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STEAM AND POWER CONVERSION SYSTEM

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CHAPTER 10

STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The steam and power conversion system is designed to convert thermal energy in the form of steam, as produced in the two steam generators, into electrical energy by means of a regenerative cycle turbine-generator. The turbine consists of a high pressure turbine element, four moisture-separator/reheater assemblies, and two low pressure turbine elements all aligned in tandem. After expanding in the turbine, the steam is condensed in the main condenser and the energy which is unusable in the thermal cycle is rejected to the circulating water system. The condensate is collected in a hotwell. Noncondensible gases in the steam are removed by the steam jet air ejectors. The condensate is returned to the steam generators by means of two condensate pumps and two steam generator feedwater pumps. The feedwater passes through five stages of heat exchangers (i.e., high and low pressure heaters) arranged in two parallel trains where it is heated by steam extracted from various stages of the turbine. The drains from the first three stages of low pressure heaters are eventually cascaded back to the condenser hotwell, and the drains from the fourth stage low pressure heaters and fifth stage high pressure heaters are returned to the feedwater system by two heater drain pumps. Heat produced in the reactor core is transferred from the reactor coolant to the water in the steam generators producing steam for use in the turbine. In the event of a turbine trip, the heat transferred from the reactor coolant to the steam generators is dissipated through the steam dump and bypass system to the condenser and/or through the atmospheric dump valves.

Safety related features of the steam and power conversion system include steam line isolation and auxiliary feedwater supply. These features are discussed in Section 10.3 and 10.5, respectively.

Design data as well as design codes applied to system components are given in Table 10.1-1. The system drawings are shown on Figures 10.1-1a through 10.1-1f, Figures 10.1-2a through 10.1-2d and 10.1-3. Data for the secondary loop heat balance is located in Figure 10.1-4.

A failure analysis of the non-seismic Class I portions of the steam and power conversion system and other systems has been performed to determine what effect a rupture of these components could have on safety related equipment.

Failures in the circulating water system have been analyzed both at the intake structure and in the turbine building. The only safety related components located on the intake structure are the intake cooling water pumps and the intake cooling water isolation valves between the essential seismic Class I headers of the intake cooling water system and the non-essential turbine cooling heat exchanger supply headers. Since the intake structure is an open deck structure with no internal compartments and since the intake cooling water pumps are located above the open deck, flooding damage to the pumps could not occur due to a rupture in the circulating water system. Water released on the deck would run off back to the intake canal or out onto the plant area. The header isolation valves are contained in a valve pit set into the deck of the intake structure. The valve pit has large drain openings which allow water entering the pit to drain off to the intake canal. The valve pit therefore cannot be flooded out due to circulating water system failures.

The main feedwater pump discharge motor-operated isolation valves are the only safety related components located in the turbine building. The turbine building is of open design and any internal flooding is designed to run out and be collected in various storm drains and catch basins. Since the main feedwater pump discharge motor-operated isolation valves are located approximately 5.5 feet above floor level in the turbine building, flooding will not affect the safety-related motor-operators of these valves. Therefore, flooding due to a rupture of the circulating water system or the condensate system within the turbine building will not lead to an unsafe plant condition or jeopardize plant safety features. Subsequent spillage out from the turbine building into the plant yard poses no threat to the auxiliary feedwater pumps which are located near the building since the pumps and motors are elevated above plant grade.

Rupture of any or all of the non-seismic Class I outdoor storage tanks, the largest of which are the city water storage tanks, primary water storage tank and turbine lube oil tank, pose no threat to safety related equipment since all released fluid will be captured, drained away in the yard drainage system or just run off the plant area. Inundation of safety related equipment from these sources is not credible.

A failure analysis of non-seismic Class I systems located in the reactor auxiliary building is discussed in Section 3.1 of the Fire Protection Appendix.

A failure analysis of non-seismic Class I systems and/or components located in the reactor building is discussed in Section 6.2.1.1(f), containment design bases.

A failure analysis of non-seismic Class I compressed gas systems and/or components located at the plant site is discussed in Section 9.3.1.3, compressed air system evaluation.

TABLE 10.1-1
DESIGN DATA FOR STEAM AND POWER CONVERSION SYSTEM COMPONENTS

1. Turbine-Generator

    a. Turbine

Throttle flow, max. guaranteed, lb/hr	10,446,749**
Throttle flow, max. calculated, lb/hr	12,266,130***
Throttle pressure, psia	806***
Steam moisture, max., percent	0.3***
Gross MWe. MW	1025.9***
KW @ VWO, max. calculated, KW	876,543**
Turbine back-pressure, in. Hg abs	3.14***
No. of extractions	5

    b. Generator

Rating, KVA	1,200,000
Power factor	0.90
Voltage, volts	22,000
Frequency/Phase, Hz	60/3
Hydrogen pressure, psig	75

2. Main Feedwater Pumps

Type	two-stage centrifugal, horizontally split case, single suction, double volute
Quantity	2
Capacity each, gpm	15,500
Head, feet	1,750
Design fluid temperature, °F	385

---

* VWO - valve wide open

** These values are retained for historical purposes.
*** EPU Operation @75°F CWT per Heat Balance

TABLE 10.1-1 (Cont'd)

Material		
Case	ASTM A487 Gr. CA6NM	
Impeller	ASTM A487 Gr. CA6NM	
Shaft	ASTM A-276, Type 410 HT	
Driver	Constant Speed, 3-ph, 60 cycle, Electric Motor, 7000 hp, 3575 rpm, 6600 v, 1.15 S.F.	
Codes	ASME Section VIII	
3. Auxiliary Feedwater Pumps	<u>Motor Driven</u>	<u>Steam Turbine Drive</u>
Type	Single suction, horizontal, split, double volute, horizontal centrifugal	
Stages	9	8
Quantity	2	1
Capacity each, gpm	*325	**600
Head, feet	2660	2660
Design fluid temperature, °F	120	120

S.F. - service factor

* includes minimum recirculation flow of 75 gpm

** includes minimum recirculation flow of 100 gpm

TABLE 10.1-1 (Cont'd)

	Motor Driven	Turbine Driven
Material		
Case	ASTM-351-52-T Gr CF8	ASTM-351-52-T Gr CF8
Impeller	ASTM A-351, Gr CA 15	ASTM A-351, Gr CA 15
Shaft	ASME SA-479, Type 410 HT	ASME SA-479,Type 410 HT
Driver	Constant Speed 3-ph 60 cycle, electric motor, 350 hp, 3570 rpm, 4000 v, 1.15 S.F.	Single stage, non-condensing steam turbine, 575 hp, 2000 to 3600 rpm.
Seismic requirements	Class I	Class I
Codes	ASME Sections III, 1971 class 3.	

4. Condensate Pumps

Type	Vertical centrifugal, 8-stage, can type
Quantity	3
Capacity each, gpm	10,200
Head, feet	1,230
Fluid temperature, °F	117.3
Material	
Case	ASTM A-278 CL 40 or ASTM A-216 Gr WCB
Impeller	ASTM A-48, CL 30, ASTM A-743 Gr CF8, or ASTM A-487 Gr CA6NM
Shaft	ASTM A-276, 410 HT or T

TABLE 10.1-1 (Cont'd)

	Driver	Constant speed, 3-ph, 60 cycle, electric motor, 4000 hp, 1190 rpm, 4000 v, 1.15 S.F.
	Codes	ASME Sections VIII through Winter 1969 addenda, or later
5.	Heater Drain Pumps	
	Type	Vertical centrifugal 7-stage can type
	Quantity	2
	Capacity each, gpm	4750 gpm
	Head, feet	850 ft
	Fluid temperature, °F	319°F
	Material	
	Case	ASTM A-285 GR C
	Impeller	ASTM A-743 Gr. CA6NM
	Shaft	ASTM A276 TY 410 COND T
	Driver	Constant speed, 3-ph, 60 cycle, electric motor, 1250 hp, 1780 rpm or 1500 hp, 1785 rpm, 4000 v, 1.15 S.F.
	Codes	ASME Sections VIII through Summer 2009 addenda.
6.	Main Condenser	API STD 682
	Type	Two shell, single pass with divided water boxes, surface condenser

TABLE 10.1-1 (Cont'd)

Design duty, Btu/hr	5.850×10^9	
Heat transfer area, ft^2	546,000	
Design pressures psig	Shell: Water Box: 25	15 psig and 30 in. Hg vacuum
Condenser Flow, max. guaranteed, lb/hr	7,820,492	
Condenser Flow, max. expected, lb/hr	8,212,960	8,234,551***
Material		
Shell	ASTM A-285, Gr C	
Tubes	ASTM-B-338 titanium Grade 2 throughout the condenser	
Tube Sheets	ASTM B-171 (Alloy 614)	
Codes	Heat Exchanger Institute Standards for Steam Surface Condensers 1965	

7. Steam Jet Air Ejector

a. Inter-Condenser

Type	single pass
Heat Transfer Area, ft^2	415
Design Pressure	
Tube side, psig	750
Shell side, psig	25
Material	
Shell	ASTM-A285, Gr C
Tubes	316 S.S. ASTM A249
Tube Sheets	316 S.S. ASTM A240

*** Cycle 15 with Replacement Steam Generators - 0% Plugging @ 2713.84 MW

TABLE 10.1-1 (Cont'd)

	Codes	Heat Exchange Institute Steam Jet Ejector Standard, Third Edition, 1956
b.	After-Condenser	
	Type	single pass
	Heat Transfer Area, ft^2	160
	Design Pressure	
	Tube side, psig	750
	Shell side, psig	25
	Material	
	Shell	ASTM-A285, Gr C
	Tube	316 S.S. (ASTM A249)
	Tube Sheets	316 S.S. (ASTM A240)
	Codes	Heat Exchange Institute Steam Jet Ejector Standard, Third Edition, 1956

8. Feedwater Heaters

Heater Numbers	1-A&1B,2A&2B,3A&3B	4A&4B	5A&5B
Type	Closed, U-tube	Closed, U-tube	Closed, U-tube
Material			
Shell	ASTM A-515-70	ASTM A-515-70	ASME SA 387-11-2
Tubes	ASME SA-688TP304	ASME SA-688TP304	ASME-SA-688-316L
Tube Sheets	ASTM A-105-II	ASTM A-105-II	ASME SA 350 LF2 & 11.375
Feedwater flow,			
Design lb/hr	7,812,500	11,169,900	13,306,000
Cycle 15 lb/hr	8,234,551	11,817,176	11,817,176

Codes ASME Section VIII through summer 1978 addenda and 2007 Edition, No addenda for Heater 5A/5B only
Heat Exchange Institute Standards for Closed
Feedwater Heaters.

TABLE 10.1-1 (Cont'd)

9. Drain Coolers

Cooler Numbers	A&B
Type	Straight Tube
Material	
Shell	ASTM A-515-70
Tubes	ASME-SA-688TP304
Tube sheets	ASTM A-105-II
Feedwater flow (lb/hr)	7,812,500
Codes	ASME Section VIII through summer 1978 addenda; Heat Exchange Institute Standards for closed Feedwater Heaters.

Heater No.	Design duty each (Btu/hr)	Design press. (psig) Shell	Tube	Design temp. (°F) Shell	Tube	Heat transfer area each (ft^2)
1A,IB	213.3x10^6	50 & V	750	300	300	20,484
2A,2B	166.2x10^6	50 & V	750	300	300	14,839
3A,3B	219.7x10^6	75 & V	750	320	320	14,452
4A,4B	399.3x10^6	300 & v	750	422	422	19,663
5A,5B	421.4x10^6	475	2025	550	500	28,109
Drain Cooler No.						
A,B	130.2x10^6	300	750	422	422	5,055

10. Piping and Valves

a. Piping	Material	Codes
Main Steam*	ASTM A-155, GR KC-65 CL I	ANSI B31,7, CL II, 1969
Main Steam to Auxiliary Feed Pump Inlet Valve	ASTM A-106, GR B	ANSI B31,7, CL II, 1969
Feedwater*	ASTM A-106, GR B	ANSI B31.7, CL II, 1969

TABLE 10.1-1 (Cont'd)

Balance of Piping		ANSI B31.1, 1967
Auxiliary Feed Pumps		
Suction (above ground)	ASTM A-106, Grade B	ANSI B31.7, CL III, 1969
Suction (under ground)	TYPE 316 SS	ANSI B31.7, CL III, 1969
Discharge	ASTM A-106, Grade B	ANSI B31.7, CL III, 1969

*To first steam isolation valve

b. <u>Main Steam Isolation Valves (HCV-08-1A,B</u>

Type	Stop & check
Quantity	2, 1 per main steam line
Design Pressure, psig	985
Design Temperature, °F	550
Materials	
Body	ASTM A216 Grade WCB
Disc	ASTM SA182-F6NM
Stem	ASTM A564 Type 630 (17-4PH)
Cover (fabricated)	ASTM A515, Grade 70 & A285 GR C
Seat facing	ASTM SA240 Grade 316
Code	ASME Draft Pump and Valve Code, Class II, 1968 Class II, 2004

c. <u>Main Steam Safety Valves</u>

Refer to Table 5.5-2.

d. <u>Atmospheric Dump Valves (HCV-08-2A, 2B)</u>

Type	Globe, angle body
Quantity	2, 1 per main steam line
Design Pressure, psig	985
Design Temperature, °F	550

TABLE 10.1-1 (Cont'd)

Materials	
Body	ASTM A-217, GR WC9
Stem	Type 316 SS
Seat & plug	17-4 PH Hardened SS
Code	ASME Draft Pump and Valve Code, Class II, 1968

e. Steam Dump Valves (PCV-8802,, 8803, 8804, 8805)

Number	4
Type	Globe
Operator	Pneumatic
Size/Class	14 in. 600 lb ANSI
Materials	
Body	ASTM A-216 Carbon Steel
Seat	410- SS
Plug	ASTM-A276/479, Type 410
Code	ASME-B16.34-2004

f. Steam Bypass Valve (PCV-8801)

Number	1
Type	Globe
Operator	Pneumatic
Size/Class	10 in. 600 lb ANSI
Materials	
Body	ASTM A-216 Carbon Steel
Seat	410- SS
Plug	ASTM-A276/479, Type 410
Code	ASME-B16.34-2004

TABLE 10.1-1 (Cont'd)

g. Steam Flow Elements (FE-8011, FE-8021)

Number	2
Type	Venturi
Pipe I.D., inches	31.50
Venturi Throat I.D., inches	20.757
Diameter Ratio	0.659
Area Ratio	0.434
Materials	
Pipe	ASTM A-155, GR KC-65 Class I
Venturi	ASTM A-240 TP 304 at Throat ASTM A-515 GR 55 at inlet & outlet
Code	ANSI B31.7 Class II, 1969

REFER TO DRAWING

8770-G-079 Sheet 1

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM MAIN STEAM SYSTEM - SH 1
FIGURE 10.1-1a

REFER TO DRAWING

8770-G-079 Sheet 2

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM MAIN STEAM SYSTEM – SH 2
FIGURE 10.1-1b

REFER TO DRAWING

8770-G-079 Sheet 3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM EXTRACTION STEAM
SYSTEM - SH 1
FIGURE 10.1-1c

REFER TO DRAWING

8770-G-079 Sheet 4

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM EXTRACTION STEAM SYSTEM - SH 2
FIGURE 10.1-1d

REFER TO DRAWING

8770-G-079 Sheet 5

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM AUXILIARY STEAM SYSTEM
FIGURE 10.1-1e

REFER TO DRAWING

8770-G-079 Sheet 6

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM AIR EVACUATION SYSTEM
FIGURE 10.1-1f

REFER TO DRAWING

8770-G-080 Sheet 1

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM CONDENSATE SYSTEM
SH 1
FIGURE 10.1-2a

REFER TO DRAWING

8770-G-080 Sheet 2

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM CONDENSATE SYSTEM
SH 2
FIGURE 10.1-2b

REFER TO DRAWING

8770-G-080 Sheet 3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM FEEDWATER &
CONDENSATE SYSTEMS SHEET 3

FIGURE 10.1-2c

REFER TO DRAWING

8770-G-080 Sheet 4

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM FEEDWATER &
CONDENSATE SYSTEMS SHEET 4

FIGURE 10.1-2d

Refer to drawing

8770-G-080 Sheet 5

Amendment No. 22 (05/07)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM MAIN FEEDWATER

FIGURE 10.1-2e

REFER TO DRAWING

8770-G-081 Sheets 1, 2 & 3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM
HEATER DRAIN AND VENT SYSTEM

FIGURE 10.1-3

Refer to drawing

8770-G-056 Sheets 1 - 29

Amendment No. 26 (11/13)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

HEAT BALANCE

FIGURE 10.1-4

10.2 TURBINE-GENERATOR

10.2.1 DESIGN BASES

The turbine-generator is intended for load following operation and is designed for load changes from 15 to 100 percent power and 100 to 15 percent power at a maximum rate of 5 percent per minute and at greater rates over smaller load change increments, up to a step change of 10 percent. However, it is acceptable to operate as a base load unit. The turbine-generator has a guaranteed gross rating of 1080 MWe and 1200 Mva. Table 10.1-1 lists other pertinent performance characteristics.

The turbine-generator is not designed for operation under the stresses that could be imposed by the operating basis earthquake (OBE) or the design basis earthquake (DBE). However, the turbine-generator is designed to function under the thermal stresses which could be imposed due to upset conditions, emergency conditions and faulted conditions as defined in Section 2 of N18.2, Nuclear Safety Criteria for the Design of Stationary Pressurized Water Reactor Plants, January 1972.

10.2.2 DESCRIPTION

The turbine is a Siemens Energy Inc., tandem-compound, four-flow exhaust, 1800 rpm unit, and has moisture separation and reheat between the high pressure and the two low pressure elements. The ac generator and brushless-type exciter are direct-connected to the turbine-generator shaft. The turbine consists of one double-flow high pressure element in tandem with two double-flow low pressure elements.

There are four horizontal-axis, cylindrical-shell, combination moisture-separator/reheater (MSR) assemblies located alongside the low pressure elements on the turbine building operating floor. This equipment receives steam from the exhaust of the high pressure turbine element. Internal manifolds in the lower section of these assemblies distribute the wet steam and allow it to rise through a chevron type moisture-separator where the moisture is removed. Steam extracted from the main steam line, upstream of the turbine, enters each MSR assembly, passes through the reheater tube bundle and leaves as condensate. The steam leaving the separator rises past the reheater tube bundle where it is reheated to approximately 510°F when operating at full power; the steam is reheated to approximately 280°F at 25 percent power. This reheated steam passes through nozzles in the top of the assemblies, flows to the low pressure turbine elements, and finally exhausts to the condenser (see Figures 10.1-1a and 10.1-1b).

The turbine is equipped with two electronic, triple redundant online testable emergency trip systems that trip the stop and control valves to a closed position in the event of turbine overspeed, low bearing oil pressure, low vacuum, or thrust bearing failure. Three electric solenoid trip valves for each trip system are provided for remote manual trips and for various automatic trips. In addition, a turbine trip initiates a main generator lockout to prevent generator damage. The turbine control system is discussed in Section 7.7.1.4. Upon occurrence of a turbine trip, a signal is supplied to the reactor protective system to trip the reactor. The logic-circuitry for this trip function is discussed in Section 7.2.

The turbine generator is provided with three overspeed protection systems (see Figure 10.2-1):

a) Overspeed protection controller (OPC)

b) Two electronic, triple redundant overspeed protection systems.

The OPC system and the primary electronic overspeed system do not share any sensing devices.

Overspeed Protection Control (OPC) System

The OPC system is an electrohydraulic control system that controls turbine overspeed in the event of a complete loss of load and if the turbine reaches or exceeds 103 percent of rated speed. It trips the turbine at 111 percent of rated speed.

Turbine input power is a function of intermediate pressure (IP) exhaust pressure; a pressure transducer provides IP exhaust pressure. A three phase watt transducer provides generated KW information. These quantities are compared; if they differ by a preset amount, protective logic is activated. The signals from the transducers are checked against high and low reference voltages to determine when a transducer fails high or low. Overspeed information (in rpm) is supplied by active (powered) pick-ups coupled magnetically to a notched wheel on the turbine rotor. These pick-ups generate pulses which are fed to the Digital Electro-Hydraulic (DEH) cabinet to form speed channels: a control speed channel and an OPC speed channel.

The output of the control speed channel cards is compared to an overspeed setpoint. The resulting signal indicates when the speed is above the setpoint. If the speed is above the setpoint, a signal is generated for use by the overspeed protection controller (OPC) circuitry. It is also checked against a high and low limit. If either limit is exceeded, corresponding failure signals are generated.

The OPC continuously monitors the protection system inputs and outputs to notify the control room operators when equipment failures are encountered.

Upon complete loss of load the mismatch of IP pressure and megawatts occurs, and the breaker opens, this condition is detected as a complete load loss. When the generator breaker opens, the Load Drop Anticipation (LDA) is set, requesting OPC action. All governor and interceptor valves are then rapidly closed. Load drop reset time is fixed at 4 sec. LDA load loss circuits are inoperable below 30 percent load.

OPC action also occurs when turbine speed is equal to, or greater than, 103 percent of rated speed. Governor and interceptor valves are closed until the speed drops below 103 percent. In addition, the redundant electronic emergency trip system will de-energize triple redundant solenoids which will cause all turbine valves to trip if the turbine speed reaches 111 percent of rated speed (see Figure 10.2-1). An air pilot valve used to vent control air to close the extraction steam non-return valves is also triggered by the trip systems.

Electronic Overspeed Protection System

Two independent, triple redundant electronic emergency trip systems replace the original mechanical overspeed protection system. Both systems independently release the control oil pressure, tripping all turbine valves when the turbine reaches an 111 percent overspeed condition. Therefore, all valves capable of admitting steam into the turbine will close. The primary protection system uses triple redundant passive speed sensors to monitor turbine speed. The redundant protection system shares the triple redundant active (powered) speed sensors with the OPC controller. Turbine speed is also monitored by "built for purpose" speed cards capable of tripping the turbine independently (communication with the electronic emergency trip system controllers is not required). The resulting overspeed protection is therefore, redundant and diverse.

Protective functions of the original auto-stop oil system are integrated into the primary electronic overspeed trip system. The turbine is tripped when any one of the pressure status manifolds detect a trip condition. Protection parameters, such as the low bearing oil pressure and low vacuum are monitored by pressure status manifolds equipped with triple redundant smart pressure transmitters. The thrust bearing is also monitored by triple redundant proximity probes. The primary protection system trips the turbine when any of these parameters exceed a setpoint specified by the turbine manufacturer. The primary protection system also provides a trip signal monitored by the redundant protection system. This results in a turbine trip from the redundant protection system. Additionally, protective logic in the original auto-stop oil systems are "hard wired", via new tripping relay contacts, into each of the triple redundant solenoid trip circuits. (See Figures 10.2-3 and 10.2-4.)

Each triple redundant electronic emergency trip system uses a testable dump manifold (TDM) to interface with the control oil system. The 2-out-of-3 solenoid logic used to provide a protective trip also provides a means to test the system automatically while on-line. The solenoids are tripped one at the time and installed test pressure transmitters monitor the manifold for a detectable pressure change.

The operator has a graphic window on the Turbine Trip Status Display graphic where he can modify the Overspeed Trip #2 Setpoint. It is normally set at 1998 rpm. During turbine run-up, a test mode can be entered which changes the overspeed trip setpoint to 1799 rpm. This test mode provides the ability to test overspeed trip capability without stressing the turbine by overspeeding. The Overspeed Trip #2 Setpoint is reset and test results are reported to the operator after completion of the test.

A turbine lube oil system supplies oil for lubricating the turbine-generator and exciter bearings. A bypass stream of turbine lubricating oil flows continuously through an oil conditioner to remove water and other impurities.

The generator is a hydrogen-cooled, rotor-and-stator unit rated at 1200 mva with the capability to accept the gross rated output of the turbine at rated steam conditions. The generator shaft seals are oil sealed to prevent hydrogen leakage. An alarm indicates any leakage of hydrogen into the exciter.

The main, extraction, and auxiliary steam system drawings are shown on Figures 10.1-1a through 10.1-1e.

The heating steam for the feedwater heaters is extracted from the turbine as follows: Extractions for the high pressure heaters (5A & 5B) and low pressure heaters (4A & 4B) are from the high pressure turbine element; the extractions for the remaining low pressure heaters (1A & 1B, 2A & 2B, 3A & 3B) are from the low pressure turbine elements. High pressure heaters 5A and 5B are drained into low pressure heaters 4A and 4B; the drains from the low pressure heaters 4A and 4B are directed to the drain coolers. The condensate accumulated in the drain coolers is then pumped by the two heater drain pumps back to the condensate and feedwater heaters and ultimately to the condenser. Alternate drains are also provided to automatically drain all the heaters directly to the condenser when a condition of high heater water level occurs. In addition, heaters 5A and 5B collect the drains from the reheater drain collectors and heaters 4A and 4B collect the drains from the moisture-separator drain pots.

10.2.3 TURBINE MISSILES

A discussion and analysis of potential turbine missiles is provided in Section 3.5.2.2 and 3.5.3.2.

10.2.4 EVALUATION

The turbine-generator unit as well as other steam handling components of the steam and power conversion system are not expected to contain significant radioactive concentrations. Refer to Table 10.2-1 for expected radioactivity concentrations in the system.

Refer to Sections 11.2.5 and 11.3.5 for discussion of radiation concentrations and expected releases of radioactivity during operation. The anticipated operating radioactive concentrations in the system do not require shielding or access control in the turbine building.

Inservice inspection of the turbine-generator unit consists of periodic visual examinations. Other nondestructive testing includes magnafluxing of the rotors and blades. An ultrasonic examination of the low pressure turbine rotor discs is required at approximately 100,000 operating hour intervals provided no cracks are detected. Inspection intervals shall not exceed 12 years to allow adjustments for operating cycles based on Siemens Energy Inc. recommendations. Refer to Section 3.5.3.2 for a discussion on the justification for the 100,000 hr inspection interval.

