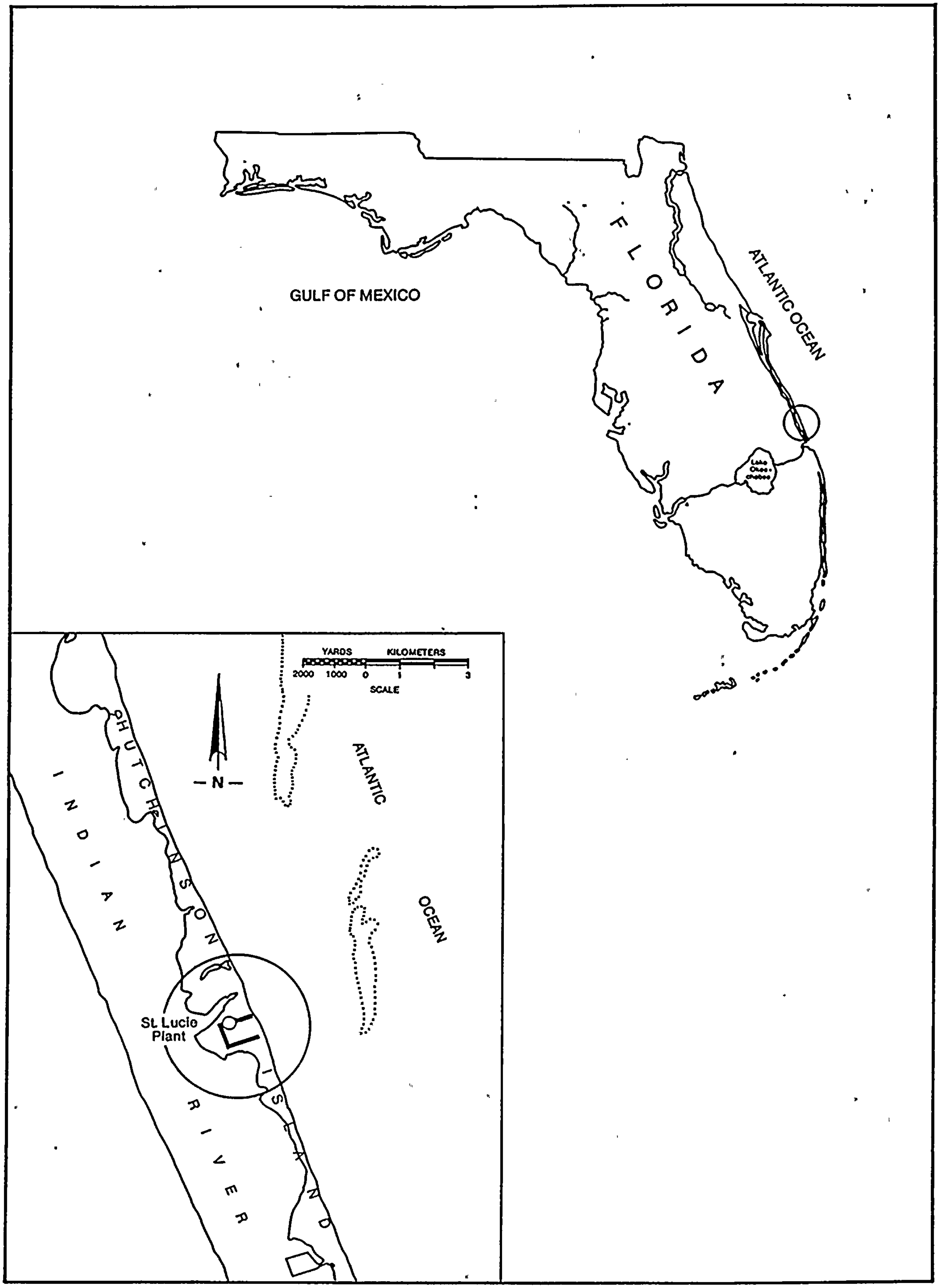

Figure 1. Location of the St. Lucie Plant.

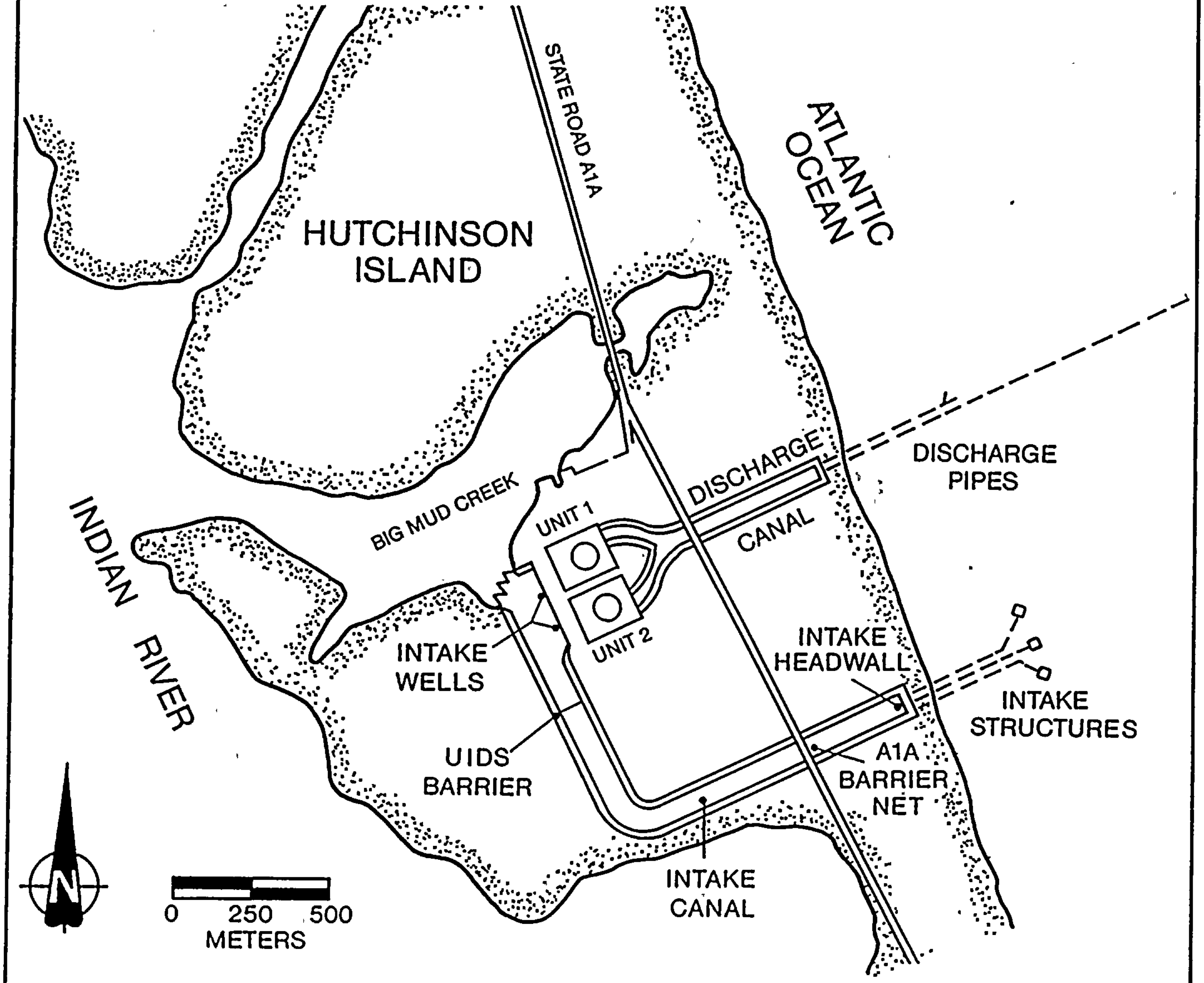

Figure 2. St. Lucie Plant cooling water intake and discharge system.

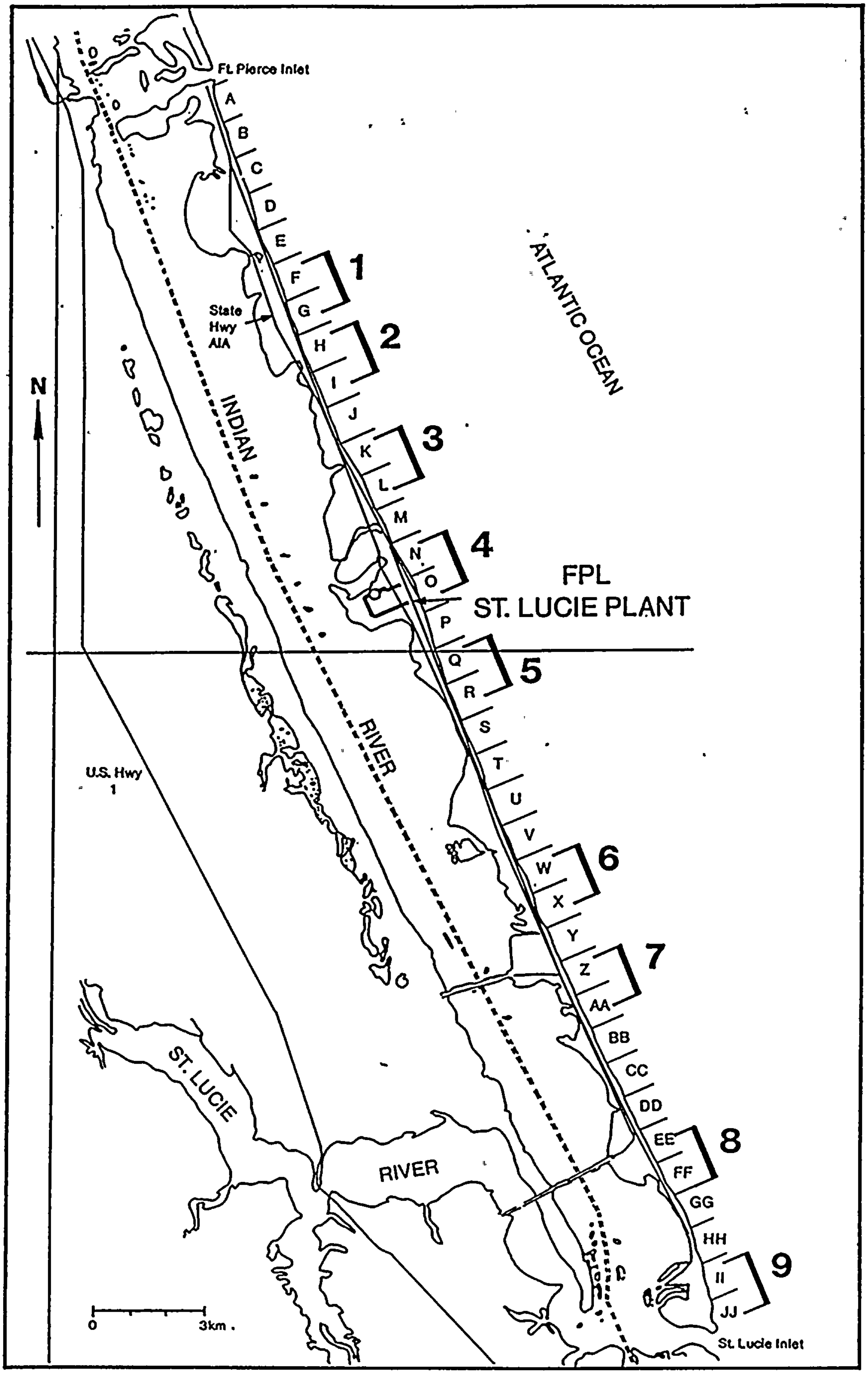

Figure 3. Designation and location of nine 1.25-km segments and thirty-six 1-km segments surveyed for sea turtle nesting, Hutchinson Island, 1971-1992.