10.2-1

EXPECTED RADIOACTIVITY CONCENTRATIONS IN THE STEAM AND POWER CONVERSION SYSTEM

```
CASE NO.   1

BLOWDOWN RATE                           1.39000E-01  (GALLONS/MINUTE)      7.40739E-08  (SEC-1)
LEAKAGE RATE OF STEAM GENERATOR         0.00000E 00  (LBS/HR)              0.00000E 00  (SEC-1)
LEAKAGE RATE OR TURBINE                 2.00000E 01  (LBS/HR)              5.30277E-08  (SEC-1)
LEAKAGE RATE OF CONDENSER               0.00000E 00  (LBS/HR)              0.00000E 00  (SEC-1)
X/Q                                     1.73000E-06  (SEC/CUBIC METER)

                                                                 SPECIFIC          SPECIFIC          SPECIFIC
          ACTIVITIES IN     ACTIVITIES IN     ACTIVITIES IN    ACTIVITIES IN     ACTIVITIES IN     ACTIVITIES IN
            (CURIES)          (CURIES)          (CURIES)       (CURIES/LBS)      (CURIES/LBS)      (CURIES/LBS)
ISOTOPES  STEAM GENERATOR     TURBINE          CONDENSER      STEAM GENERATOR     TURBINE           CONDENSER
********  ***************  *************    *************    ***************     *******           *********

H-3         1.58260E-01     9.08004E-02      1.39532E 00       6.06359E-07      8.66689E-07       8.66655E-07
KR-85M      1.09058E-05     6.24307E-06      0.00000E 00       4.17846E-11      5.95976E-11       0.00000E 00
KR-85       2.82835E-06     1.62275E-06      0.00000E 00       1.08366E-11      1.54891E-11       0.00000E 00
KR-87       5.87763E-06     3.34841E-06      0.00000E 00       2.25196E-11      3.19605E-11       0.00000E 00
KR-88       1.89899E-05     1.08590E-05      0.00000E 00       7.27583E-11      1.03649E-10       0.00000E 00
XE-131M     1.08720E-05     6.23755E-06      0.00000E 00       4.16553E-11      5.95374E-11       0.00000E 00
XE-133      1.32952E-03     7.62750E-04      0.00000E 00       5.09396E-09      7.28044E-09       0.00000E 00
XE-135      5.52205E-05     3.16503E-05      0.00000E 00       2.11573E-10      3.02101E-10       0.00000E 00
XE-138      2.47767E-06     1.36861E-06      0.00000E 00       9.49298E-12      1.30634E-11       0.00000E 00
I-129       1.69010E-08     4.84866E-10      7.44741E-09       6.47580E-14      4.62804E-15       4.62572E-15
I-131       1.89367E-01     5.43215E-03      8.33750E-02       7.25545E-07      5.18498E-08       5.17857E-08
I-132       2.24198E-02     6.43085E-04      9.85970E-03       8.58998E-08      6.13824E-09       6.12403E-09
I-133       3.57744E-02     1.02581E-03      1.56498E-02       1.37067E-07      9.79138E-09       9.72037E-09
I-134       1.75731E-04     4.98843E-06      6.59024E-05       6.73299E-10      4.76145E-11       4.09332E-11
I-135       5.61685E-03     1.60910E-04      2.42036E-03       2.15205E-08      1.53588E-09       1.50333E-09
BR-84       8.42854E-06     2.37957E-07      2.76454E-06       3.22932E-11      2.27130E-12       1.71711E-12
RB-88       2.66712E-04     7.42444E-06      7.76097E-05       1.02188E-09      7.08662E-11       4.82048E-11
RB-89       5.88682E-06     1.63146E-07      1.62746E-06       2.25549E-11      1.55723E-12       1.01084E-12
SR-89       1.12005E-03     3.21311E-05      4.93519E-04       4.29139E-09      3.06691E-10       3.06534E-10
SR-90       4.70624E-05     1.35065E-06      2.07446E-05       1.80392E-10      1.28920E-11       1.28848E-11
SR-91       6.55961E-05     1.88150E-06      2.88357E-05       2.51326E-10      1.79589E-11       1.79104E-11
Y-90        1.76646E-09     1.48809E-11      6.02055E-12       6.76804E-15      1.42037E-16       3.73947E-18
Y-91        1.69341E-02     4.85739E-04      7.46084E-03       6.48817E-08      4.63638E-09       4.63406E-09
MO-99       3.89302E-02     1.11664E-03      1.71152E-02       1.49158E-07      1.06583E-08       1.06306E-08
RU-103      5.39649E-04     1.54808E-05      2.37746E-04       2.06762E-09      1.47764E-10       1.47668E-10
RU-106      5.35477E-05     1.53613E-06      2.35942E-05       2.05163E-10      1.46623E-11       1.46548E-11
TE-129      3.05232E-03     8.75614E-05      1.34145E-03       1.16947E-08      8.35773E-10       8.33205E-10
TE-132      7.29639E-03     2.09290E-04      3.20885E-03       2.79555E-08      1.99767E-09       1.99307E-09
TE-134      6.62958E-06     1.87904E-07      2.43997E-06       2.54007E-11      1.79353E-12       1.51551E-12
CS-134      2.25146E-02     6.45880E-04      9.92049E-03       8.62630E-08      6.16492E-09       6.16179E-09
CS-136      1.77352E-03     5.08757E-05      7.81089E-04       6.79508E-09      4.85608E-10       4.85149E-10
CS-137      7.48004E-02     2.14581E-03      3.29591E-02       2.86592E-07      2.04817E-08       2.04715E-08
CS-138      1.26025E-04     3.55565E-06      4.34078E-05       4.82855E-10      3.39386E-11       2.69614E-11
BA-140      4.24949E-04     1.21902E-05      1.87155E-04       1.62816E-09      1.16355E-10       1.16245E-10
LA-140      6.96427E-05     1.99739E-06      3.05712E-05       2.66830E-10      1.90651E-11       1.89883E-11
PR-143      4.12470E-04     1.18323E-05      1.81661E-04       1.58035E-09      1.12939E-10       1.12833E-10
CE-144      8.72378E-04     2.50260E-05      3.84385E-04       3.34245E-09      2.38873E-10       2.38749E-10
* CO-60     1.19723E-03     3.43452E-05      5.27531E-04       4.58709E-09      3.27824E-10       3.27659E-10
* CO-58     7.67050E-03     2.20044E-04      3.37955E-03       2.93889E-08      2.10032E-09       2.09910E-09
* FE-59     3.00506E-05     8.62059E-07      1.32394E-05       1.15136E-10      8.22834E-12       8.22321E-12
* MN-54     5.84151E-05     1.67576E-06      2.57388E-05       2.23813E-10      1.59951E-11       1.59866E-11
* CR-51     4.17112E-03     1.19656E-04      1.83749E-03       1.59813E-08      1.14211E-09       1.14130E-09
* ZR-95     5.44477E-10     1.47630E-11      1.19877E-10       2.08612E-15      1.40913E-16       7.44575E-17
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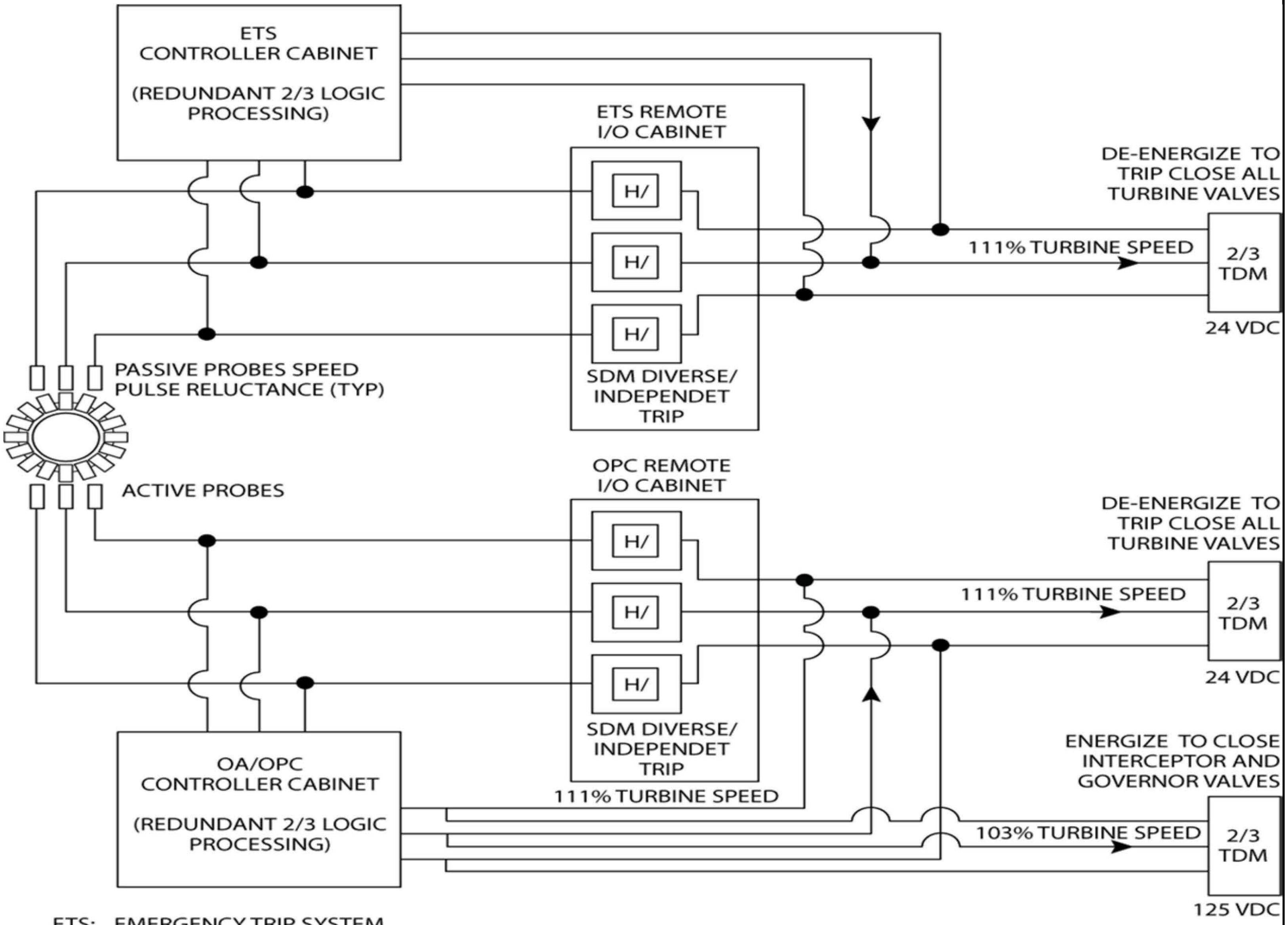
* Corrosion Products



ETS:	EMERGENCY TRIP SYSTEM
OA:	OPERATOR AUTOMATIC
OPC:	OVERSPEED PROTECTION CONTROLLER
SDM:	SPEED DETECTOR MODULE
TDM:	TESTABLE DUMP VALVE

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

TURBINE OVERSPEED PROTECTION
ELECTRO-HYDRAULIC SYSTEM

FIGURE 10.2-1

NOT USED

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MECHANICAL TURBINE OVERSPEED
PROTECTION SYSTEM
FIGURE 10.2-2

REFER TO DRAWING
8770-G-086 Sheet 2

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM TURBINE LUBE OIL
SYSTEM - SH 2
FIGURE 10.2-3

REFER TO DRAWING
8770-G-086 Sheet 3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM TURBINE LUBE OIL
SYSTEM - SH 3
FIGURE 10.2-4

10.3 MAIN STEAM SUPPLY SYSTEM

10.3.1 DESIGN BASES

The main steam piping system has the following safety design bases:

a) Maintain containment integrity in the event of a loss of coolant accident (GDC 57 criteria)

b) Prevent uncontrolled blowdown of both steam generators in the event of a steam line rupture accident

c) Provide means for reactor coolant system decay heat removal in the event of a loss of off-site power

d) Provide system integrity by design to seismic Class I standards for those components serving an isolation function and/or other safety function

e) Provide overpressure protection for the steam generators and main steam supply system

The main steam isolation valves and their actuation system components (i.e., solenoid valves, nitrogen accumulators and control devices) are required to perform an isolation function and are designed to perform their safety related function during or following a design basis earthquake. All components are designed for seismic loads (after appropriate amplification) of 0.6g horizontal and 0.375g vertical acting simultaneously and are classified as seismic Class I as expressed in item (d) above. Seismic qualification of the actuator system precludes inadvertent MSIV closure during a seismic event should there be a failure of the non-safety related air supply system. Nitrogen accumulator tanks are provided to close the MSIV 30 minutes after the initiation of a Steam Generator Tube Rupture (SGTR) event. Section 10.3.2 discusses further the intended function of these valves.

The main steam atmospheric dump valves are designed to withstand design basis earthquake loads as specified above in addition to the simultaneous effects of discharge thrust, dead weight and internal pressure loads.

10.3.2 SYSTEM DESCRIPTION

The main steam supply system is shown in Figures 10.1-1a and 10.1-1b.

Each of the two steam generators supplies steam to the turbine through a separate 34-inch O.D. main steam line. The main steam line containment penetrations are designed with the flexibility to accommodate the expansions and contractions of the containment vessel. The steam lines, which are anchored on the outside of the penetration assemblies, have enough flexibility to accommodate the expansions and contractions of the steam generators and the lines up to the anchor point. The design of the main steam line penetration assemblies is discussed in Section 3.8.2.

There are eight spring-loaded main steam safety valves located outside the containment in each main steam line upstream of the isolation valve which discharge to atmosphere when actuated. Refer to Section 5.5 for a detailed description of these valves.

An atmospheric dump valve, operated manually from the control room, is connected to each main steam line upstream of the steam line isolation valve. Together the two valves have the capacity to dissipate decay heat at the level existing immediately following reactor shutdown, with an adequate margin to initiate cooling at 75°F/hr down to approximately 350°F. Cooling beyond this would be accomplished at a lower rate. Using both valves, the plant can be cooled down to 325°F in about 7-2/3 hours, including 1 hour at hot standby (RCP's not operating). Note that plant procedures limit the cooldown rate to a maximum of 50°F/hr under natural circulation conditions with 2 ADV's available. During normal startup, shutdown and load change operations, secondary steam may be released to the atmosphere. The steam dump and bypass system, which uses the condenser as a heat sink, may otherwise be utilized. Additional cooldown capability is provided by the steam dump and bypass system which consists of four dump lines and one bypass line. These lines connect to the steam lines going to the moisture-separator/reheater tube bundles and discharge through control valves to the condenser.

The two main steam lines are cross connected between the isolation valves and the turbine stop valves. Steam from the common header is supplied to the high pressure turbine leads, four moisture-separator/reheater assemblies, turbine gland steam sealing system, auxiliary steam system, steam jet air ejectors, and water box priming ejectors. Each steam turbine lead has an automatic turbine stop valve and a steam turbine governing control valve upstream of the turbine. The feedwater heaters do not receive steam directly from the steam generators but from extraction from various stages of the turbine.

A four inch branch line from each of the main steam lines is used to supply steam for the turbine drive on auxiliary feedwater pump 1C. The two branch lines are formed upstream of the main steam isolation valves and are headered just before the auxiliary turbine inlet. The lines are designed to seismic Class I standards. Refer to Table 10.3-1 for a tabulation of the branches from the main steam lines and for a listing of the various extractions to the feedwater heaters.

Each of the two main steam lines is provided with one main steam line isolation valve assembly consisting of a pneumatic/hydraulically operated stop valve butt welded to a check valve. The assembly is located outside the reactor containment structure and as near to it as practical. The isolation stop valve, mounted on the steam generator side of the assembly, is used to prevent steam from flowing from the steam generator to the turbine inlet manifold. The check valve is used to prevent backflow if the steam generator pressure drops below the turbine inlet manifold pressure.

Both isolation stop valves will close automatically on a main steam isolation signal (MSIS), which is actuated by either steam generator on steam generator low pressure, to prevent rapid flashing and blowdown of water in the shell side of the steam generator in the event of a steam line break, and thus avoid a rapid uncontrolled cooldown of the reactor coolant system. The isolation valve assemblies also prevent simultaneous release to the containment of the contents of the secondary sides of both steam generators in the event of the rupture of one main steam line inside the containment vessel. The check valve in the assembly prevents backflow through the cross connection and the stop valve on the intact steam generator will close on the faulted generator MSIS. The isolation valves can be remotely operated from the control room.

During normal at power operation the isolation stop valves will fail in the open position on loss of electric power to the solenoid valve and in the open position, due to residual hydraulic pressure, on loss of air supply. The stop valves will remain open for at least 8 hours after a loss of normal air supply, unless the valves are tripped or closed. Nitrogen accumulator tanks are provided to close the stop valves 30 minutes after the initiation of a Steam Generator Tube Rupture (SGTR) event. Further description of the air supply system is provided in Section 9.3. The isolation stop valves have limit switches for valve operation and open/close position indication in the control room. A pressure switch will initiate an alarm in the control room in the event of low pressure in the air accumulator system. The trip circuitry for the main steam isolation valves is discussed further in Section 7.3. EC288435

10.3.3 SYSTEM EVALUATION

The steam and power conversion system is designed to meet its safety design bases under conditions postulated to exist for each of the abnormal incidents for which it must perform a safety function.

The main steam system from the steam generators up to and including the main steam line isolation valves is designed as seismic Class I. This portion of the system provides a containment isolation function in case of a loss of coolant accident.

The main steam system is designed to prevent blowdown of both steam generators in the event of a postulated steam line break accident. Both main steam line isolation valves will receive a closure signal upon MSIS actuation from either steam generator. If the break should occur downsteam of the main steam line isolation valves, low steam generator pressure signals will cause closure of the main steam line isolation valves. The system is designed such that no single failure will cause both isolation valves to remain open. If the break should occur upstream of the steam line isolation valve of a steam generator, blowdown of the other steam generator by backflow will be prevented by the check valve in the broken steam line. If the check valve should fail to close, blowdown of the intact steam generator will still be prevented by the steam line isolation valve in the unbroken steam line. A steam flow element, venturi type, in each main steam line upstream of the main steam isolation valves is a component of the feedwater control system and also acts as a flow restrictor to impede the discharge of steam into the containment following a postulated steam line break accident. Appendix 3C presents a discussion of a main steam line break and mitigation on the main steam and feedwater systems with the resultant effects on safety related equipment due to the accident environment. Further information on the isolation function of this system is given in Table 6.2-16. Further discussion of the control circuitry for the main steam line isolation valves is given in Section 7.3.

The main steam system piping is arranged and restrained such that a rupture of one steam line cannot cause rupture of the other steam line damage containment or prevent reactor system residual heat removal through the intact steam generator. This is done by the placing of pipe whip restraints and a guard pipe around the main steam line as it penetrates the containment. Further discussion of the design and analysis of the main steam line piping is given in Sections 3.7.3 and 3.9.2.

Operating instrumentation is adequate to permit the operators to monitor individual component and system performance as well as secondary system radioactivity.

The design basis and actuator capabilities for MV-08-1A, 1B, 3, 13, and 14 have been reviewed in accordance with the requirements of Generic Letter 89-10, "Safety Related Motor Operated Valve Testing and Surveillance," as noted in Section 3.9.2.4.

10.3.4 TESTING AND INSPECTION

Inservice inspection and preoperational testing requirements are provided for as described in Chapter 16 and Chapter 14 respectively. Testing of system performance can be accomplished during normal operation.

The main steam isolation valves are capable of being tested during normal operation via a local test panel with test switches, push buttons and indicating lights. One panel is located near each valve. Testing can be accomplished during normal operation by energizing the test stroke solenoid valves, shown in Figure 10.3-1. For this type of test, the valve spindle will move downward approximately 1-1/2 inches and then will return to its original full open position. Testing of the MSIV at power is no longer routinely performed since even a part-stroke exercise increases the risk of a valve closure with the unit generating power (described in NUREG-1482).

During normal operation, solenoid valves SE-08-1A1, 1A2, 1A3, 1A4, 1B1, 1B2, 1B3 and 1B4 can be tested without disturbing MSIV operation. Testing of the solenoid valves is performed by stroking each valve separately. The test selector switch allows testing of one solenoid valve at a time using a selector switch and pushbutton switch. Valve position change is noted by test panel. The actuator is designed such that none of these valves can close an MSIV by itself. Pressure switches PS-08-12A3, 12A4, 12B3 and 12B4, located in the hydraulic circuits, are utilized to provide indication of solenoid valve position by means of additional test panel indicating lights.

It should be noted that the MSIV test control circuitry is physically separated from the safety related circuits required to close the MSIVs during a MSIS and, except during testing, these circuits are deenergized. The test circuit is automatically isolated from the safety related circuits should MSIS occur during a test.

Refer to Figure 7.3-18 for the MSIS logic diagram. The MSIS will override the open and close solenoids, and associated test solenoids during testing. Open and close solenoid valves will be energized upon receipt of MSIS whether they are in "Test" or in normal operating configurations.

During hot standby when the turbine stop valves are closed, the main steam isolation actuation devices and valves may be individually tested at approximate operating pressure and temperature by inputting an MSIS to each valve. The closure time for each valve can be precisely obtained from the computer-based sequence-of-events recorder.

The main steam isolation valve specification specifies that the stop and check valves shall be capable of stopping steam flow against full differential pressure of 1000 psi. The actual maximum differential being 900 psi. The vendor's instruction manual also indicates that the stop and check valve as a single unit is capable of stopping flow in either direction against full differential pressure. In order to open the valve once having closed it against full differential pressure it is necessary that the pressure on both sides of the valves be nearly equal. This is done by opening the 3 inch motor operated bypass valve. When the pressure on both sides of the tripped disc is nearly equal, the air pressure in the pneumatic cylinder opens the valve

Testing of the isolation valve closure provides assurance that the valve will operate when called upon to do so, and that the closure time is within specified limits. Assurance of the ability to function is tested by actually tripping the valve. Testing valve closure at the hot shutdown cooling steam flow condition provides adequate confirmatory data. The program for testing of these valves is as follows: Full closure testing shall be performed by verifying full closure within 6.0 seconds when tested pursuant to the Inservice Testing Program.

An analysis showing that the main steam isolation valves can withstand the blowdown forces accompanying a postulated break both inside containment and downstream of the valves has been done. The results are presented in Appendix 10A.

Qualification testing of system components is in accordance with requirements of the design codes listed in Table 10.1-1.

10.3.5 SECONDARY WATER CHEMISTRY

10.3.5.1 Chemistry Control Basis

Steam generator secondary side water chemistry control is accomplished by:

a. Control of Feedwater purity to limit the amount of impurities introduced into the steam generator.
b. Minimize Feedwater oxygen content prior to entry into steam generators.
c. Chemical addition to establish and maintain an environment which minimizes system corrosion.
d. Continuous steam generator blowdown to reduce concentration effects within steam generator.
e. Condensate polisher filter demineralizer (CPFD) system use.

Secondary water chemistry is based on the zero solids treatment method. This method employs the use of volatile additives to maintain system pH and to scavenge dissolved oxygen present in the feedwater.

An Oxygen scavenger, such as Hydrazine, is injected continuously into the secondary system to scavenge dissolved oxygen present in the feedwater and to promote the formation of a protective oxide layer on metal surfaces by keeping these layers in a reduced chemical state. An excess amount of hydrazine is maintained in the feedwater which thermally breaks down into the amine ammonia (ammonium hydroxide) within the steam generators. Since ammonia is volatile, it carries over with the steam and does not concentrate in the steam generator. Ammonia reaches an equilibrium level and establishes an alkaline condition in the steam generators and Condensate and Feedwater Systems. Oxygen scavengers (i.e., Hydrazine and/or Carbohydrazide) are also added to the steam generators during wet layup.

Secondary side pH is controlled to minimize general corrosion of ferrous material, reduce flow-accelerated corrosion and ultimately to minimize corrosion product transport to the steam generators and reduce secondary system component degradation. Neutralizing amines other than ammonia can also be injected to establish and optimize alkaline conditions. Amine additions may not be necessary during operation due to the ammonia produced from the decomposition of hydrazine. Amines may be used for pH control during wet lay-up of the steam generators and/or wet layup of secondary systems. Amines may also be used for pH control during plant startup.

A combination of amines is generally used to establish an effective pH control program throughout the steam, condensate and feed cycle. Dimethylamine (DMA) may be added to the secondary system to aid removal of sludge deposits from the steam generators and improve feed train pH control. DMA and ammonia have similar volatilities but may not be optimum for controlling pH and minimizing corrosion in wet steam areas. Ethanolamine (ETA) provides more effective pH control in wet steam areas and during plant startup and transients when ammonia levels may not yet be properly established in the feedtrain.

Boric acid may be added as an inhibitor to S/G tube denting or intergranular attack on the secondary side of the S/G tubes. Since boric acid is a weak acid and disassociates at steam generator operating conditions, it will not concentrate in the steam generator.

Condensate polishing is used as necessary to remove low level impurities (such as iron and copper oxides, and ions such as sodium and chloride) that enter the condensate during normal plant operation. Tables 10.3-4 and 10.3-5 show the system effectiveness in maintaining water chemistry.

Operating and non-operating modes' chemistry limits, specifications and Action Levels for the steam generators, Feedwater System and Condensate System are established and maintained in accordance with EPRI PWR Secondary Water Chemistry Guidelines, and controlled by plant procedures.

Poly Acrylic Acid may be added to inhibit the ability of iron oxide particles to agglomerate on the secondary side of the steam generator tubes. EC284034

10.3.5.2 Corrosion Control Effectiveness

Alkaline conditions in the feed train and the steam generator reduce general corrosion at elevated temperatures and decrease the release of soluble corrosion products from metal surfaces. These conditions promote the formation of a protective metal oxide film and thus reduce the corrosion products released into the steam generator.

Some oxygen scavengers also promote the formation of a metal oxide film by the reduction of ferric oxide to magnetite. Ferric oxide may be loosened from the metal surfaces and be transported by the feedwater. Magnetite, however, provides an adhesive, protective layer on carbon steel surfaces.

The use of boric acid to reduce the effects of steam generator tube denting and intergranular attack in steam generator crevices caused by a caustic environment, has been found effective in the EPRI/NP-6239 PWR Secondary Water Chemistry Guidelines, Rev. 2, 12/88. A low power soak with 50 ppm boron followed by normal operation with 5-10 ppm in the steam generator blowdown is recommended if the steam generators exhibit these tube degradation mechanisms.

Wet layup of the steam generators during outages with chemically treated water is performed to minimize corrosion and oxidation during the layup period. Protection is provided by an amine for pH control and an oxygen scavenger to maintain a protective oxide film and a reducing environment.

The removal of oxygen from the secondary waters is also essential in reducing corrosion. Oxygen dissolved in water causes corrosion that can result in pitting of ferrous metals, particularly carbon steel. Oxygen is removed from the steam cycle condensate in the main condenser deaerating section. Additional oxygen protection is obtained by chemical injection of an oxygen scavenger into the condensate stream. Maintaining a residual level of oxygen scavenger in the feedwater also ensures that any dissolved oxygen not removed by the main condenser is scavenged before it can enter the steam generator.

The presence of free hydroxide (OH) can cause rapid caustic stress corrosion if it is allowed to concentrate in a local area. Free hydroxide is avoided by maintaining proper pH control, and by minimizing impurity ingress into the steam generator.

Zero solids treatment is a control technique whereby both soluble and insoluble solids are excluded from the steam generator. This is accomplished by maintaining strict surveillance over the possible sources of feed train contamination (e.g.: main condenser cooling water leakage, air inleakage and subsequent corrosion product generation). Solids are also excluded by injecting only volatile chemicals to establish conditions which reduce corrosion and, therefore, reduce the transport of corrosion products into the steam generator.

In addition to minimizing the sources of contaminants entering the steam generator, continuous blowdown, described in Section 10.4.7 and condensate polishing described in Section 10.3.5.5, are employed to minimize their concentration. With the low solid levels which result from employing the above procedures, the accumulation of scale and deposits on steam generator heat transfer surfaces and internals is limited. Scale and deposit formations can alter the thermal hydraulic performance in local regions to such an extent that they create a mechanism which allows impurities to concentrate to high levels, and thus could possibly cause corrosion. Therefore, by limiting the ingress of solids into the steam generator, the effect of this type of corrosion is reduced.

Because they are volatile, the chemical additives will not concentrate in the steam generator, and do not represent chemical impurities which can themselves cause corrosion.

10.3.5.3 Chemistry Control Effects on Iodine Partitioning

System design and operating practices are directed towards the goal of corrosion protection which at the same time provides an excellent environment for the suppression of iodine emissions in steam. Secondary water chemistry will suppress the formation of volatile species of iodine in the steam generators and convert volatile iodine that may be carried over via primary to secondary leakage to non-volatile iodine compounds. As demonstrated in CE Topical Reports entitled "Iodine Decontamination Factors During PWR Steam Generation and Steam Venting" (References 1 and 2), iodine carryover in the steam generators is a function of moisture separator performance.

This report supports C-E's position on iodine decontamination factors in C-E designed and fabricated steam generating equipment. As a direct result of this work, steam generator iodine decontamination factors should not be lower than a value of 400 for design basis studies or less than 1000 for normal operation studies.

10.3.5.4 Secondary Side Wet Layup System

The purpose of the Secondary Side Wet Layup (SSWL) System is to protect the condensate/feedwater piping and equipment from corrosion and keep them clean during a plant outage. This is done by completely filling the secondary piping and equipment with a demineralized water solution containing 75 to 200 ppm of an approved oxygen scavenger and approximately 10 ppm of ammonia. The 10 ppm of ammonia is used to maintain a solution pH of 9.8 to 10.5. This solution is recirculated during wet layup periods.

The system is designed to fill the tube and shell side of the secondary side system simultaneously in approximately six hours, at a flow rate on each side of 200 gpm. The system is also capable of recirculating a volume equal to the total wet layup fluid inventory of the secondary side system in approximately six hours.

The extraction steam system piping will be filled with wet layup solution from the connection to the feedwater heaters to the nonreverse current valves, but this system is not included in the recirculation mode of the SSWL system. Also heaters 1A, 1B, 2A and 2B and the alternate drain piping of the heater drain system will be filled with wet layup fluid but are not included in the SSWL recirculation mode.

Wet layup piping tapping into the existing carbon steel lines are of carbon steel up to the first isolation valve (or double isolation valves, as applicable). The remainder of the wet layup piping system and equipment are Type 316 stainless steel.

Double isolation valves are provided at all interface points between high and low pressure systems where a differential operating pressure in excess of 600 psi can exist.

Pressure relief valves are provided at appropriate locations in the SSWL system to protect the system against overpressurization resulting from tie-in isolation valve seat leakage into the SSWL system.

A surge tank is provided to allow for free expansion and contraction of the fluid in the system resulting from ambient temperature variations. The surge tank will also be used to supply makeup water to the SSWL system. Flow indicators and throttling valves are provided for balancing the wet layup fluid flow between trains A and B for both the tube and shell side subsystem.

10.3.5.5 Condensate Polisher Filter Demineralizer (CPFD) System

The Condensate Polisher Filter Demineralizer (CPFD) System is designed to filter and deionize 15,840 GPM of condensate. The CPFD System is comprised of five filter/demineralizer units, a backwash pump, a resin precoat subsystem, an air subsystem, and a battery of isolation valves. Each filter/demineralizer unit is sized to handle a maximum flow rate of 5,100 GPM and is made up of a Powdex vessel, a resin trap and a holdup pump. (See Figures 10.3-5 and 10.3-6) Condensate is directed through the Powdex vessels, through the resin trap, and then back to the condensate system. The resin trap removes any resin that may have entered the condensate flow when it passed through the Powdex vessel.

The 24-inch headers (influent and effluent lines) connect the Condensate Polisher Demineralizer System (CPFD) with the existing condensate piping system. Condensate is normally diverted to the CPFD system prior to and during plant start-up. It also may be used during normal plant operation. The system can be connected to serve either Unit 1 or Unit 2 but not both at the same time.

Administrative controls will preclude the operation of the Backwash Treatment System if the resin becomes radioactive. However, the Backwash Treatment System is equipped with emergency provisions to handle potentially radioactive resin. After the spent resin is collected in the backwash receiver tank, the heavier solids are allowed to settle to the bottom of the tank. At a preset level in the backwash receiver tank, the backwash recovery pump will start to decant the water and process it through the PHP filter where it is cleaned of any fine resin particles. The solids settled at the bottom of the backwash receiver tank are then processed through a portable radioactive waste solidification system. (The portable radioactive waste -solidification system is not within the scope of the condensate polisher system).

REFERENCES FOR SECTION 10.3.5

1. J. A. Martucci, Iodine Decontamination Factors during PWR Steam Generation and Steam Venting, Topical Report CENPD-67, Rev. 1, Nuclear Power Department, Combustion Engineering, November 1974.

2. R. E. Mayer and E. R. D'Amaddio, Iodine Decontamination Factors During PWR Steam Generation and Steam Venting, Topical Report CENPD-67, Revision 1, Addendum 1, Nuclear Power Department, Combustion Engineering, November 1974.

TABLE 10.3-1

MAIN STEAM LINE AND TURBINE STEAM EXTRACTIONS

1. Line to Auxiliary Feedwater Pumps	
pipe size, in./schedule	4/80
Material	Carbon steel, A-106 GR B, A-335 P22 (P11)
Max. operating saturation pressure, psig	885
Design saturation pressure psig	985
Seismic class	Class I
Codes	ANSI B31.7, Class II
2. Auxiliary Services	
Pipe sizes, in./schedule	4 and 2½/80
Material	ASTM A-106 GR B, A-335 P22 (P11)
Max. operating saturation pressure, psig	885
Design saturation pressures psig	985
Seismic Class	None
Code	ANSI B 31.1, latest applicable edition
3. Lines to Moisture Separater Reheaters	
Pipe sizes, in./schedule	20/80 and 8/40
Material	ASTM A-106 GR B, A-335 P22 (P11)
Max. operating saturation pressure, psig	885
Design saturation pressure, psig	985
Seismic Class	None
Code	ANSI B 31.1, latest applicable edition

TABLE 10.3-1 (Cont'd)

4. Extraction to Heaters

	Heater 5	Heater 4	Heater 3	Heater 2	Heater 1
Line Size, in.	12/16	20	24	24 (2)	32 (4)
Wall Thickness, in.	0.375	0.375	0.375	0.375	0.375
Material	A106GRB, A335P22 (P11)	A106GRB, A335P22 (P11)	A106GRB, A335P22 (P11)	A106GRB, A335P22 (P11)	A106GRB, A335P22 (P11)
Operating Press, psia**	386	219	50	15.4	7.3
Operating Temp, °F	441	389	280	214	179
Design Pressure, psig	475	300	75	50	50
Design Temp, °F	550	425	320	250	250
Seismic Class	None	None	None	None	None
Code	ANSI B 31.1	ANSI B 31.1	ANSI B 31.1	ANSI B31.1	ANSI B 31.1

** Expected Operating Values For EPU

TABLE 10.3-2

DELETED

TABLE 10.3-3

DELETED

TABLE 10.3-4
CPFD SYSTEM DESIGN INFLUENT WATER QUALITY

Total dissolved solids	-100 - 3000 ppb as $CaCO_3$
Total suspended solids	-100 - 2000 ppb
Dissolved Silica	-20 -300 ppb as SiO_2
Total iron	-50 - 2000 ppb as Fe
Total copper	-10 -110 ppb as Cu
pH	-9.2 - 9.5

TABLE 10.3-5
CPFD SYSTEM DESIGN EFFLUENT WATER QUALITY

Total dissoved solids	-less than 20 ppb as $CaCO_3$
Total suspended solids	-less than 5ppb
Dissolved silica	-less than 10 ppb as SiO_2
Total iron	-less than 3 ppb as Fe
Total copper	-less than 1 ppb as Cu
pH	-9.2 - 9.5
Conductivity (cation) at 25°C	-less than 0.1 µmho/cm
Specific conductivity at 25°C	-less than 0.1 µmho/cm
Sodium	-less than 1ppb as Na
Chlorides	-less than 0.3 ppb as Cl

REFER TO DRAWING

8770-G-079 Sheet 7

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM MAIN STEAM

FIGURE 10.3-1

REFER TO DRAWING

8770-9673

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MSIV ASSEMBLY, SH.1

FIGURE 10.3-2

REFER TO DRAWING

8770-G-094 Sheet 1

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM SECONDARY SIDE WET LAYUP SYSTEM FEEDWATER HEATERS TUBE SIDE
FIGURE 10.3-3

REFER TO DRAWING

8770-G-094 Sheet 2

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM SECONDARY SIDE WET LAYUP SYSTEM FEEDWATER HEATERS SHELL SIDE
FIGURE 10.3-4

REFER TO DRAWING

8770-G-095, Sheets 1A & B

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM
CONDENSATE POLISHER FILTER
DEMINERALIZER
FIGURE 10.3-5

REFER TO DRAWING

8770-G-095, Sheet 2

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM
CONDENSATE POLISHER FILTER
DEMINERALIZER SYSTEM
FIGURE 10.3-6

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

Except for a portion of the feedwater system piping, the features, components and systems described in this section serve no safety function since they are not required for safe shutdown or to mitigate the effects of a LOCA and their failure will not result in the release of significant uncontrolled radioactivity.

10.4.1 MAIN CONDENSER

The main condenser is of the deaerating type and is sized to condense exhaust steam from the main turbine under full load conditions. The condenser consists of two 50 percent capacity, divided-water-box, surface condensers of the single pass type with tubes arranged perpendicular to the turbine shaft. The condenser shells are connected to the low pressure turbine exhausts by belt type, rubber expansion joints.

The condenser hotwell is a storage reservoir for the deaerated condensate which supplies the condensate pumps. The storage capacity of the hot well is sufficient for four minutes of operation at maximum throttle flow. The hotwell supply of condensate is backed up by the condensate storage tank from which condensate may be admitted into the condenser for deaeration.

The surface condenser water boxes were shop hydrostatically tested to 30 psig. After installation, the condenser was tested for leak tightness by filling with water to a level above the turbine exhaust flange. Field tests run to demonstrate performance are governed by the provisions of ASME Power Test Code for Steam-Condensing Apparatus.

Refer to Table 10.2-1 for a listing of expected condenser radioactivity inventory during normal operation.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

The main condenser evacuation system is shown on Figure 10.1-1f. The main condenser evacuation system consists of two hogging ejectors, two steam jet air ejectors with associated inter-and after-condensers, manifolds, valves and piping. The system is designed to establish and maintain condenser vacuum during start-up and normal operation.

During start-up, the two hogging ejectors evacuate a combined turbine and main condenser (empty hotwell) steam space of 142,000 cubic feet within a period of 60 minutes and thereafter maintain a condenser pressure of 5 inches Hg absolute. The steam-air mixture from the hogging ejectors is discharged to the atmosphere via discharge silencers. As start-up progresses, condenser evacuation is maintained by the two-stage, twin element, steam jet air ejectors. The steam jet air ejectors are designed to achieve a condenser vacuum of 3.5 to 1 inches Hg absolute during normal operation.

The steam jet air ejectors pass the evacuated mixture of air and water vapor through its inter- and after-condensers where most of the water vapor is condensed and the remaining noncondensable gases are discharged to the plant vent. Nitrogen is injected into the condenser to aid in removal of noncondensable gases. Noncondensable gases from the steam jet air ejectors are monitored for radioactivity prior to being discharged to the plant vent. The presence of radioactivity would indicate a reactor coolant-to-secondary system leak in the steam generators. Refer to Section 11.4.2.5.

Low condenser vacuum will cause a turbine trip as discussed in Section 7.7.

10.4.3 TURBINE GLAND STEAM SYSTEM

The turbine gland steam system is shown on Figures 10.1-1b and 10.1-1c.

The turbine gland steam system controls the steam pressure to the turbine glands to maintain adequate sealing under all conditions of turbine operation. The system consists of individually controlled diaphragm operated valves, relief valves, and a gland steam condenser.

The design of the diaphragm operated valves is "fail safe" such that failure of any valve will not endanger the turbine.

Gland steam is supplied from the main steam header. Each of the low pressure turbine glands have a gland steam supply regulator. Both high pressure turbine glands are supplied from one regulator. A spillover valve in the high pressure turbine gland seal will provide pressure regulation for the dumping of excess turbine gland leakage to the main condenser during high plant loads.

Noncondensable gases from the gland steam condenser may be monitored for radioactivity by the Condenser Air Ejector monitor and are normally routed to the plant vent. Refer to Section 11.4.2.5.

10.4.4 STEAM DUMP AND BYPASS SYSTEM

The steam dump and bypass system is shown on Figure 10.1-1b.

The Steam Dump and bypass System is designed to remove excess heat from the Nuclear Steam Supply system (NSSS) during load reductions, after unit trips, and anytime conditions exist which may result in high secondary system pressure. If the turbine cannot accept all the steam being produced in the steam generators, for example in the event of a turbine trip or partial loss of electrical load on the generator, an alternate heat removal path is provided to remove the sensible heat in the reactor coolant and the reactor decay heat to limit the pressure rise in the steam generators. Steam dump and bypass valves, located downstream of the main steam isolation valves, connect the main steam header outside containment directly to the main condenser and are programmed to bypass steam directly to the condenser when such a high pressure condition should arise. The system is designed to enable the plant to accept a loss of electrical load on the generator of 29 percent of full power, without tripping the turbine.

In the event that the steam dump and bypass valves fail to open on complete loss of turbine generator load with offsite power available, the turbine will trip resulting in an increase in steam pressure in the steam generators as shown on Figure 5A-1. The steam generator pressure rise is terminated by opening of the main steam safety valves. Main steam safety valves continue to release to the atmosphere until either the manual atmospheric dump valves are opened or the steam dump and bypass system valves are restored to the operating open position to discharge steam to the condenser. The consequences of the failure of the steam dump and bypass valves to open is discussed in Section 15.2.7.

On a load rejection the steam dump and bypass valves are modulated in sequence to control main steam pressure to a fixed set point. A quick opening signal is generated as a function of the magnitude and rate of change of the load rejection determined by monitoring the steam flow. The duration of the quick opening signal is proportional to the flow magnitude and rate of change. Once the signal is removed the valves revert back to modulation control.

On a reactor trip the dump valves are positioned by the reactor coolant average temperature while the bypass valve remains on main steam pressure control. The quick opening signal on a reactor trip is generated when the reactor coolant average temperature is above the value corresponding to the maximum valve opening demand. The valves are designed to close on loss of actuator power or control signal. In the event of loss of condenser vacuum the valves close automatically. Redundancy is provided in the design to prevent a single equipment failure or operator error from opening more than one valve. The system controls, which are a subsystem of the Distributed Control System (DCS), are designed for either automatic or remote manual control.

The system may also be used to remove reactor decay heat following a reactor shutdown or during hot standby conditions.

The original system design flow capacity of 45% was restored as part of the modifications implemented in support of the Extended Power Uprate. The system is designed to mitigate challenges to the pressurizer and steam generator safety valves during large load rejections.

The steam dump and bypass system has no safety functions since overpressure protection is provided by ASME Code safety valves. Consequently, design of the system to seismic Class I or limiting environmental conditions is not required.

During plant shutdown with off-site power available, the required number of valves may be remote manually positioned to remove reactor decay heat, pump heat, and reactor coolant system sensible heat to reduce the reactor coolant temperature at the design cool down rate until shutdown cooling is initiated.

For plant shutdown without off-site power, the atmospheric-dump valves may be used to remove reactor decay and sensible heat by venting steam from the steam generators directly to the atmosphere.

Preoperational testing has been performed to demonstrate that the system operates to control reactor coolant temperature during turbine load transients. Refer to Section 14.1.

10.4.5 CIRCULATING WATER SYSTEM

The circulating water system is designed to provide a sink for the removal of heat from the main condenser under normal operating and shutdown conditions. The system is discussed in Section 9.2.3.

10.4.6 CONDENSATE AND FEEDWATER SYSTEM

The condensate and feedwater system is designed to supply heated condensate to the steam generators for steam production.

The feedwater and condensate systems are shown in Figures 10.1-2a through 10.1-2e. The heater drain and vent system are shown in Figure 10.1-3.

Refer to Figures 10.1-2a through 10.1-2e for the following discussion: The feedwater cycle is a closed regenerative system with deaeration accomplished in the main condenser. Condensate from the hotwell is pumped by two vertical, can-type, motor-driven centrifugal condensate pumps (operating in parallel) through the steam jet air ejector inter and after-condensers, the gland steam condensers, three stages of low pressure heaters (two heaters per stage), the low pressure drain coolers, and the fourth stage low pressure heaters to the suction of two horizontal, motor-driven, multi-stage feedwater pumps (operating in parallel). The feedwater is then pumped through one stage of high pressure feedwater heaters to the steam generators. At low loads, minimum condensate flow for condensing the supply steam for the steam jet air ejectors and gland steam condenser is maintained by recirculating condensate downstream of the gland steam condenser to the main condenser. In addition, when flow through the condensate pumps discharge line drops below a preset limit, the pump recirculation valve is opened manually to provide cooling flow through the pump. Each feedwater pump is protected from overheating during start-up and reduced load operation by a recirculation control system which discharges to the main condenser.

The feedwater heaters are of the U-tube type and are arranged in two parallel streams. Each stream carries approximately half of the feedwater flow and consists of four low pressure heaters and one high pressure heater. The two lowest pressure heaters are mounted in the neck of the main condenser. Bypasses and crossties between the split streams are provided for flexibility in operation.

Each steam generator feedwater line is provided with a three-element controller which combines the steam generator steam signal, feedwater flow signal and steam generator water level. The output of each three-element controller actuates the 100 percent capacity feedwater regulating valve to effect the desired feedwater flow to each steam generator. In addition to the air operated feedwater regulating valve, there is a remote manually operated 15 percent capacity bypass valve and a 100 percent capacity motor operated bypass valve used for backup in case of outage of the regulating unit. Refer to Section 7.7 for a complete description of steam and feedwater control.