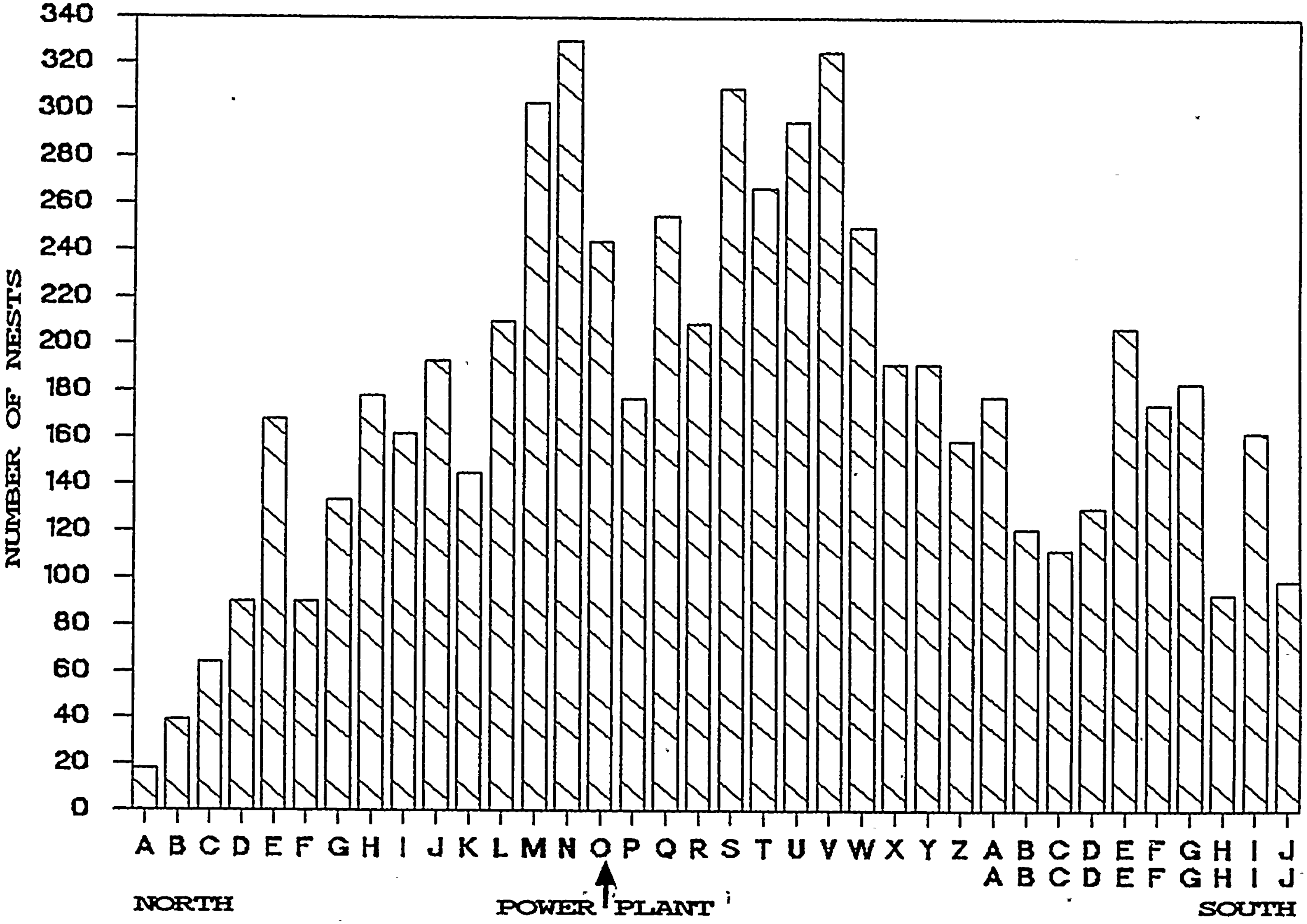

Figure 4. Number of loggerhead turtle nests in each of the thirty-six 1-km-long survey areas, Hutchinson Island, 1992.

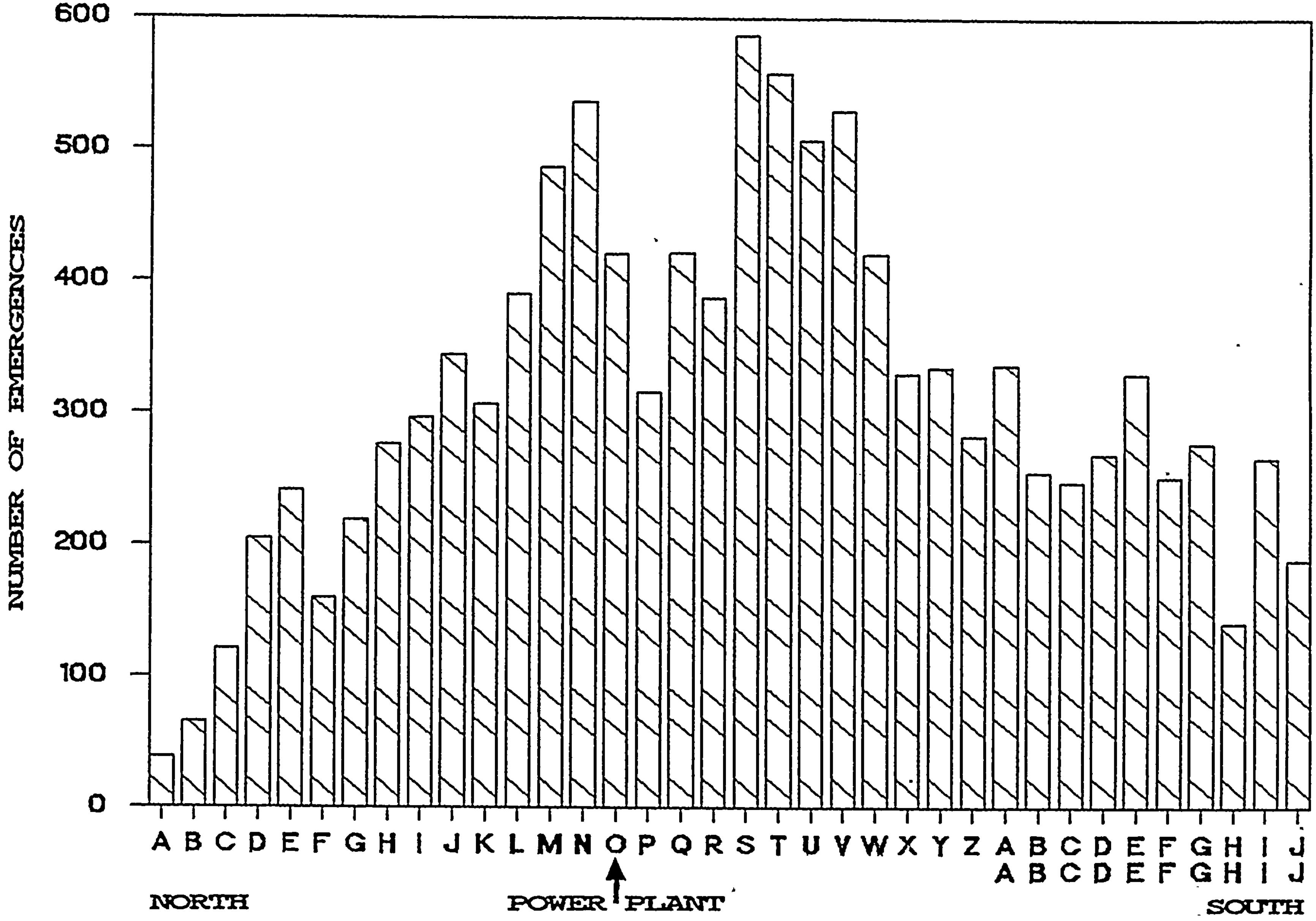

Figure 5. Number of loggerhead turtle emergences in each of the thirty-six 1-km-long survey areas, Hutchinson Island, 1992.

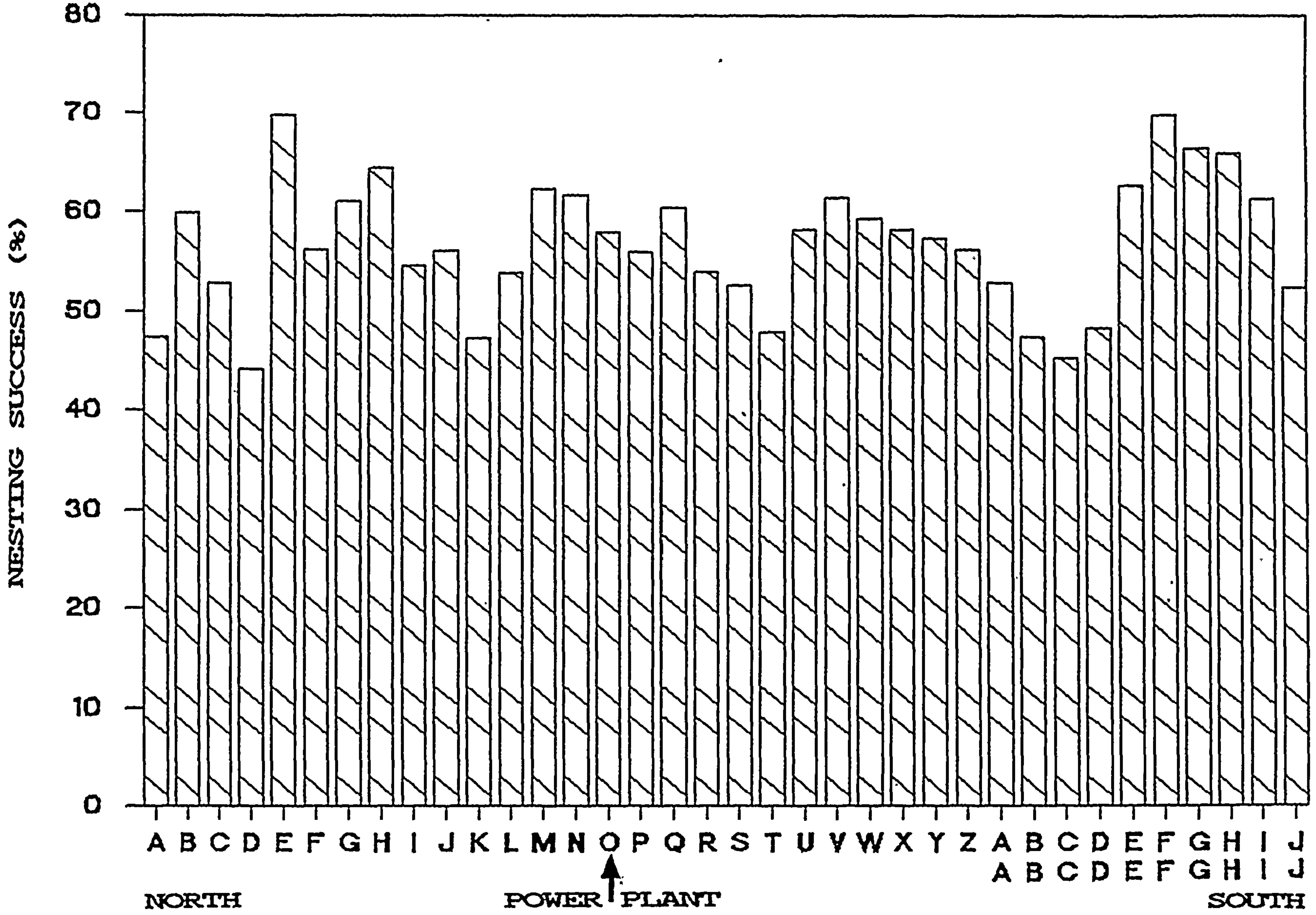

Figure 6. Loggerhead turtle nesting success (percentage of emergences that resulted in nests) for each of the thirty-six 1-km-long survey areas, Hutchinson Island, 1992.

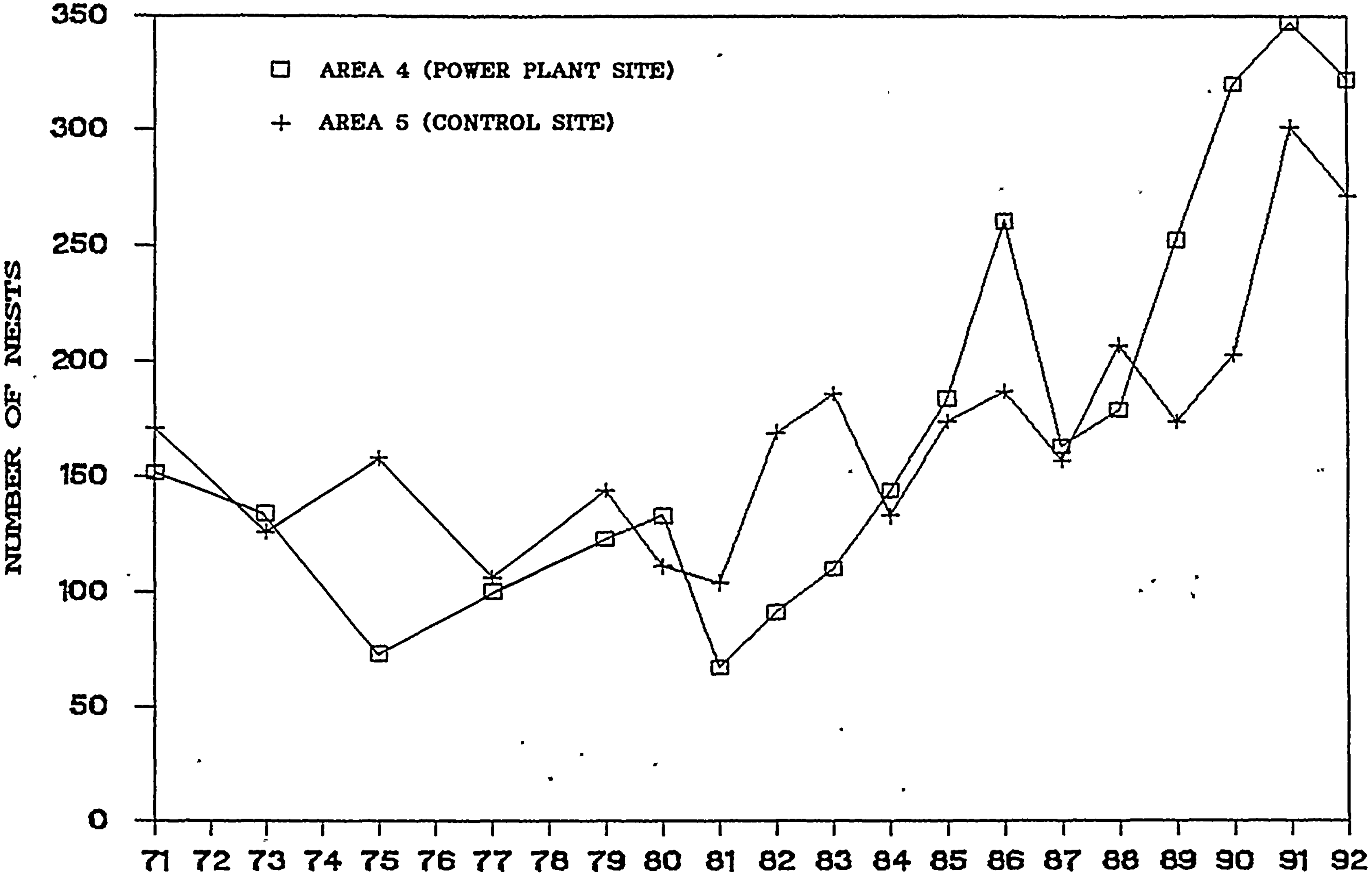

Figure 7. Number of loggerhead turtle nests in Areas 4 and 5, 1971-1992.

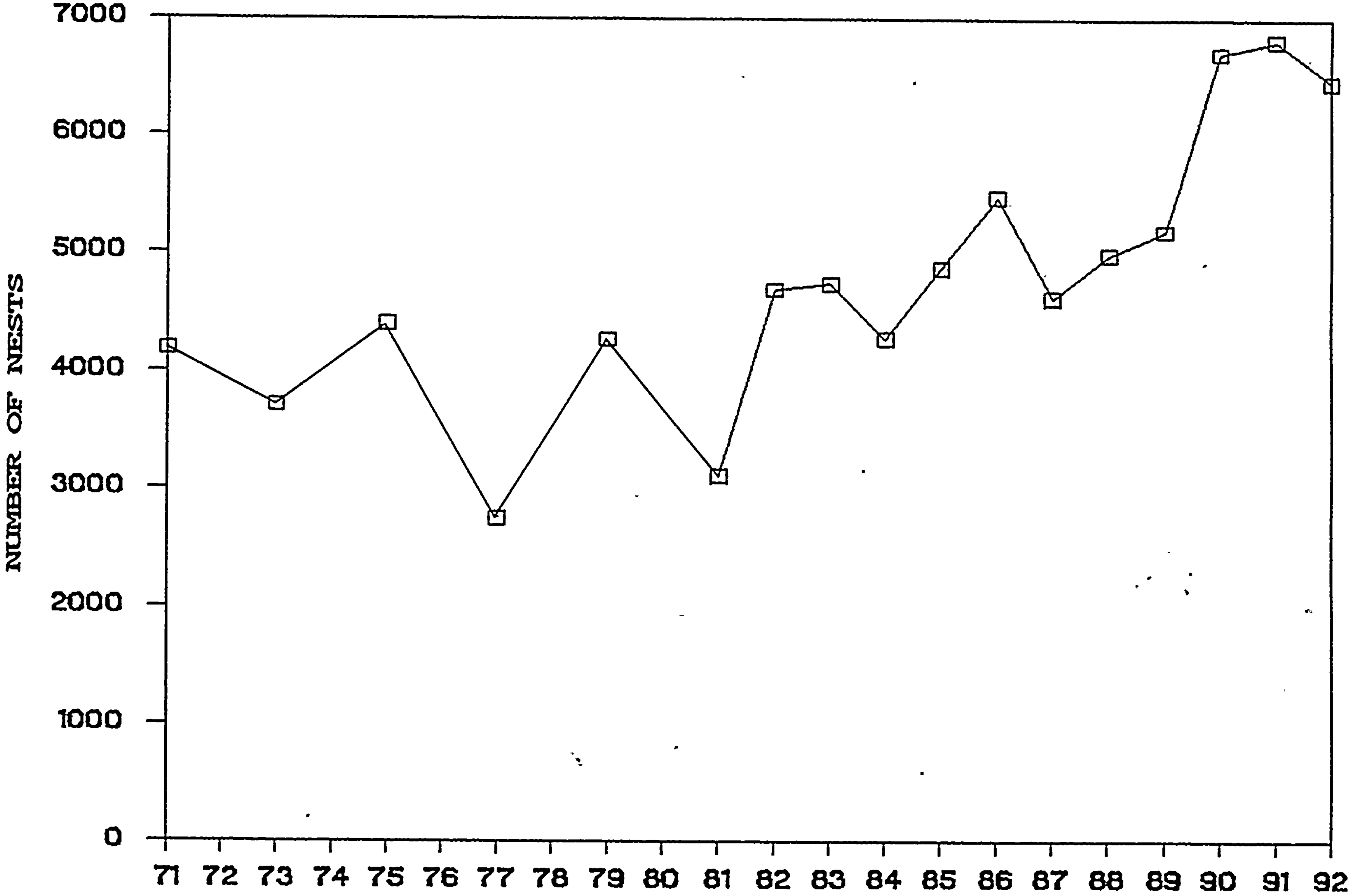

Figure 8. Number of loggerhead turtle nests, Hutchinson Island, 1971-1992. Numbers for 1971-1979 are estimates; numbers for 1981-1992 are recorded values (see text).