In addition to the existing venturi method for measuring feedwater flow, the new Leading Edge Flow Meter (LEFM) System is installed as part of a Measurement Uncertainty Recapture (MUR) effort for the Extended Power Uprate. The LEFM is a highly sophisticated feedwater mass flow measurement system. It employs the ultrasonic transit time method to determine path sound velocity and axial fluid velocity. It also contains an automatic self-checking system to continuously verify if it is performing properly and to initiate alarms at the control room when unsatisfactory conditions are detected. The design parameters for the LEFM are present in Table 10.4-1.

A neutralizing amine and an oxygen scavenger are added to the condensate at the condensate pump discharge to control pH and oxygen. These additives are also injected into the steam generator for water conditioning.

The condensate and feedwater system is not designed to seismic Class I standards except for the piping from the steam generators to the first check valve (I-V09248 & I-V09280) outside containment, and seismic Class I feedwater pump isolation valves I-MV-09-1 and I-MV-09-2. Details of isolation provisions are contained in Table 6.2-16. The auxiliary feedwater system described in Section 10.5 is used to achieve safe plant shutdown by removal of reactor decay heat from the steam generators in the event of loss of the normal feedwater system or loss of off-site power.

The design basis and actuator capabilities for MV-09-01, 02 have been reviewed in accordance with the requirements of Generic Letter 89-10, "Safety Related Motor Operated Valve Testing and Surveillance," as noted in Section 3.9.2.4.

The main feed pumps, heater drain pump, and the condensate pumps are tested at the manufacturer's shop, in the presence of the purchaser's inspector, to demonstrate successful operation and performance of the equipment. Hydrostatic and performance tests were governed by the provisions of the ASME Power Test Codes for Centrifugal Pumps and the Hydraulic Institute Test Code for Centrifugal Pumps.

Performance tests for feedwater heaters have been conducted during operation in accordance with the ASME Power Test Code for Feedwater Heaters No. PTC 12.1. Shop hydrostatic tests at 1-1/2 times the design pressure on shell, tube side and external drain receiver were performed at a minimum temperature of 60°F.

Preoperational testing of this system as an integrated unit is discussed in Section 14.1 and is designed to verify pump, valve and control operability and setpoints, and to verify design head capacity characteristics of pumps.

10.4.7 STEAM GENERATOR BLOWDOWN SYSTEM (SGBS)

Steam generator blowdown is utilized to maintain the impurity content of steam generator secondary side coolant within normal operating limits. Primary to secondary leakage would result in some activity accumulation within the steam generator secondary. Thus, under these circumstances the blowdown stream would have an activity level associated with it. A blowdown sample stream is continuously monitored by process radiation monitors. If the monitor indicates that radionuclide concentrations are unacceptable, the blowdown is automatically isolated.

The blowdown was originally designed to be discharged to the circulating water discharge canal or recovered and returned as makeup to the feedwater cycle (condenser) via the Steam Generator Blowdown Treatment Facility (SGBTF). Should the radioactivity level exceed a specified limit, the blowdown stream would be processed prior to its return to the condenser. Three blowdown process streams provide this capability. Each stream can process the total combined blowdown (40 gpm or greater) from both Units 1 and 2.

The system was originally designed for automatic monitoring of the process effluent for radioactivity within the SGBTF. Indication of radioactivity from the SGBTF monitors would have initiated automatic closure of the isolation valves discharging to the discharge canal when the radioactivity was above a preset limit. This design feature is no longer used. Additionally, effluent from the monitor storage tanks is no longer pumped to the discharge canal. Automatic isolation function to the SGBTF is currently performed by RT-23910 & RT-23920. Plant controls and procedures govern processing of effluent prior to return to the condenser.

10.4.7.1 Design Bases

The SGBS design bases are:

a) to control steam generator secondary side coolant chemistry within normal operating limits;

b) to ensure that any activity levels associated with the blowdown effluent when combined with other liquid effluents will comply with limitations governing these releases as set forth in the Offsite Dose Calculation Manual; and

c) to provide blowdown system containment isolation capability in accordance with General Design Criterion 57 (GDC 57).

The SGBS is required to support normal operations. It is not required to achieve a safe shutdown, or mitigate the consequences of an accident. Although based on the guidance set forth in Regulatory Guides 1.26 and 1.29 it is a Quality Group D system that need not be seismically designed, the portion of the piping and valves at the containment penetrations are seismic to insure containment integrity following a containment isolation signal. Since the SGBS is not safety related, it is housed in a structure designed to standards appropriate for non-safety related structures.

10.4.7.2 System Description

A SGBS process and instrumentation diagram is provided as Figures 10.4-1, 10.4-2 and 10.4-3. Normally the blowdown from the steam generators is cooled in a closed blowdown heat exchanger. These heat exchangers eliminate the need for a blowdown storage tank and its atmospheric vent. Blowdown pressure is then reduced by a pressure reducing valve. The cooled, low pressure blowdown is then routed directly to the discharge canal, or recovered and returned as makeup to the feedwater cycle. Effluent releases to the discharge canal are no longer done directly from the monitor storage tanks. Prior to returning to the feedwater cycle, the effluent may be polished in the SGBTF.

Each of the three blowdown process streams is capable of processing the blowdown from both Units 1 and 2 (40 gpm or greater). The three 100 percent streams and the associated valving and piping interconnections (see Figures 10.4-1, 10.4-2 and 10.4-3) provide considerable operational flexibility. One operating mode would have one process stream aligned to receive Unit 1 blowdown and one process stream aligned to receive Unit 2 blowdown. Should either stream be required, it would be automatically placed in service.

The remaining spare process stream would be available to reprocess liquids recirculated from a monitor tank should reprocessing be required.

Blowdown sent to a process stream passes through a blowdown filter where suspended solids are removed. It then enters the blowdown demineralizer system where the concentration of exchangeable ions in the coolant is reduced significantly. The processed blowdown stream passes through a resin trap enroute to a monitor storage tank. Since the decontamination factor of the process stream is more than sufficient to achieve activity levels acceptable for release, the monitor storage tanks were originally designed so that they could be pumped directly to the discharge canal. NOTE: Current plant configuration prevents effluent discharge from the monitor storage tanks to the discharge canal. Provisions are also provided to allow the monitor tank contents to be recycled to the plant for use as makeup. Low water level in a monitor tank will automatically terminate discharge from that tank.

The blowdown demineralization system consists of a cation bed demineralizer and a mixed-bed demineralizer connected in series. The cation resin used in the cation and mixed-bed demineralizers is a high capacity, strong acid exchange resin in the H^+ form. The mixed-bed anion resin is a high capacity, Type I, strong-base exchange resin of the OH^- form. Spent ion exchange resins can be gravity fed to a spent resin storage tank for temporary storage prior to disposal as a solid waste. Other methods of resin transfer can occur by using a temporary pumping system and filling shipping liners or temporary storage containers (e.g., a 55 gallon drum). Additionally, the resin can be reused in other plant ion exchangers. Plant procedures or chemistry instructions would govern the transfer or reuse of the resin.

Since the blowdown lines penetrate containment and are connected to a closed Class I system (steam generator secondary) within containment, one isolation valve is provided inside and one outside on each blowdown line. The isolation valve is located outside containment and is automatically closed on a containment isolation signal (CIS), High Radiation or low blowdown line pressure. The CIS and High Radiation signals can be overridden by a Control Room Operator. Appendix 3D presents a discussion of a blowdown system rupture and mitigation with the resultant effect on safety related equipment due to the accident environment.

10.4.7.3 Process Sampling and Monitoring

Process radiation monitoring is provided for each steam generator at the blowdown sampling panel. In addition, sampling capability is provided at several locations to allow for periodic monitoring of system performance. The sampling locations are:

a) blowdown filter influent and effluent.

b) demineralizer influent and effluent.

c) monitor storage tank contents

Capability is provided to recirculate the monitor tank contents prior to sampling to insure a representative sample.

10.4.7.4 System Evaluation

Radiological evaluations of normal gaseous and liquid are provided in Sections 11.2 and 11.3. The process streams are required if a coincidence of failed fuel level, primary to secondary leakage and blowdown rate are such that activity levels in the blowdown stream reach a level exceeding that allowable for direct release to the discharge canal. Should this occur three 100 percent separate process streams (40 gpm or greater/stream) are available. Thus, sufficient redundancy is provided to ensure the availability of the process stream as required to support normal plant operations. There are no safety related functional considerations associated with this system.

10.4.7.5 Instrumentation

Instruments are provided as required to monitor system operation. The number, type and location are shown on Figures 10.4-1 and 10.4-2. The sampling capability discussed in Section 10.4.7.3 is available to supplement process instrumentation data.

10.4.7.6 Testing and Inspection

The process streams are required from time to time during plant operation thereby providing an opportunity to periodically monitor process stream performance.

TABLE 10.4-1

DESIGN PARAMETERS FOR LEADING EDGE FLOW METER

Component ID	Description
Leading Edge Flow Meter (LEFM)	Feedwater Flow and Temperature Instrumentation
LEFM-1A	
LEFM-1B	

PARAMETER	VALUE
1. Design Pressure (Spool)	1875 psi
2. Design Temperature (Spool)	500°F
3. Design Feedwater Flow (Spool)	7.318×10^6 lb/hr
4. Internal Diameter (Spool)	16.50 in.
5. External Diameter (Spool)	20.00 in.
6. Material of Construction (Spool)	ASTM A-216 Gr. WCC

REFER TO DRAWINGS

3509-G-115, Sheets 1A & 1B

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM STEAM GENERATOR
BLOWDOWN PROCESS SYSTEM

FIGURE 10.4-1

REFER TO DRAWING

3509-G-115 Sheet 2

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM STEAM GENERATOR
BLOWDOWN PROCESS SYSTEM SH 2

FIGURE 10.4-2

REFER TO DRAWING

3509-G-116, Sheet 1

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FLOW DIAGRAM
STEAM GENERATOR BLOWDOWN
COOLING SYSTEM

FIGURE 10.4-3

10.5 AUXILIARY FEEDWATER SYSTEM

10.5.1 DESIGN BASES

The function of the Auxiliary Feedwater System (AFWS) is to ensure a sufficient supply of cooling water to the steam generators when main feedwater is not available. Motor operated valve actuator capabilities for MV-09-09, 10, 11 and 12 have been reviewed in accordance with the requirements of Generic Letter 89-10, "Safety Related Motor Operated Valve Testing and Surveillance", as noted in Section 3.9.2.4 and Table 3.9-6.

The AFWS design bases are as follows:

(a) Provide cooling water to either one or both steam generators during normal shutdown and accident conditions to ensure the following:

  1. Provide sufficient capability for the removal of sensible and decay heat from the reactor coolant system (RCS) during forced or natural circulation cooldown, assuming a single active failure concurrent with a loss of offsite power.

  2. Provide sufficient capacity to reduce RCS temperature to 325F (Entry conditions for the Shutdown Cooling System (SDCS) under normal conditions), assuming a single active failure and loss of offsite power.

(b) Deliver auxiliary feedwater flow against the maximum steam generator pressure.

(c) Store sufficient demineralized water, in the seismic Category I Condensate Storage Tank, such that during normal operation the AFWS can cooldown the RCS (at 75 F/hr) to the SDCS entry temperature. Refer to Subsection 9.2.8.

(d) Operate automatically upon receipt of a low steam generator level signal, with loss of either offsite or onsite ac power, with no operator action required outside of the Control Room.

(e) Ensure system performance with redundant and diverse power sources, i.e., with two ac-powered motor-driven pumps and one steam turbine-driven pump.

(f) Preclude hydraulic instabilities; e.g., waterhammer

(g) Perform its design function following design basis natural phenomena (i.e., following a hurricane, tornado, or a safe shutdown earthquake).

(h) Withstand pipe rupture effects, including pipe whip and jet impingement forces.

(i) Perform its function assuming a main feedwater line break concurrent with a loss of offsite power and a single active failure in the AFWS.

(j) Provide sufficient feedwater capability to maintain the RCS in hot standby conditions following a high energy break in the AFWS concurrent with a single active failure. (The AFWS was not categorized as a high energy system as part of original licensing. This bases is in accordance with the acceptance criteria invoked by Standard Review Plan 10.4.9 Rev. 1 and Branch Technical Position ASB 10-1 Rev. 1).

10.5.2 SYSTEM DESCRIPTION

The major active components of the system consist of one greater than full flow capacity and two full flow capacity auxiliary feedwater pumps. The larger pump is driven by a noncondensing steam turbine. The turbine receives steam from the main steam lines upstream of the isolation valves and exhausts to atmosphere. The two motor driven pumps are powered from the emergency generators in case of loss of normal power. The pumps take suction from the condensate storage tank and discharge to the steam generators. Refer to Figure 10.5-2.

The turbine-driven pump is capable of supplying auxiliary feedwater flow to the steam generators for the total expected range of steam generator pressure (985 psig to 50 psig) by means of a variable speed turbine driver controlled by a variable speed hydraulic governor. The turbine operates through a speed range of 3600 to 2000 rpm when supplied with saturated steam from 985 to 50 psig, respectively. The turbine-driven pump relies solely on a dc power supply; the valves associated with the turbine-driven pumps also are powered from a dc source. Each motor-driven pump generally supplies feedwater to one steam generator. A cross connection has been provided to enable the routing of the flow of the two motor-driven pumps to one steam generator. The turbine-driven pump supplies feedwater to both steam generators by means of two separate lines each with its own control valve. The control of auxiliary feedwater flow and steam generator level is normally accomplished by means of control-room operated control valves each sized to pass the full flow. A local control station is provided to facilitate shutdown if the control room is not accessible.

During normal operation, feedwater is supplied to the steam generators by the feedwater system. If this system is unavailable due to loss of feedwater pumps or offsite power, steam generator feedwater levels will decrease. The Auxiliary Feedwater (AFW) system is provided with complete sensor and control instrumentation to enable the system to automatically respond to a loss of steam generator inventory. Should the steam generator level decrease to the low steam generator level trip setpoint, an alarm is sounded in the control room and an Auxiliary Feedwater Actuation Signal (AFAS) time delay is actuated. Actuation of the AFW system is delayed for a pre-selected period of time. If the steam generator water level increases to reset the low level actuation bistable before the AFAS time delay expires, the time delay will reset and the AFW system will not actuate. If the AFAS time delay expires while the steam generator level is below the AFAS low level actuation bistable (first) reset, then the AFW system will receive an AFAS.

The AFAS signal starts the auxiliary feedwater pumps associated with the steam generator with a low water level and fully opens the isolation valves, thus providing auxiliary feedwater flow to that steam generator. If the auxiliary feedwater pumps were operating when offsite power was lost, the pumps would automatically restart using diesel generator power. Following full actuation of the AFW system, the control room operators will be able to take manual control of the system (i.e., pumps and valves) should the need arise. If manual control is not taken, the AFW system will supply water to the steam generator(s) until the steam generator level(s) increase to the second AFAS reset setpoint, where the AFW pump discharge valves will automatically close, thereby, diverting flow from the steam generator(s) to the condensate storage tank. Refer to Section 7.3.1.1.13 for further discussion of system circuitry.

The AFAS logic employs four channels of initiating signals to provide a two out of three actuation sequence of system components. A separate AFAS is generated for each steam generator, AFAS 1 for generator A and AFAS 2 for generator B. An AFAS 1 will indicate that SG A requires feedwater and thus, will start auxiliary feedwater pumps A and C and will open isolation valves (MV-09-9, MV-09-11). Similarly, an AFAS 2 will indicate that SG B requires feedwater and thus will start pumps B and C and will open isolation valves (MV-09-10, MV-09-12). An AFAS 1 or AFAS 2 signal opens the steam inlet valves MV-08-13, MV-08-14 and MV-08-3 to start the turbine driven Auxiliary Feedwater Pump C.

Both "latched" and "unlatched" signals are generated by an AFAS. The pumps, whose operation is initiated and never interrupted, receive latched signals. The isolation valves, which open on low steam generator level and close on high level, receive unlatched signals. Additionally, using four channel pressure instrumentation on the main steam and feedwater lines, the system has the ability to identify and isolate a faulted steam generator or ruptured feedwater line. Should a SG differential pressure of approximately 275 psid or feedwater header differential pressure of 150 psid be detected, feedwater flow to the loop with the lower pressure is isolated. This is done by closing the applicable auxiliary feedwater isolation valves.

A complete description of the AFAS logic circuitry is provided in Subsection 7.3.1.1.13. This complies with SRP 10.4.9 (Rev 1) and BTP ASB 10-1 (Rev 1).

Diverse power sources have been utilized to ensure that the Auxiliary Feedwater System is capable of performing its intended safety function. The design features incorporated into the Auxiliary Feedwater System, which assure diversity of power sources, are:

a. Each motor-driven auxiliary feedwater pump is aligned to a separate diesel generator, with its associated normally closed, motor-operated flow control valves being fed from the same diesel as the pump.

b. The turbine-driven pump and its associated normally closed steam inlet and discharge flow control valves are fed from a dc power supply, which may be aligned to either the A or B dc power source.

The seismic Category I Condensate Storage Tank (CST) provides the water supply from the Auxiliary Feedwater System. The CST is sized to provide a minimum (Technical Specification) of 153,400 gallons of a demineralized water for start-up, hot standby and cooldown operations. The quantity of water needed for St. Lucie Unit 1 cooldown is determined assuming the unit is brought to a hot standby and held there for one hour (this procedure requires about 30,500 gallons of water); the plant is then cooled down at a maximum rate of 75 F per hour until the shutdown cooling entry temperature of 325F is reached (about 100,000 gallons required).

The steam generated during decay heat removal and cooldown after a loss of offsite power will be discharged though the atmospheric dump valves, except for that steam used by the auxiliary feed pump. If offsite power and the main condenser are available, the condenser may be used as a heat sink.

10.5.3 SYSTEM EVALUATION

The auxiliary feedwater system is designed to provide feedwater for the removal of sensible and decay heat from the reactor coolant system. The system can cool the reactor coolant system to 325F in the event the main condensate pumps or the main feedwater pumps are inoperative due to pump failures, MSIS, SIAS (Trip of main feedwater pumps only), or to a loss of normal electric power. The auxiliary feedwater system may also be used for normal system cooldown to 325F. Reactor decay heat and sensible heat are transferred to the steam generators by natural circulation of the reactor coolant if power is not available for the reactor coolant circulating pumps.

The motor-driven and steam-driven auxiliary feedwater systems are designed as seismic Class I and are capable of withstanding tornado wind loading. The auxiliary feedwater pumps are protected from design basis missiles by protective shielding. The auxiliary feedwater system is protected from flooding by placing all system components susceptible to flooding damage above the probable maximum flood level or by providing flood protection barriers around them.

The storage capacity of the condensate storage tank is 250,000 gallons, a sufficient quantity to meet the requirements for decay heat removal and cooldown of the nuclear steam supply system. After a loss of normal feedwater, approximately 130,500 gallons of water are required to permit cooldown to 325F following a reactor trip. The results are presented in Figure 10.5-1. This volume is based on loss of offsite power (no RCP's, using 2 ADV's, initiate cooldown following 1 hour at Hot Standby). Refer to Section 9.2.8 for design details for the condensate storage tank. A crosstie is provided between the Unit 1 auxiliary feedwater pumps and the Unit 2 Condensate Storage Tank (CST) solely for the unlikely event that a vertical tornado missile disables the Unit 1 CST. As a result, it is designed and installed as Quality Group D, non-seismic (Ref PSL-ENG-SEMS-97-064).

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As stated in item (c) of Section 10.5.1, auxiliary feedwater piping is designed to withstand design basis earthquake loads. The feedwater supply piping from the auxiliary feedwater pumps is dynamically analyzed to assure that design stress limits would not be exceeded during an earthquake. The analysis is based upon the actual physical piping configuration, from which natural frequencies and mode shapes are determined, and the floor response spectra for the steam trestle at its various elevations. The anticipated seismic accelerations are determined from the floor response spectra at the natural frequencies of the pipe. A response analysis is done for the pipe to evaluate the seimsic forces upon the pipe. These loads are combined with appropriate dead and operational loads to assure that the code stress limits are not exceeded. Methods of seismic analysis are discussed in Section 3.7.

The seismic Category I piping from the condensate storage tank to the auxiliary feedwater pumps, which pass underneath the turbine building, is adequately protected. The turbine building design was reanalyzed for seismic loading to assure the integrity of the turbine building structure for the seismic loading condition even though it is not classified as a Category I structure. A collapse of the turbine building during a seismic event is not postulated therefore it has no effect on the seismic qualification of the subject piping runs.