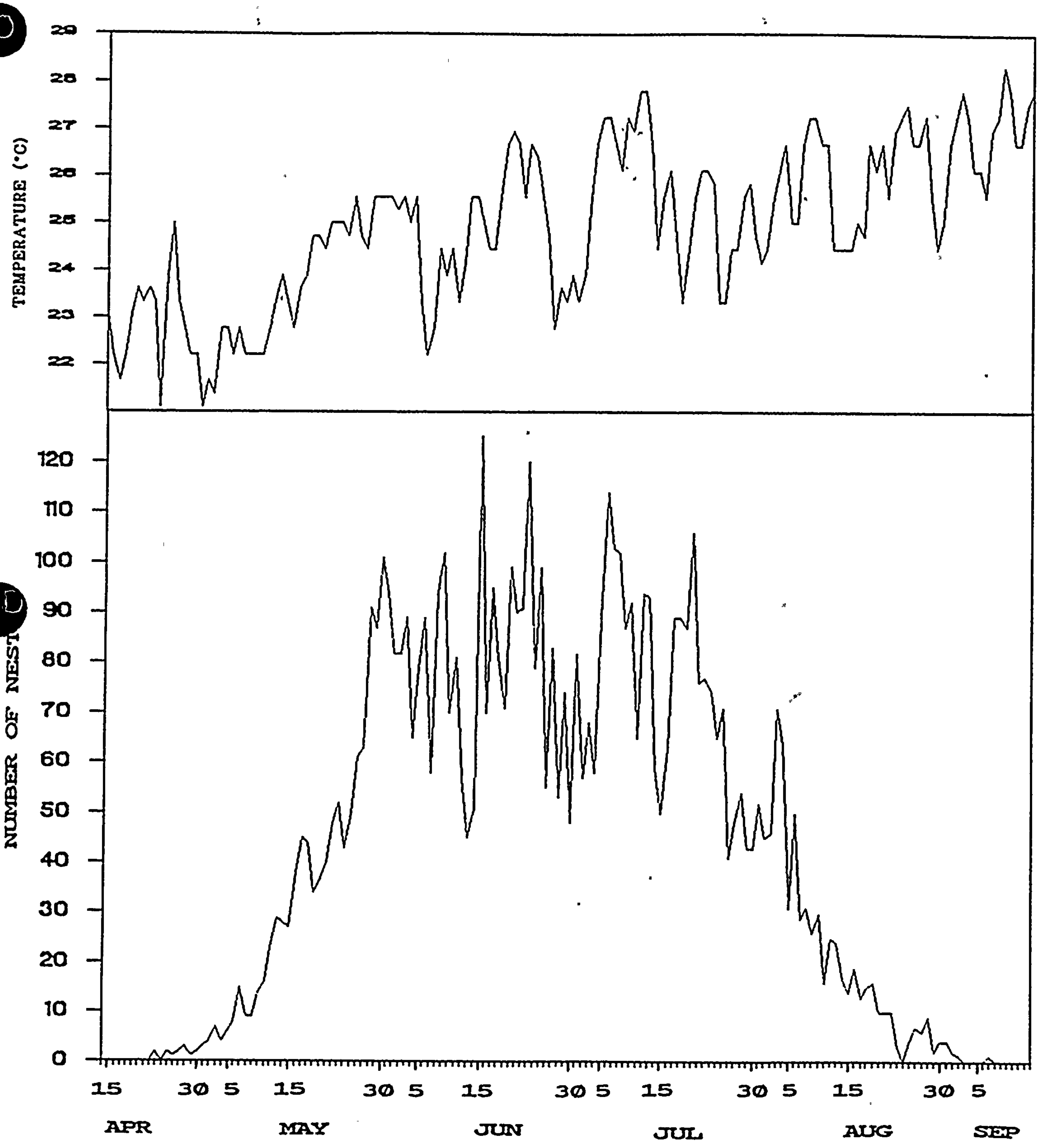

Figure 9. Daily loggerhead turtle nesting activity and water temperature, Hutchinson Island, 1992.

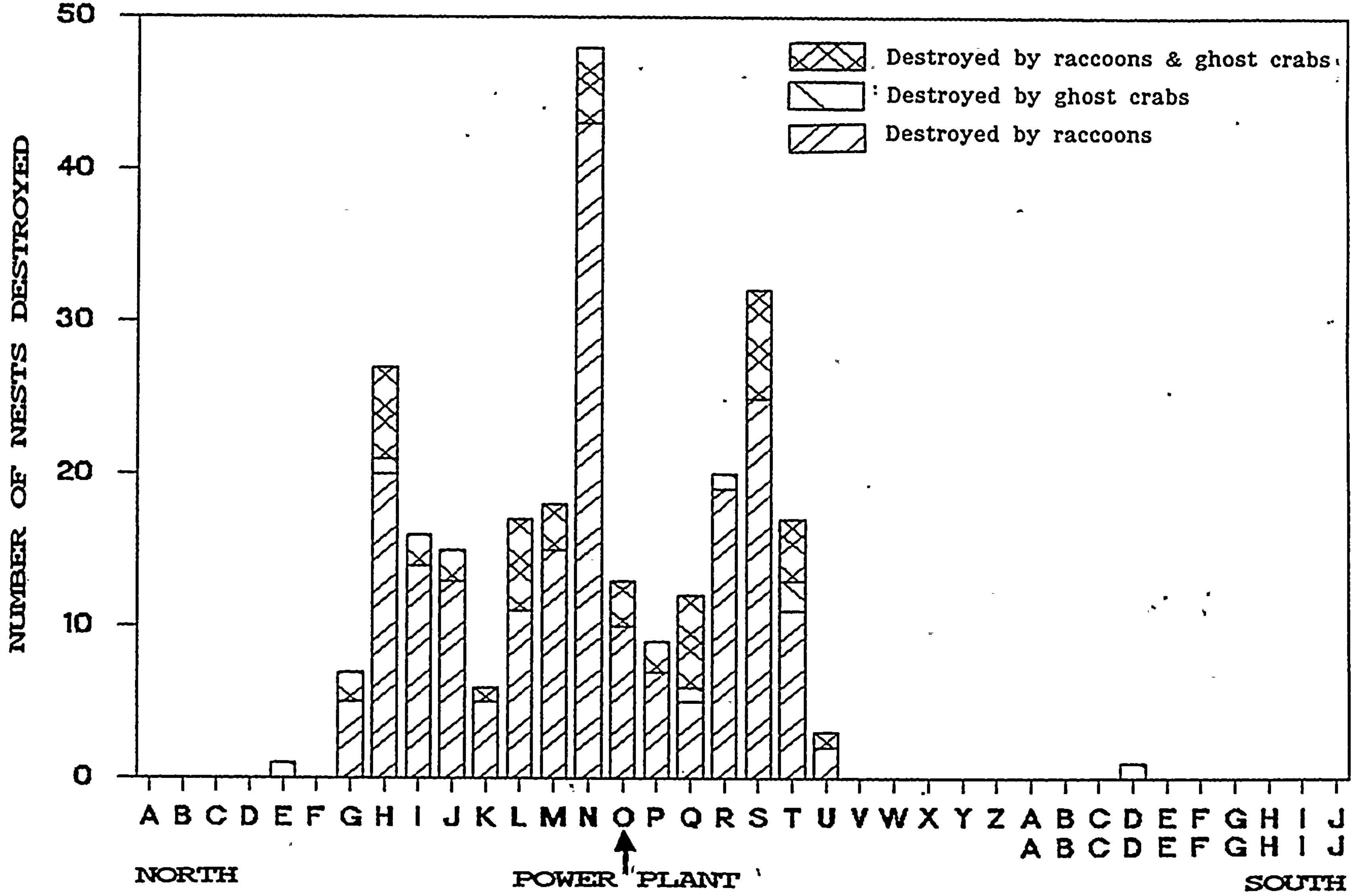

Figure 10. Number of loggerhead turtle nests destroyed by raccoons and ghost crabs in each 1-km-long survey area, Hutchinson Island, 1992.

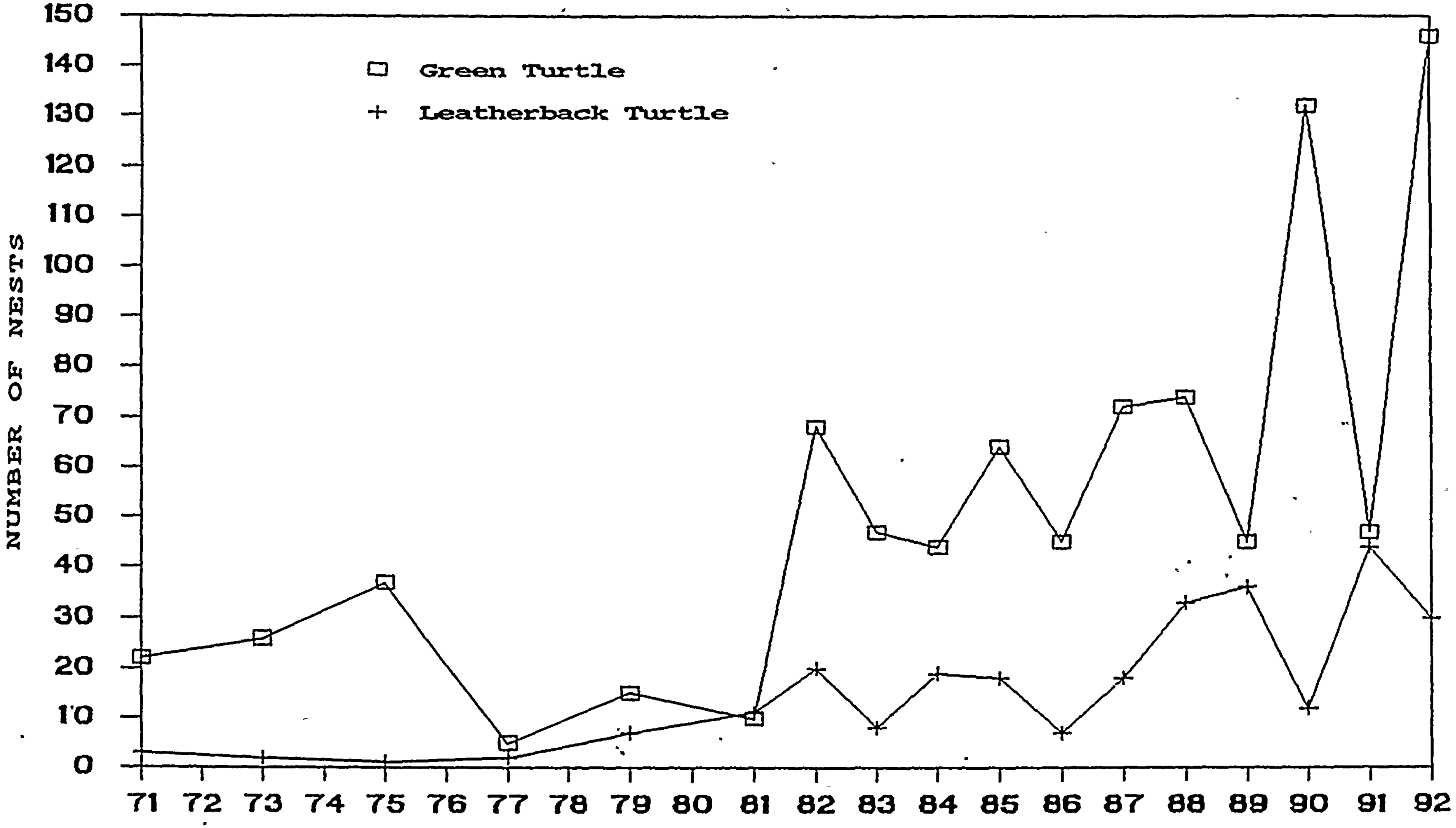

Figure 11. Number of green and leatherback turtle nests, Hutchinson Island, 1971-1992.

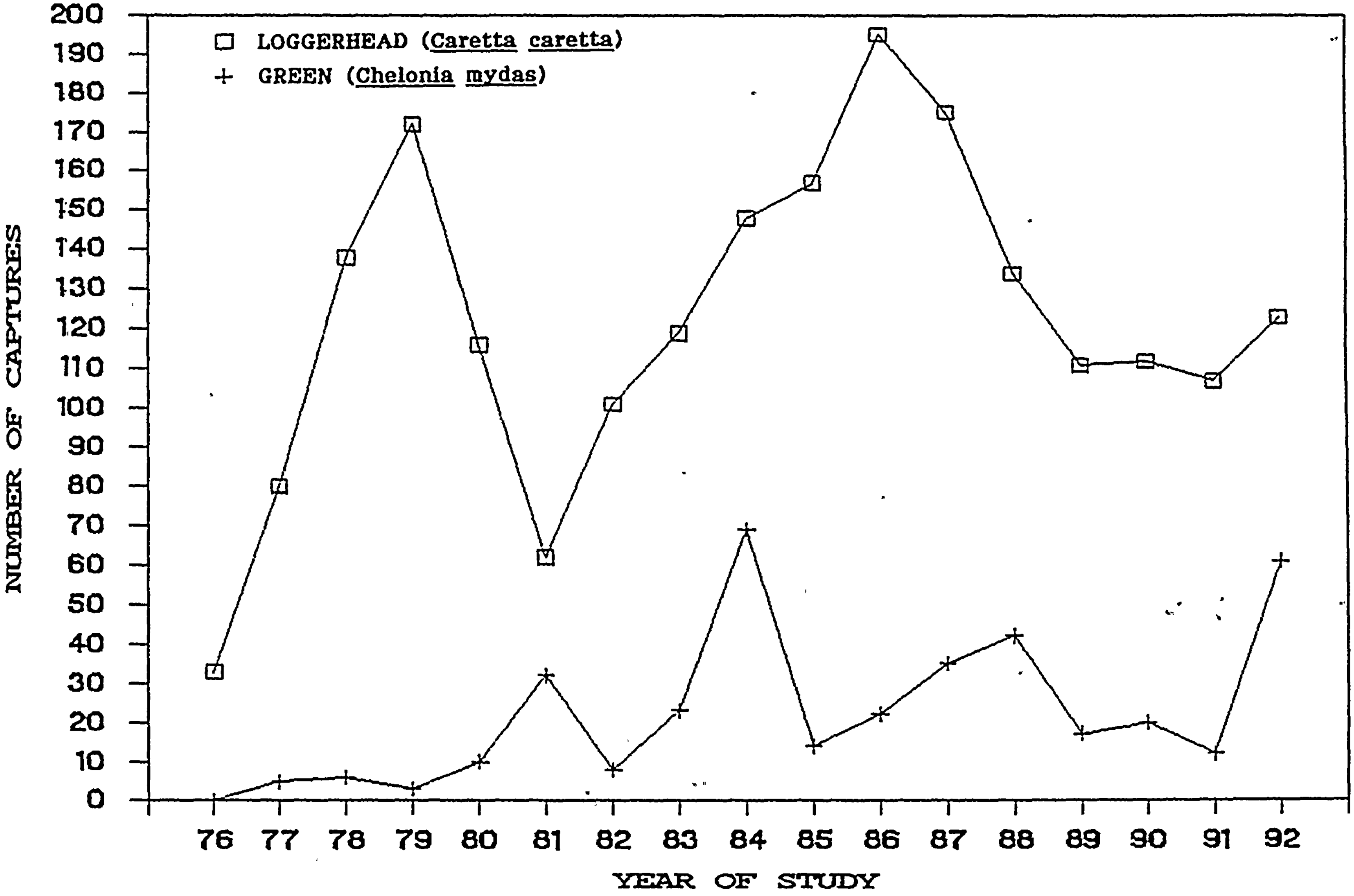

Figure 12. Number of loggerhead and green turtles removed each year from the intake canal, St. Lucie Plant, 1976-1992.

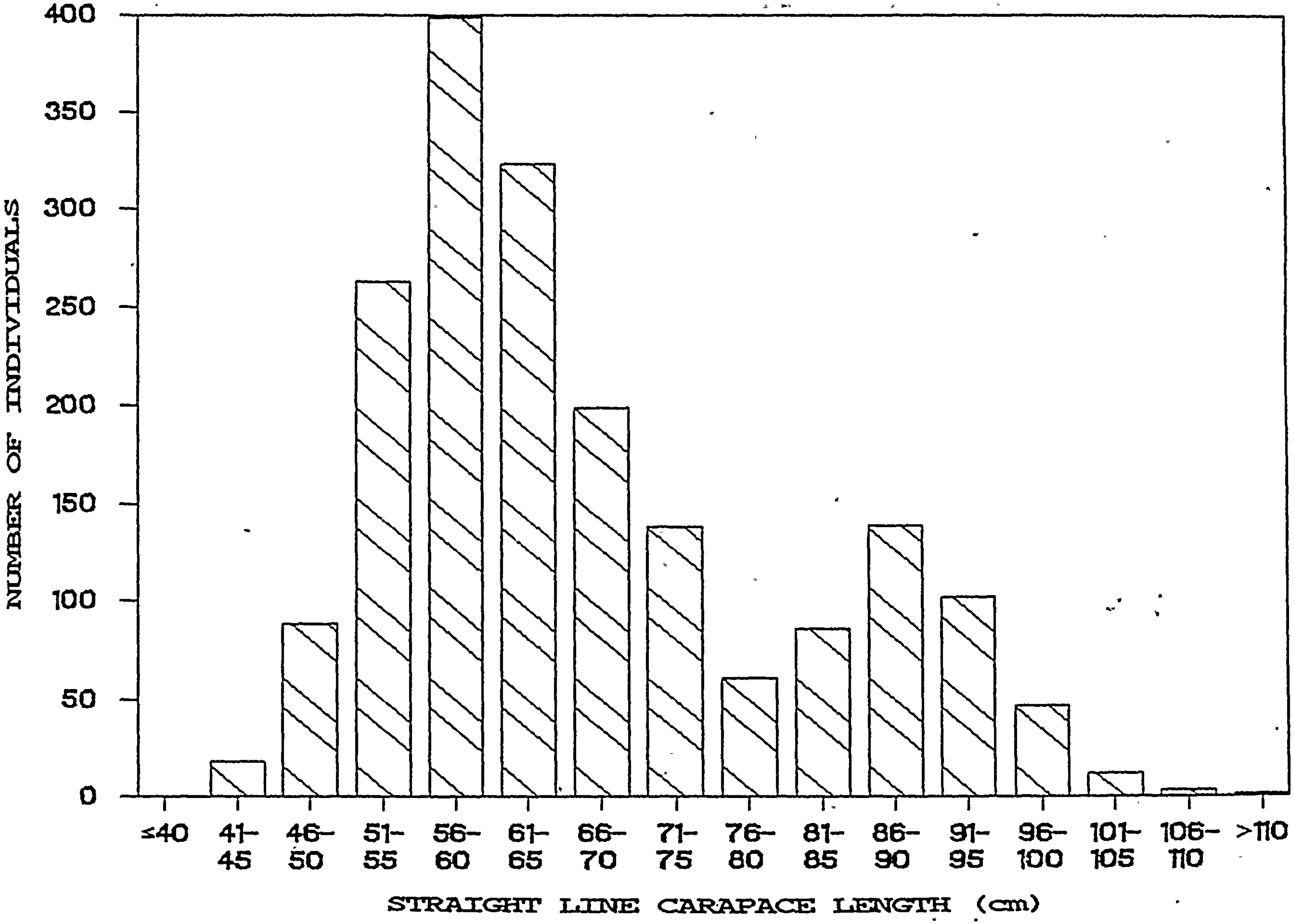

Figure 13. Length distribution (SLCL) of loggerhead turtles (N=1,879) removed for the first time from the intake canal, St. Lucie Plant, 1976-1992. No data collected for 83 individuals.