The design provisions utilized to protect the AFWS against the dynamic effects of pipe rupture and jet impingement from a Main Feedwater System line break or a Main Steam Line break have been presented in Appendix 3C. In addition, although the AFWS design basis did not include categorization as a high energy system, sufficient separation has been provided to prevent the turbine-driven pump header from whipping into the motor-driven pump header; this ensures the integrity and operability of the motor-driven feedwater train. Since the AFWS is located in the steam trestle area, protection from internally-generated missiles outside of containment is provided by the missile protection barriers which are around the motor-driven pumps and around the turbine-driven pump. The auxiliary feedwater turbine-driven pump utilizes both electrical and mechanical overspeed protection with the electrical trip set at 115 percent overspeed and the mechanical trip set at 125 percent overspeed.

The potential for hydraulic instability has been considered in the original design of the Main Feedwater System and the Auxiliary Feedwater System piping. Routing of the feedwater piping is such that draining of the feedwater line is minimized. A check valve and a 32-foot vertical drop in the feedwater piping immediately outside the feedwater nozzles provides assurance that the piping will not drain and prevents entrapment of air. Design provisions are also incorporated into the feedwater sparger to minimize draining.

The system is designed such that no single active failure can prevent plant cooldown to 325°F in the event of a loss of offsite power. Refer to Table 10.5-1.

A single failure analysis of the auxiliary feedwater system assuming a feedwater line break accident and loss of offsite power is presented in Table 10.5-1A. Figure 10.5-2 provides the auxiliary feedwater flow schematic for the single failure analysis.

The single failure analysis for the failure of the 125V dc A bus is based on the following assumptions:

a) Steam generator B is the faulted steam generator,

b) The AB electrical systems are initially aligned to the A supply,

c) A seismic event and station blackout accompany the faulted condition,

d) The single failure is postulated to be the A 125V dc battery.

Before proceeding, it should be noted as a point of clarification that the motor operated valves, shown on Figure 10.5-2 are labeled to designate their respective bus and power supply. The ac powered valves are powered by 480V ac whereas the dc powered valves are powered by 125V dc.

The Emergency Operating Procedures (EOP's) direct the operator to status essential systems and components and important parameters after a plant trip. One of the first steps after a reactor trip requires the control room operator to verify that the AB DC bus is aligned to an energized power supply. Other EOP's also direct the operator to verify power to the AB DC bus in the event AFW flow is lost. The operator would identify that the AB DC bus is aligned to the failed battery. The operator then transfers the AB DC bus from supply A to supply B from the control room. Refer to Figure 10.5-3 depicting the 125V dc bus transfer circuit capability in the control room. The changeover requires the following operator action:

a) Transfer of 125V dc AB bus - Four control switches with key locks are switched from the A-AB (AB-A) positions to the B-AB (AB-B) positions. The design of the key locks (key removable in open-reset position only) precludes cross connecting of power sources. When the transfer is complete, two misalignment alarms will be annunciated indicating improper alignment of 4160 and 480 volt buses.

b) Observes that AFAS time delay has expired and the AFAS automatically opens the AFW steam admission valves (MV-08-3, 13 and 14) and the appropriate 1C AFW pump discharge valves (MV-09-11 or 12) then verifies that the 1C AFW pump is delivering flow to the unaffected S/G(s).

c) The 1C AFW pump and associated motor operated valves can be placed in service without 480V or 4160V ac power, therefore, realignment of these ac buses would not be required to establish the required AFW flow.

It can be concluded from the above described action that auxiliary feedwater flow can be initiated within 10 minutes.

The operator actions described above demonstrate that the time required to perform the necessary switching is within the analysis time limit (within 10 minutes) for auxiliary feedwater initiation, to ensure adequate heat removal and safe plant shutdown. It is concluded, therefore, that the operator has sufficient time to initiate auxiliary feedwater flow.

The above battery single failure analysis results in loss of power to the 480V A bus and the 125V AB bus. No A flow control valve motions are required to initiate auxiliary feedwater flow from the turbine pump to the unfaulted steam generator (1A).

Calculations have been performed to determine if the containment building response (pressure) and the core reactivity response (return to power) are acceptable following a main steam line break inside containment when auxiliary feedwater is added without regard to the identification of the affected steam generator. Both the containment pressure and the reactivity values were found to be within acceptable limits. See Reference 1.

Pursuant to an NRC request (NUREG-0737) a supplemental evaluation of the Auxiliary Feedwater System, assuming auto initiation of the system, was prepared. See Reference 2. The AFW system was evaluated against ten plant transient and accident conditions for the purpose of meeting NRC Standard Review Plan 10.4.9 and Branch Technical Position 10-1, and to establish AFWS design flow requirements. The condition identified as the most limiting was loss of offsite power with AFW high energy line break. (It should be noted that while loss of off-site power is most limiting from a single failure standpoint, the analyses were also performed with offsite power available and no main feedwater; RCP's are running to maximize RCS heat input.

Loss of offsite ac power in effect results in loss of main feedwater, reactor trip due to low steam generator level, turbine trip and the necessity to power the AFWS components from emergency buses A(AC), B(AC) and AB-DC tie. The most limiting single active failure is failure of either "A" or "B" battery. The failure of battery "A", assuming "A" bus is initially aligned to "AB" bus, will result in failure of "A" - AC motor driven pump and the AB-DC tie bus to the A bus. Thus when evaluating the proposed AFWS automatic initiating control system against BTP 10-1, high energy line break should be considered with the single active failure of battery "A". As a result, two postulated break locations are identified as "most limiting". Each case is further evaluated below:

Condition A - High energy line break at turbine pump discharge concurrent with single active failure.

For this case, following an AFAS time delay, the automatic initiated control logic for the AFWS will align all pump discharges to the steam generators. This will result in one motor driven pump (pump B) feeding B steam generator.

The initial conditions for the current limiting analysis are listed in Table 10.5-4 and the analysis assumptions are presented in Table 10.5-5, and the transient results are shown in Figures 10.5-4 through 10.5-18. The event is initiated by a total loss of all main feedwater. The reactor tripped on low SG level. EC288300 Subsequent to reactor trip, the turbine tripped and the main steam safety valves opened briefly to relieve the secondary side pressure. The steam bypass control system controlled the steam generator pressure in automatic mode. The auxiliary feedwater from one motor driven pump injected water into one generator after the AFAS time delay.

Early in the event, the flow from the single AFWS pump was not adequate to remove decay heat and pump heat. This resulted in a slow decrease in the SG liquid inventory as the SBCS steam flow required to remove decay heat exceeded the AFWS pump flow. As the steam generators approach dryout, the steam generators pressures fall below the MSIS setpoint, thereby closing the MSIVs. Following closure of the MSIVs, RCS temperature rises, and steam pressure in the SG fed by the single operating AFWS pump slowly rises until it reaches the MSSV setpoint. Once the steam generators dry out, the RCS temperature increases, thereby increasing RCS pressure until reaching the pressurizer spray setpoint. Fifteen minutes after loss of all MFW, operators trip all RCPs, and the decreased heat load slows the EC289558 RCS temperature increase. RCS temperature continues to rise until decay heat decreases to the point that AFWS pump flow is adequate to remove the decay heat. RCS temperature stabilizes, and then slowly decreases as decay heat continues to decrease. Eventually, decay heat decreases to the point that the AFWS pump is able to begin recovery of the fed SG liquid inventory and level.

The analysis performed with degraded AFW system capacity and biased reactor trip and AFW actuation setpoints demonstrates that the degraded AFW system is adequate to maintain primary-to-secondary heat transfer such that the plant can be stabilized and brought to a safe shutdown in a controlled manner. Adequate cooling was maintained through the vaporization of the AFW and pressurizer steam space was preserved. There was no significant heatup of the primary system.

The primary temperature is controlled by the actuation of the steam dump and bypass system until closure of the MSIVs, and by the MSSVs following closure of the MSIVs. The acceptance criteria for this event (no loss of primary subcooling margin and pressurizer level < 100% of the total pressurizer volume) are met.

Condition B - High energy line break at "B" pump discharge concurrent with single active failure.

For this case the operators have sufficient time to initiate AFW flow, via the turbine, by transferring electrical AB dc loads from the dead "A" bus to the energized "B" bus. This transfer, as presented earlier in this Section is conservatively assumed to take less than 10 minutes. The analysis for this case, where no AFW is made available to the steam generators, demonstrates that the operators will have 10 minutes to initiate AFW flow to remove decay heat and place the plant in a safe shutdown condition. The plant initial conditions and analysis assumptions are presented in Tables 10.5-6 and 10.5-7, respectively. Figures 10.5-19 through 10.5-33 show the transient results. EC288300

Plant cooldown is accomplished for condition A and B using either motor driven pump or turbine driven pump.

Feedwater Line Break Decay Heat Removal

The FWLB Event is defined as a major break in a main feedwater line that is sufficiently large to prevent maintaining the secondary side water inventory in the affected steam generator. A feedwater line break between the SG and an upstream feedwater line check valve is the worst case, as blowdown of the steam generator secondary side water cannot be isolated. Depending on the size of the break, all feedwater may be lost to the affected steam generator, including auxiliary feedwater. The hydraulic resistances in the feedwater piping network determine the extent to which the unfaulted steam generator is deprived of feedwater.

The analysis was performed assuming that a double-ended guillotine break of the largest pipe downstream of the check valve, i.e., the feedwater nozzle, occurred. All main feedwater was instantaneously lost to both steam generators upon occurrence of the FWLB. One motor-driven auxiliary feedwater pump was assumed to be available for delivery to the unfaulted steam generator following the actuate signal and associated delays.

The FWLB event is not limiting with respect to DNBR and is insensitive to fuel design; however, a heat-up analysis is performed to:

- Demonstrate that adequate cooling can be provided to remove post-trip decay heat and maintain RCS subcooling margin through the time the operators would reasonably be expected to take control of the plant and begin emergency operation procedures;

- Verify the low steam generator water level reactor trip setpoint and error allowance needed to compensate for the hostile environment that could be created by the break of a feedwater line inside containment;

- Verify the capability to establish and maintain natural circulation cooling by showing that saturation conditions do not occur in the reactor coolant system prior to operator intervention.

Two cases were analyzed; one with offsite power available and the other with loss of offsite power at turbine trip following reactor trip. Analytical parameters employed in the heat-up analysis of the feedwater line break cases are provided in Table 10.5-8. Table 10.5-9 provides that sequence of events for the more limiting case, which had offsite power available, and Table 10.5-10 provides the sequence of events for the loss of offsite power case. Offsite power available was more limiting because of the additional heat added by the operating reactor coolant pumps. Figure 10.5-34 and Figure 10.5-35 show the eroding subcooling margin (due to RCS heat-up) until the time that the AFW heat removal matched decay heat production at 2610 seconds for the limiting offsite power available case, and at 2408 seconds for the loss of offsite power case. The subcooling margin beyond those times is a function of RCS pressurization and would be controlled by operator action.

The augmented AFWS for St. Lucie Unit No. 1 has been reviewed and found to meet all the acceptance criteria provided in Standard Review Plan (SRP) 10.4.9 (Revision 1) and Branch Technical Position (BTP) ASB 10-1 (Revision 1). Refer to Table 10.5-3 for this comparison.

Similar to the issues discussed in NRC Generic Letter 2008-01 and INPO SER 2-05, the presence of unanticipated gas voids within the AFW System can challenge the ability of the system to perform its design functions due to issues such as gas binding, water hammer, injection delay times, etc. AFW system has little opportunity for gas to enter the pump suction piping, but it may be possible for system leaks to result in voiding in the discharge piping or the Unit 1 and Unit 2 CST crosstie.

10.5.4 TESTING AND INSPECTION

Auxiliary feed pumps are tested with cold water at the manufacturer's shop, in the presence of the purchaser's inspector, to demonstrate successful operation and performance of the equipment. Performance tests are governed by the provisions of the ASME Power Test Codes for Centrifugal Pumps (PTC 8.2) and the Hydraulic Institute Test Code for Centrifugal Pumps. Pumps casings receive hydrostatic tests at 150 percent of maximum operating head.

The auxiliary feedwater pump and noncondensing turbine manufacturers supply calculations which substantiate that the equipment will not suffer loss of function due to design bases earthquake loadings.

Both motor-driven pumps and associated controls were given preoperational tests after erection and before plant start-up. All three of the auxiliary feed pumps can be tested during normal operation by recirculating to the condensate storage tank though miniflow lines. The system will be tested periodically as described in the Technical Specifications.

Monitoring of fluid conditions within the AFW system is performed on a regular basis to preclude a steam binding condition. Should such a condition exist additional procedures are provided to restore the AFW system to operable status. These inspections and procedures are provided in accordance with I&E Bulletin 85-01, “Steam Binding of Aux Feedwater Pumps”.

10.5.5 INSTRUMENTATION APPLICATION

Refer to Section 7.4 for a description of the auxiliary feedwater system controls and instrumentation required for safe plant shutdown.

The controls and instrumentation for this system are shown in the system P&ID, Figure 10.5-2, and tabulated in Table 10.5-2.

REFERENCES FOR SECTION 10.5

1. R.E. Uhrig (FPL) to R.W. Reid (NRC) Re: St. Lucie Unit No. 1, Docket No. 50-335, Auxiliary Feedwater Systems, L-80-36, dated 1/24/80.

2. R.E. Uhrig (FPL) to D.G. Eisenhut (NRC) Re: St. Lucie Unit 1, Docket No. 50-335, Post TMI Requirements, L-81-4 dated 1/2/81.

3. FPL letter L-88-19, "IE Bulletin 85-03", from C.O. Woody (FPL) to J.N. Grace (NRC), dated January 14, 1988.

TABLE 10.5-1

SINGLE FAILURE ANALYSIS - AUXILIARY FEEDWATER SYSTEM

Component Identification and Quantity	Failure Mode	Effect on System	Method of Detection	Monitor(1)	Remarks
Offsite Power	Lost	Normal feedwater flow is unavailable. Operator has 10 minutes to verify auto start of auxiliary feedwater.	Various loss of power alarms.	CRI	Two motor driven pumps powered by the emergency diesel generator sets operate, supplemented by the steam turbine driven pump.
Auxiliary Feedwater Pump Suction line	Valve inadvertently closed	No auxiliary feedwater flow in affected line.	Pump suction line low pressure alarm.	CRI	The remaining open line supplies either the steam turbine driven pump or the two motor driven pumps.
Steam turbine driven pump steam inlet valve(1)	Fails to open	No feedwater flow from turbine driven pump.	No discharge line flow or pressure indication.	CRI	Two motor driven pumps available.
One Motor driven	Fails to start	Loss of one motor driven pump.	No discharge line flow or pressure indication.	CRI	The steam turbine driven pump and one pump motor driven pump available.
Diesel Gen. A	Fails to start	Loss of A motor driven pump. Valves MV-09-9 and 13 do not open.	No discharge line flow or pressure indication.	CRI	The steam turbine driven pump and one motor driven pump available.
Diesel Gen. B	Fails to start	Loss of B motor driven pump. Valves MV-09-10 and 14 do not open.	No discharge line flow or pressure indication.	CRI	The steam turbine driven pump and one motor driven pump available.
One M.O. control valve (MV-09-9, -10, -11, -12)	Fails to open	One auxiliary feed line lost.	No discharge line flow or pressure indication.	CRI	Remaining three lines available for delivery or required auxiliary feedwater
Loss of offsite power and failure of 125v dc A bus	Lost	Loss of A motor-driven pump (due to A diesel failure to start) and the steam turbine driven pump is unavailable.	Various loss of power alarms	CRI	Operator aligns the 125V dc AB bus and 480V ac AB bus to the respective B bus from the control room to establish feedwater flow with the steam turbine-driven pump. If desired, the B motor-driven pump is also available, independent of the AB bus control power transfer.

(1) CRI - control room indication.
(2) The 125v dc AB bus is initially aligned to the 125v dc A bus.

TABLE 10.5-1A
SINGLE FAILURE ANALYSIS - AUXILIARY FEEDWATER SYSTEM ASSUMING A FEEDWATER LINE BREAK(1)

Component Identification and Quantity	Failure Mode	Effect on System	Method of Detection	Monitor(2)	Remarks
Loss of offsite power and failure of 125v dc B bus	Lost	Loss of B motor driven pump (resulting from failure of B diesel to start)	Various loss of power alarms	CRI	The steam driven turbine pump is available power and one motor driven pump is also available.
Offsite Power	Lost	Normal feedwater flow is unavailable. Operator has 10 minutes to verify auto start of auxiliary feedwater flow.	Various loss of power alarms. Steam generator 1B water level indication.	CRI	Two motor driven pumps powered from the emergency diesel generator sets and one steam turbine driven pump are available to supply feedwater to steam generator 1A. Flow control valves MV-09-10 and/or MV-09-12 are closed to isolate auxiliary feedwater flow to steam generator 1B.
Auxiliary Feedwater Pump Suction line	Valve Inadvertently closed.	Same as loss of offsite power plus flow from either the steam turbine driven pump or the motor driven pumps is unavailable.	Pump section line low pressure alarm. Steam generator 1B water level indication.	CRI	The remaining open line supplies the steam turbine driven pump or the two motor driven pumps. Flow control valve MV-09-12 is closed to isolate feedwater flow to steam generator 1B and flow is established to steam generator 1A. Alternately flow control valve MV-09-10 is closed to isolate flow to steam generator 1B, cross connection valves MV-09-13 and MV-09-14 are opened to establish flow to steam generator 1A from the motor driven pumps.
Steam turbine driven pump stream inlet valve(1)	Fails to open	Same as loss of offsite power plus the steam turbine driven pump is unavailable.	Discharge line flow, or pressure indication. Steam generator 1B water level indication.	CRI	Flow control valve MV-09-10 is closed to isolate feedwater flow to steam generator 1B. Cross connection valves MV-09-13 and MV-09-14 are opened and flow is established to steam generator 1A via the two motor driven pumps.
One motor driven pump	Fails to start	Same as loss of offsite power plus one motor driven pump is unavailable.	Motor status lights, discharge line flow or pressure indication. Steam generator 1B water level indication.	CRI	Flow control valve MV-09-12 is closed to isolate feedwater flow to steam generator 1B and flow is established to steam generator 1A via the steam turbine driven pump. One motor driven pump is also available if desired.

TABLE 10.5-1A (Cont'd)

Component Identification and Quantity	Failure Mode	Effect on System	Method of Detection	Monitor[2]	Remarks
One MO flow control valve (MV-09-11,12)	Either valve fails to open	Same as loss of offsite power plus steam turbine driven pump may be ineffective to deliver required flow to steam generator 1A.	Valve controller and feedwater flow rate.	CRI	Flow control valve MV-09-10 is closed to isolate feedwater to SG 1B. Cross connect valves MV-09-13, 14 are opened to establish flow to SG 1A via the two motor driven pumps.
One MO flow control valve (MV-09-9 10,13,14)	One valve fails to open	Same as loss of offsite power plus motor driven pumps may be ineffective to deliver required flow to steam generator 1A.	Valve controller and feedwater flow rate. Steam generator 1A water level indication.	CRI	Flow control valve MV-09-12 is closed to isolate feedwater flow to SG 1B and flow is established to SG 1A via the steam driven pump.
Diesel Generator B	Fails to start	Loss of one motor driven pump. Valve MV-09-10 and 14 do not operate.	Motor status lights, discharge line flow, or pressure indication SG 1A water level indication.	CRI	Flow to SG 1A is established via the steam driven and one motor driven pump.
Diesel Generator A	Fails to start	Same as loss of offsite power plus motor driven pump is unavailable. Valves MV-09-9 and 13 do not open. No auxiliary feedwater available.	Motor status lights, discharge line flow, or pressure indication. Steam generator 1A water level indication.	CRI	MV-09-12 is closed and MV-09-11 is open, giving flow to SG 1A via steam driven pump.
Failure of 125v dc A bus	Lost	Same as loss of offsite power plus the A motor driven pump is unavailable (due to A diesel failure to start) and the steam turbine driven pump is unavailable until control power is transferred to the 125v dc B bus.[3]	Various loss of power alarms.	CRI	See discussion in Table 10.5-1.
Failure of 125v B bus	Lost	Same as loss of offsite power plus the B motor driven pump is unavailable (due to B diesel failure to start).	Various loss of power alarms.	CRI	Flow control valve MV-09-12 is closed to isolate feedwater flow to steam generator 1B and flow is established to steam generator 1A via the steam turbine driven pump. The A motor driven pump is also available if desired.

(1) To facilitate analysts, the feedwater line break is assumed to occur in the B system. Validity of analysis is not changed if break is assumed for the A system.
(2) CRI - control room indication.
(3) The 125v dc AB bus is initially aligned to the 125v dc A bus.

TABLE 10.5-2

AUXILIARY FEEDWATER SYSTEM INSTRUMENTATION APPLICATION

System Parameter & Location	Indication		Alarm (1)		Recording(1)	Control Function	Instrument Range(4)	Normal Operating Range	Instrument Accuracy(4)
	Local	Control Room	High	Low					
Condensate Storage Tank Level(2)	*	*	*	*		Regulates flow from demineralized water system to maintain minimum condensate tank level.		>185,000 gallons	
Aux. Feedwater Pumps									
1. Steam pressure at turbine inlet(3)		*		*				985 – 50 psig	
2. Pump suction pressure	*			*				11.5 psig	
3. Pump discharge pressure	*	*						1200 psig Motor driven 250 gpm	
4. Pump discharge flow		*						Flow is manually regulated from control room.	
5. Pump speed(3)	*							3600 - 2000 rpm	

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(1) All alarms and recordings are in the control room unless otherwise indicated.