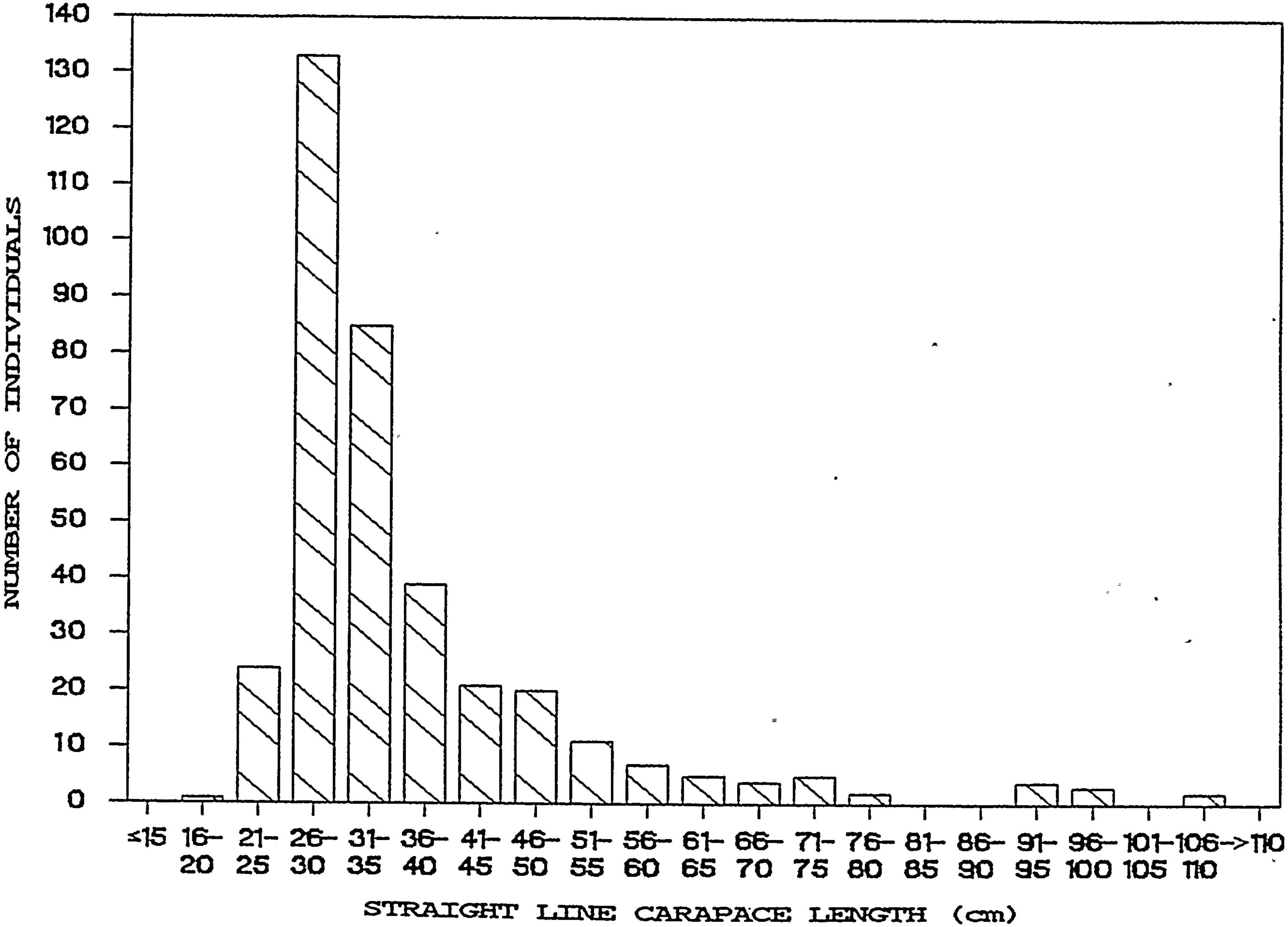

Figure 14. Length distribution (SLCL) of green turtles (N=366) removed for the first time from the intake canal, St. Lucie Plant, 1976-1992. No data collected for 10 individuals.

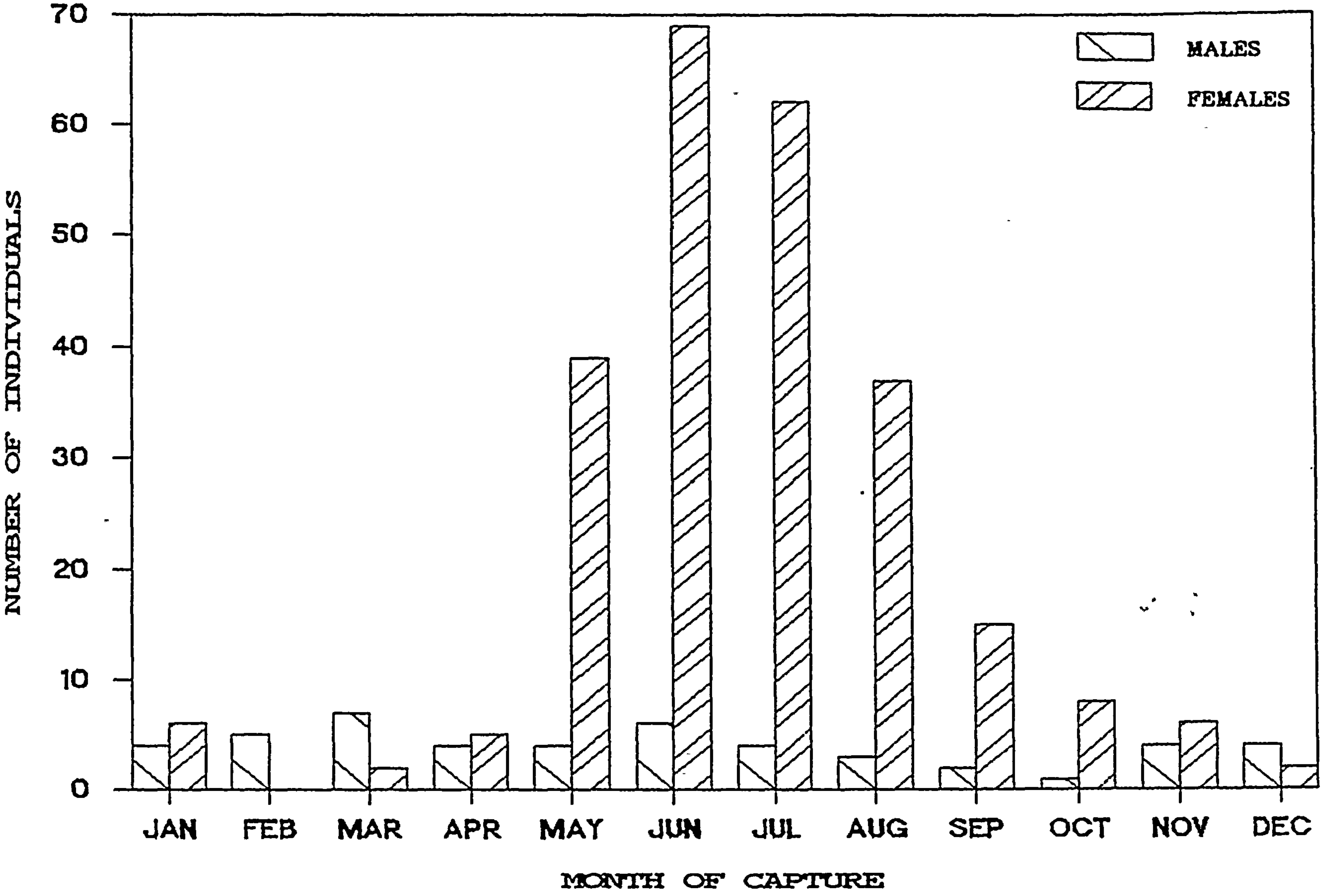

Figure 15. Numbers of adult loggerheads (SLCL>85.0 cm), including recaptures, removed each month from the intake canal, St. Lucie Plant, 1976-1992 (N=299, sex not recorded for 5 individuals >85.0 cm).

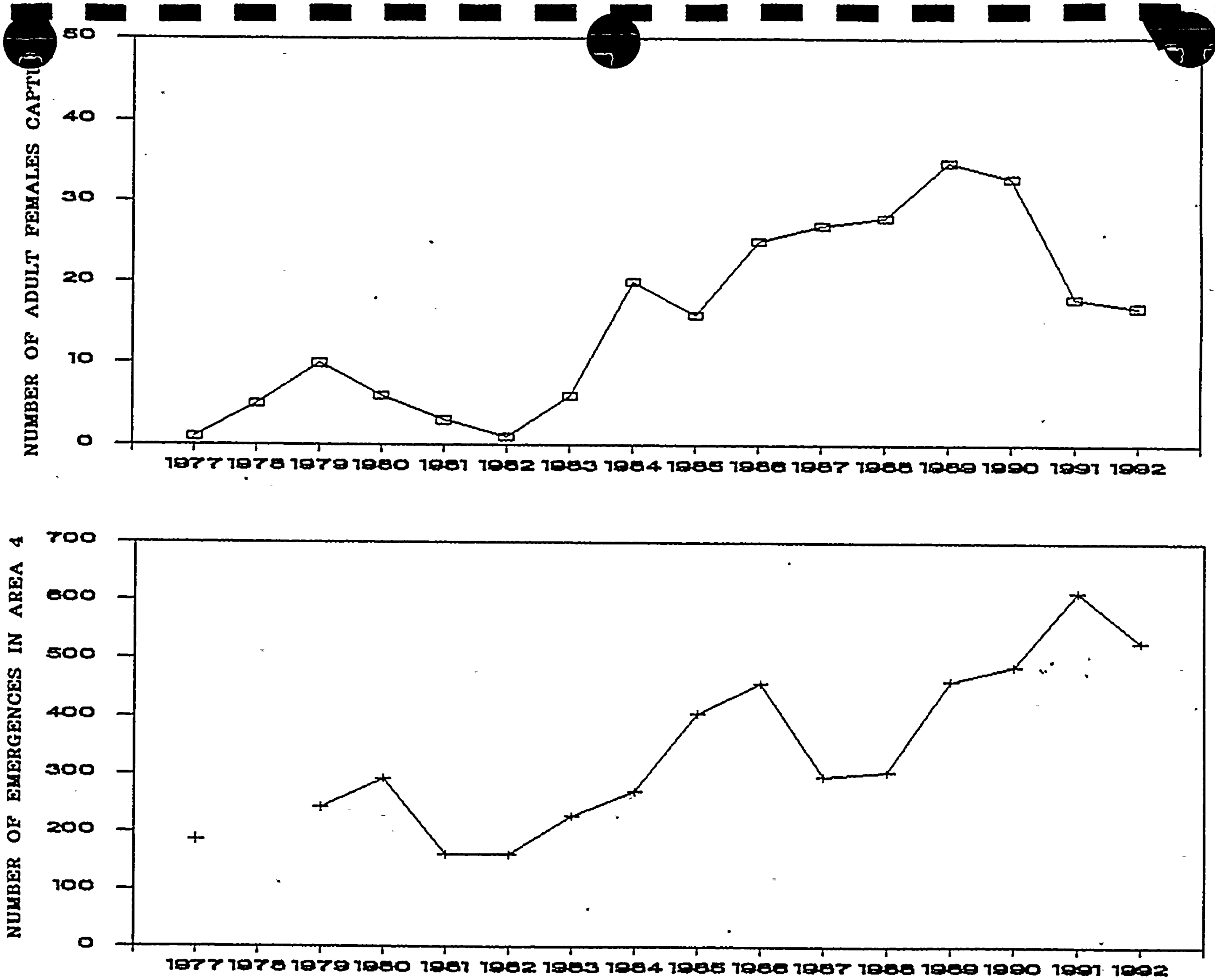

Figure 16. Comparison of captures of adult female loggerheads (SLCL>85.0 cm) in the intake canal, St. Lucie Plant, 1977-1992, and numbers of loggerhead emergences in area 4 adjacent to the plant. Nesting activity was not monitored in 1978.

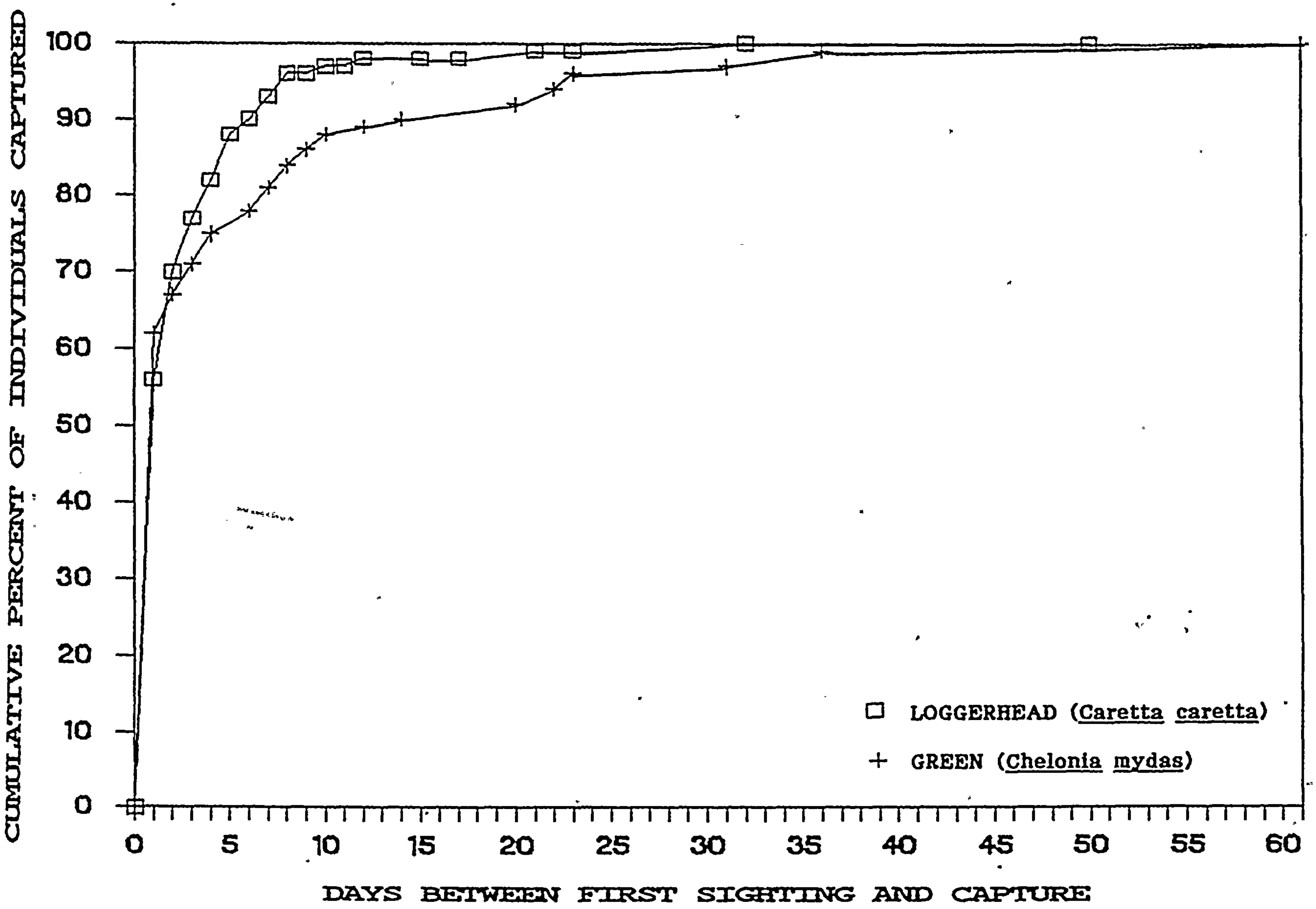

Figure 17. Capture efficiency, expressed as days between first sighting and capture, for loggerhead (N=272) and green turtles (N=73) entrapped in the intake canal, St. Lucie Plant, April, 1990-December, 1992.

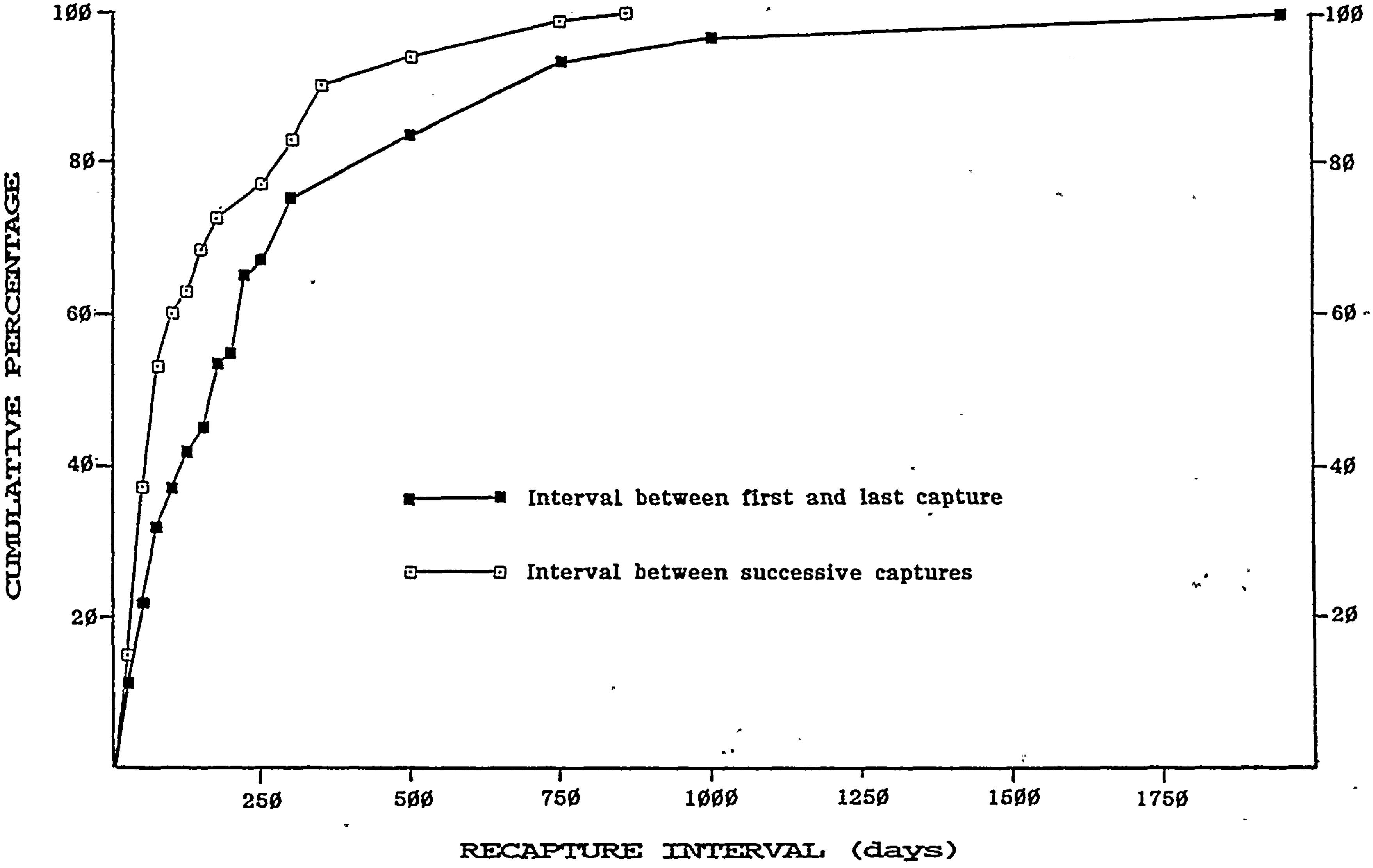

Figure 18. Cumulative percentage of all loggerhead recaptures occurring within various time intervals between successive captures (N=119) and first and last capture (N=68), St. Lucie Plant intake canal 1976-1992.