(2) Low-low, low and high level alarms are provided in control room: high & low level alarms provided on water treatment panel. Redundant safety related indicators on RTGB-102 are shown in Table 7.5-2.

(3) For turbine driven pump only.

(4) Instrument ranges are selected in accordance with standard engineering practices. Instrument accuracies are selected such that existing instrument loop performance and safety analysis assumptions remain valid. Where applicable, instrument accuracies are also evaluated for their impact on setpoints in accordance with the FPL Setpoint Methodology.

TABLE 10.5-3

AUGMENTED AUXILIARY FEEDWATER SYSTEM

ACCEPTANCE CRITERIA	COMPLIANCE	REMARKS
Acceptability of the design of the auxiliary feedwater system, as described in the applicant's safety analysis report (SAR), is based on specific general design criteria and regulatory guides. An additional basis for determining the acceptability of the AFS is the degree of similarity of the design with that for previously reviewed plants with satisfactory operating experience. Listed below are the specific criteria as they relate to the AFS.		The Unit 1 Auxiliary Feedwater System (AFWS) will be augmented as described supra in the System Description and Safety Evaluation. Following is a review of that augmented AFWS which described how the system meets present NRC Staff criteria.
1. General Design Criterion 2, as related to structures housing the system and the system itself being capable of withstanding the effects of natural phenomena such as earthquakes, tornadoes, hurricanes and floods, as established in chapters 2 and 3 of the SAR.	1. The Auxiliary Feedwater System, including the instrumentation and controls thereto, is designated seismic Category I, designed to withstand tornadoes and hurricanes and located at an elevation above the probable maximum flood level. See Subsection 10.5.3.	1. Also see System Description and Safety Evaluation discussions in main text.
2. General Design Criterion 4, with respect to structures housing the system and the system itself being capable of withstanding the effects of external missiles, pipe whip, and jet impingement forces associated with pipe breaks.	2. The AFWS is located in an outdoor area below the main feedwater and main steam lines, and is surrounded by tornado missile-resistant shielding. The turbine-driven pump is missile shielded from the motor-driven pumps. The only high-energy lines traversing the AFS area are the Main Steam and Main Feedwater lines above the AFW pumps. A discussion of the jet impingement forces from a MSLB or MFLB is provided in Appendix 3C.	
	A review of the AFWS has been performed in light of current NRC criteria, and sufficient pipe separation has been provided which precludes the turbine-driven pump header from whipping into the motor-driven header.	2. The Unit 1 AFWS was not categorized as a high-energy system nor was the Staff Safety Evaluation Report predicated on this basis; however, the AFWS meets the HELB criteria, accounting for a single active failure, as discussed in BTP ASB 10-1 position 5, below.

ACCEPTANCE CRITERIA	COMPLIANCE	REMARKS
3. General Design Criterion 5, as related to the capability of shared systems and components important to safety to perform required safety functions.	3. The SL-1 AFWS has no structures, systems or components important to safety which are shared with Unit 2. However, a Condition of License for SL-1 includes a commitment to provide an inter-tie with the Unit 2 Condensate Storage Tank (CST). Thus, the only "shared" component in the AFWS is the Unit 2 CST (capacity 400,000 gal.). A connection from the Unit 2 CST will be provided to the suction of the Unit 1 AFWS pumps for the unlikely event that a tornado missile penetrates the top of the Unit 1 CST and destroys that source of water. The connection for Unit 1 is of sufficiently high elevation up the Unit 2 tank to assure an adequate condensate supply for Unit 1 (150,400 gal.), while providing Unit 2 with a sufficient quantity (150,400 gal.) to safely shutdown also, assuming a hypothetical loss of the Unit 1 CST to a tornado missile.	3. The Unit 2 CST inter-tie is required only in the event that a tornado missile somehow penetrates the top of the Unit 1 CST (which is protected on all sides by a 2-foot thick concrete tornado missile barrier to a height of 30 feet) and penetrates through the CST water and penetrates the CST tank wall. This scenario is highly unlikely.
4. General Design Criterion 19, as related to the design capability of system instrumentation and controls for prompt hot shutdown of the reactor and potential capability for subsequent cold shutdown.	4. Adequate instrumentation and controls are provided to assure the plant is brought to a hot standby condition and subsequent cold shutdown during both normal operation and under accident conditions, including a LOCA. The control of AFWS flow and SG level is accomplished by control room operated valves; however, local control stations are also provided, instrumentation is also provided at the remote Hot Shutdown Panel, as indicated at Subsection 7.4.1.8, which provided capability for a prompt hot shutdown and capability for subsequent cold shutdown using appropriate procedures.	4. The augmented AFWS will be designed such that an Automatic Feedwater Actuation Signal (AFAS) automatically starts all three AFWS pumps and opens the valves for both trains to both SGs. In the event of a Main Feedwater line rupture, or an AFWS line break, the AFAS will automatically isolate the affected SG and will automatically feed to the intact SG(s).

TABLE 10.5-3 (Continued)

ACCEPTANCE CRITERIA	COMPLIANCE	REMARKS
5. General Design Criterion 44, to assure:		
a. The capability to transfer heat loads from the reactor system to a heat sink under both normal operating and accident conditions.	5. a. During normal operation, the AFWS provides a water inventory to the SGs for removal of decay and sensible heat to the Steam Dump and Bypass System (SDBS). Under accident conditions heat removal is via the SDBS or to the atmosphere via the Main Steam Safety Valves or the Atmosphere Dump valves.	5. a. The motor-driven AFW pump capacity has been tested and shows a flowrate in excess of 350 gpm per pump. Analyses demonstrate that this flowrate is adequate for decay heat removal.
b. Redundancy of components so that under accident conditions the safety function can be performed assuming a single active component failure. (This may be coincident with the loss of offsite power for certain events.)	5. b. The AFWS is designated as seismic Category I, Safety Class 3 and capable of withstanding a single active component failure. A single failure analysis of the AFWS, including loss of offsite power, is provided in Table 10.5-1.	5. b. The design basis for the SL-1 AFWS is HFW rupture with loss of offsite power plus AFW single active failure. This is satisfied by the design; see Table 10.5-1A. Also see BTP ASB 10-1, position 5.
c. The capability to isolate components, subsystems, or piping if required so that the system safety function will be maintained.	5. c. Sufficient remote-manual features are provided to permit isolation of failed components and maintain AFW flow to the steam generators.	5. c. See Tables 10.5-1 and 10.5-1A. The proposed AFAS logic will detect a rupture in a MFW line or AFWS line and isolate that line so that AFW flow is maintained to the intact SG(s).
6. General Design Criterion 45, as related to design provisions made to permit periodic in-service inspection of system components and equipment.	6. Design provisions are provided to assure periodic ISI of the system as required, i.e., removable insulation on Class 2 components to test welds; only visual inspection required on Class 3 components.	6. FPL's in-service inspection and testing program has been submitted to NRC.
7. General Design Criterion 46, as related to design provisions made to permit appropriate functional testing of the systems and components to assure structural integrity and leak-tightness, operability and performance of active components, and capability of the integrated system to function as intended during normal, shutdown, and accident conditions.	7. Design provisions are provided to assure that the Auxiliary Feedwater System can be tested by flow transmitters to test pumps, pressure indicators to test integrity, and remote-manual means to activate valves from the control room.	7. FPL's in-service inspection and testing program has been submitted to NRC.

ACCEPTANCE CRITERIA	COMPLIANCE	REMARKS
8. Regulatory Guide 1.26, as related in the quality group classification of system components.	8. The AFWS is designed Quality Group C in accordance with Regulatory Guide 1.26.	8. These portions of the AFWS connected to the Main Feedwater line are Quality Group B to the isolation valve(s).
9. Regulatory Guide 1.29, as related in the seismic design classification of system components.	9. The AFWS is designated seismic Category I in accordance with Regulatory Guide 1.29.	
10. Regulatory Guide 1.62, as related to design provisions made for manual initiation of each protective action.	10. The AFWS will meet the requirements of Regulatory Guide 1.62. The operator may manually initiate the Automatic water Actuation Signal (AFAS) from an easily accessible location in the control room. Manual initiation ensures that protective action goes to completion.	
11. Regulatory Guide 1.102, as restructures, systems, and components important to safety from the effects of flooding.	11. All AFWS components are located above the maximum probable flood level.	
12. Regulatory Guide 1.117, as related to the protection of structures, systems and components important to safety from the effects of tornado missiles.	12. The AFWS is protected from the effects of tornado missiles as described in item 2 and in the Safety Evaluation.	12. See position of 2 SRP 10.4.9 above.
13. Branch Technical Positions ASB 3-1 and MEB 3-1, as related to breaks in high and moderate energy piping systems outside containment.	13. The SL-1 AFWS was not categorized or licensed as a high-energy system; nonetheless the AFWS meets these criteria.	13. See position 5 of BTP ASB 10-1, which is part of this Table.
14. Branch Technical Positions ASB 10-1, as related to auxiliary feedwater pump drive and power supply diversity.	14. The augmented AFWS will have the turbine-driven train wholly independent of ac power.	14. Refer to lineup given for BTP ASB 10-1, which is part of this Table.

BRANCH TECHNICAL POSITION	COMPLIANCE	REMARKS
1. The auxiliary feedwater system should consist of at least two full-capacity, independent systems that include diverse power sources.	1. The Auxiliary Feedwater System (AFWS) consists of two full-capacity motor-operated pumps in one train and another redundant full-capacity turbine driven pump in the other system. One system is ac powered and the other is steam/dc power.	1. The augmented AFWS will power the steam inlet valves and AFW turbine pump flowpath outlet valves by dc power, thus being independent of ac power.
2. Other powered components of the auxiliary feedwater system should also use the concept of separate and multiple sources of motive energy. An example of the required diversity would be two separate auxiliary feedwater trains, each capable of removing the afterheat load of the reactor system, having one separate train powered from either of two ac sources and the other train wholly powered by steam and dc electric power.	2. The motor driven system (pumps, valves) is powered by the ac system whereas the turbine driven system (pumps, valves) will be wholly powered by the dc system and steam. Either train provides sufficient capability of cooling the RCS to the temperature and pressure required for initiation of shutdown cooling.	2. Analyses performed by the reactor vendor demonstrate that one motor driven pump, with an installed capacity of over 350 gpm, is capable of removing reactor decay heat.
3. The piping arrangement, both intake and discharge, for each train should be designed to permit the pumps to supply feedwater to any combination of steam generators. This arrangement should take into account pipe failure, active component failure, power supply failure, or control system failure that could prevent system function. One arrangement that would be acceptable is crossover piping containing valves that can be operated by remote control from the control room, using the power diversity principle for the valve operators and actuation systems.	3. The piping arrangement, both intake and discharge, permits feedwater to any combination of SGs. SL-1 uses the crossover piping scheme, so as to withstand single active component failure, where the flow path will be arranged by remote control from the control room which will use the power diversity principle. Local control provisions enable system function upon loss of control failure. For power supply failure the design will provide diversity by having ac powered and dc/steam powered trains. Additionally, upon loss of offsite power, ac power is supplied by the diesel generators.	3. Power diversity is arranged such that motor-driven AFWS train “A” is powered by ac safety bus “SA” which is automatically loaded on diesel generator 1A; the similar train “B” is on bus “SB” and loaded on DG 1B. The turbine-driven pump 1C is on dc swing bus “AB” and can be aligned to either “SA” or “SB”. The augmented AFWS will have dc power to all valves is the turbine-driven flow path. Pipe failure of the AFWS is addressed in position 5 below.

TABLE 10.5-3 (Continued)

BRANCH TECHNICAL POSITION	COMPLIANCE	REMARKS
4. The Auxiliary Feedwater System should be designed with suitable redundancy to offset the consequences of any single active component failure, however, each train need not contain redundant active components.	4. The AFWS is designed such that single active failures are accommodated as per Table 10.5-1. The cross-ties and valves are arranged such that single active failure of a component is accommodated. For example, on failure of a valve in a motor-driven pump line to open, or on failure of a motor-driven pump to start, the turbine-driven pump supplies both SGs; or on failure of a valve/pump in the turbine-driven train, the motor-driven pumps supply both SGs.	4. The augmented AFWS will contain dc powered valves in the turbine-driven pump flowpath.
5. When considering a high energy line break, the system should be so arranged as to permit the capability of supplying necessary emergency feedwater to the steam generators, despite the postulated rupture of any high energy section of the system, assuming a concurrent single active failure.	5. Postulation of an HELB in the Auxiliary Feedwater System was never a design basis for SL-1. Nevertheless, the system has been reviewed for this postulate also assuming a concurrent single active failure. Results for the worst cases indicate that the unfaulted SG is always fed by at least one motor-driven pump, and for most single failures the unfaulted SG is fed by at least one motor-driven and the turbine-driven pump, or both motor-driven pumps.	5. Design criteria for Unit 1 was MFW rupture and single failure in AFWS. The AFAS will detect the rupture in the affected line and close the appropriate valves to isolate the ruptured line. As-built capacity of the motor-driven pump is over 350 gpm. Analyses indicate that this is sufficient flow to remove RCS decay heat and remain at hot standby conditions. For an AFWS HELB, hot standby is the safe condition.

Table 10.5-4

Plant Initial Conditions for Loss of Feedwater Analysis With Degraded Auxiliary Feedwater Flow (Offsite Power, 58% SBCS)

EC288300

Parameter	Value
Core Power	3029.06 MWt
Core Inlet Temperature	551°F
Pressurizer Pressure	2250 psia
Pressurizer Liquid Level	65.6%
Reactor Vessel Flow Rate	410,922 gpm
Moderator Temperature Coefficient	+2.0 pcm/°F
Doppler Coefficient	-0.80 pcm/°F
Steam Generator Pressure	851 psia
Steam Generator Liquid Level	64.9% Narrow Range
Steam Generator Secondary Total Mass Inventory	127,000 lbm
Main Steam Flow	13.26 x 10^6 lbm/hr
Steam Generator Blowdown Flow	120 gpm each
Auxiliary Feedwater Temperature	111.5°F
Total RCS Pump Heat	14.6 MWt

Table 10.5-5

Analysis Assumptions for Loss of Feedwater Analysis with Degraded Auxiliary Feedwater Flow (Offsite Power, 58% SBCS)

EC288300

1.	Initiating Event	Instantaneous loss of all main feedwater.	
2.	RPS Trip Setpoint	30% of Narrow Range SG Level. This value includes all necessary uncertainties.	EC288300
3.	AFW Actuation Trip Setpoint	14% of Narrow Range SG Level. This value includes all necessary uncertainties.	
4.	Primary System Pressure Control	The power operated relief valves (PORVs), pressurizer heaters, and pressurizer spray system are enabled and function at nominal setpoints. (Note: The SRV setpoints are inconsequential since the safety valves are not challenged by this event.)	
5.	Secondary System Pressure Control	The dump and bypass valve areas were assumed to pass 8.0 Mlbm/hr assuming critical flow conditions, however, when modeled in the transient analysis, the valves were modeled without assumed choking, as depicted by Figures 10.5-9 and 10.5-10. The Main Steam Safety Valves (MSSVs) are enabled and set to open at the nominal setpoints plus 3% tolerance. MSSV blowdown is 1%.	
6.	Reactor Coolant Pump Operation	All four RCPs remain on until all RCPs are tripped* at 900 seconds after the loss of feedwater. The total RCP heat is 14.6 MWt.	EC288300 EC289558
7.	Auxiliary Feedwater Flow and Delay	The turbine-driven AFW pump is not credited due to the assumption of a break in the pump discharging piping. The single failure assumed is the loss of one motor-driven AFW pump. A degraded flow rate as a function of SG pressure is assumed for the single operating motor-driven pump. The initiation of auxiliary feedwater is delayed 330 seconds after the auxiliary feedwater actuation signal (AFAS).	EC288300
8.	Primary System Charging	No primary system charging was assumed.	EC288300
9.	Steam Generator Tube Plugging Level	It was assumed that no tubes are plugged in the steam generators.	
10.	Reactor Kinetics Feedback and Decay Heat Calculations	Reactor kinetics feedback due to changing primary system conditions prior to reactor scram is calculated using the S-RELAP5 code. Following reactor scram, the ANS 1973 Standard decay heat formulation was applied, including the contribution due to actinide decay.	
11.	Steam Generator Blowdown Flow	SG blowdown rate is 120 gpm per SG. The blowdown flow is isolated at 25 minutes.	
12.	Letdown Flow	Letdown flow of 128 gpm is assumed.	EC288300

* - The accident analysis conservatively assumes 900 seconds operator action time to trip all RCPs based on the SG level in both SGs falling well below 20%NR within the first minute. The required operator action is thus to trip RCPs once the levels in both SGs fall below 20%NR. EC289558

Table 10.5-6

Plant Initial Conditions for Loss-of-Feedwater With No AFW (58% SBCS)

EC288300

PARAMETER	VALUE
Core Power	3029.06 MWt
Core Inlet Temperature	551°F
Pressurizer Pressure	2250 psia
Pressurizer Liquid Level	65.6%
Primary System Loop Flow Rate	410,922 gpm
Moderator Temperature Coefficient	+2.0 PCM/°F
Doppler Coefficient	-0.8 PCM/°F
Steam Generator Pressure	850 psia
Steam Generator Liquid Level	64.9% Narrow Range
Steam Generator Secondary Mass Inventory	127,000 lbm
Auxiliary Feedwater Temperature	111.5°F*
Reactor Coolant Pump Heat (4 pumps)	14.6 MWt
Steam Generator Blowdown Flow	120 gpm per SG

* AFW is not initiated.

Table
10.5-7

Analysis Assumptions for Loss-of-Feedwater With No AFW (58% SBCS)

EC288300

1. Initiating Event: Instantaneous loss of all main feedwater.

2. RPS Trip Setpoint: 25% of Narrow Range SG Level. This value included all necessary uncertainties.

3. AFAS Trip Setpoint: AFW not used in this analysis.

4. Primary System Pressure Control: PORVs, pressurizer heaters, and pressurizer spray systems were assumed to be operable, and to function at nominal setpoints.

5. Secondary System Pressure Control: Dump and bypass valve areas were assumed to pass 8.0 Mlbm/hr assuming critical flow conditions, however when modeled in the transient analysis, the valves were modeled without assumed choking, as depicted by Figures 10.5-24 and 10.5-25.

6. Reactor Coolant Pump Operation: All four Reactor Coolant Pumps (RCP) were on throughout the transient. The RCP heat is 14.6 MWt (4 pumps). This value has accounted for piping and radiation losses along with heat removed by Component Coolant Water System. Hence, this is the net heat load on SG contributed by RCPs.

7. Auxiliary Feedwater Flow and Delay: There was no auxiliary feedwater during this event.

8. Primary System Charging and Letdown Systems: No primary system charging or letdown flows were assumed.

9. Steam Generator Tube Plugging Level: It was assumed that no tubes are plugged in the steam generators. This is a conservative assumption because it maximizes the heat transfer from the primary to the secondary systems.

10. Reactor Kinetics Feedback and Decay Heat Calculation: Reactor kinetics feedback due to changing primary system conditions prior to reactor scram was modeled using the S-RELAP5 code. After reactor scram, the nominal ANS 1973 Standard decay heat formulation was applied, including the contribution due to actinide decay.

11. Steam Generator Blowdown Flow: SG blowdown rate is 120 gpm per SG.

Table 10.5-8

Analysis Parameters for Feedwater Line Break (Heat-up Analysis)		
Parameter	Value Offsite Power Available Case	Value Loss of Offsite Power Case
Core Power	3029.06 MWt	
Core Inlet Temperature	554°F	
Pressurizer Pressure	2185 psia	
Pressurizer Level	68.6%	
Primary system Loop Flow Rate	375,000 gpm	
Moderator Temperature coefficient	+2 pcm/°F	
Doppler Multiplier	-0.80 pcm/°F	
Steam Generator Pressure	854 psia	
Steam Generator Liquid Level	Faulted: 70%NR Intact: 60%NR	
Steam Generator Low Level Trip Setpoint	5%	
AFW Temperature	111.5°F (276 gpm)	104°F (296 gpm)
Reactor Regulating system	Manual Mode	
Steam Dump and Bypass	Automatic Mode with 24% of full power steaming capacity	Not available following loss of offsite power
Feedwater Regulating System	Instantaneously isolated at event initiation (both SGs)	
Auxiliary Feedwater System	Automatic Mode: One motor-driven pump 330 seconds after steam generator liquid level reached 5%	
Pressurizer Pressure Control System	Heaters disabled, spray automatic	
Pressurizer Level Control System	Charging and Letdown not modeled	
Total RCS Pump Heat	20 MWt	
Reactor Coolant Pump Operation	RCPs running until all 4 RCPs tripped by operator by 15 minutes	RCPs running until loss of offsite power at turbine trip due to reactor trip

TABLE 10.5-9

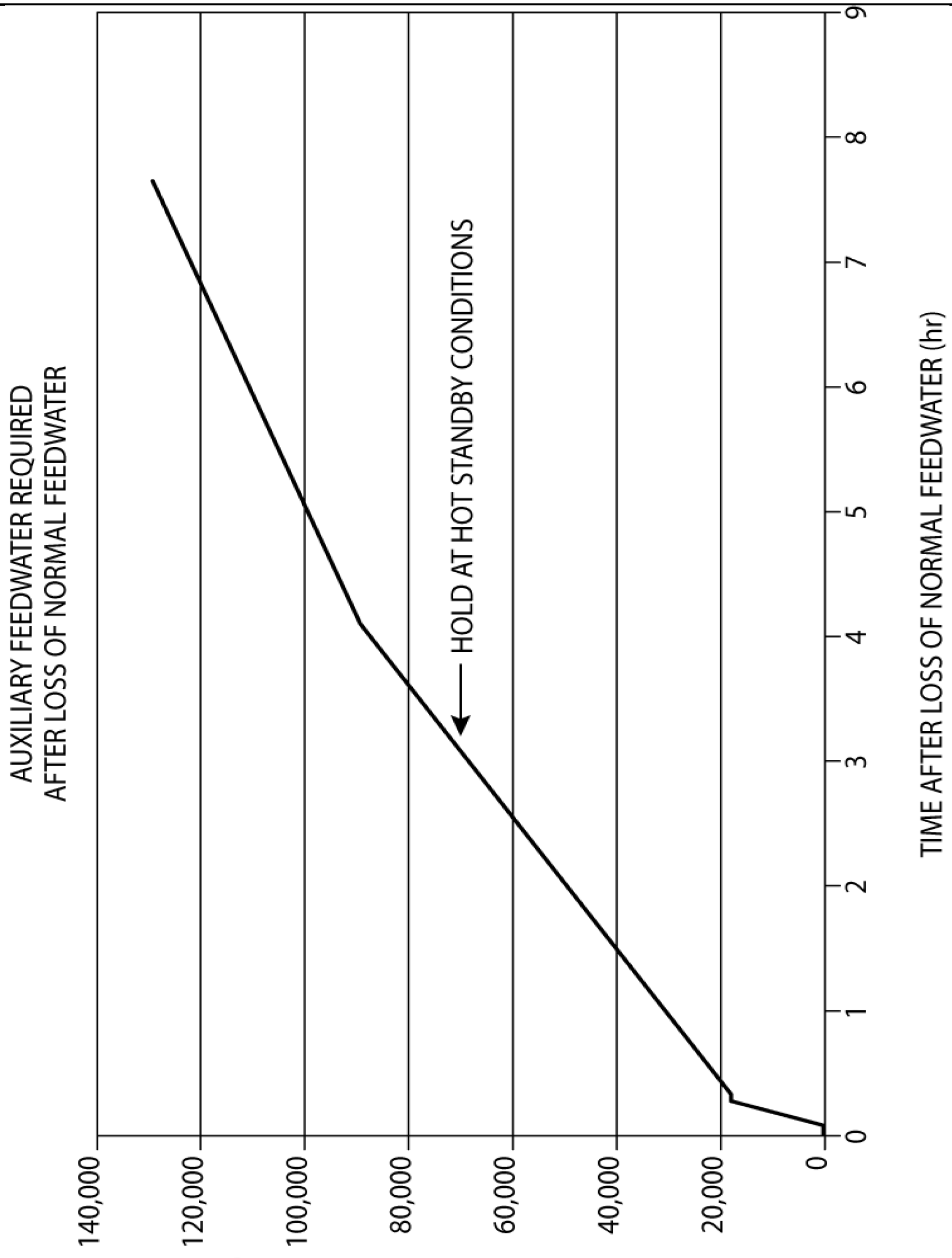
Sequence of Events for Feedwater Line Break (Heat-Up Analysis) – Offsite Power Available Case

Time (s)	Event
0	Double-ended guillotine break of MFW nozzle occurred, resulting in assumed instantaneous loss of MFW to both SGs
7.8	Trip signal on low steam generator level
8.7	Reactor tripped
372	Auxiliary feedwater to intact SG began
909	All RCPs tripped by operator
2610	AFW heat removal matched core decay heat and peak RCS temperature occurred; subcooling as 7°F
4000	Calculation terminated

TABLE 10.5-10

Sequence of Events for Feedwater Line Break (Heat-Up Analysis) – Loss of Offsite Power Case

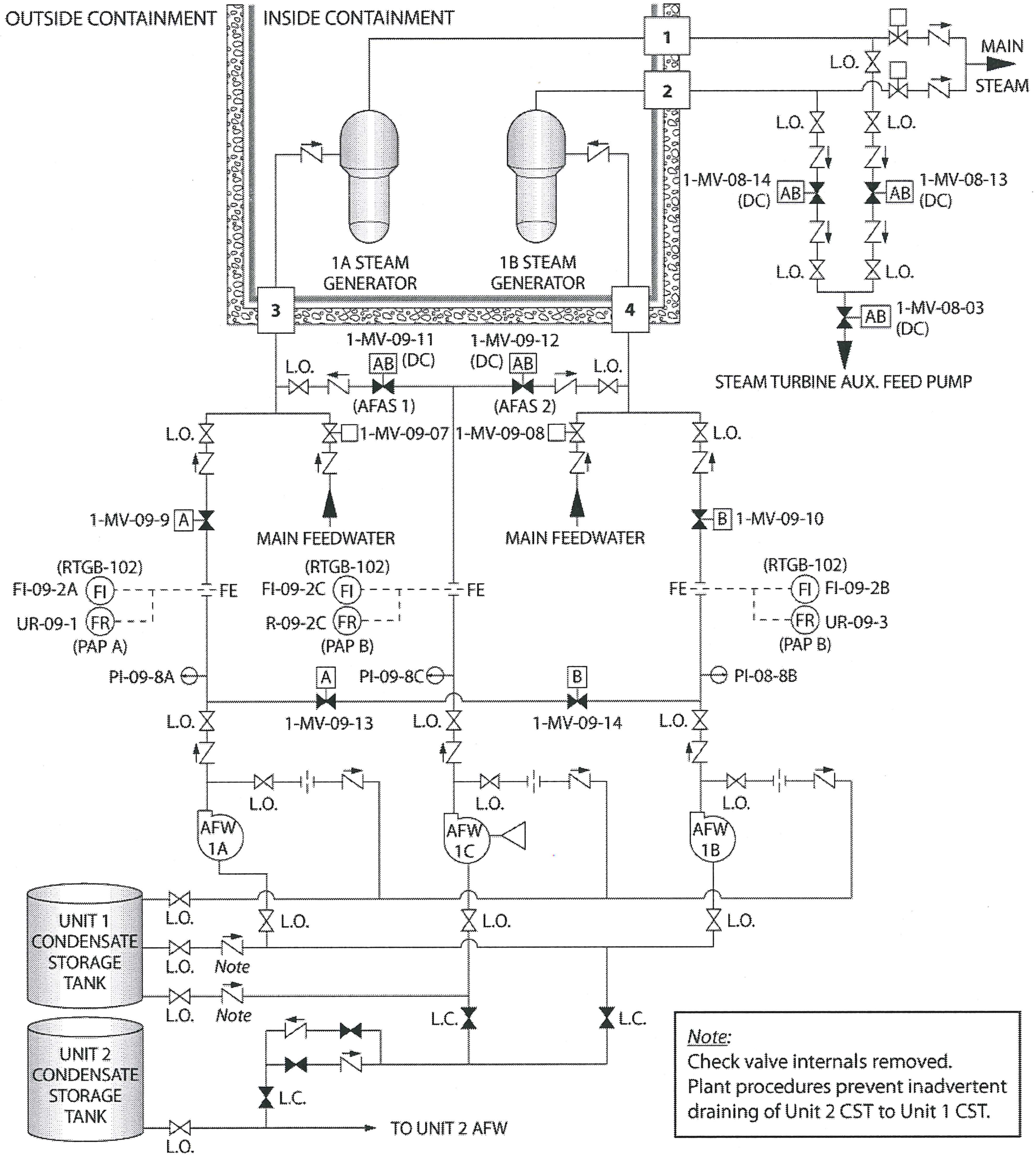
Time (s)	Event
0	Double-ended guillotine break of MFW nozzle occurred, resulting in assumed instantaneous loss of MFW to both SGs
7.8	Trip signal on low steam generator level
8.7	Reactor tripped, all RCPs tripped on loss of offsite power
371	Auxiliary feedwater to intact SG began
2408	AFW heat removal matched core decay heat and peak RCS temperature occurred; subcooling as 34°F
3000	Calculation terminated



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

AUXILLIARY FEEDWATER REQUIRED AFTER LOSS OF NORMAL FEEDWATER

FIGURE 10.5-1



Note:
Check valve internals removed.
Plant procedures prevent inadvertent draining of Unit 2 CST to Unit 1 CST.

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AUXILLIARY FEEDWATER SYSTEM
SCHEMATIC
FIGURE 10.5-2

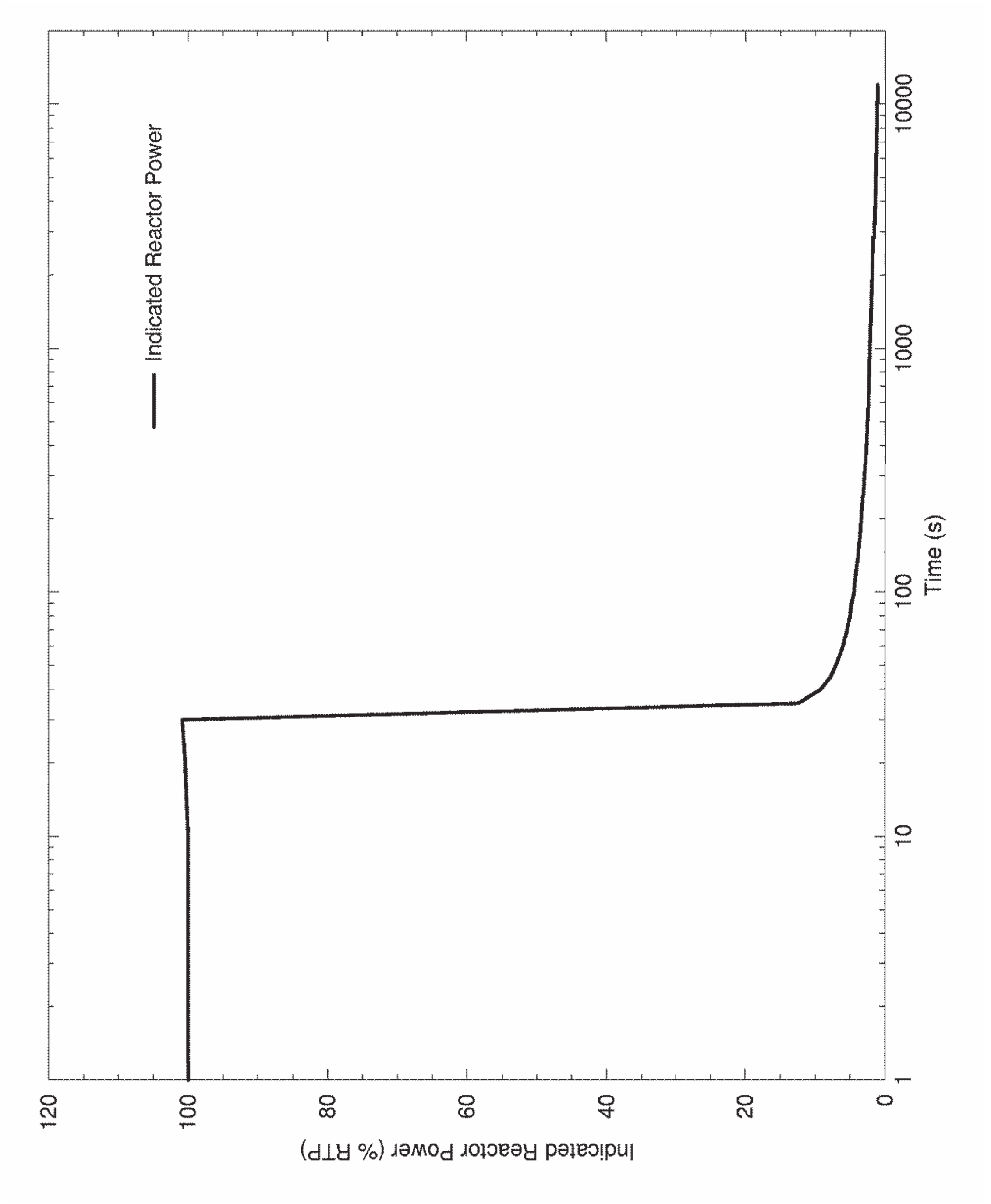
REFER TO DRAWING
8770-B-326 Sheet 1000

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

SCHEMATIC DIAGRAM 125V DC BATTERY SYSTEM
FIGURE 10.5-3

Amendment 15 , (1/97)

EC288300



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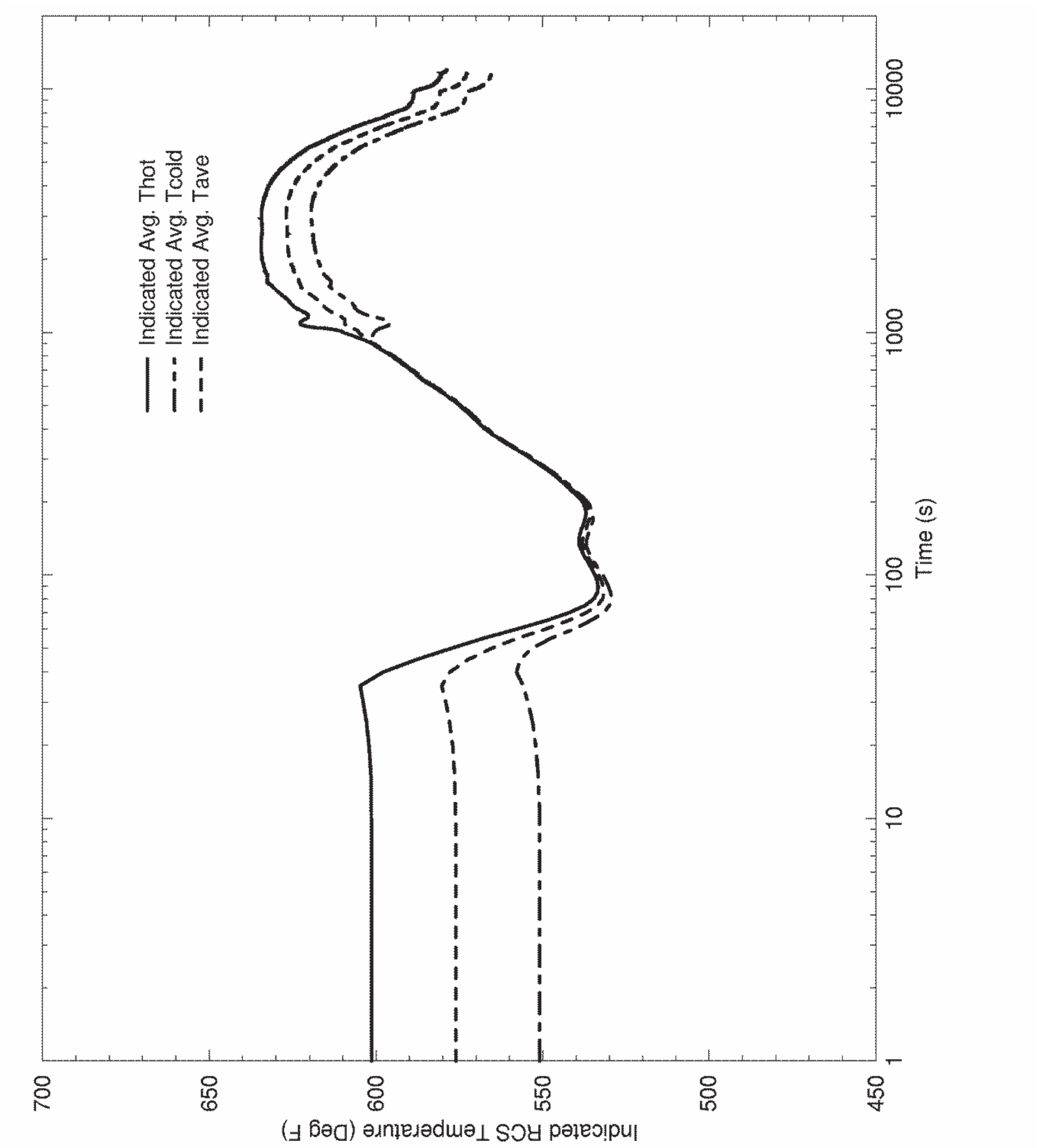
ST. LUCIE PLANT UNIT 1

INDICATED REACTOR POWER-LOSS OF FEEDWATER FLOW COINCIDENT WITH AUXILIARY FEEDWATER LINE BREAK

FIGURE 10.5-4

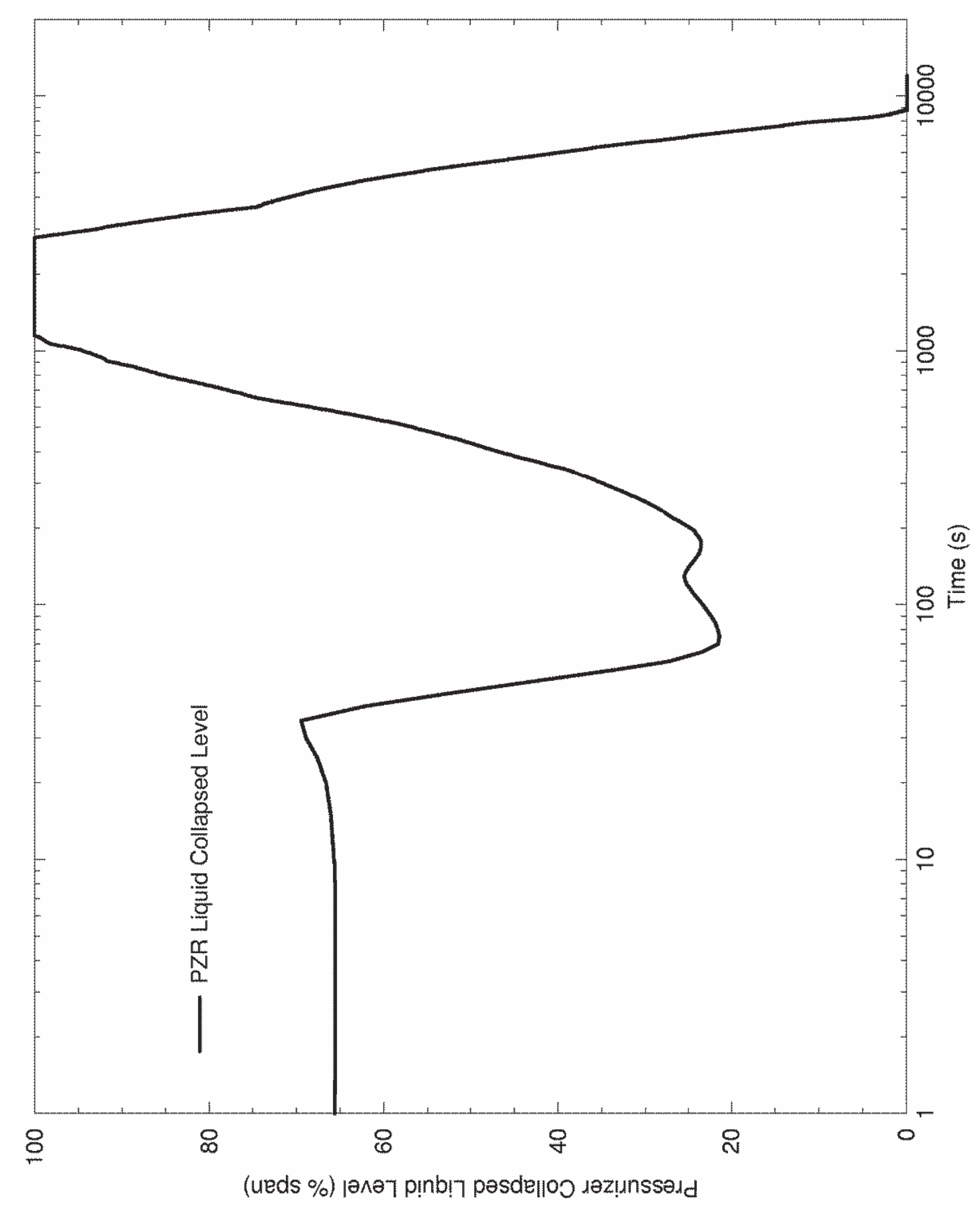


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

INDICATED RCS COOLANT TEMPERATURE
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-5

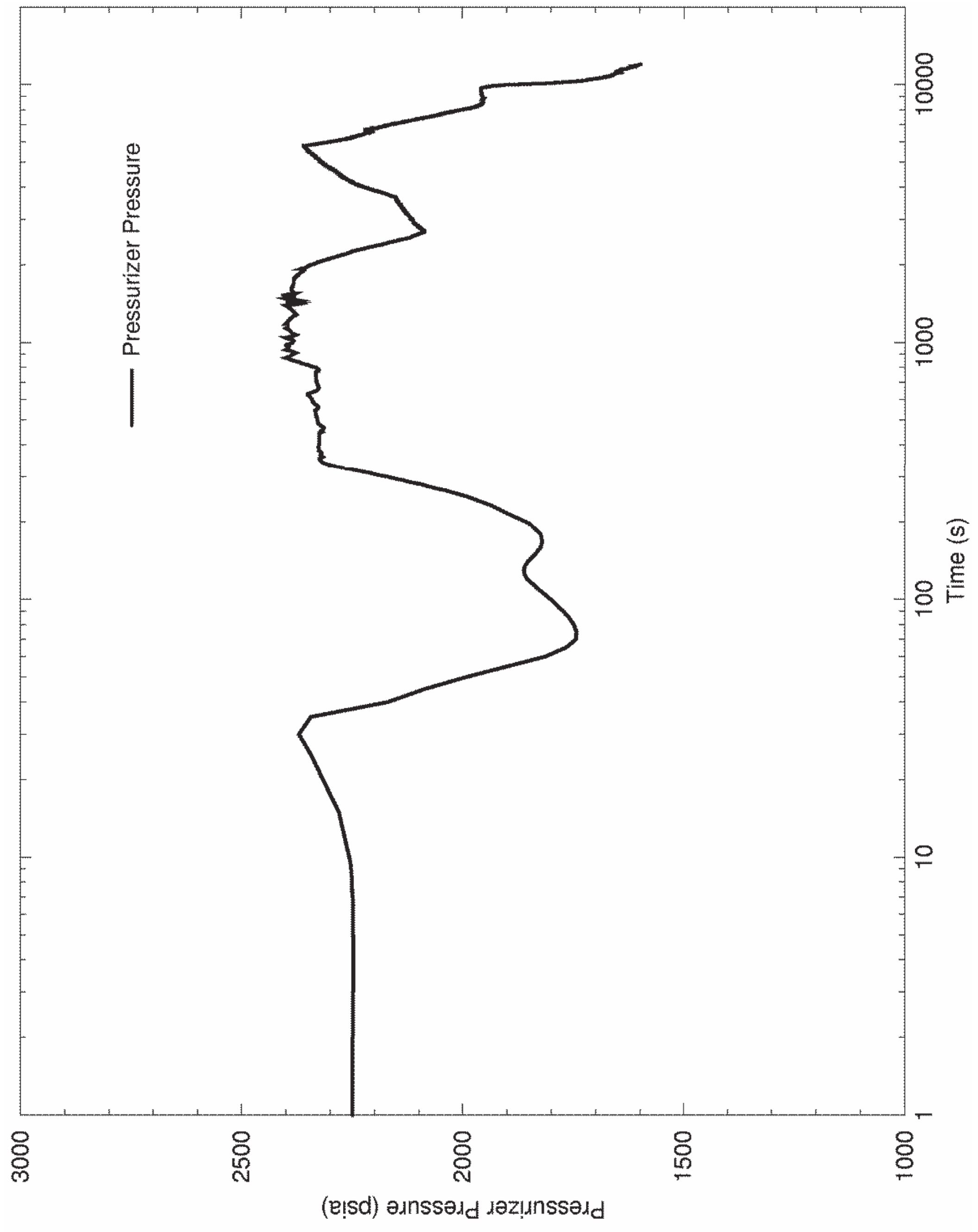
EC288300



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

PRESSURIZER LEVEL
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-6

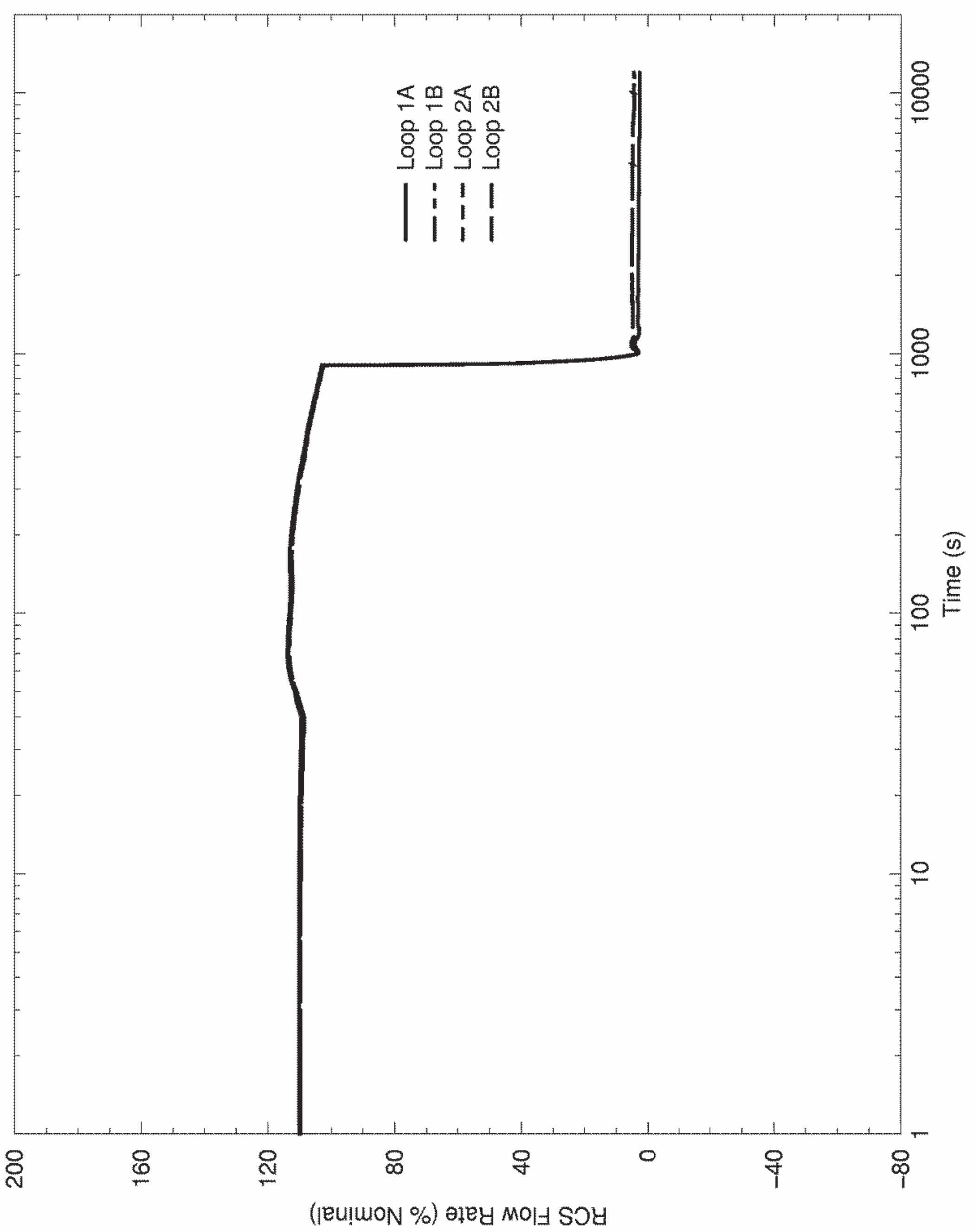


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

PRESSURIZER PRESSURE
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-7

EC288300

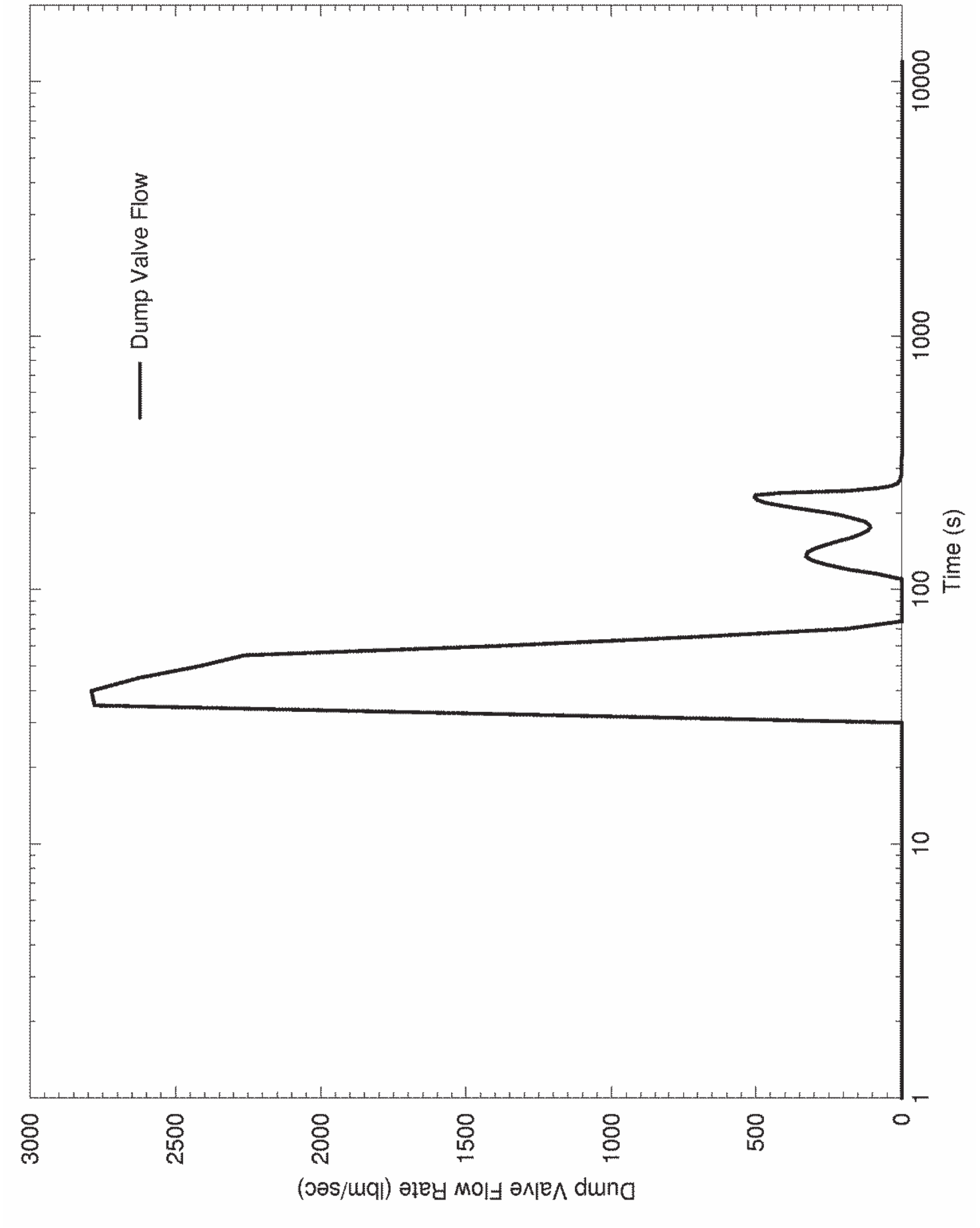


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

RCS LOOP FLOWS
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-8

EC288300

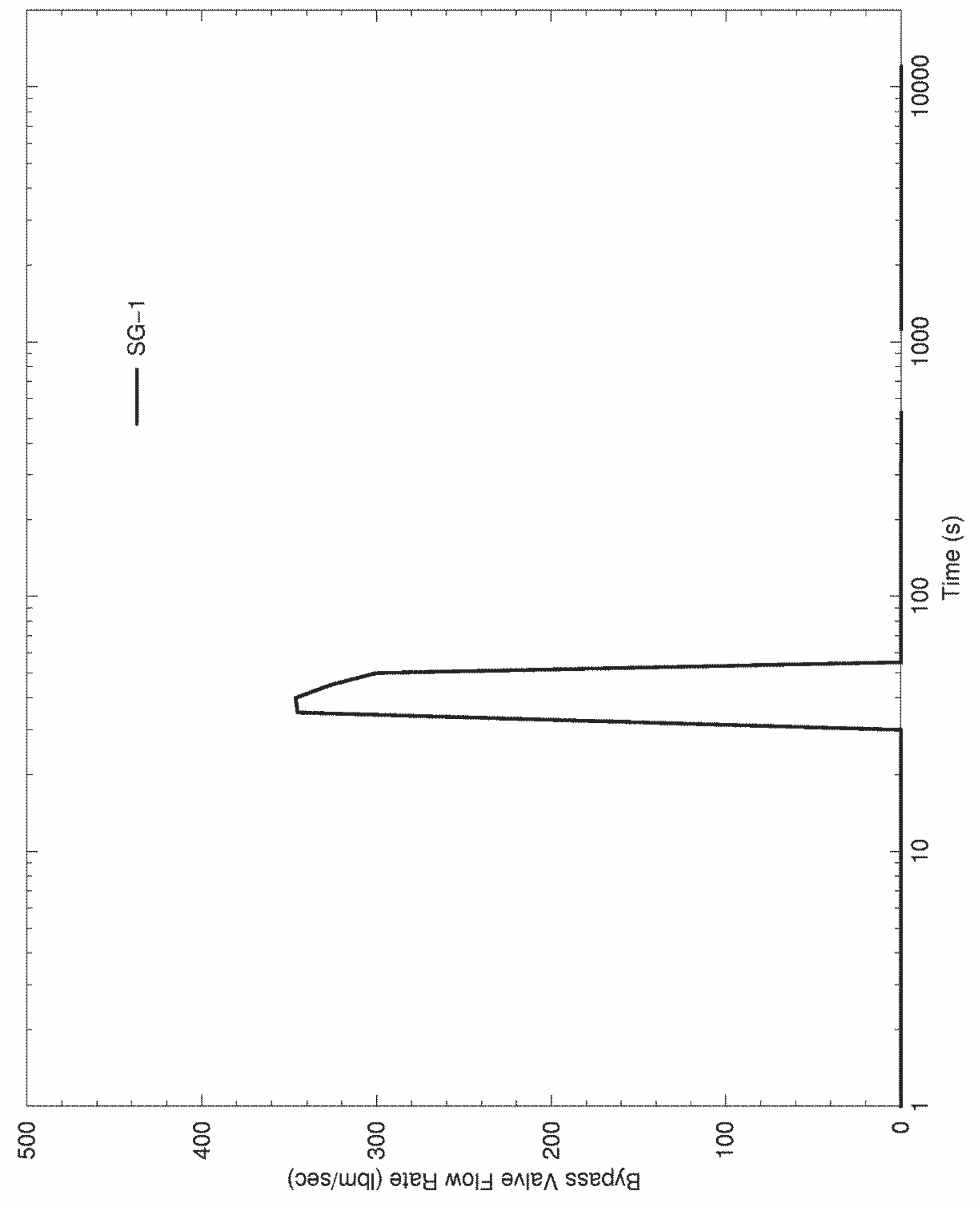


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

DUMP TO CONDENSER FLOW
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-9

EC288300

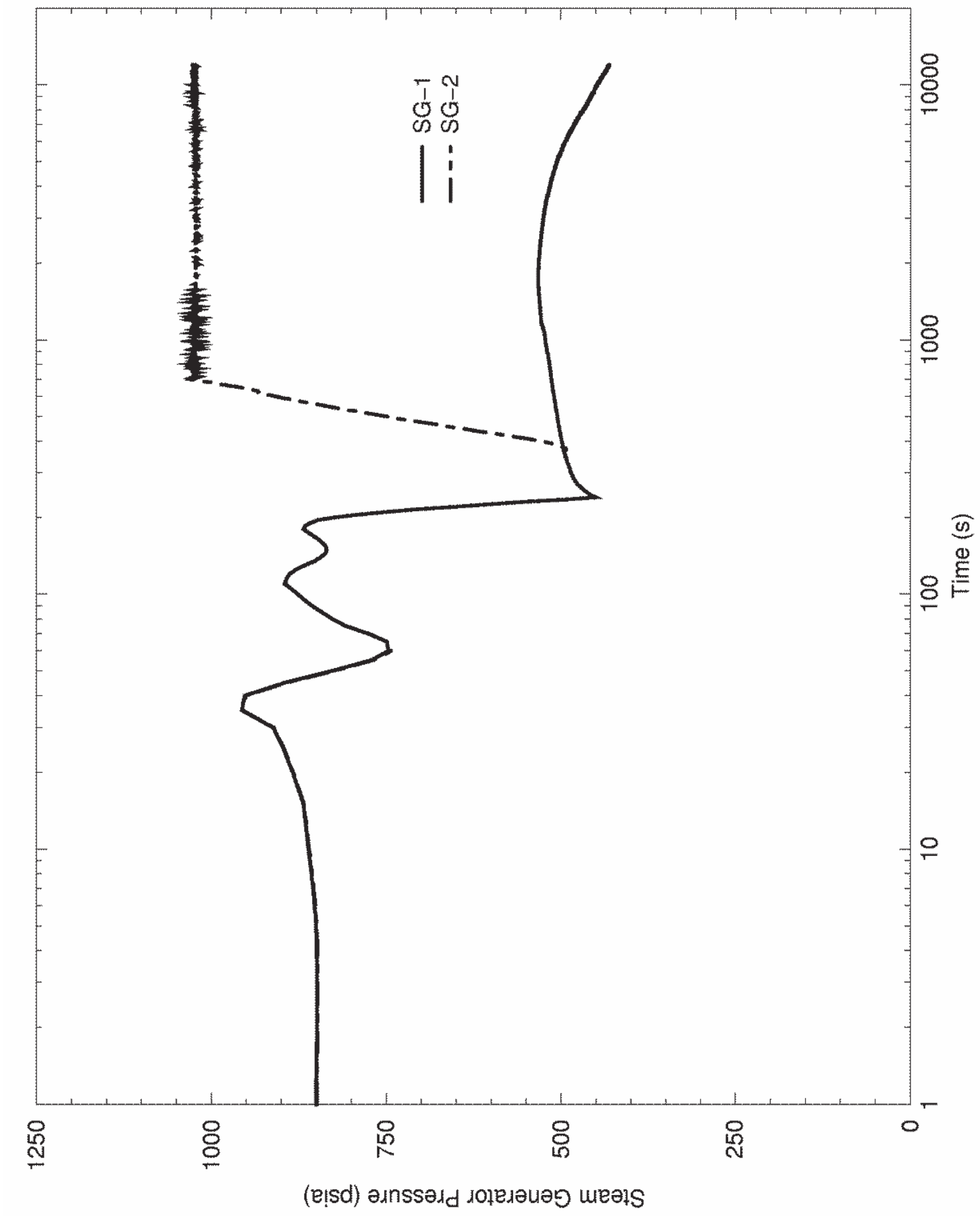


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

BYPASS TO CONDENSER FLOW
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-10

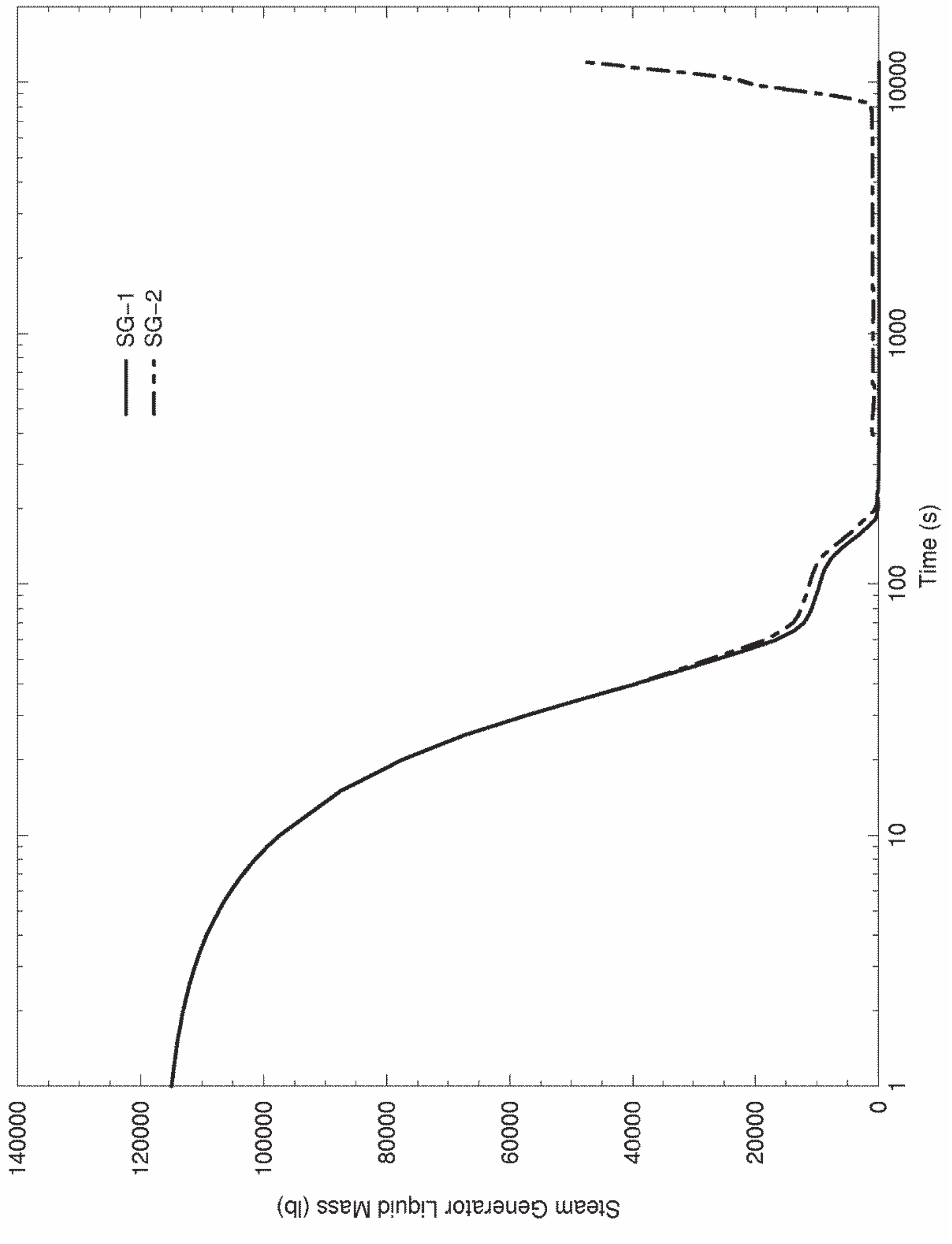
EC288300



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

STEAM GENERATOR PRESSURE
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-11

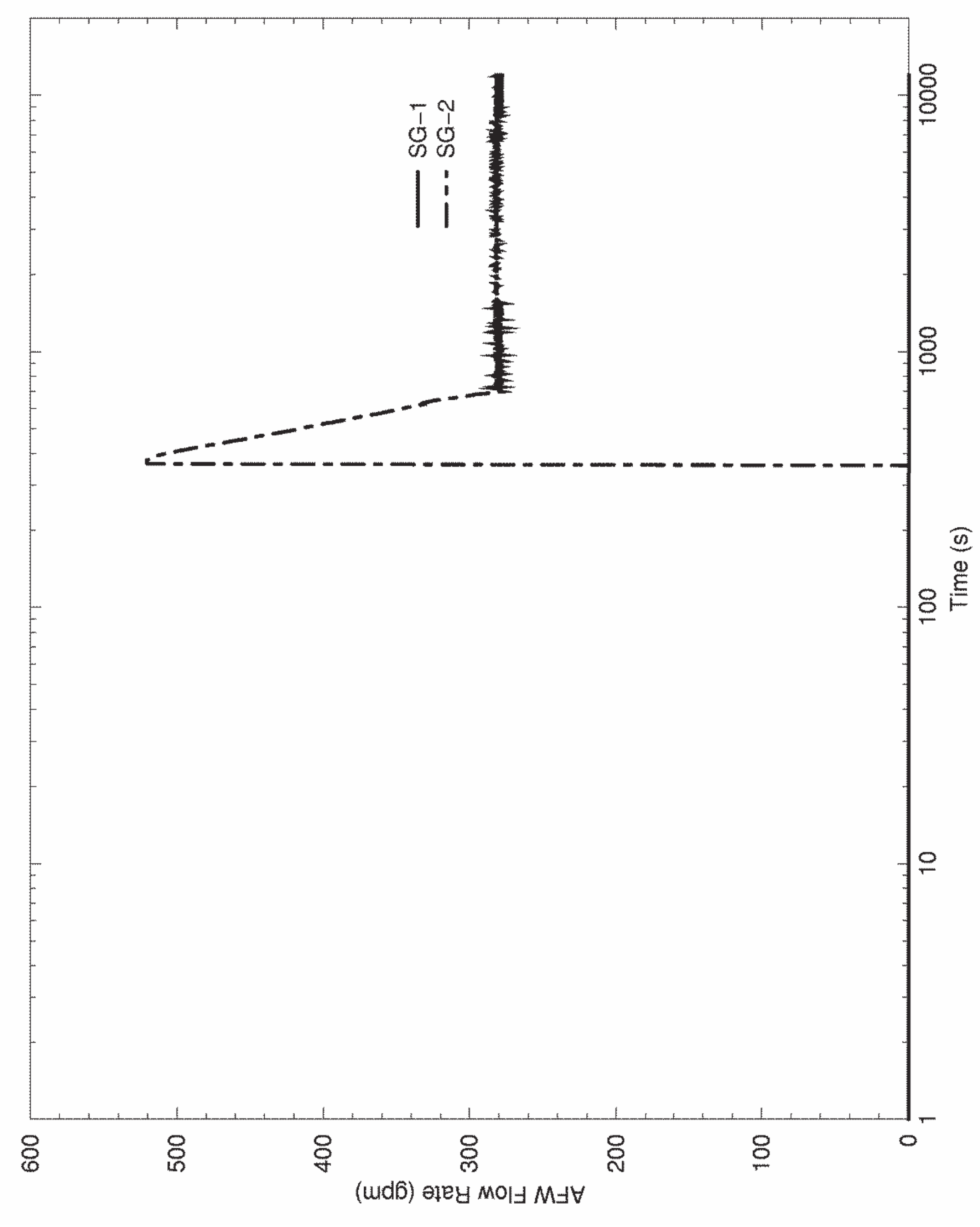


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

STEAM GENERATOR LIQUID MASS
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-12

EC288300

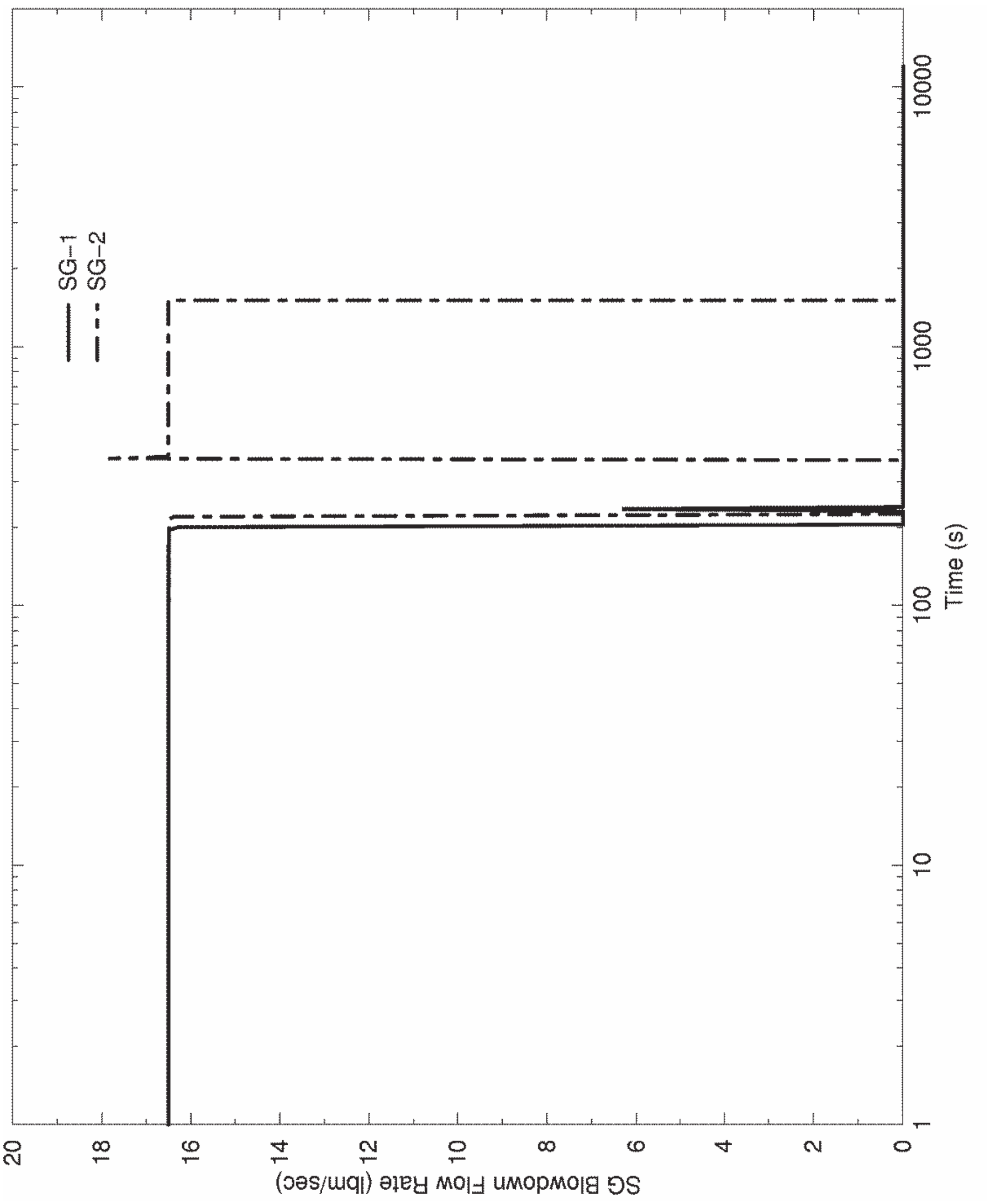


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

AUXILIARY FEEDWATER FLOW
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-13

EC288300

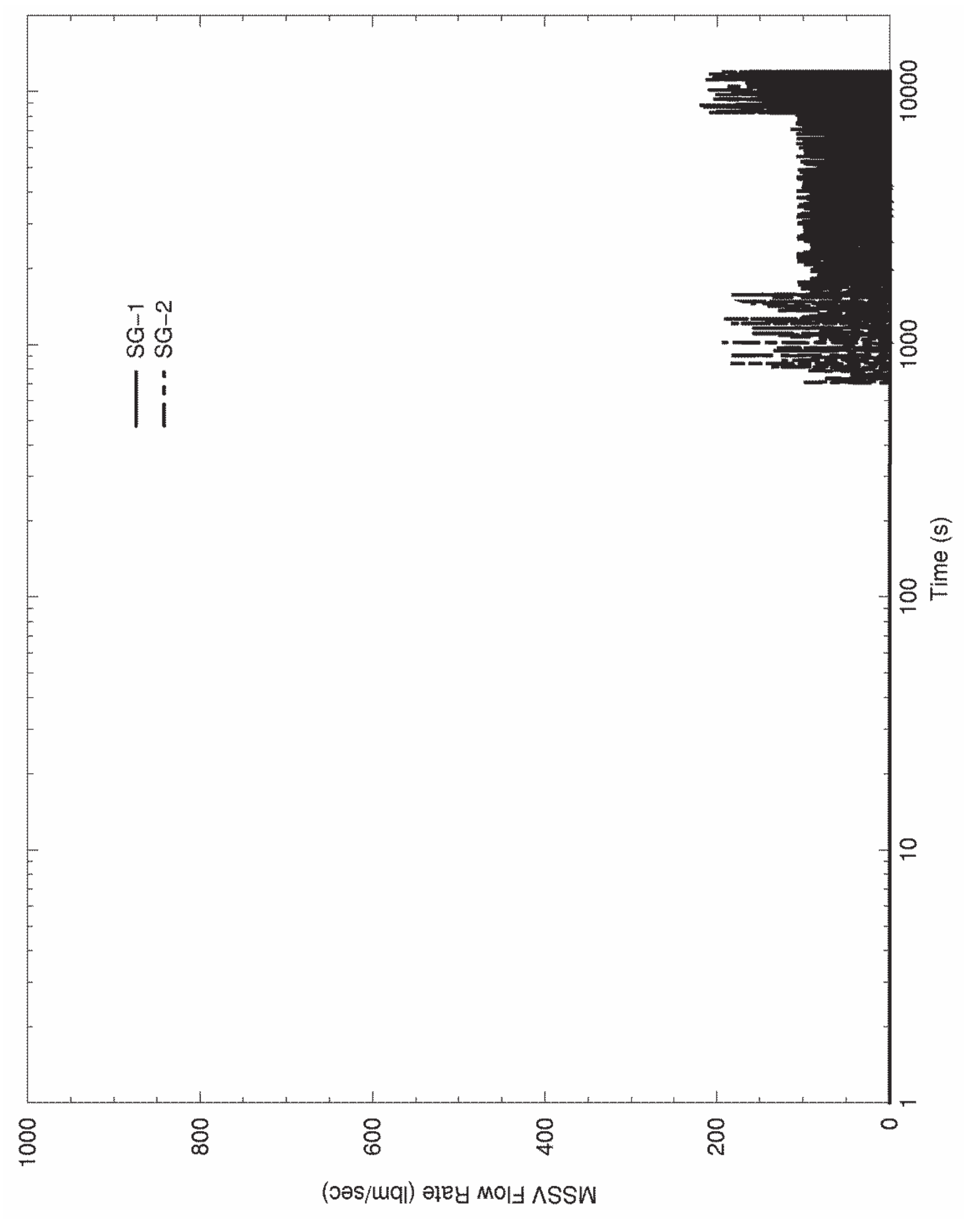


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

STEAM GENERATOR BLOWDOWN FLOW
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-14

EC288300



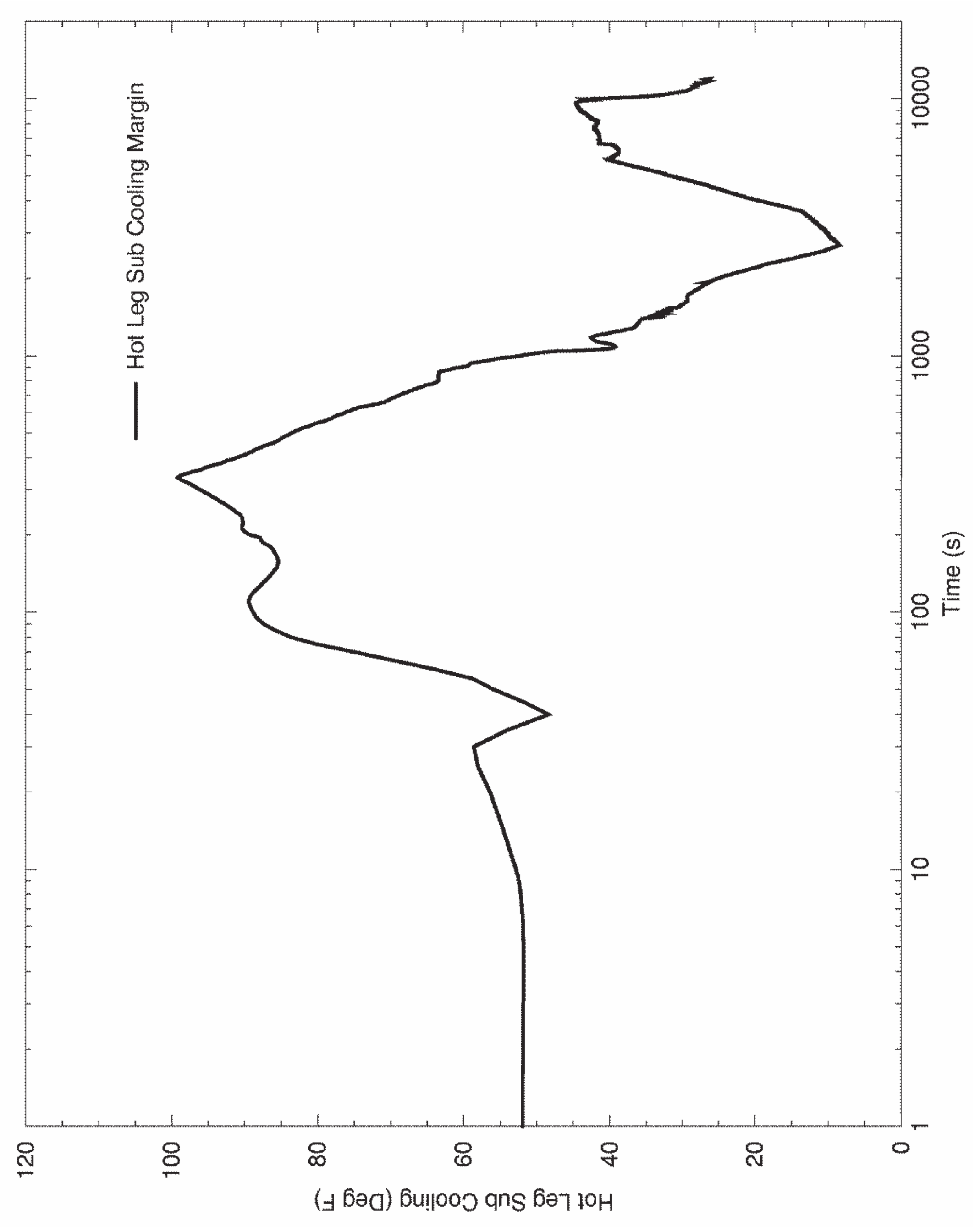
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

STEAM GENERATOR MSSV FLOW
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-15

Amendment No. 29 (10/18)

EC288300

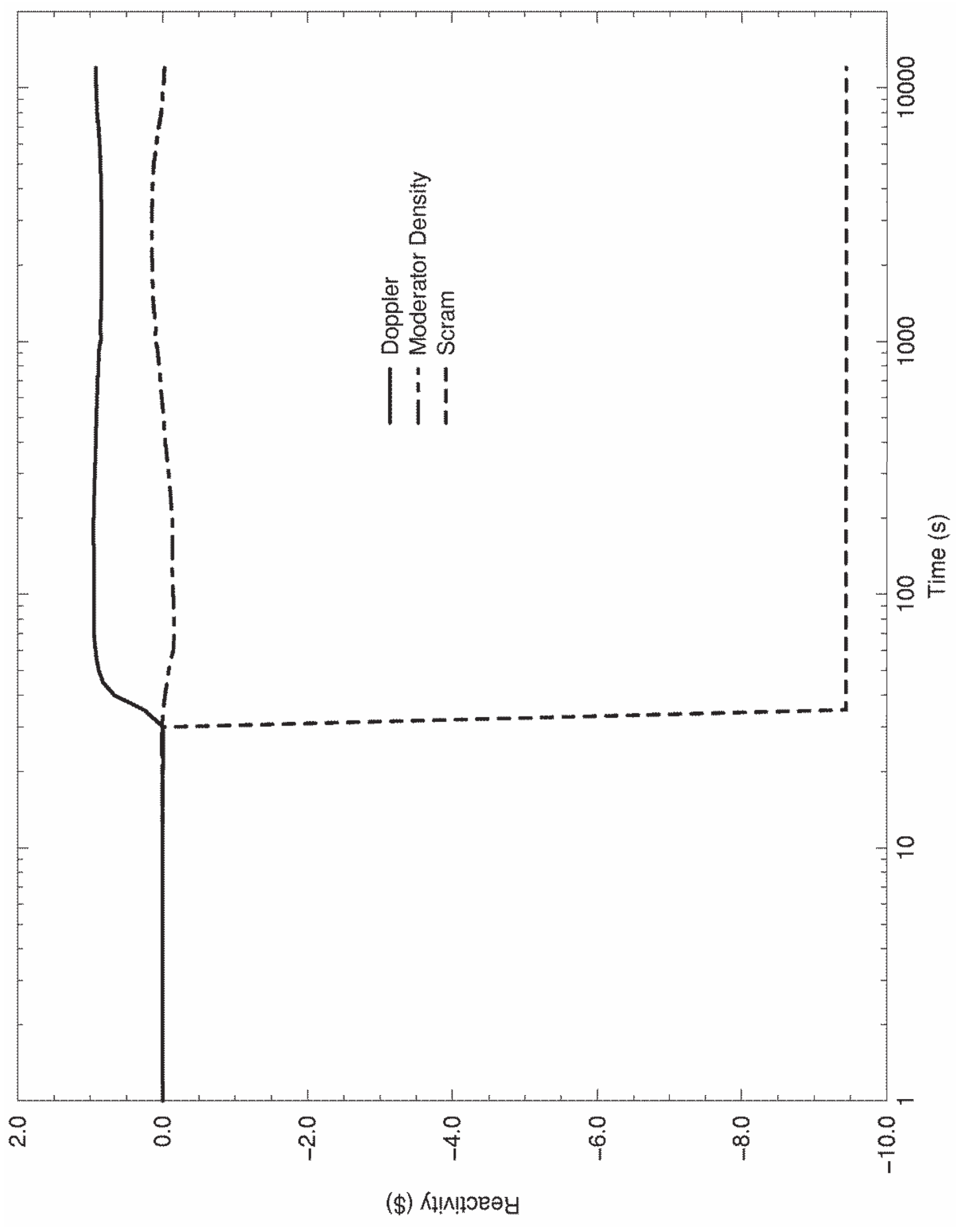


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

SUBCOOLING MARGIN
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-16

EC288300

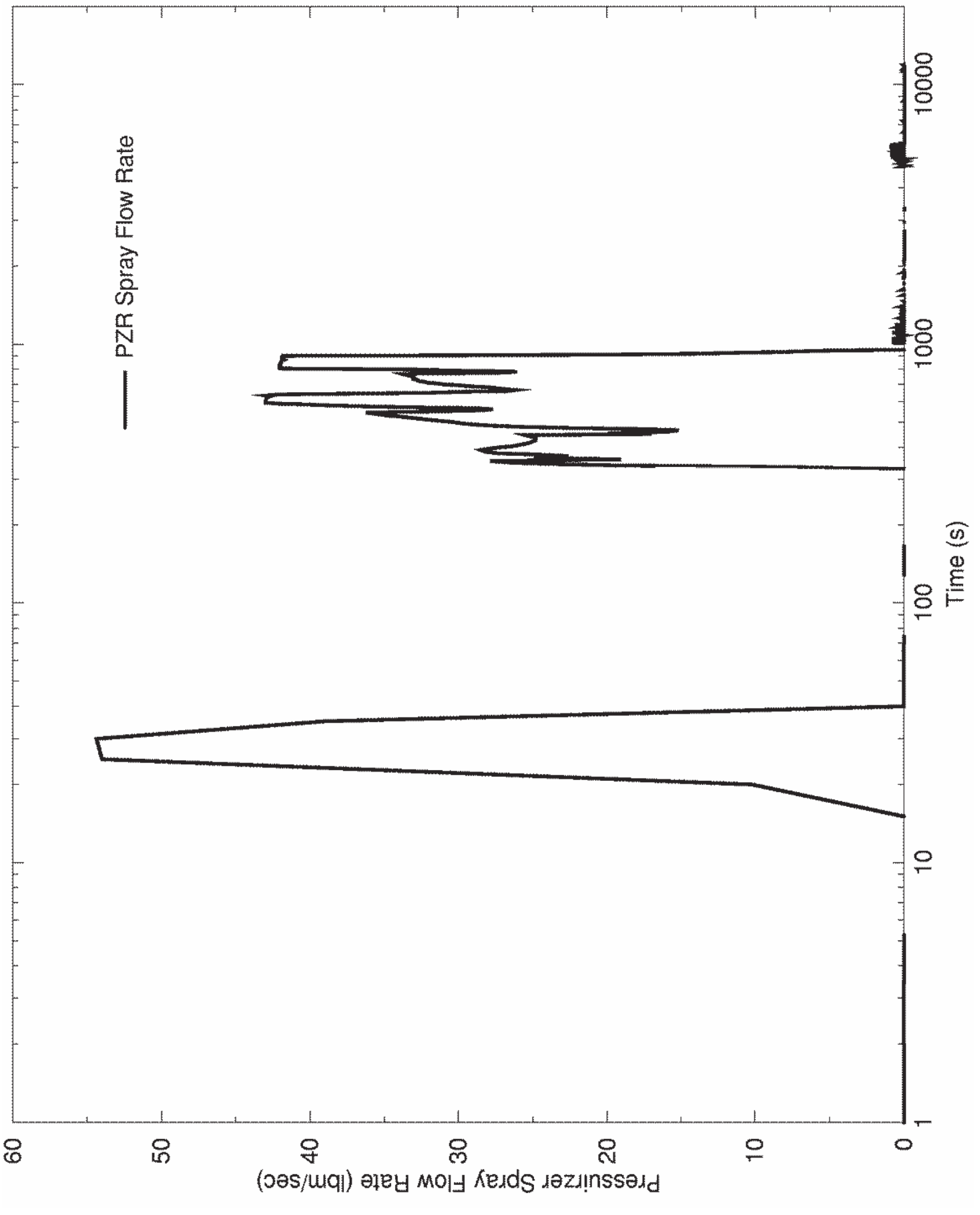


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

REACTIVITY COMPONENTS
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-17

EC288300

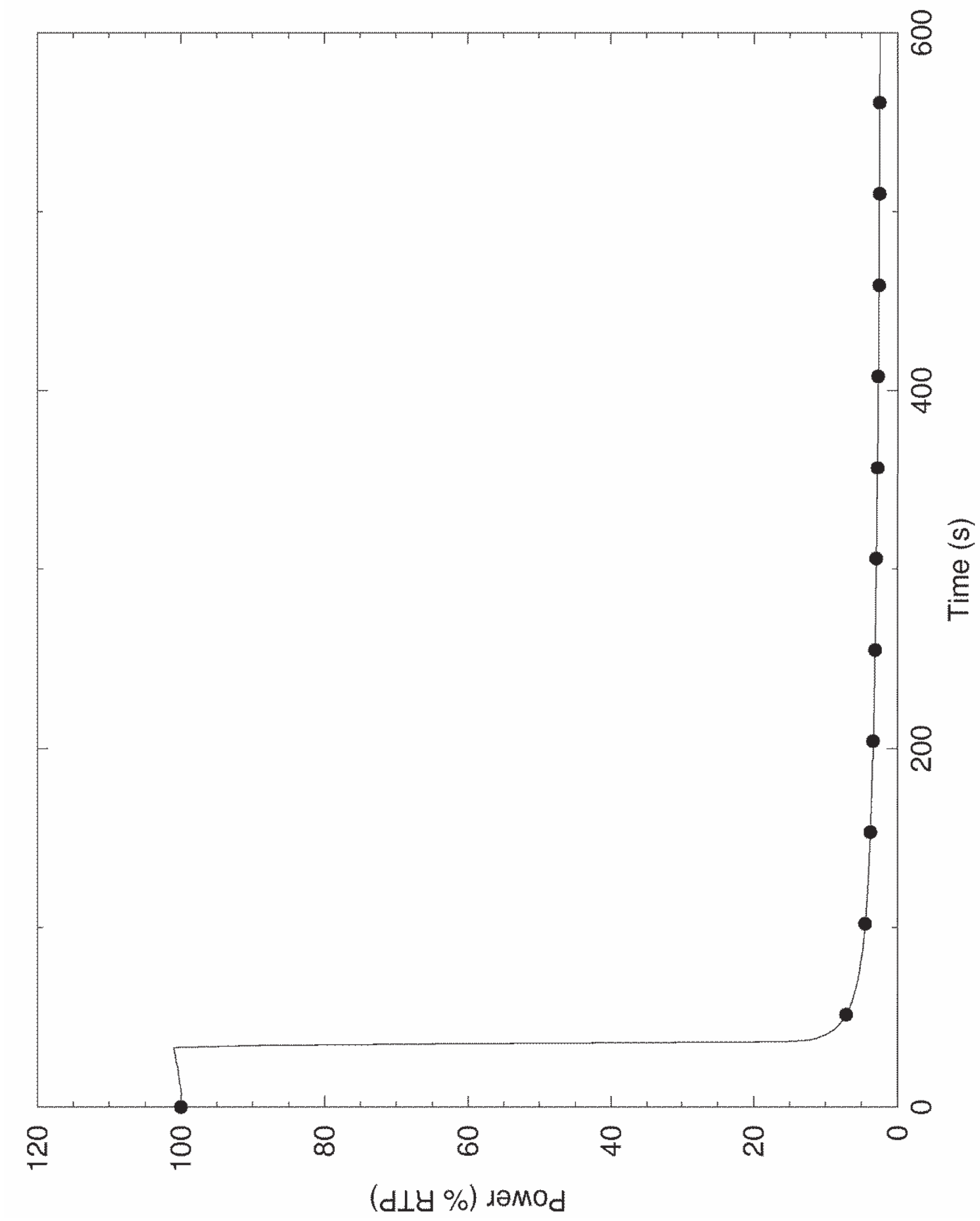


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

PRESSURIZER SPRAY FLOW
LOSS OF NORMAL FEEDWATER FLOW
(DEGRADED AFW FLOW)

FIGURE 10.5-18

EC288300

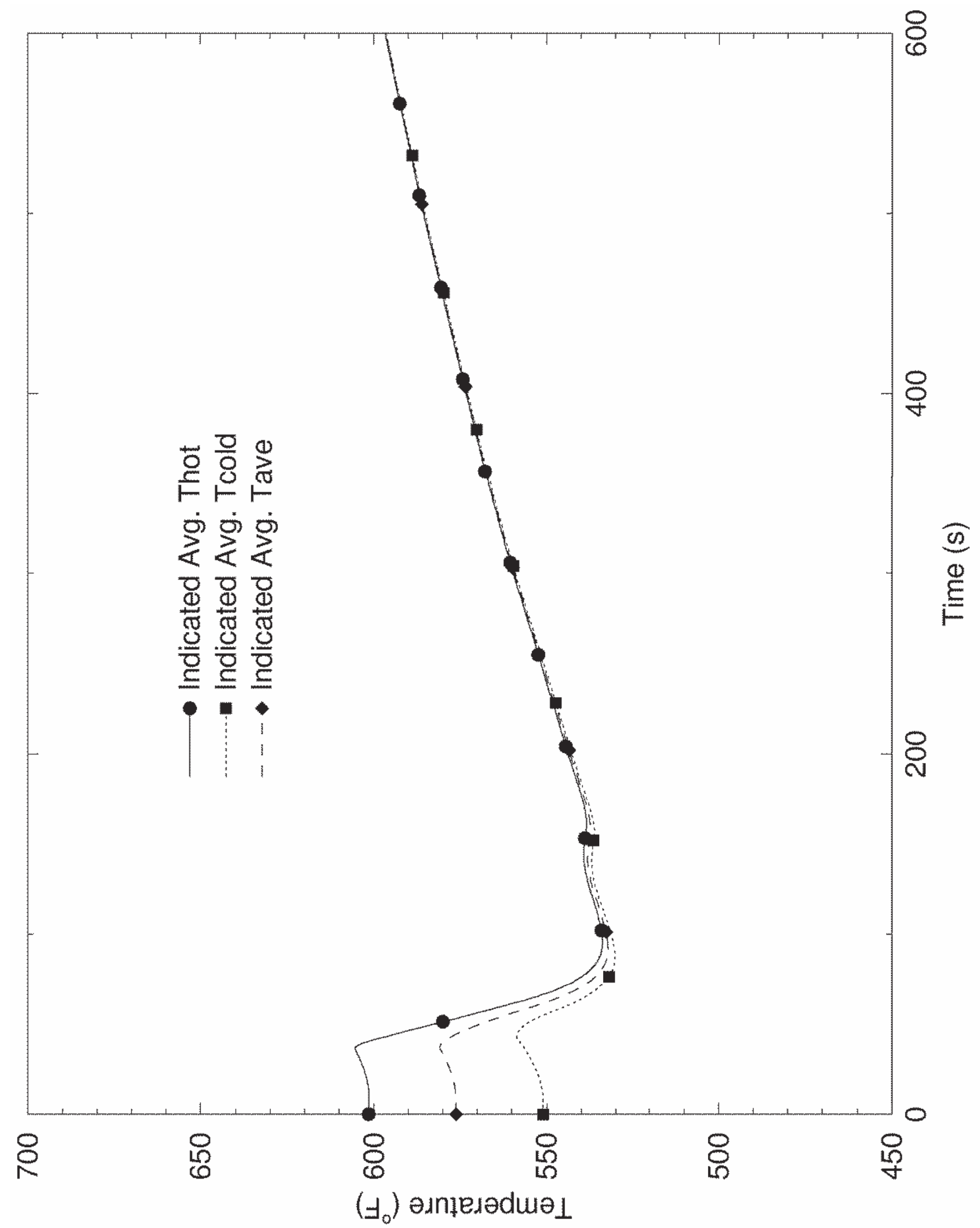


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

INDICATED REACTOR POWER
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-19

EC288300

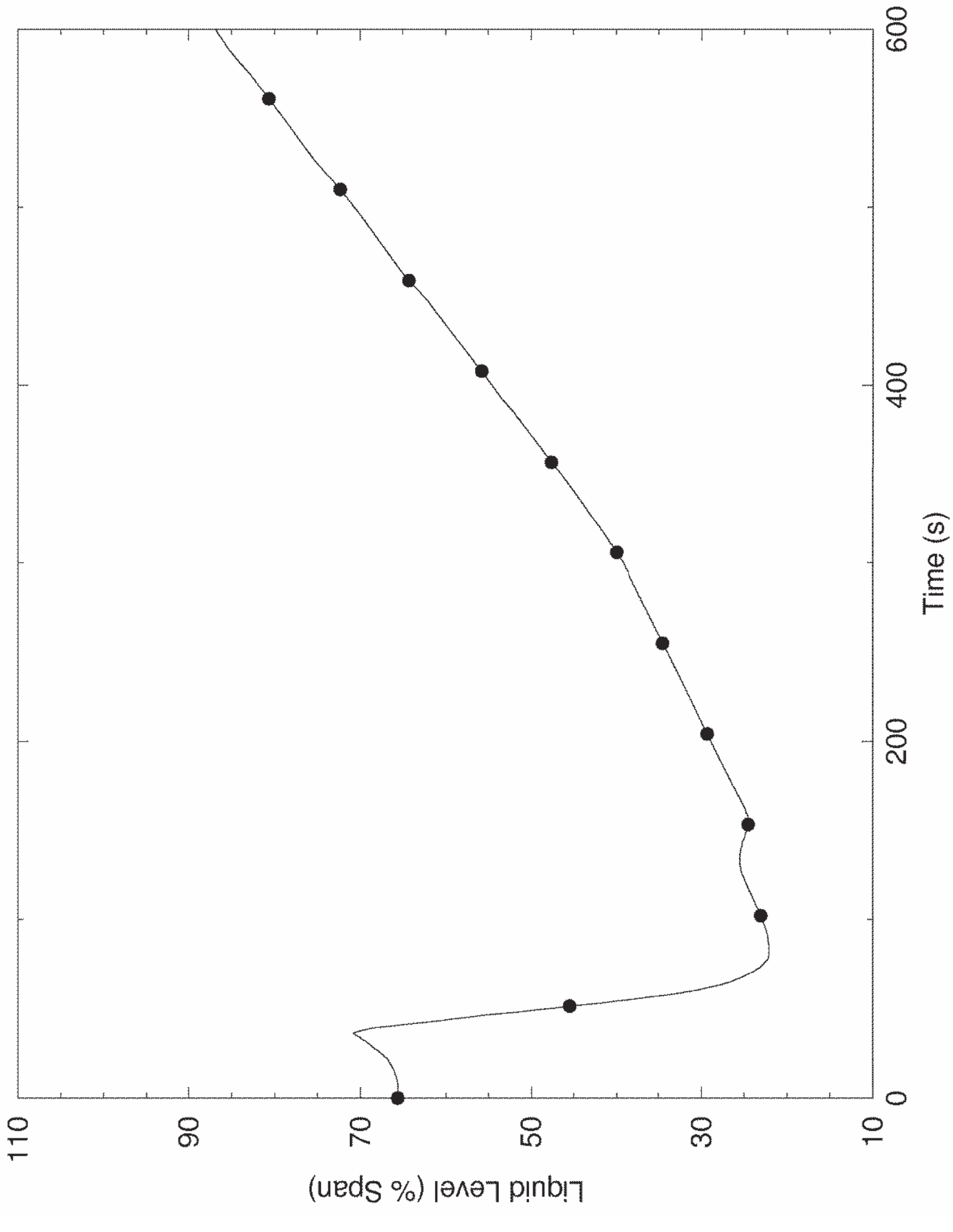


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

INDICATED RCS COOLANT TEMPERATURE
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-20

EC288300

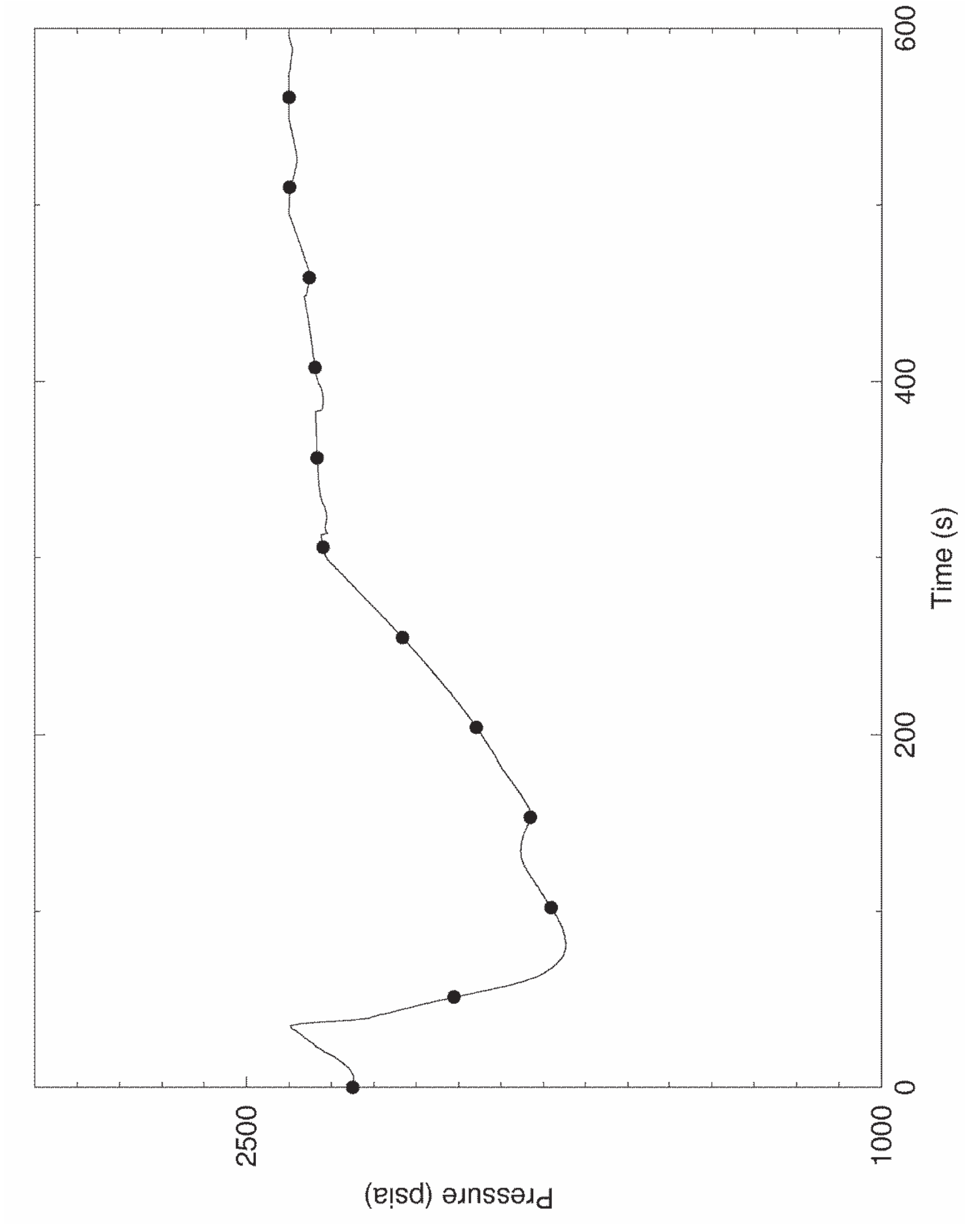


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

PRESSURIZER LEVEL
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-21

EC288300

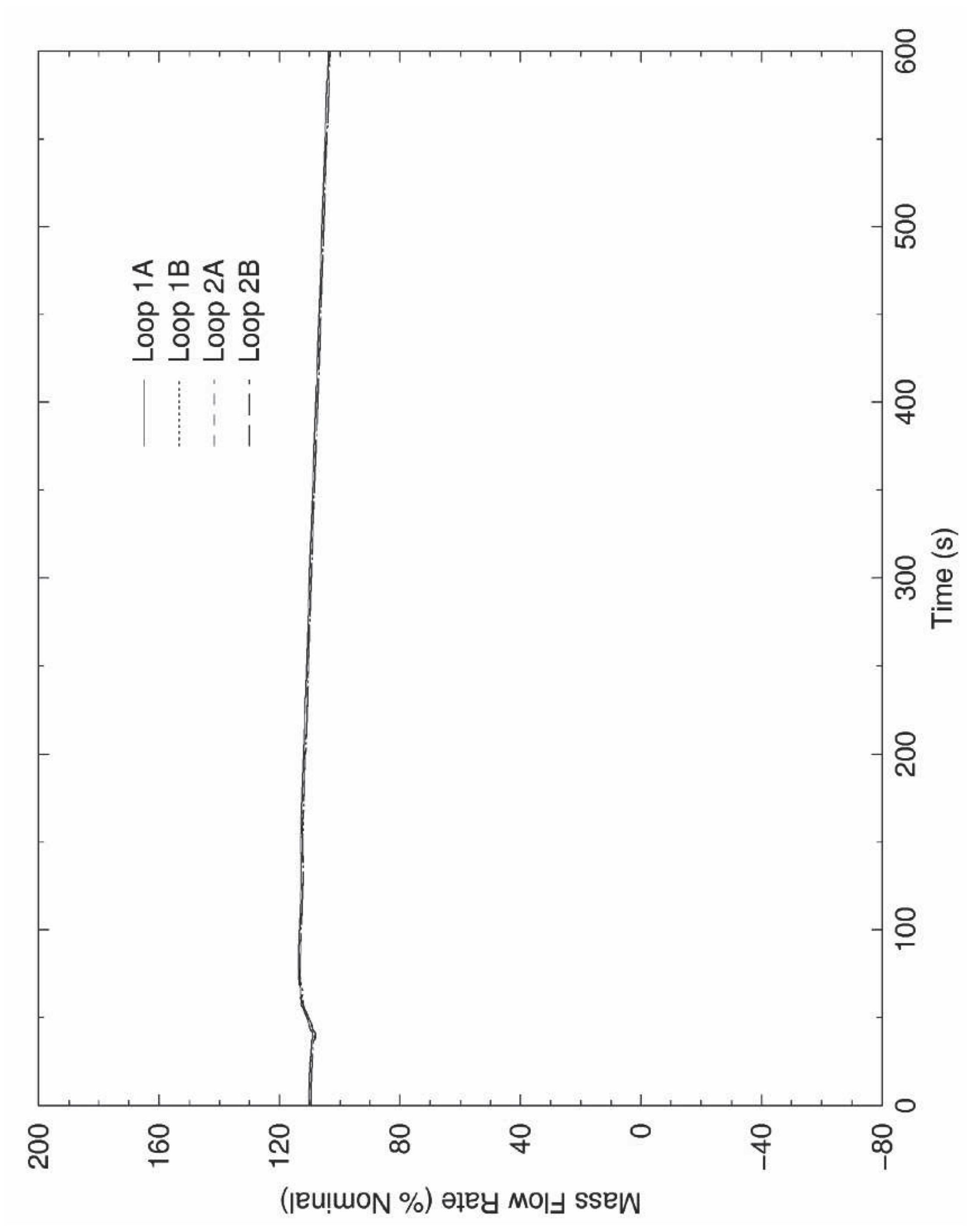


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

PRESSURIZER PRESSURE
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-22

EC288300

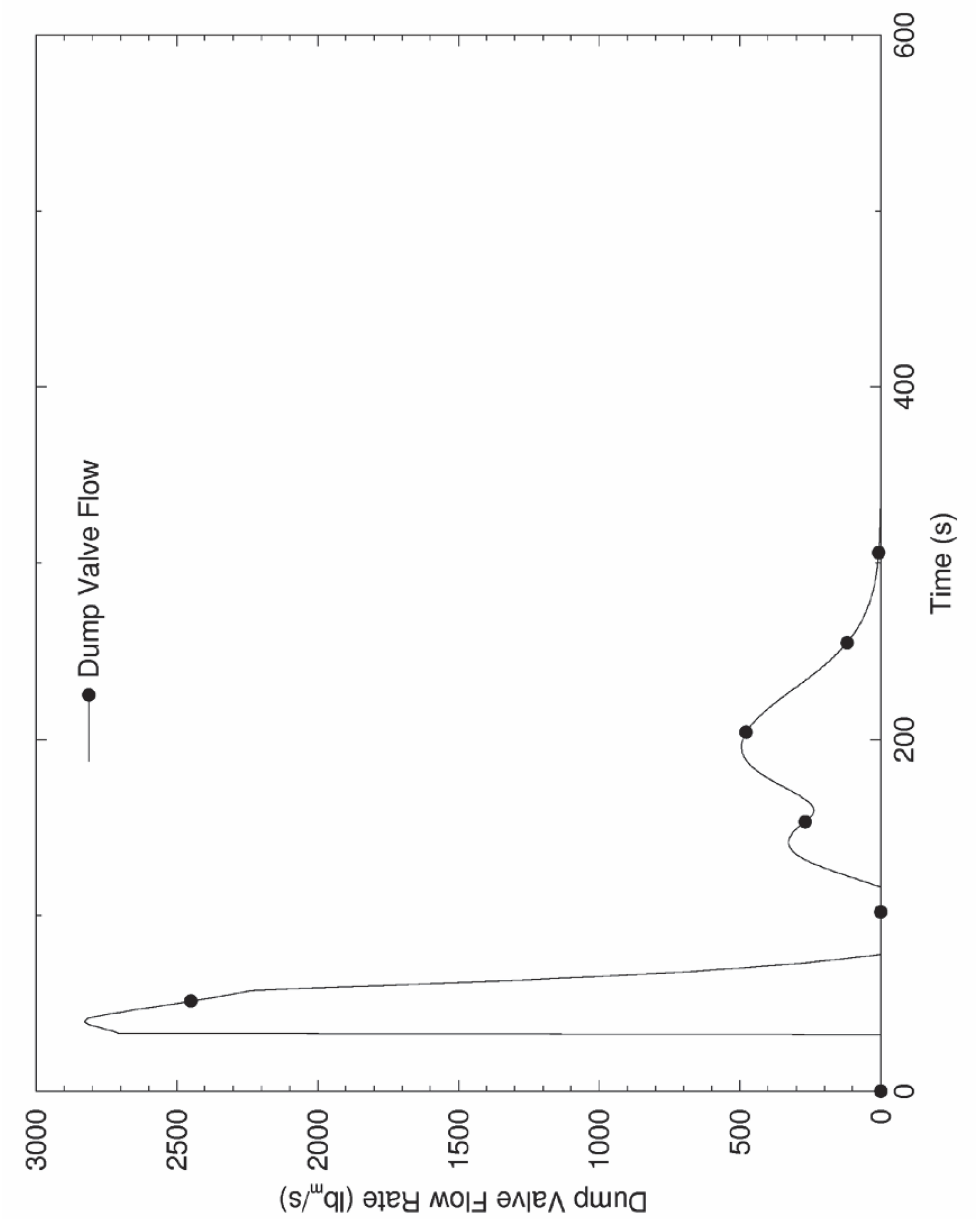


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

RCS LOOP FLOWS
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-23

EC288300

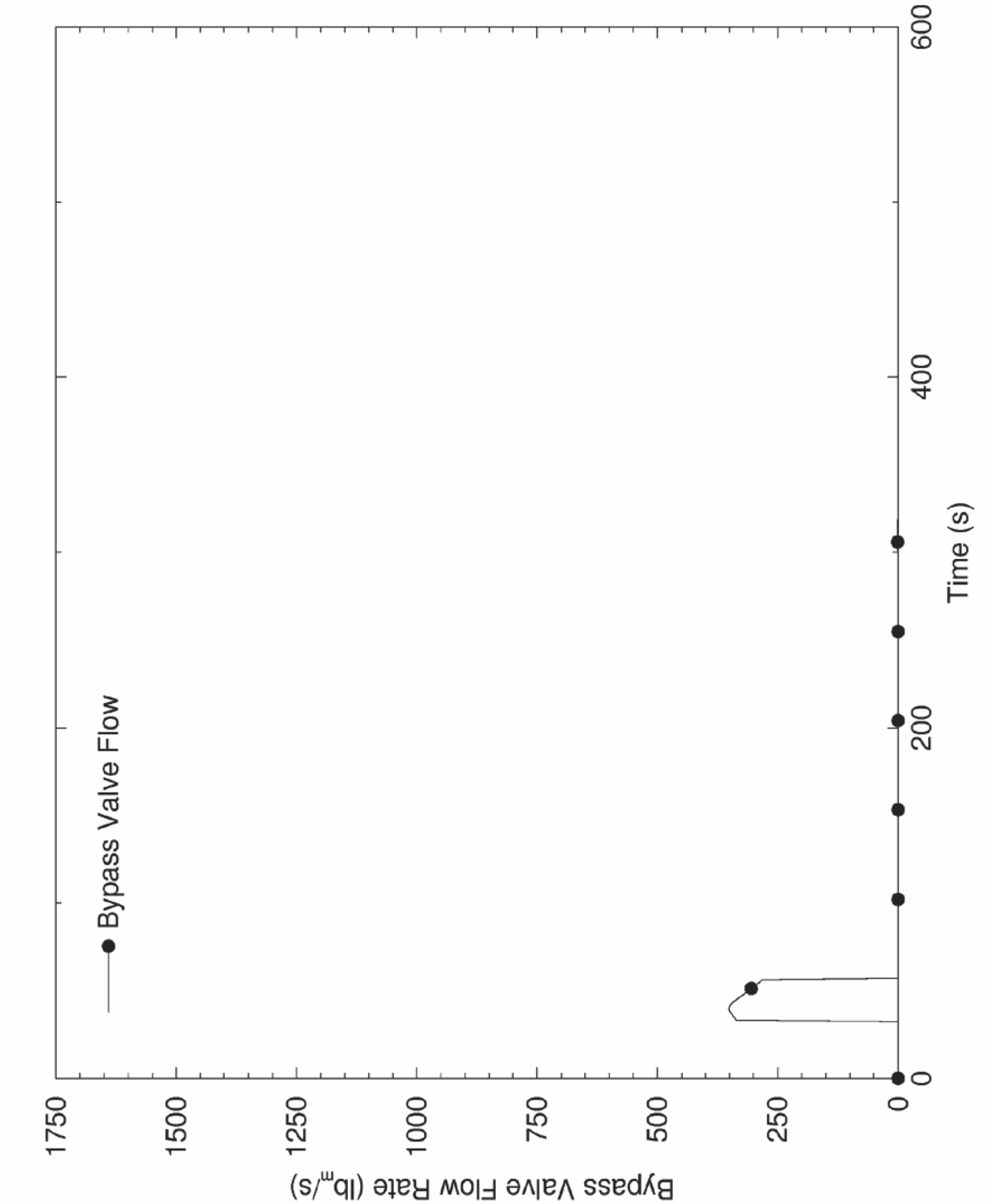


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

DUMP TO CONDENSER FLOW
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-24

EC288300

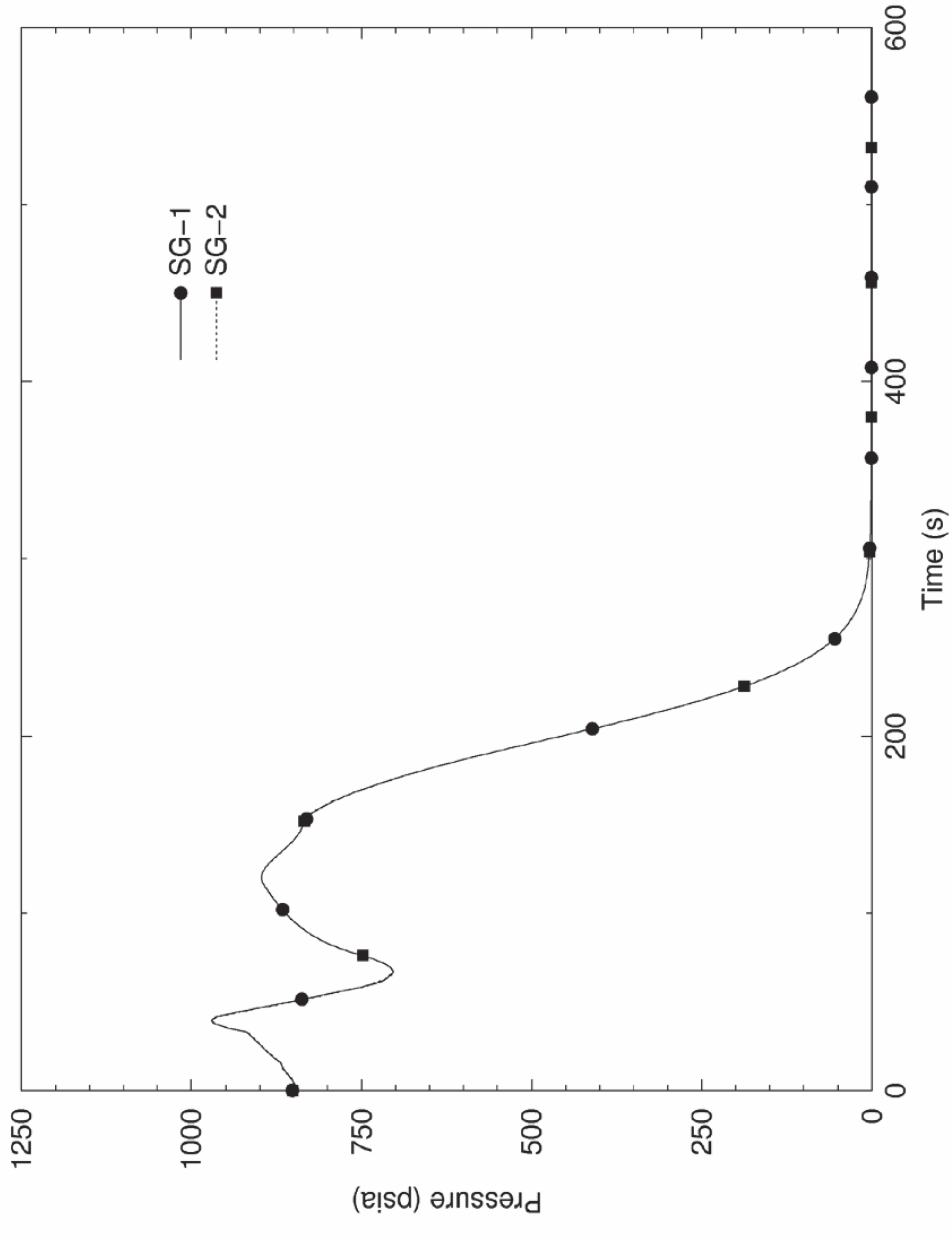


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

BYPASS TO CONDENSER FLOW
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-25

EC288300

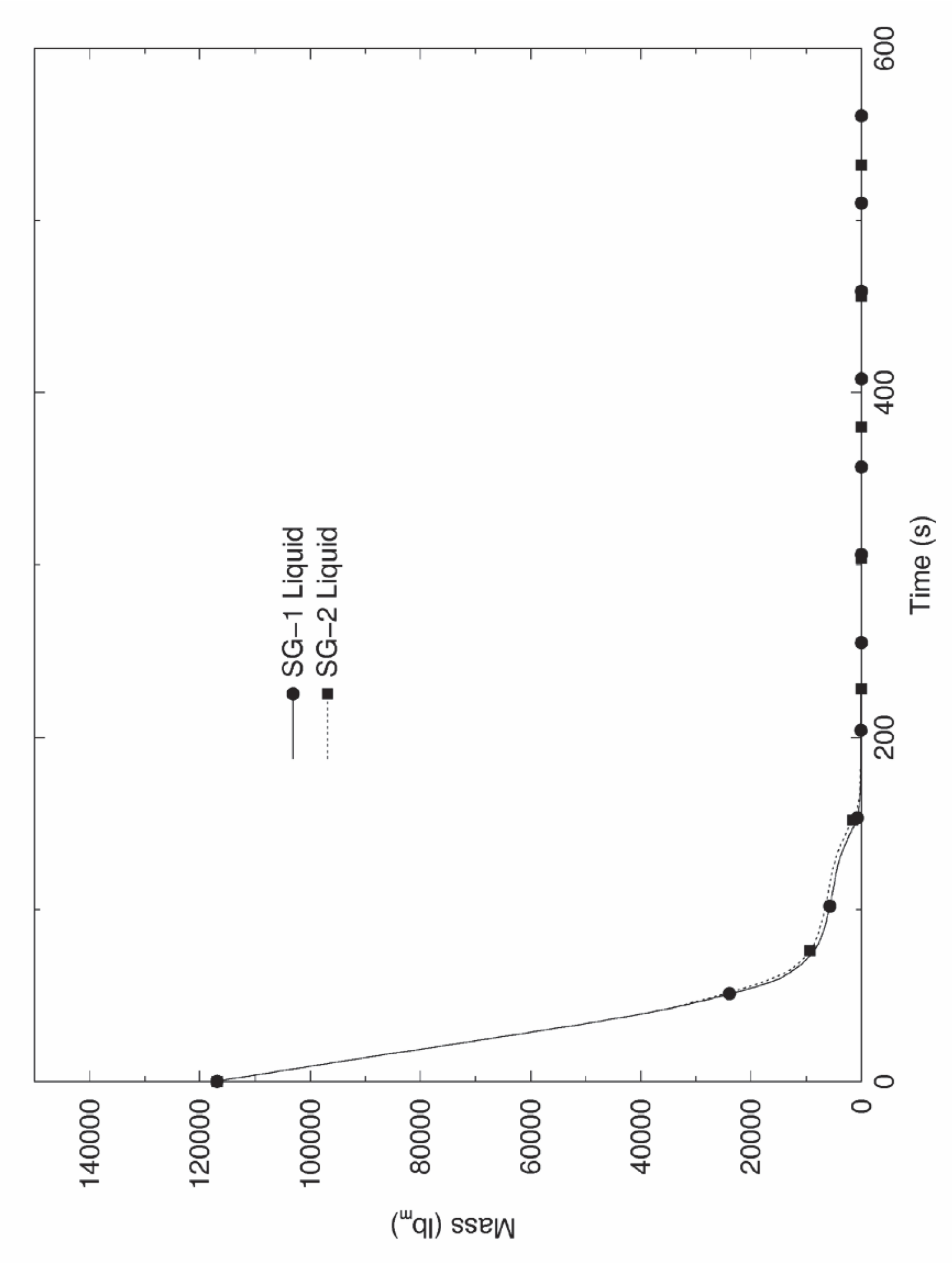


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

STEAM GENERATOR PRESSURE
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-26

EC288300

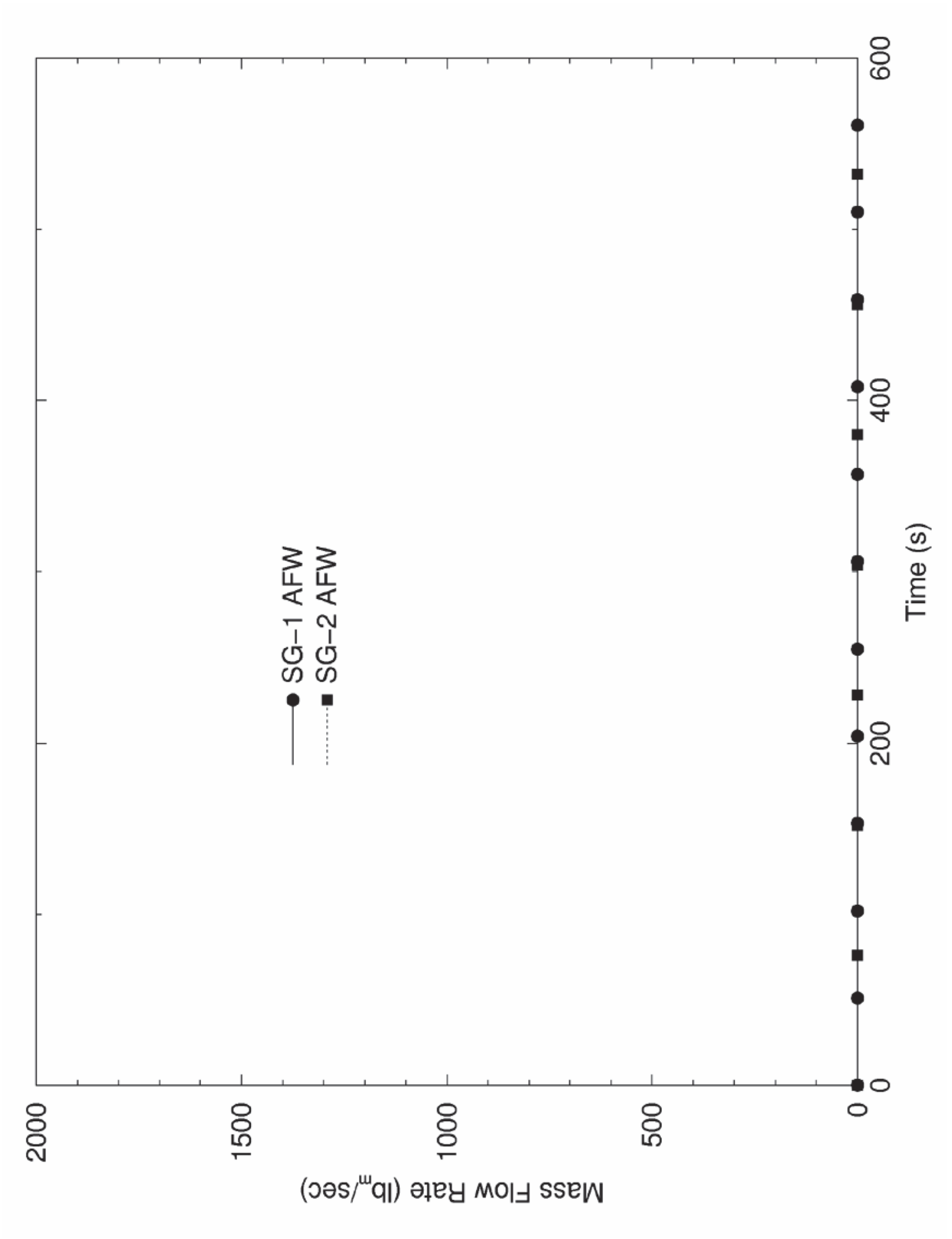


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

STEAM GENERATOR LIQUID MASS
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-27

EC288300

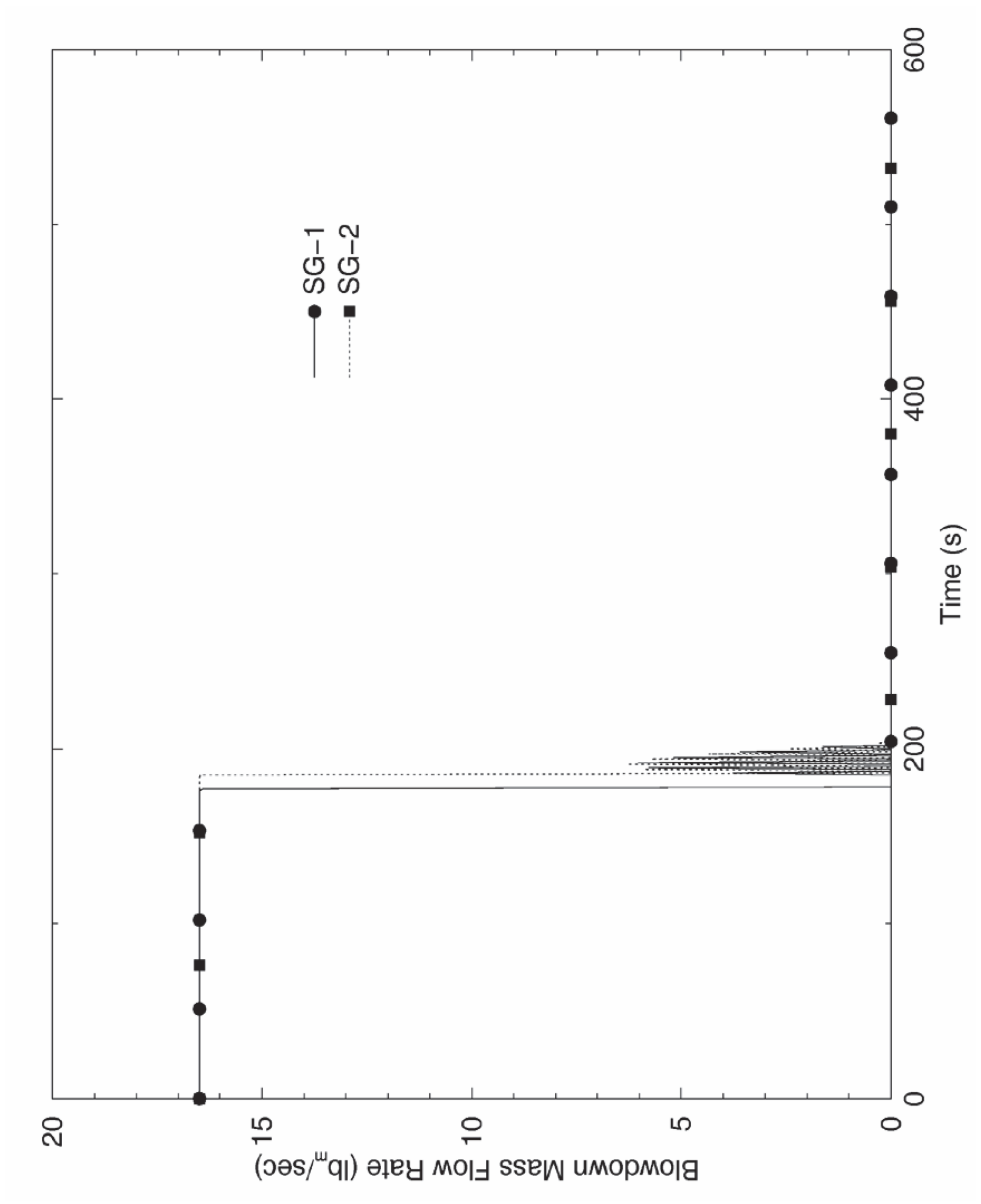


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

AUXILIARY FEEDWATER FLOW
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-28

EC288300

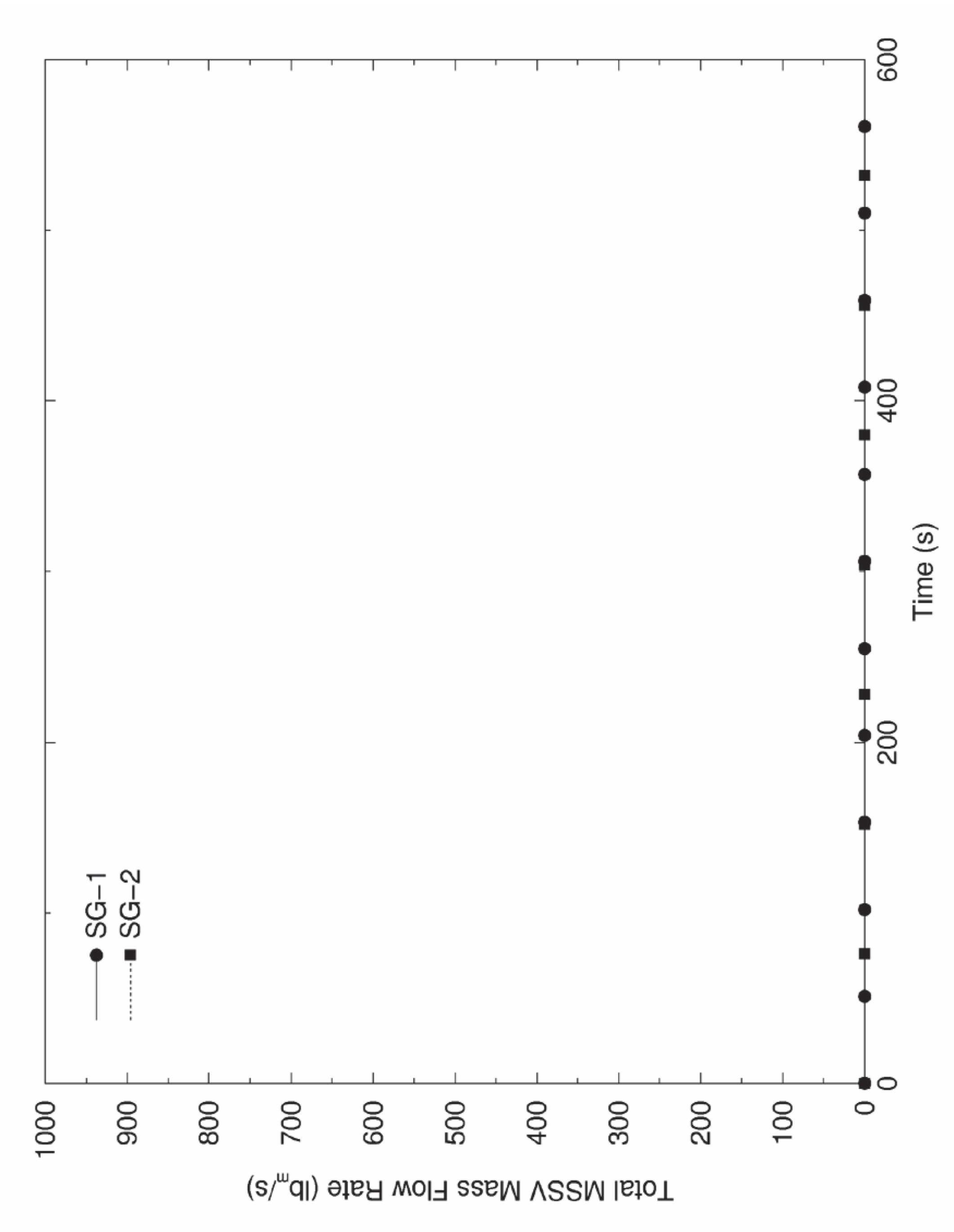


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

STEAM GENERATOR BLOWDOWN FLOW
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-29

EC288300

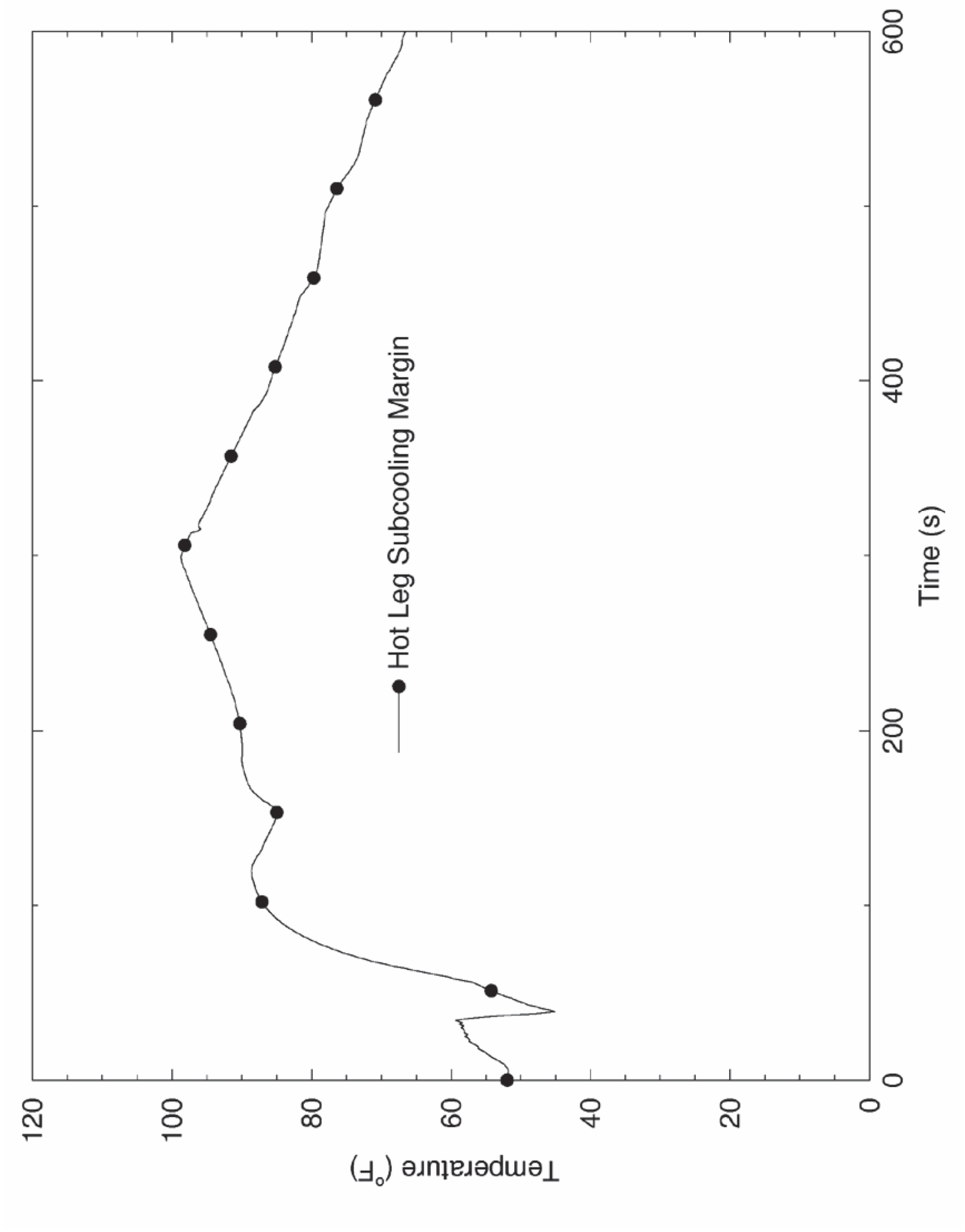


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

STEAM GENERATOR MSSV FLOW
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-30

EC288300

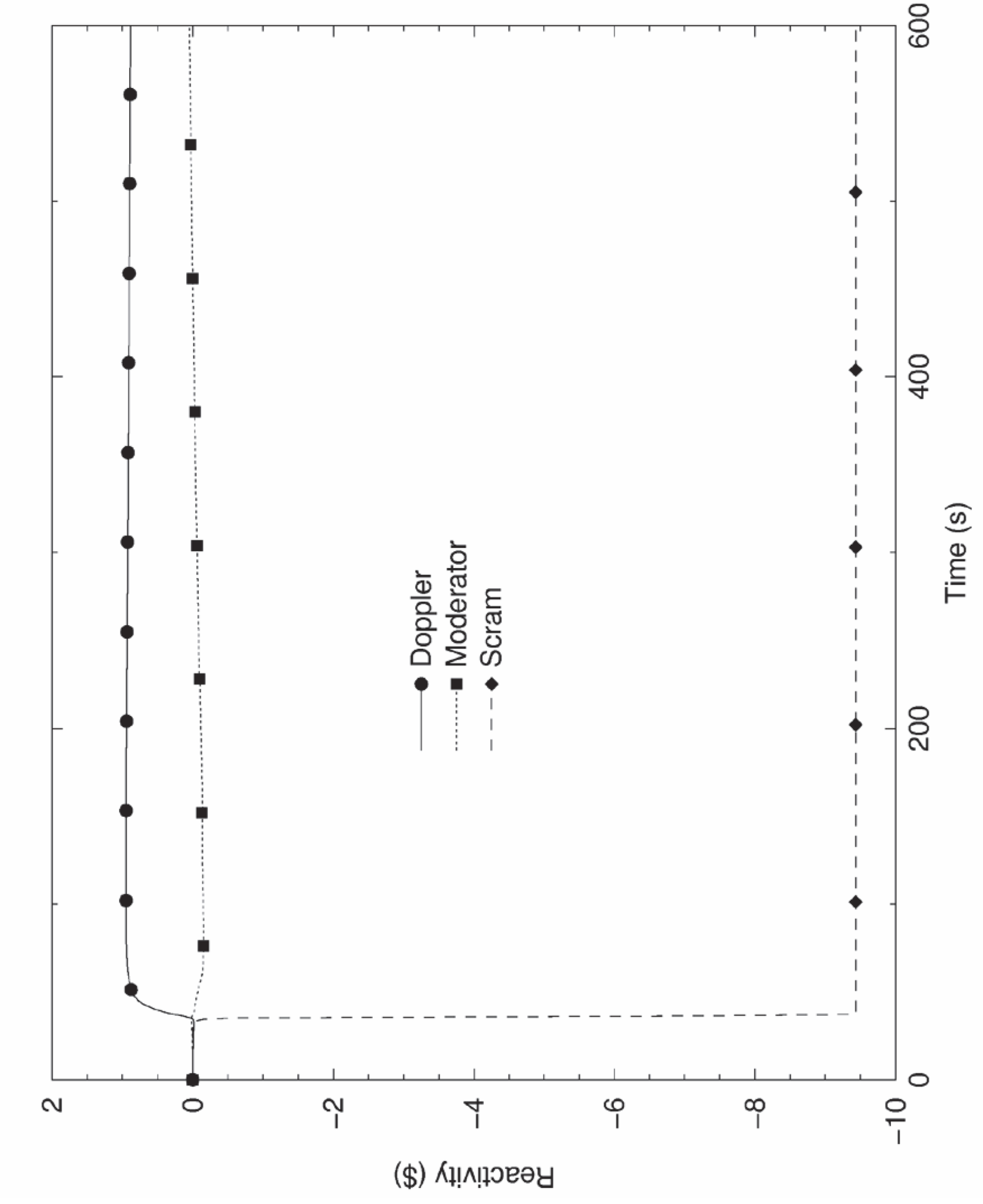


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

SUBCOOLING MARGIN
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-31

EC288300

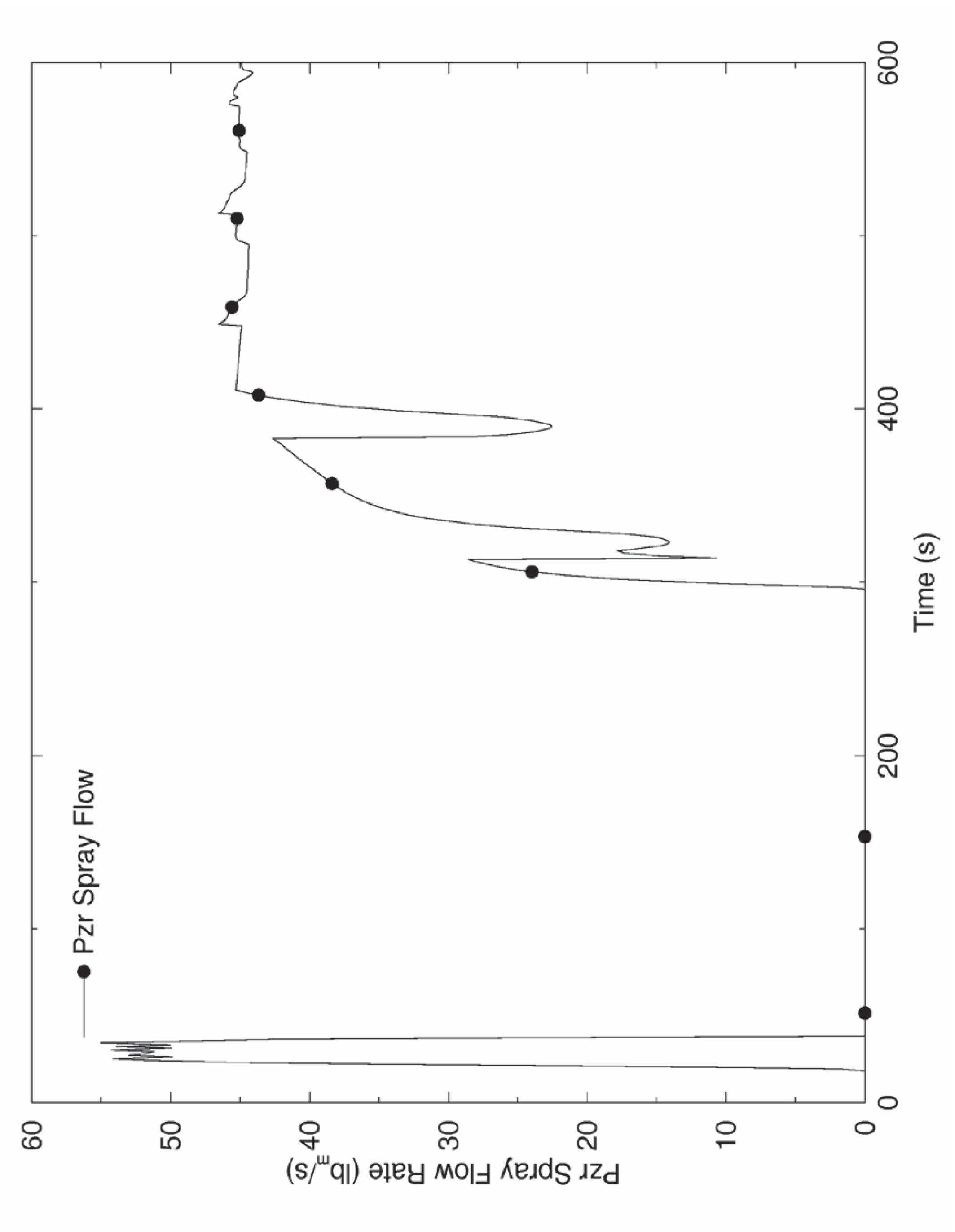


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

REACTIVITY COMPONENTS
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-32

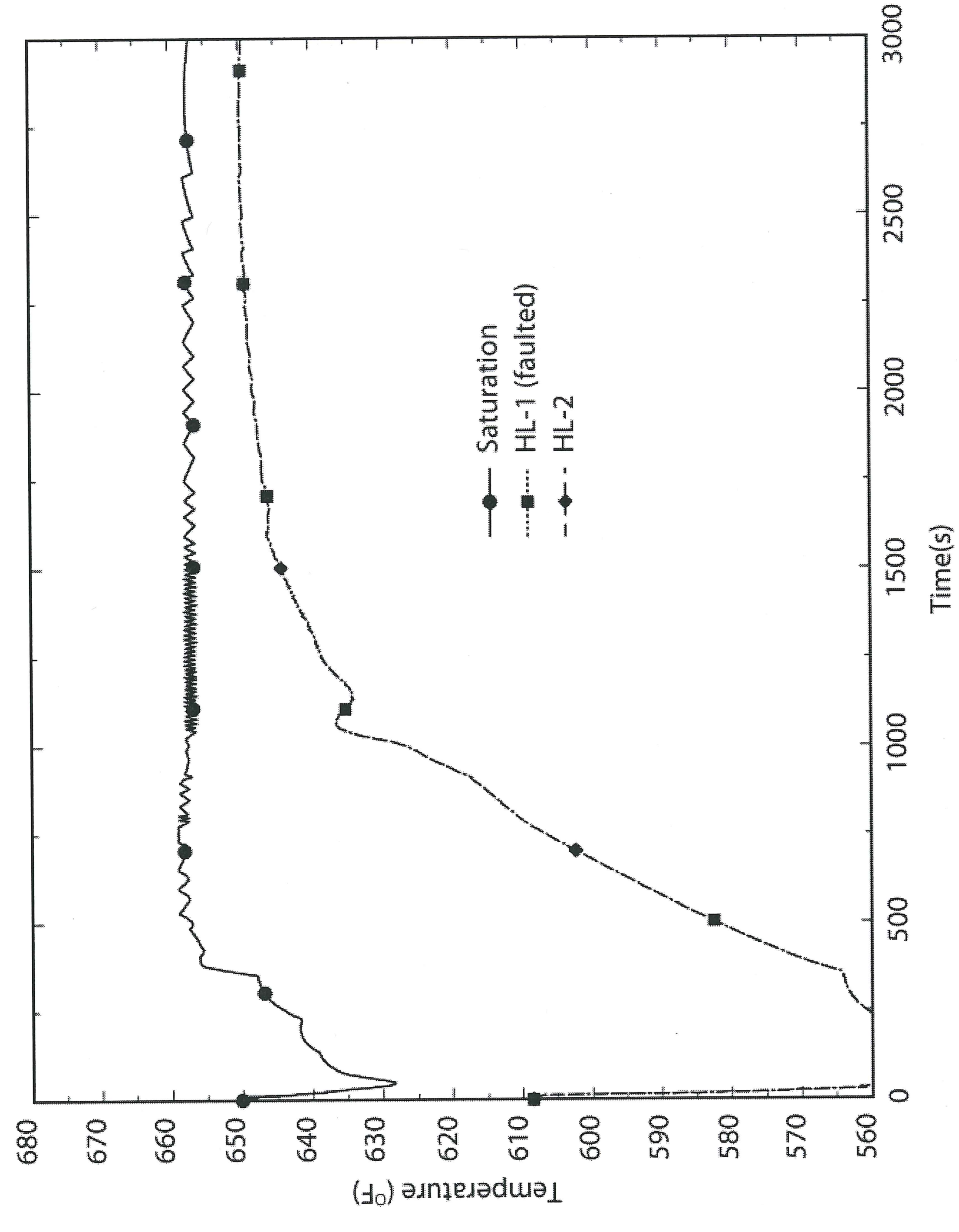
EC288300



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

PRESSURIZER SPRAY FLOW
LOSS OF NORMAL FEEDWATER FLOW
(NO AFW FLOW)

FIGURE 10.5-33

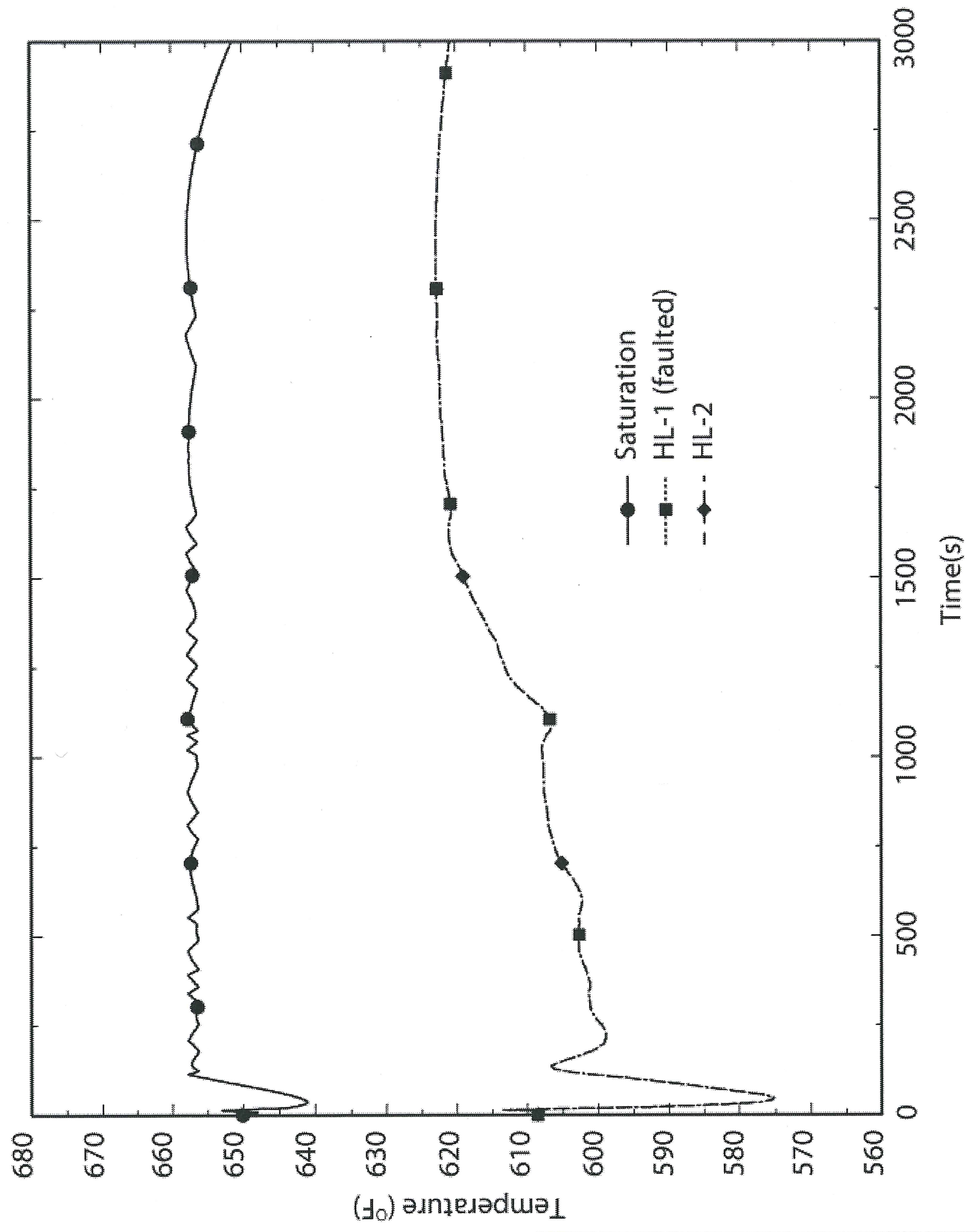


FEEDWATER LINE BREAK
HOT LEG TEMPERATURES (OFFSITE POWER AVAILABLE CASE)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FEEDWATER LINE BREAK
HOT LEG TEMPERATURES
OFFSITE POWER AVAILABLE CASE
FIGURE 10.5-34

FEEDWATER LINE BREAK
HOT LEG TEMPERATURES (LOSS OF OFFSITE POWER CASE)



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FEEDWATER LINE BREAK
HOT LEG TEMPERATURES
LOSS OF OFFSITE POWER CASE
FIGURE 10.5-35

APPENDIX 10A

ANALYSIS OF MAIN STEAM

ISOLATION VALVES

NOTE: Appendix 10A has been retained for historical information. The system was re-analyzed for stretch power and the rupture discs have been replaced by 600 psia rupture discs to increase fatigue life and decrease impact force.

For EPU, the MSIVs were modified to reduce the disc impact velocity and increase the fatigue life due to the decreased impact force. The MSIV modification replaced each air driven actuator with a gas/hydraulic unit capable of a relatively constant spindle velocity, replaced the MSIV spindle, the MSIV H-Link and pins, MSIV rockshaft bearings, the MSIV tail link, and MSIV disc. The MSIV modification also replaced the MSIV cover with a more robust cover to maintain the pressure boundary integrity following a spurious closure.

TABLE OF CONTENTS

APPENDIX 10A

I. INTRODUCTION

The NRC staffs question 10.8, dated May 8, 1974, requested "the method of analysis, the assumptions, and the results of the analysis" for the main steam line isolation valves under rupture conditions. This report is a summation of analytical work which was performed to review the structural adequacy of the subject valves for rupture and spurious signal conditions.

The study has been performed by Ebasco Services Inc. based on an analytical representation of the valves and the appropriate operating or accident parameters. All of the analytical work was performed using established computer analysis methods and parameters that reflect reasonable engineering judgement.

The results of the analysis have shown a need for valve modification. The modifications and analysis thereof are discussed herein. They are shown to be adequate to allow the valves to remain functional under the postulated conditions.

In response to the NRC staff's question 10.10, dated June 23, 1975, the following information has been incorporated in this appendix.

a) The maximum calculated impact energy has not been defined as such. The stresses and/or strains sustained by the valve internal elements and seating surfaces as a result of the impact and preimpact conditions subsequent to a pipe rupture have been included.

b) The methods used to calculate the stresses and/or strains are discussed or referenced in this appendix. These methods are not ameneable to the intermediate step of calculating the impact energy.

c) The maximum stress and/or strain in the principle element have been discussed.

d) The appendix provides assurance that the valve modifications will allow the valve to perform its specified safety functions.

NRC question 10.11, dated June 23, 1975 requests a description of the MSIV modifications and an implementation schedule. The major modifications to the MSIV and MSCV are discussed in this appendix. Components not essential to the design safety function (i.e. air cylinder) have been discussed but the modifications have not yet been finalized and so detailed drawings are not presented. Additionally, certain details such as the rock shaft bushings have not been included since they are not necessary to adequately demonstrate the capability of the valves. The valve modifications are expected to be completed before hot operational tests with fuel in the core. These tests are presently scheduled for late September or early October of 1975. However, if materials availability is such that the modifications cannot be implemented on this schedule, the modifications will be made as soon as practical after commercial operation.

II. GENERAL DESCRIPTION

A. Purpose

The purpose of the main steam isolation valve (MSIV) and main steam check valve (MSCV) analysis was to assure valve operability for the following:

1. the MSIV and its operator must remain operable when subjected to the stress cycling associated with a spurious signal at full power operation; and
2. the MSIV or MSCV must seat effectively following a guillotine pipe rupture either downstream or upstream of the valve, respectively.

The analysis indicates that alterations to the existing valve are necessary. In arriving at suitable alterations there was an effort to achieve the following:

1. maintain the design steam and mass flow as closely as possible;
2. minimize valve body alterations due to drilling, machining, etc.
3. maintain the original mass of the moving parts as closely as possible; and
4. assuring the feasibility of expeditiously procuring, fabricating, and machining new parts.

B. Results

As a result of the analysis, it was determined that modifications should be made to the MSIV and MSCV. Figures 1 through 9 represent the proposed modifications. It is anticipated that field measurement and "as built" dimensions may slightly alter the dimensions as given on the Figures, where mating of existing components is required. No more significant alternations are contemplated. Table 10A-1 presents the materials that will be used in the proposed modifications. A summary of the changes is presented in the following discussions.

The rockshaft (refers to both MSIV and MSCV) was examined for deflections under the stresses imposed by the rotating disc assembly and it was noted that deflections of up to 1 inch could occur. This original rockshaft was made from ASTM A276 Type 416 (a more machinable version of Type 410) in a heat treated condition. The minimum material properties are 80-90 ksi yield strength (σ_y), 100-120 ksi tensile strength (TS), and 12-15 percent elongation. In order to decrease the deflection to the point where proper seating could occur, it was determined that a yield strength of 150 ksi would be required. The material chosen was SA-564 Type 630 (17-4PH precipitation hardening stainless steel) in H 1025 condition. The specified room temperature minimum material properties are 165 ksi σ_y, 175 ksi TS, and 12 percent elongation. The typical properties in the H 1025 condition are approximately 138 ksi σ_y 148 ksi TS, and 10 percent elongation at 550 F and will be stable under these conditions. In order to ensure that the minimum strength level requirements are met, material test reports will be provided with complete traceability. In order to assure that no defects exist in the finished rockshaft, non destructive tests (ultrasonic, and surface inspection by liquid penetrant or magnetic particle) will be performed in accordance with ASME Section III. Analysis has shown that the modified rockshaft deflections are acceptable (i.e., proper seating) with the new materials and increased dimensions.

The tail links were inadequate to withstand the stresses generated during a pipe rupture. The original tail links were constructed of A 216 Grade WCB cast carbon steel with A 285 Grade C carbon steel plates attached by welding. The cast WCB and Grade C minimum material properties are 36 ksi σ_y, 70 ksi TS, and 22 percent elongation, and 30 ksi σ_y, 55 ksi TS, and 23 percent elongation, respectively. The new tail links are cast of A 351 Type CA 6 NM alloy, a martensitic stainless steel derived from the family of 12 percent chronium steels of the 400 series. This alloy has significant advantages with respect to high strength, lower sensitivity to solidification and weld repair, cracking, easier control of strength levels, and good impact strength. The typical minimum material properties are 125 ksi σ_y, 135 ksi TS, and 18 percent elongation at room temperature. Properties at a 550 F test temperature were 12 percent lower. The materials traceability and ASME Section III non destructive tests will be required. The non destructive tests will include ultrasonic or radiographic inspection to ensure that there are no casting defects (i.e., porosity, gas pockets), and liquid penetrants or magnetic particle testing for surface defects. The analysis showed a requirement for a minimum yield of 90 ksi which is within the capabilities of the new material.

The original design of the MSIV and MSCV used a weld stud to connect the discs to the tail links. Extensive analysis showed this area was subject to severe bending moments and shear and tension forces during a rupture or spurious signal. The weld stud has been replaced by a system, see Figure 10A-7, which recesses the tail link hub into a disc socket and holds them together with a high strength bolt which acts only in tension. The bolt is a AISA 193 B16 stud with a yield stress of 80 ksi, an ultimate strength of 97 ksi, and 17 percent elongation at 550F. The present design philosophy is to allow the enlarged, strengthened, and recessed tail link hub to support all the bending moments and shear forces at the hub and allow the stud to take all the tension force.

The analysis of the original seats showed that they were inadequate, from a geometrical viewpoint, to fulfill their function of absorbing the impact forces. The present narrow ring design has been modified to spread out the impact forces rather than concentrate them by increasing the available contact area of the seats. The seats will still use SA240 Grade 316 stainless steel which has adequate capabilities to absorb strain energy. The typical material properties at 550F are a yield stress of 38 ksi, and 55 percent elongation. The same material has been used to increase the face of the peripheral contact region. If a material with higher yield stress had been used, extensive damage to the facing on the disc would result.

The acceptance criteria for all of the design changes discussed above was generalized strain less than 60 percent ultimate strain for each material, see reference 5. No localized strain criteria were defined since the generalized strain is a more conservative design parameter.

III. ANALYSIS

A. VELOCITY CALCULATIONS

1. Velocity Calculations - Spurious Signal

The model for velocity calculations is a dynamic rotational movement calculation which is interfaced with a steam hammer program.(1) The calculation is done by an iteration process using a time interval of 0.1 msec. For each iteration the steam hammer program (SHP) provides the pressure drop across the valve, the flow velocity, and the flow density. The velocity calculation model (VCM) then uses this input and the other model parameters to calculate the valve position at the end of each interval as percentage of valve open and the valve velocity. The valve position and velocity is input for the next SHP iteration. The process is repeated for the full valve closing cycle to determine the velocity profile which is presented on Figure 10A-12.

The VCM is based on certain valve characteristics which vary with valve position and can be expressed in a free body diagram (see Figure 10A-10). The parameters used in making the free body diagram were derived as follows:

a. The Valve Weight (F1)

The weight of all the valve components is 1246 lb. The mass center for this combined weight was calculated to be 19.32 inches from the rock shaft centerline. The torque (T_w) due to valve weight is 2.407272E4 Sin θ.

b. Drag Force (F2)

The drag force (lbf) represents components of drag and lift that are calculated using the following:

$F_o = \quad 1/2 C_D \rho A_v (V \cos \theta)^2$

The lift force calculation is identical except for the substitution of a lift coefficient. The valve area (A_v) is 649.182 square inches and the velocity (V) is derived from the SHP. The lift force has been neglected since the lift coefficient is 0 when θ is 50° or less, the zone of interest is during impact, and the calculations are conservative. Based upon the above and the momentum arm of 20 inches (rocker arm to disc centerline, the torque (T_D) due to the drag force is $1.68008 \rho V^2 \cos^2 \theta$.

c. Air Cylinder and Spring Force (F3)

To calculate the force exerted by the piston requires a number of relationships to be developed.

The first relationship involves the velocities at the pin connection (V_p), the disc centerline (V_c), and the stem or piston velocity (V_s). Since V_c and V_p are velocity measurements of points turning around the same point, the ratio of the velocities will equal the ratio of the moment arms. The relationship between V_s and V_p can be found through geometry as :

$$\frac{V_s}{V_p} = \frac{R}{L} \mathrm{Sin}\,\phi \,\mathrm{Cos}\,\phi \text{ - } \mathrm{Sin}\,\phi \text{ - } \frac{h}{L} \mathrm{Cos}\,\phi$$

Where:

R = 18.75 inches (rock shaft to pin, see figure 10A-11)

L = 8.0 inches (See Figure 10A-11)

h = 16.5 inches (See Figure 10A-11)

Φ = θ + 50

The next parameter that must be calculated is the force on top of air cylinder. The air temperature was assumed to be at a constant 100F and it was assumed that there was no friction factor between the piston and cylinder walls. The air flow into the cylinder was calculated using a formula from reference 2 as follows:

$$\omega = 0.525(Y_u)\,d^2 \sqrt{\frac{\Delta P}{Kv}} \qquad (1)$$

Where:

ω = air flow rate (lbm/sec)

Y_u = expansion factor in upper cylinder

d = pipe diameter (1 inch)

ΔP = air supply (P_s = 114.7 psia) - upper cylinder air pressure (P_u)

K = friction factor (48.78)

v = specific volume of supply air (1.8085 cubic foot/lbm)

The graphs of reference 2 show a linear relationship between Y_u and $\Delta P/P_s$ until sonic flow is reached. The expansion factor can, on the basis of these graphs, be defined as $Y_u = 1.0 - 0.326103\ \Delta P/P_s$. The sonic flow condition would exist when Y_u reaches 0.71 which corresponds to a P_u of 12.7 psia. A sonic flow condition cannot exist since cylinder pressure never drops below atmospheric.

The mass change (ΔM in lbm/sec) for each time interval is equal to the flow rate times the time interval of 0.1 milliseconds. The change in volume (ΔV) was determined by the product of the piston area (78.5 square inches), the time interval, and V_c . Using the formulas for ΔM and ΔV the values for mass and volume was calculated for the end of each time step. P_u was then calculated for each time interval using the state equation PV = MRT. The force on the top of the piston (defined as F11) can now be calculated by the product of the piston area and P_u.

To calculate the force on the bottom of the piston use formula 1 with the following differences.

1) Y_b is substituted Y_u;

2) ΔP is the bottom cylinder air pressure (P_b) atmospheric pressure;

3) the friction factor is 6.8; and

4) the specific volume is that of the cylinder air.

Using reference 2, Y_b can be defined as 1.0 - 4329317 P/P_b before sonic flow is reached. Sonic flow exists when Y_b equals 0.677 which is equivalent to a $P_b \geq 58.1$ psia. The calculational difference for sonic flow is the definition of ΔP as 0.747 P_u.

The specific volume at the end of each time interval was calculated using the state equation. The same formulas for ΔM and ΔV were used as in the upper cylinder calculations so that equation of state could be used to calculate P_b. The force under the piston (defined as F13) is negative because of decreasing volume, and equal to P_b times the lower piston area (76.13 square inches).

The valve spring exerts a downward force (defined as F14) as the valve first opens. The spring is compressed when the valve is fully open and exerts a downward force of 4400 lbf. The relaxation of length is 11 inches. Therefore, the force of the spring at "x", a specific distance downward, is:

$$F14 = -400\ (11 - X)$$

The upstream pressure of the main steam line exerts an upward force on the stem. This force (defined as F12) is:

$$F12 = P_{s1}\ A_s$$

Where:

A_s = stem area (2.37 in^2)

P_{s1} = Steam line pressure

The sum of forces F11, F12, F13 and F14 all act along the stem. The torque on the rock shaft from these forces is calculated as follows:

$$T_{F3} = F3 \left(\frac{R \ \text{Cos}\beta}{\text{Cos} \propto} \right) = (F3)\ R \ \frac{\text{Cos}\beta}{\text{Cos} \propto}$$

Where:

F3 = F11 + F12 + F13 + F14

R = rockshaft to pin (18.75 inches)

$\propto$ = see Figure 10A-11

β = see Figure 10A-11

The values of Cos $\propto$ Cos β were calculated by the graphical method based on the mechanistic design. See Table 10A-3 for results.

d. Pressure Drop Across Valve (F4)

The steam hammer program (reference 1) is used to calculate the pressure drop across the valve. The force acting on the disc is the pressure differential times the disc area (649.182 square inches). The moment arm is 20 inches. The torque (T_p) is 12,985.64 P.

Having derived the forces and torques that are shown on the free body diagram (Figure 10A-10) the total torque can now be expressed as follows:

$T_T = T_w + T_D + T_F + T_p$

The angular velocity (γ) during each time interval is equal to the total torque divided by the mass moment of inertia. The linear acceleration is mass centerline arm times the angular velocity. The linear distance traveled and velocity for each time interval can be calculated using the standard velocity and distance formulas. The linear velocity at the disc center is equal to the linear velocity at the mass center times the ratio of the disc centerline (20 inches) to the mass center line (19.32 inches). Calculating the angle θ from these values, the percentage the valve is open (AR) can be calculated as:

AR = 1.2100138 (1.0 - Cos θ)

The final results of all calculations are discussed in other sections where applicable.

2. Velocity Calculations - Rupture

In the rupture case the computer code RELAP-3 and the velocity calculation model were used. For conservatism, the forces generated in the air cylinder and spring were neglected. The pressure across the valve was first calculated by the RELAP-3 assuming valve closure at time zero. The velocity model then used the pressure drop to calculate the velocity and a new valve closure curve. The process is iterated until the valve closure curves from the RELAP-3 and the velocity calculation model are asymtotically converging. Both the check valve and isolation valve calculations are the same. The MSCV closes more quickly than the MSIV as shown by Figure 10A-13. The MSCV will start to close when the rupture occurs while the MSIS signal does not occur until the steam generator pressure reaches 478 psig (~4.8 seconds). This initial driving force, when coupled with the heavier MSCV, results in the faster closure. The blowdown rates were calculated using the CE Steam Generator blowdown code described in Appendix 6A.

B. COMPUTER MODELING

1. Valve Body, Seat and Disc

A dynamic finite element analysis of the valve body, seat, and disc was performed for both the MSIV and MSCV under rupture conditions.