TABLE 1

ESTIMATES OF THE NUMBERS OF LOGGERHEAD TURTLE NESTS ON HUTCHINSON ISLAND BASED ON SURVEYS OF NINE 1.25-KM-LONG SURVEY AREAS, 1971 - 1992, COMPARED TO THE ACTUAL NUMBER OF NESTS ON THE ISLAND, 1981 - 1992

Year	Number of nests in the nine 1.25-km-long survey areas	Extrapolation from the nine survey areas to the entire island (see text)	Actual number of nests on the entire island
1971	1420	4188	-
1973	1260	3716	-
1975	1493	4403	-
1977	932	2748	-
1979	1449	4273	-
1981	1031	3040	3115
1982	1634	4819	4690
1983	1592	4695	4743
1984	1439	4244	4277
1985	1623	4786	4877
1986	1839	5423	5483
1987	1645	4851	4623
1988	1701	5016	4990
1989	1774	5232	5193
1990	2177	6420	6700
1991	2409	7104	6812
1992	2150	6340	6459

TABLE 2

TOTAL NUMBER OF SEA TURTLE CAPTURES AND (NUMBER OF DEAD) TURTLES REMOVED FROM THE INTAKE CANAL

ST. LUCIE PLANT, 1976 - 1992

	Species					
Year	loggerhead	green	leatherback	hawksbill	Kemp's ridley	Total
1976	33(4)					33(4)
1977	80(5)	5(2)	1			86(7)
1978	138(19)	6(1)	3	1		148(20)
1979	172(13)	3(1)				175(14)
1980	116(5)	10(3)				126(8)
1981	62(5)	32(2)	2		1	97(7)
1982	101(16)	8	1			110(16)
1983	119(4)	23(4)				142(8)
1984	148(3)	69(2)		1	2	220(5)
1985	157(4)	14		1		172(4)
1986	195(27)	22(1)	1	1	1	220(28)
1987	175(11)	35		2	6(2)	218(13)
1988	134(6)	42(2)			5(2)	181(10)
1989	111(4)	17(1)	1	2	2	133(5)
1990	112(1)	20(2)				132(3)
1991	107(1)	12		1	1	121(1)
1992	123(2)	61(2)	1	2		187(4)
Total	2083(130)	379(23)	10(0)	11(0)	18(4)	2501(157)
Annual Mean[a]	128.1	23.7	0.6	0.7	1.1	154.3
Std. Deviation	35.2	19.7	0.9	0.8	1.9	43.3

[a] Excludes 1976 (partial year of plant operation).

TABLE 3

TOTAL NUMBER OF LOGGERHEAD TURTLES REMOVED EACH MONTH FROM THE INTAKE CANAL
ST. LUCIE PLANT, 1977[a] - 1992

Month	1977 Through 1992						1992
	Number of Captures	Percent of All Captures	Minimum	Maximum	Mean	Standard Deviation	
January	251	12.2	6	39	15.7	8.5	19
February	202	9.9	5	29	12.6	5.8	12
March	175	8.5	1	27	10.9	7.0	3
April	189	9.2	0	24	11.8	7.3	13
May	176	8.6	0	28	11.0	8.8	1
June	224	10.9	3	30	14.0	9.2	5
July	187	9.1	0	27	11.7	9.1	16
August	186	9.1	2	34	11.6	9.2	8
September	138	6.7	1	19	8.6	5.5	11
October	129	6.3	0	17	8.1	5.3	11
November	93	4.5	0	15	5.8	4.2	11
December	100	4.9	1	13	6.3	4.1	13
Total	2050		0	39			123
Mean	170.8				10.7		10.3
Std. Deviation	47.7				7.6		5.2

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[a] First full year of plant operation. An additional 33 loggerheads were captured during 1976.

TABLE 4

TOTAL NUMBER OF GREEN TURTLES REMOVED EACH MONTH FROM THE INTAKE CANAL

ST. LUCIE PLANT, 1977[a] - 1992

	1977 Through 1992						1992
Month	Number of Captures	Percent of All Captures	Minimum	Maximum	Mean	Standard Deviation	
January	102	26.9	0	37	6.4	9.7	2
February	58	15.3	0	11	3.6	3.4	6
March	35	9.2	0	6	2.2	2.1	0
April	22	5.8	0	3	1.4	1.0	2
May	10	2.6	0	3	0.6	0.9	1
June	18	4.7	0	6	1.1	1.6	0
July	8	2.1	0	2	0.5	0.7	0
August	12	3.2	0	3	0.8	1.0	3
September	12	3.2	0	6	0.8	1.5	6
October	33	8.7	0	18	2.1	4.5	18
November	33	8.7	0	12	2.1	3.1	12
December	36	9.5	0	11	2.3	3.5	11
Total	379		0	37			61
Mean	31.6				2.0		5.1
Std. Deviation	26.6				3.9		7.8

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[a] First full year of plant operation.

TABLE 5

NUMBER OF MONTHLY CAPTURES BY SIZE CLASS FOR LOGGERHEAD TURTLES REMOVED FROM THE INTAKE CANAL ST. LUCIE PLANT, 1977 - 1992[a]

	Size classes (SLCL in cm)[b]											
	Juveniles					Transition		Adults				
Month	41-50	51-60	61-70	Total	Percentage	71-85	Percentage	86-90	91-100	>100	Total	Percentage
January	17	106	84	207	15.1	28	9.5	7	3	0	10	3.3
February	12	84	66	162	11.8	21	7.1	2	4	0	6	2.0
March	9	75	53	137	10.0	21	7.1	1	6	2	9	3.0
April	17	57	61	135	9.8	31	10.5	3	6	0	9	3.0
May	12	59	40	111	8.1	17	5.8	15	28	1	44	14.5
June	13	52	44	109	8.0	29	9.8	44	29	3	76	25.0
July	4	47	35	86	6.3	33	11.2	28	34	4	66	21.7
August	7	45	51	103	7.5	36	12.2	21	20	1	42	13.8
September	4	55	42	101	7.4	16	5.4	6	9	2	17	5.6
October	9	41	37	87	6.3	28	9.5	6	2	1	9	3.0
November	6	27	24	57	4.2	21	7.1	4	5	1	10	3.3
December	5	43	28	76	5.5	14	4.7	2	4	0	6	2.0
Total	115	691	565	1371		295		139	150	15	304	
% of Total					69.6		15.0					15.4

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[a] Excludes 1976 (partial year of data).

[b] No data were collected for 80 individuals.

TABLE 6

RELATIVE CONDITION OF SEA TURTLES REMOVED FROM THE INTAKE CANAL

ST. LUCIE PLANT, 1976 - 1992

Relative condition	Loggerheads		Greens		Leatherbacks		Kemp's ridleys		Hawksbills		All species	
	Number	%	Number	%	Number	%	Number	%	Number	%	Number	%
1	479	23.0	176	46.4	1	10.0	3	16.7	9	81.8	668	26.7
2	586	28.1	72	19.0	2	20.0	3	16.7	2	18.2	665	26.6
3	548	26.3	57	15.0	7	70.0	3	16.7			615	24.6
4	237	11.4	38	10.0			3	16.7			278	11.1
5	76	3.6	8	2.1			2	11.1			86	3.4
6	130	6.2	23	6.1			4	22.2			157	6.3
7	27	1.3	5	1.3							32	1.3
Total	2083		379		10		18		11		2501	

1 Excellent: normal or above normal weight, active, very few or no barnacles or leeches, no wounds.

2 Very good: intermediate good to excellent.

3 Good: normal weight, active, light to medium coverage of barnacles and/or leeches, wounds absent, healed or do not appear to debilitate the animal.

4 Fair: intermediate poor to good.

5 Poor: emaciated, slow or inactive, heavy barnacle coverage and/or leech infestation, debilitating wounds or missing appendages.

6 Dead

7 Alive but otherwise condition not recorded.

FLORIDA POWER & LIGHT COMPANY

ST. LUCIE UNIT 2

ANNUAL ENVIRONMENTAL OPERATING REPORT (FPL-92)

APRIL 1993

VOLUME II

ANNUAL ENVIRONMENTAL OPERATING REPORT

I. Introduction

The St. Lucie Unit 2 Environmental Protection Plan (EPP) requires the submittal of an annual report for various activities at the plant site including the reporting on sea turtle monitoring programs, and other matters related to Federal and State environmental permits and certifications. This report and Volume I described below fulfill these reporting requirements.

II. Sea Turtle Monitoring and Associated Activities

A report on aquatic and terrestrial sea turtle monitoring programs as described in EPP Sections 4.2.1 (Beach Nesting Surveys), 4.2.3 (Studies to Evaluate and/or Mitigate Intake Canal Mortality) and 4.2.5 (Capture and Release Program) is concurrently submitted in a separate report (AB-623 Vol. I) prepared by Applied Biology, Inc. of Jensen Beach, Florida and Atlanta, Georgia.

Studies to evaluate and/or mitigate intake entrapment required by Section 4.2.2 of the EPP have been previously performed. A final report was submitted to the Office of Nuclear Reactor Regulation on April 18, 1985. With submittal of that report, the EPP requirement was fulfilled and will not be readdressed in this or future reports.

Surveillance and maintenance of the light screen to minimize sea turtle disorientation as required by Section 4.2.4 of the EPP is ongoing. The Australian Pine light screen or other vegetation located on the beach dune between the power plant and the ocean is routinely surveyed to determine its overall vitality. The vegetation line is surveyed for any gaps occurring from mortality, which would result in unacceptable light levels on the beach. Trees, vegetation or shade cloth are replaced as necessary to maintain the overall integrity of the light screen.

III. Other Routine Reports

The following items for which reporting is required are listed by section number from the plant's Environmental Protection Plan (EPP):

5.4.1(a) EPP NONCOMPLIANCES AND CORRECTIVE ACTIONS TAKEN

No noncompliances under EPP Section 5.4.1(a) were determined to have occurred during 1992.

5.4.1(b) CHANGES IN STATION DESIGN OR OPERATION, TESTS, AND EXPERIMENTS IN ACCORDANCE WITH EPP SUBSECTION 3.1

No plant site activities were determined to be reportable under Section 5.4.1(b) during 1992.

5.4.1(c) NONROUTINE REPORTS SUBMITTED TO THE NRC FOR THE YEAR 1992 IN ACCORDANCE WITH EPP SUBSECTION 5.4.2:

1. Report concerning a modification to the St. Lucie Plant site's NPDES Permit issued by the USEPA for the use of the biocide Clamtrol; reported to the NRC on March 18, 1992.

2. Report concerning the application-for-renewal of the St. Lucie Plant site's NPDES Permit; reported to the NRC on May 7, 1992.

3. Report concerning an exceedance of the NPDES Permit minimum pH limitation for sewage treatment plant effluent; reported to the NRC on June 24, 1992.

4. Report concerning the release of hydrazine in an amount over the CERCLA RQ to the onsite Stormwater Basin; reported to the NRC on June 5, 1992.

5. Report concerning the release of hydrazine in an amount over the CERCLA RQ to the onsite Stormwater Basin; reported to the NRC on July 17, 1992.

6. Report concerning the exceedance of the NPDES Permit maximum time allowed for chlorination of the Unit 1 condensers; reported to the NRC on September 22, 1992.