The valve body, seat, and disc were modeled as an axi-symmetric, elasto plastic, strain hardening continuum. The valve body represents the conditions in the regions 0, 3π/2, and π as shown on Figure 10A-5. Substructuring of the continuum resulted in finite element mesh as shown in Figures 10A-13 through 10A-15. The elements outside the reduced mesh were assumed to behave elastically while those inside were allowed to yield. The assumption has proved to be conservative. Had substructuring not been used, yielding would have appeared more extensively in the valve body and the generalized strain levels in the region considered would be lower than indicated. The SHP and the velocity model were used to develop the final velocity at impact and final pressure drop across the disc. The disc was assumed to have a uniform velocity upon impact which was increased by approximately 10 percent to account for the actual variations of velocity on the radius from the

Preliminary analysis of the as built valve indicated unacceptable strain and displacement levels in both the valve seat and the discs with potential rupture of the valve body. Alterations to the design were made and a new analysis was performed using the data on Table 10A-4. This analysis indicated that yielding occurs throughout the disc and the substructured valve seat. Because of this yielding, the magnitude of the generalized strain was compared to ultimate strain of the materials with the generalized strain being defined as:

$$\varepsilon_g = \frac{1}{\sqrt{2(1+v_{eff})}} \sqrt{(\varepsilon_1^T - \varepsilon_2^T)^2 + (\varepsilon_2^T - \varepsilon_3^T)^2 + (\varepsilon_3^T - \varepsilon_1^T)^2}$$

Where

$\varepsilon_{1,2,3}^{T}$ = total (elastic plus plastic) principle strains

$v_{eff} = 0.5\ (1 - vE_s/E)$

E = youngs modulus

E_s = secant modulus

The maximum generalized strains after impact are as shown on Figures 10A-17 through 10A-20. The results indicate, for the assumptions of this analysis, that the generalized strains are at or below 1/2 the ultimate strains and therefore, it is concluded that rupture of the body seat will not occur. The 1200 psig pressure drop across the disc will maintain bearing contact of the disc and valve seat.

Having determined the modifications of seat, valve body, and disc for the rupture case, the MSIV was examined for the spurious signal. Since the MSIV is designed for only one pipe rupture, the analysis of fatigue life is only applicable for the spurious signal case. The spurious signal case has an 18.4 ft/sec impact velocity and a 300 psig pressure differential. From our finite element analysis using ANSYS the maximum stress difference (S_n) was determined to be 59,475 psig. The generalizes strain curves for the most important elements are shown on Figures 10A-21 through 10A-23. The stress allowable for the valve material was taken from Table 1.7-2 of ASME Section III. This value is:

S_m = 17,500 psi at 550 F (35_m = 52.350 psi) rockshaft axis to the tip of the disc. The uniform velocity assumption is the only practical one for the non-linear axisymmetric analysis. This assumption is more conservative than a linear velocity profile for the following reasons:

a) All kinetic energy, at impact, is transformed into the strain energy of axi-symmetric deformation. Lateral rigid body motion of the valve and piping perpendicular to the axis of flow does not occur for a uniform velocity profile as it does for a linear velocity profile and hence absorbs none of the impact energy.

b) Axial symmetry imposes a constraint on the kinematics of deformation of the seat, body, and disc. This results in a stiffer structure and a higher strain amplitude than would occur in an unconstrained 3 dimensional model associated with linear velocity profile. The total kinetic energy in the disc, based on the linear velocity distribution associated with the 3D Model is 745,000 ft lbs with its centroid located 24.58 inches from the center of the rock shaft. The kinetic energy of the disc in the axi-symmetric model, based on the uniform velocity of 2300 is 768,000 ft - lbs. Comparisons were made with a 3D finite element analysis of the same valve before modification performed by SEAC, reference 6, and results are shown in Table 10A-9 for representative regions. In regions outside the impact zone, in-plane strains predominate and display a-rather flat gradient. At the zone of impact, strains normal to the surfaces of impact are large and all strains display a steep gradient. Since shell elements can't be used to detect strains normal to the shell surfaces and are coarsely mixed, the two results are in disagreement at the impact zone, however agreement is excellent in regions distant from the impact zone. Based on the regions of agreement, it may be inferred that a fine mesh 3D finite element analysis (using solid bricks or tetrahedron elements rather than shell elements) would result in good agreement with the axi-symmetric results.

   It can be concluded that the deformation calculations using uniform velocity assumed in the axi-symmetric analysis was conservative with respect to the use of a velocity profile (which had a peak velocity of 306 ft/sec) in a 3D shell analysis.

c) As discussed earlier, substructuring results in further conservatism in the strait. levels.

A velocity of 2,300 inches/sec was used for both valves although the MSIV impact velocity is slightly less than that of the MSCV. The ANSYS code (reference 3) was used on the CDC 6600 at VCS, update 144, Rev. 2 Jan 1, 1972, employing the large deformation option, and using slip and gap elements at the interface of the disc and valve seat.

Since $S_n > 3S_m$, it was necessary to utilize Section NB 3228.3 "Simplified Elastic Plastic Analysis". This section defines the alternating stress intensity as:

$$S_{alt} = K_e \frac{S_p}{2} \qquad (1)$$

The code gives the following formulas for K_e:

$$K_e = 1 \quad \text{where } S_n < 3S_m \qquad (2)$$

$$K_e = 1 + \frac{1-n}{n(m-1)}\left(\frac{Sn}{3S_m} - 1\right) \text{where } 3S_m < S_n < 3mS_m; \qquad (3)$$

$$K_e = \frac{1}{n} \text{ where } S_n \geq 3mS_m \qquad (4)$$

Where:

m = 1.7 (material constant)

n = 0.3 (material constant)

Using the above values it was determined that equation 3 was applicable ($3S_m < S_n < 3mS_m$) and K_e can be calculated to be 1.443. The alternating stress from equation 1 is then calculated to be 42,907 psi.

As required by the code, the effect of modulus of elasticity was taken into account as follows:

$$S'_{alt} = S_{alt} \frac{E'}{E} = 43{,}324 \text{ psi} \qquad (5)$$

Where:

E' = modulus of elasticity of the S-N curve used
E = analysis modulus of elasticity

From the S-N curve (ASME Section III, subsection NA, Figure I-9.2) the maximum cycles to failure was determined to be 36,958. In addition, it was determined that the requirements of ASME Section III, Subsection NB 3228.3(c) through (f) were satisfied.

2. Tail Link

The tail link and rockshaft of the MSIV and MSCV were analyzed using the program "PLAST". Under pipe rupture conditions, the forces and bending moments obtained from PLAST showed the existing tail link geometry to be unsatisfactory. These results were used to change the existing geometry of the tail links so that most, if not all of the tail link would remain elastic. The post impact MSIV models of the new geometry are presented on Figure 10A-24 through 10A-26. The geometric and material properties of the elements are found in Table 10A-5. Similar data for the MSCV post impact analysis is found on Figures 10A-27, 10A-28 and Table 10A-6 Although the new material has a yield stress of 90 ksi at 550 F it was not possible to achieve a completely elastic design. This is because deep beam factors (reference 4) applied to the PLAST results increase bending stresses beyond the material yield point. The principal stresses for the MSIV and MSCV tail links in the rupture case are presented on Table 10A-7. Because the maximum strain corresponding to the stresses in Table 10A-7 is well below Eμ/2 for the materials of both tail links, it has been concluded that both tail links will be able to withstand the full effects of impact following a pipe rupture without loss of function.

The rupture case post-impact models were used in the preimpact analysis to show that the tail link modifications were governed by the post-impact analysis.

3. Rockshaft

The rockshafts of the MSIV and MSCV were analyzed using PLAST. The design changes for the rockshaft were necessitated by the pre-impact deflections experienced in the rupture case. Too large a deflection when the valves swing closed will allow the disc to hit the valve body and preclude proper seating. The rockshaft material was changed to give a minimum yield stress of 150 ksi and the diameter was increased to 3 inches. Subsequent analysis showed that the maximum disc deflection was 0.339 inches for the MSIV and 0.206 inches for the MSCV. This analysis was performed with a tail link material whose yield stress was significantly lower than that of the material presently being used. The sleeve concept used in the analytical model has been superceded by a solid casting which gives greater stiffness against radial deflection. The double sleeve concept should be noted as a conservatism in the tail link model. The maximum allowable deflection was 0.5 inch. The model and associated material characteristics are shown on Figure 10A-29 and Table 10A-7A respectively. For this model, Table 10A-8 presents a conservative estimate of the maximum tensile and compressive strains at the most critical locations. These were obtained by adding the plastic strain of the pre-impact case to the maximum total strain of the post-impact case.

C. AIR CYLINDER

In the description of the air cylinder, the piston rod, the piston, the spindle (from the piston rod to the H-linkage), the H-linkage (from the spindle to the tail linkage), and the air cylinder are discussed.

1. Air Cylinder

The velocity calculations of Item A include the maximum pressures in the air cylinder for the spurious signal and pipe rupture cases. The present cylinder will be replaced to assure continued integrity in the event of either case. The new air cylinder is rated for 1000 psia and has three 2 inch diameter rupture discs set at 150 psig. Subsequent analyses indicate that the maximum pressures will be 500 psia and 850 psia for the spurious signal and pipe rupture cases, respectively.

2. Linkages - Piston to Tail Link

Although the retarding effect of the air cylinder was conservatively neglected in the MSIV pipe rupture analysis, an analysis of the linkages from the air cylinder piston to the tail link was made as part of the overall determination of pipe rupture effects.

The model presented on Figure 10A-30 was used in conjunction with the ANSYS Program to determine the effect on the various linkages. The most critical linkage is the spindle. The model permits sliding at modes one and two with the spindle fully extended at all times. At valve closure, the disc impact on the valve seat was simulated by the impact of node 8 on an external spring. Time histories of the valve opening angle and the vertical force exerted on the air cylinder are presented in Figure 10A-31.

The results of the analysis show the maximum lateral deflection of the as 1.8 inch and the maximum strain at the collar of 2.2 percent. These values are considered high, because the full spindle extension will not occur until the instant before impact .

Material modifications were made to the air cylinder linkages a s part of the overall program of upgrading the MSIV. The new material (A 564, Type 630, 17-4 ph) for the spindle (i.e., the most critical element) has an ultimate strain capacity of 10 percent and can sustain the above maximum collar strain without material rupture. The materials used for other linkages have been chosen for similar margins of safety. Hence the air cylinder linkages will remain intact and will perform their required function under pipe rupture conditions.

REFERENCES FOR APPENDIX 10A

1. R & D Report No. 1006 - "Steam Hammer Analysis", R C Iotti, C G Kan, D R de Boisblanc, and L Blumenau, November, 1974.

2. Technical Paper 410 - "Flow of Fluids Through Valves, Fittings, and Pipes", Crane.

3. "ANSYS", Swanson Analysis Systems Inc., January 1, 1972, update 144, Rev. 2.

4. Roark, R. "Formula for Streps and Strain", McCraw Hill 4th Edition, p 131.

5. "U.S. Reactor Containment Experience - A Handbook of Current Practice, Analysis, Design, Construction, Test and Operation", Chapter 6.5 - "Structural Problems", B. L. Greenstreet, M.A. Salmon, and N. A. Weil, March 1966, p 6.92-6.121.

6. "Dynamic Structural Analysis of St. Lucie #1 Main Steam Isolation and Check Valves", A J Errett, and P A Stancampiano, Swanson Engineering Associates Corporation;report to Ebasco Services inc., June 1975.

TABLE 10A-1

MSIV AND MSCV PARTS LIST

Part No	Description	Figure	Material	Notes
1	MSIV disc and stainless steel weld overlay	10A-2	E-309	4,6
2	MSIV and MSCV seat	10A-3	SA-240 Grade 316	4,5
3	rockshaft	10A-4	A-564 Type 630 (17-4PH)	4,8,9,10
4	stud	10A-9	A/SA 193 B 16	2,3
5	MSCV disc and stainless steel weld overlay	10A-6	E-309	4,6
6	MSIV tail link	10A-7	SA-351 Grade CA6NM	4,5,7,11
7	MSCV tail link	10A-8	SA-351 Grade CA6NM	4,5,7,11
8	original MSIV disc	10A-2	SA-515 Grade 70	1
9	original MSCV disc	10A-6	SA-515 Grade 70	1
10	nuts		SA-194-7	12
11	Washer		Hardened carbon steel	13

Notes: (NON-DESTRUCTIVE TESTS AND HEAT TREATMENT)

1. Non-Destructive tests to be performed in accordance with NC-2500 for class 2 materials
2. Ultrasonic inspection using straight beam radial scan method
3. Magnetic particle on finished stud.
4. Certified material test reports with complete traceability
   i) composition ii) mechanical properties
5. Ultrasonic or radiographic inspection
6. Liquid penetrant on machined surface and finished weld overlay
7. Liquid penetrant or magnetic particle
8. Ultrasonic testing using straight beam techniques on two (2) diameters at right angles (100 percent volumetric)
9. All surfaces to be tested by liquid penetrant or magnetic particle

TABLE 10A-1 (Cont'd)

10. Heat to 1900°F + 25°F and air cool to room temperature (70°F-75° F); reheat to H1025°F and hold for four (4) hours; air cool
11. Heat to 1900°F and hold for one (1) hour; air cool to room temperature; temper at 1050°F for two (2) hours; air cool to room temperature; test as per notes 4,5, and 7
12. Nut to match SA-193-B16 stud, with magnetic particle testing
13. Hardened carbon steel washer to fit SA-193-B16 stud and SA-194-7 nut.

TABLE 10A-2

MSIV DRAG AND LIFT COEFFICIENTS VS.ANGLE

Valve Angle (θ)	C_L	C_D
80	0.94	1.2
70	1.56	1.2
60	1.22	1.2
50	0.33	1.2
40	0	1.2
30	0	1.2
20	0	1.2
10	0	1.2
0	0	1.2

TABLE 10A-3

MECHANISTIC COSα COSβ

Point	Valve Angle(o)	α	β	COSβ / COSα
0	80	15.5	57.0	0.5652
1	75	7.0	43.0	0.7368
2	70	1.8	33.5	0.8343
3	65	3.5	21.5	0.9322
4	60	7.0	11.5	0.9873
5	55	11.0	3.5	1.0168
6	50	13.0	4.0	1.0238
7	45	15.0	10.0	1.0196
8	40	16.0	16.5	0.9975
9	35	15.5	21.0	0.9688
10	30	14.0	24.0	0.9415
11	25	11.0	26.0	0.9156
12	20	7.5	28.0	0.8906
13	13	2.5	28.3	0.88l3
14	10	2.5	28.0	0.8838
15	5	7.5	27.0	0.8987
16	0	15.0	24.5	0.9421

TABLE 10A-4

VALVE BODY, SEAT, AND DISC - RUPTURE ANALYSIS DATA

Description	Data
uniform disc velocity, inches/sec	2300
disc pressure differential, psig	1200
operating temperature, F	550
valve body and disc material properties (excluding bearing rings)	
1. E, ksi	27.2E3
2. σ_y, ksi	29.7
3. S, ksi	0.005E
4. v	0.28
5. ϵ_{μ}, percent	22
Valve Seat and Disc bearing ring material properties	
1.E, ksi	27.2E3
2. σ_y, ksi	49.5
3.S, ksi	0.004 E
4.v	0.28
5.ϵ_{μ}, percent	20
Disc /Seat sliding friction	0.5

TABLE 10A-5

GEOMETRICAL AND MATERIAL PROPERTIES OF MSIV ELEMENTS

Elements 1 and 10

Model, beam	rockshaft and bearing
Outside radius (R_o), inches	1.375
Inside radius (R_1), inches	0.0
E, psi	27E6
σ_y, ksi	150
S, psi	0.0 E
Area (A), square feet	0.0412636
weight (Wt), lbs/ft.	20.19
Moment of inertia (I)	
$I = R^4_o /4$, inches^4	2.8085
1/2 ultimate strain, in/in	0.07

Elements 2,3,4,5,6,7,8 and 9

Model, beam	rockshaft
R_o, inches	1.5
R_i, inches	0.0
E, psi	27E6
σ_y, ksi	150
S, psi	0.0 E
A, square feet	0.04910714
Wt, lbs/ft	24.02779
I, inches^4	3.977678
1/2 ultimate strain	0.07

TABLE 10A-5 (Cont'd)

Elements 11,12,13,14,15,16 and 17

Model, spring	bearing surface of rockshaft and sleeve
Spring constants	
K, lbs/inch	1.0E7

Elements 18,19,20,21,22,and 23

Model, beam	inner portion sleeve
R_o , inches	2.5625
R_i, inches	1.5
E, psi	27E6
σ_y, ksi	90
S, psi	0.0 E
A, square feet	0.094207
Wt, lbs/ft	46.23241
$I = (R_o-R_i)^4 /4$, inches ^{4}	29.9005
1/2 ultimate strain, in/in.	0.12

Elements 24,25,26,27,28 and 29

Model, beam	outer portion sleeve
R_o, inches	3.25
R_i, inches	2.5625
E_i, psi	27E6
σ_y, ksi	90
S, psi	0.0 E
A, square feet	0.087216
Wt, lbs/ft.	42.8014
I, inches ^{4}	53.781133
1/2 ultimate strain, in/in	0.12

TABLE 10A-5 (Cont'd)

<u>Elements 30, 31, 32, and 33</u>	
Model, beam	tail link - modeled as circular rods with I and fully plastic moment equal to that of the original section. D_{av} and b are parameters used to derive the equivalencies for each section.
E, psi	27E6
σ_y, ksi	90
S, psi	0.0 E
R_i, inches	0.0
1/2 ultimate strain, in/in	0.12
Element 30	
R_o $[9/8\ D^2_{av}]^{1/3}$ inch	2.675
A (D_{av} b), square feet	0.17187
$I = b\ (D_{av})^3/12$, inches ^{4}	35.09
Element 31	
R_o, inches	3.434
A, square feet	0.25
I, inches ^{4}	108
Element 32	
R_o, inches	4.374
A, square feet	0.3593
I, inches ^{4}	320.809
Element 33	
R_o, inches	5.144
A, square feet	0.4583
I, inches ^{4}	665.5

TABLE 10A-5 (Cont'd)

Element 34

Model, beam	the model is comprised of a section as in element 30 and consideration of the stiffeners.
E, psi	27E6
σ_y, ksi	90
S, psi	0.0 E
R_o, inches	5.144
R_i, inches	0.0
Volume (b D_{av} L), ft^3	0.0907
Area, square feet	0.4583
wt, lbs/ft	232.15
wt 1/2 stiffeners, lbs	59.54
wt of volume, lbs	44.44
I, $inch^4$	665.5
1/2 ultimate strain, in/in	0.12

Element 35

Model, beam	modeled as an element are the hub and bolt
E, psi	27E6
σ_y, ksi	90
S, psi	0.0 E
R_o, inches	3.0
R_i, inches	0.0
A(Bolt), sq. ft.	0.1964
W, lbs/ft (as per element 34)	233.956
I_{hub}, $inches^4$	265.76
1/2 ultimate strain, in/in	0.12

TABLE 10A-5 (Cont'd)

Elements 36 and 37	
Model, beam	the clapper area is modeled by the method of element 30 and is used to represent the mass moment of inertia of the clapper itself.
E, psi	29.8E6
σ_y, ksi	38.0
S, psi	0.0 E
R_o , inches	4.127
R_i, inches	0.0
A, square feet	0.371729
Wt, lbs/ft	398.858
I, inches ^{4}	228.0
1/2 ultimate strain, in/in	0.105
Restraint Data Nodes 25 and 26	
Model	elasto-plastic spring acting in Compression only
K,lb/in	10E7
S,lb/in	0.1K

TABLE 10A-6

GEOMETRICAL AND MATERIAL PROPERTIES OF MSCV ELEMENTS

Elements 1 through 29

All properties are identical to corresponding elements on Table 10A-5.

Elements 30, 31, 32

Model, beam	Tail link-modeled as circular rods with I and fully plastic moment equal to that of the original section. D_{av} and b are parameters used to derive the equivalencies for each section.
E, psi	27E6
σ_y, ksi	90
S. psi	0.0 E
R_i, inches	0.0
1/2 ultimate strain, in/in.	0.12

Element 30

R_o,$[9/8\ D_{av}{}^2]^{1/3}$ inch	2.62
A(D_{av} b), square feet	0.16666
$I = b(D_{av})^{3/12}$, inches^4	32.0

Element 31

R_o, inches	4.094
A, square feet	0.3255
I, inches^4	238.418

Element 32

R_o, inches	4.5415
A, square feet	0.3802
I, inches^4	379.899

TABLE 10A-6 (Cont'd)

Element 33

Model beam	the model is comprised of a section as in element 30 and consideration of the stiffener.
E, psi	27E6
σ_y, ksi	90
S, psi	0.0 E
R_o, inches	5.144
R_i. inches	0.0
Volume (b D_{av} L), ft^3	0.16045
Area, square feet	0.4583
Wt, lbs/ft	1232.15
wt. 1/2 stiffener, lbs	59.54
wt. of volume, lbs	44.44
I, inches^4	589.21
1/2 ultimate strain, in/in	0.12

Element 34

Model, beam	modeled as elements are the hub and bolt
E, psi	27E6
σ_y, ksi	90
S, psi	0.0 E
R_o, inches	3.0
R_i, inches	0.0
A (Bolt), square feet	0.1964
Wt,lbs/ft (as per element 33)	233.956
I_{hub}, inches^4	265.76
1/2 ultimate strain, in/in	0.12

TABLE 10A-6 (Cont'd)

Element 35 and 36	
Model, beam	the clapper area is modeled by the method of element 30 and is used to represent the mass moment of inertia of the clapper itself.
E, psi	29.8E6
σ_y, ksi	38.0
S, psi	0.0 E
R_o, inches	4.127
R_i, inches	0.0
A, square feet	0.371729
Wt, lbs/ft	398.858
I, inches^4	228.0
1/2 ultimate strain, in/in.	0.105
Restraint Data Nodes 24 and 25	
Model	elasto-plastic spring acting in compression only
K, lb/in	10E7
S, lb/in	0.1 k

TABLE 10A-7

PRINCIPLE STRESSES IN TAIL LINKS - RUPTURE CASE

MSCV Node Number	Plast(1) Mmax (intb)	Time (sec)	I (in^4)	ft (ref 4)	f_c (ref 4)	θ_t (psi)	θ_c psi	M fully plastic (in - 16)
1	(M_y)-227E2	0.7469E-3	3.98	1.00	1.00	-85,553	-85,553	6.75E5
2	(M_y) 4.91E5	0.37609E-3	3.98	1.00	1.00	153,536	-153,536	6.75E5
6	(M_y) 1.452E5	0.69558E-3	3.98	1.00	1.00	54,724	- 54,724	6.75E5
12	(M_R) 4E4 (M_z)-9.72E4	0.69742E-3	29.89	0.996	0.855	6,205	-5,879	2.69E6
15	(MR) 1.039E6 (M_z) 3.82E5	0.69881E-3	83.65	0.972	1.605	40,595	-65,629	6.19E6
19	(M_z) 2.154E6	0.79532E-3	176.12	0.976	1.469	43,137	-63,421	6.73E6
20	(M_z) 1.26E6	0.79532E-3	385.91	0.961	2.133	32,561	-85,047	13.15E6
21	(M_z) 1.89E6	0.79532E-3	200.57	0.964	1.835	33,520	-63,806	7.34E6
22	(M_z)-3.45E6	0.79095E-3	137.31	1.10	1.531	32,806	-45,659	5.7E6
23	(M_z)-3.6E6	0.77562E-3	462.83	1.513	6.140	51,487	101,914	9.785E6

(1) MR = $M_x^2 + M_y^2$

TABLE 10A-7 (Cont'd)

PRINCIPLE STRESSES IN TAIL LINKS - RUPTURE CASE

MSCV Node Number	Plast$^{(1)}$ Mmax (intb)	Time (sec)	I (in^4)	ft (ref 4)	f_c (ref 4)	θ_t (psi)	θ_c psi	M fully plastic (in - 16)
1	(My)-566E2	0.17177E-3	3.98	1.00	1.00	213.32	-213.32	6.75E5
2	(My)-1.97E5	0.21144E-3	3.98	1.00	1.00	74,247	-74,247	6.75E5
6	(My)-2.23E5	0.21144E-3	3.98	1.00	1.00	84,046	-84,046	6.75E5
12	(MR) 2.11E5 (M_z) 5.15E4	0.21144E-3	29.89	0.966	0.855	18,267	-15,761	2.69E6
15	(MR) 2.65E6 (M_z)-2.43E5	0.20769E-3	83.65	0.972	1.605	77,704	93,835	6.19E6
19	(M_z) 1.78E6	0.21144E-3	77.64	0.985	1.209	60,747	-74,561	3.9E6
20	(M_z) 2.22E6	0.21144E-3	221.66	0.963	1.891	36,747	-72,158	7.85E6
21	(M_z)-1.50E6	0.20849E-3	621.25	1.037	3.564	19,806	-44,920	14.69E6
22	(M_z)-1.73E6	0.21144E-3	762.88	1.005	3.119	14,518	-37,204	19.37E6
23	(M_z) 2.92E6	0.21144E-3	385.91	0.961	2.133	32,431	-61,169	13.15E6
24	(M_z)-3.55E6	0.21144E-3	462.83	1.513	6.140	50,772	101,615	9.785E6

TABLE 10A-7A

GEOMETRICAL AND MATERIAL PROPERTIES OF THE ROCKSHAFT ELEMENTS

Rockshaft-Elements 1 through 5

E, psi	27E6
σ_y, ksi	150
S, psi	0.1 E

Bearing Surface-Elements 6 through 9

See Table 10A-5

Tail Link - Elements 10 through 12

E, psi	27E6
σ_y, ksi	28.1
S, psi	0.0 E

Sleeve - Elements 13 through 15

E, psi	27E6
σ_y, ksi	62
S, psi	0.0 E

Mass Center - Node 13

MSIV

1/2 wt, lbs.	461
Displacement, inches	0.339
Time displacement, sec	.045

MSCV

1/2 wt- lbs	431
displacement, inches	0.206
time of displacement, secs	.02934

TABLE 10A-8

ROCKSHAFT AND TAILLINK SLEEVES - COMBINED EFFECTS OF PRE AND POST IMPACT

Rockshaft	Element Pre Imp.	Element Post Imp.	Node Pre Imp.	Node Post Imp.	Post Imp E_p (%)	E^t (%)	$E_p + E^t$ (%)	E_u(%)
MSIV	1	1	2	2	1.6375	0.352	1.9395	14.0
MSCV	1	2	1	2	0.6797	0.89	1.5697	14.0
<u>Fail Link Sleeve</u>								
MSIV	15	26	10	15	3.2995	1.1140	4.4135	15.0
MSCV	15	26	10	15	1.49	0.287	1.779	15.0

TABLE 10A-9

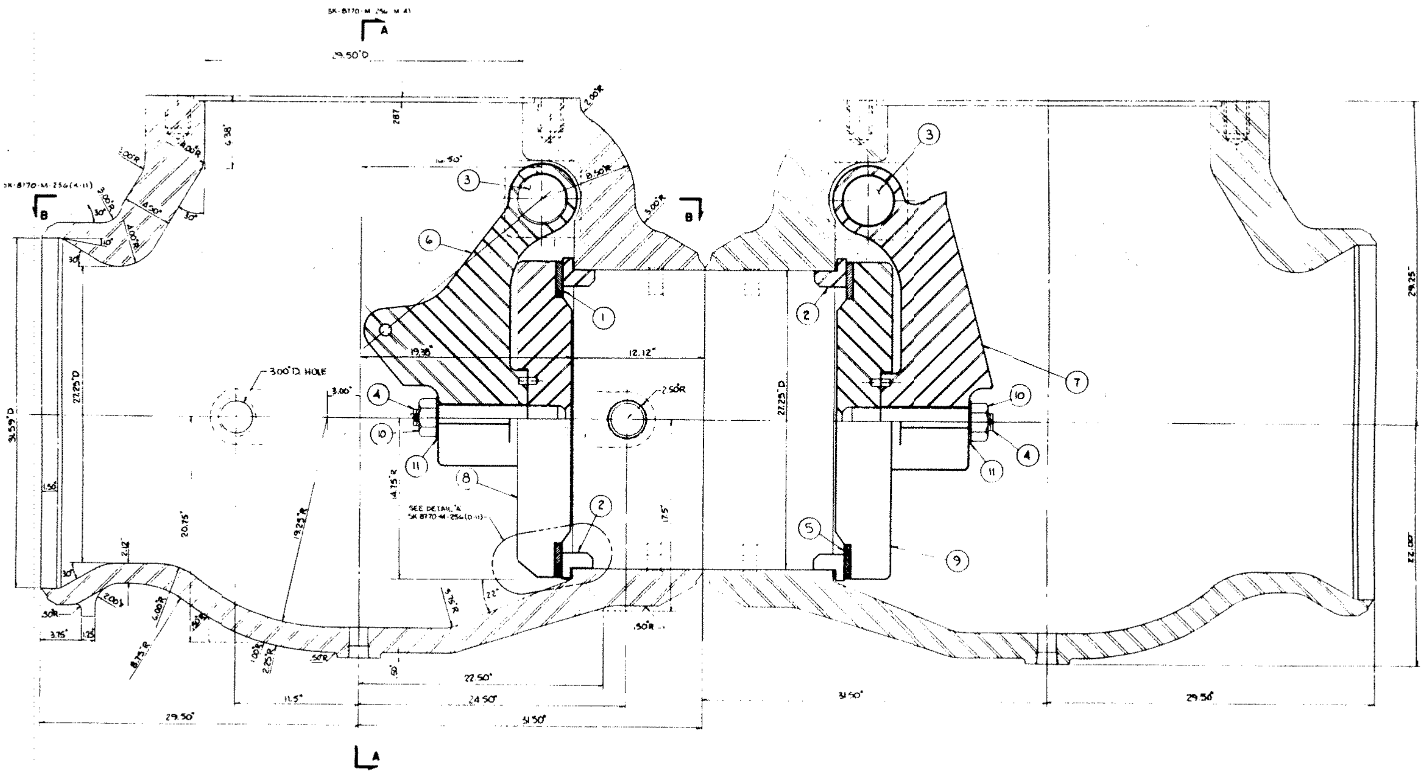
COMPARISONS OF 3-D SHELL AND AXI-SYMMETRIC RESULTS AT TIME 0.0043 SEC. AFTER IMPACT FOR UNMODIFIED MSIV/MSCV

ELEMENT NUMBER (1)		$^{\varepsilon}$G%	
3-D SHELL	AXI-SYM.	3-D SHELL	AXI-SYM.
210			
Mid Surf.	74	1.65	1.6
88			
Top Surf.	2	4.75	5.2
Bottom Surf.	9	5.3	5.8
161(2)			
Mid Surf.	56	0.02	15.8
Bottom Surf	58	2.65	19.2

Notes:

(1) 3-D shell elements are shown on Figures 10A-32 and 10A-33. The axi-symmetric elements are shown on Figures 10A-34 and 10A-35.

(2) Impact zone of disc.

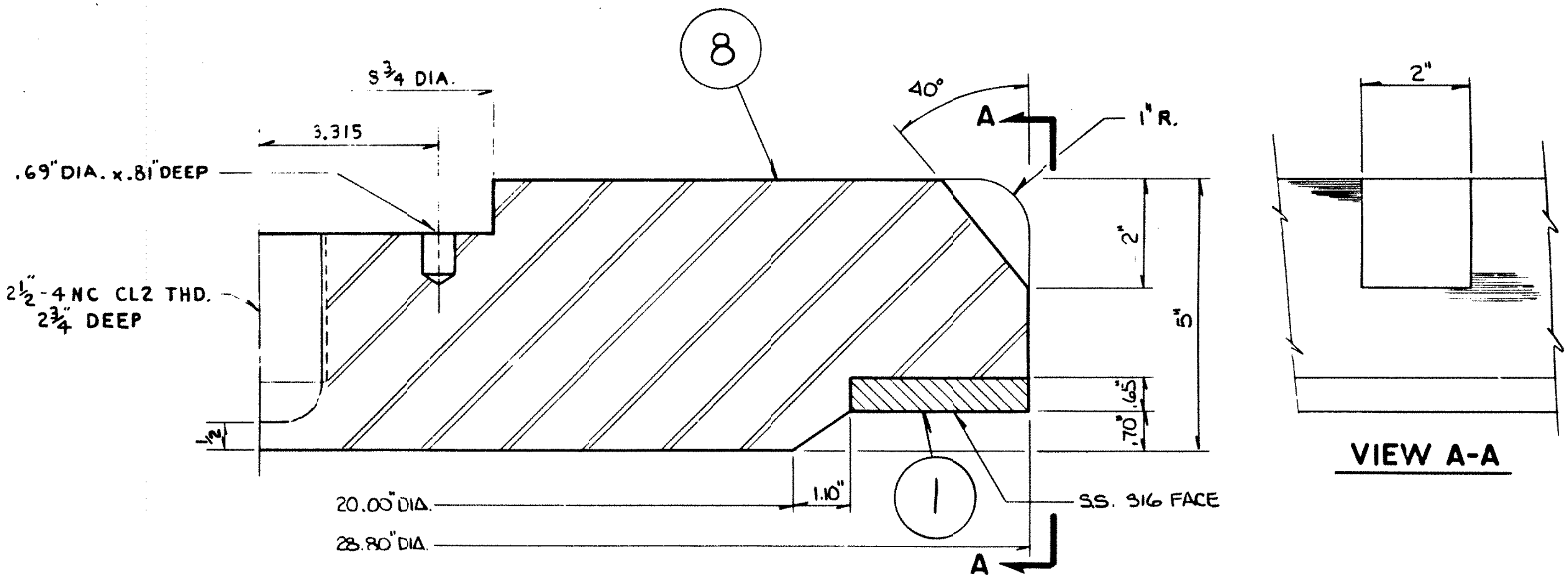


8770 – M-255

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MAIN STEAM ISOLATION VALVE

FIGURE 10A-1

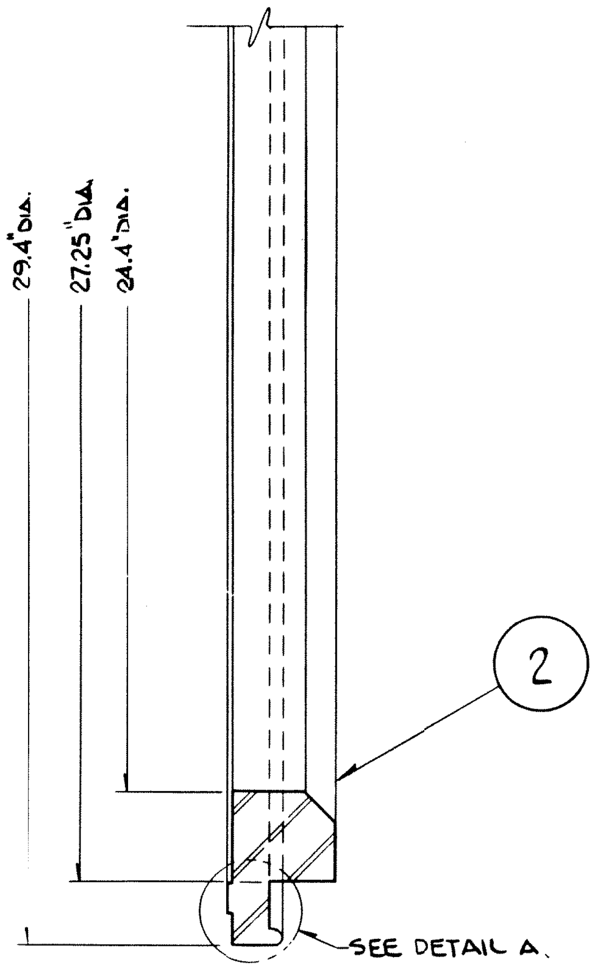


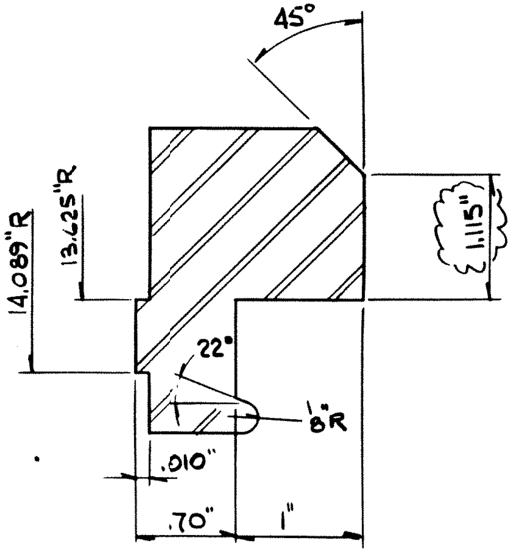
8770 – M-268

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

NEW DISC FOR MSIV

FIGURE 10A-2





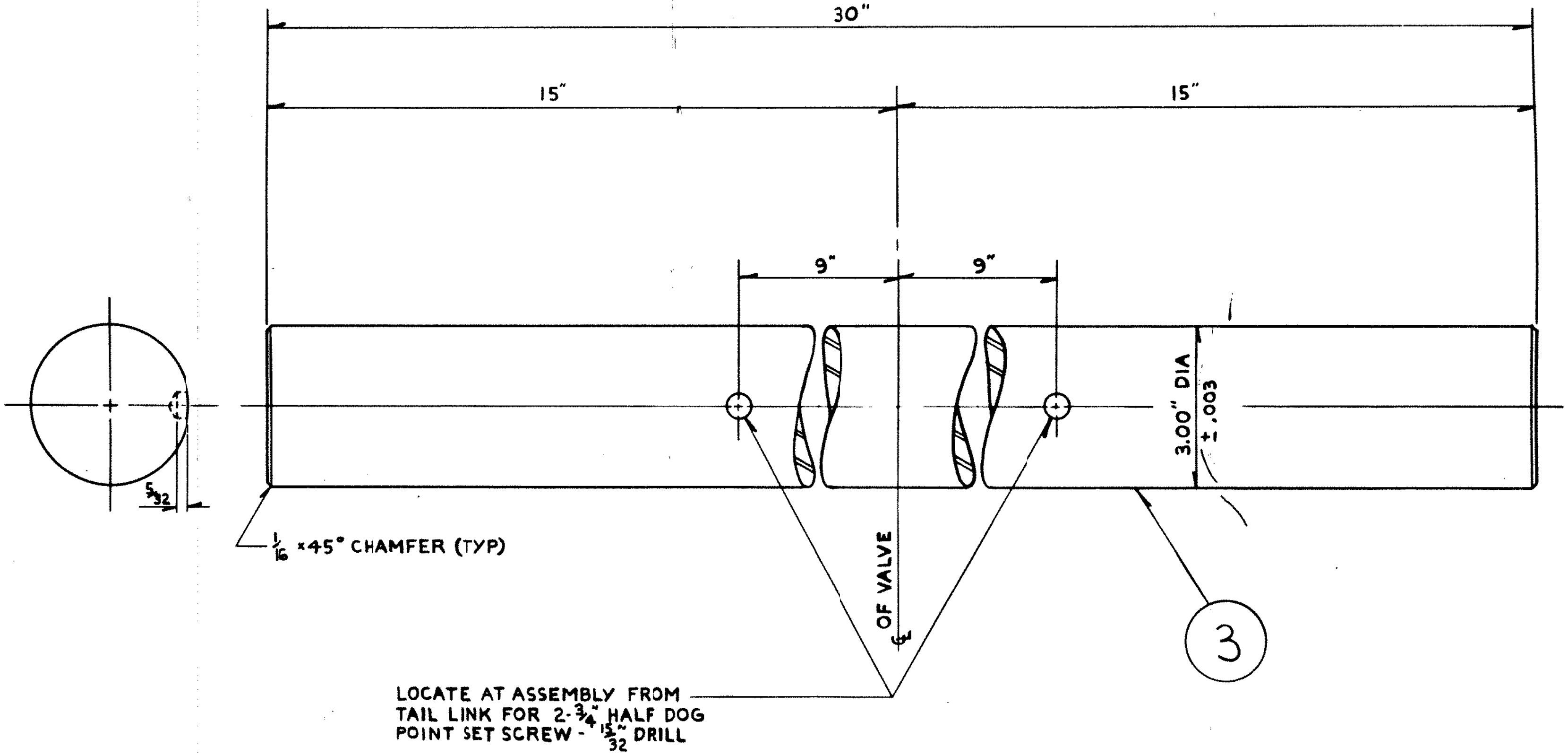
DETAIL A

8770 – M-270

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

NEW SEAT FOR MSIV AND MSCV

FIGURE 10A-3

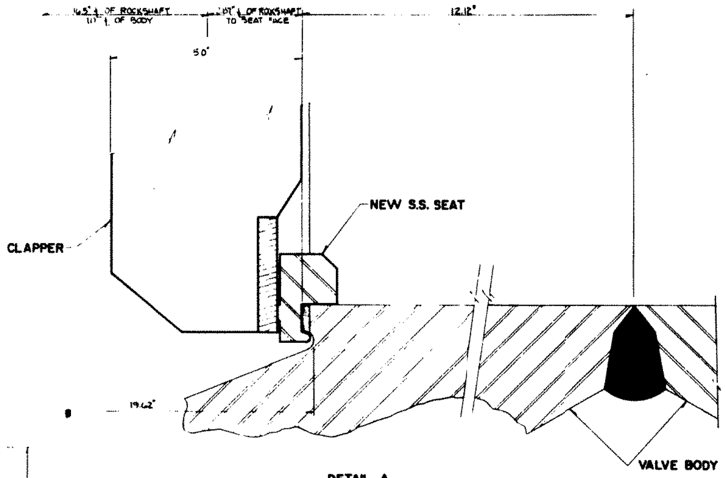


8770 – M-261

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

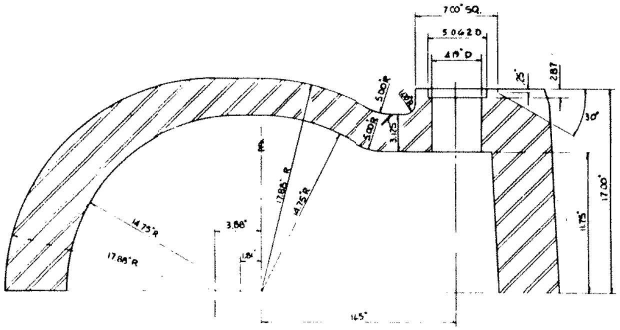
ROCKSHAFT FOR MSIV AND MISCV

FIGURE 10A-4



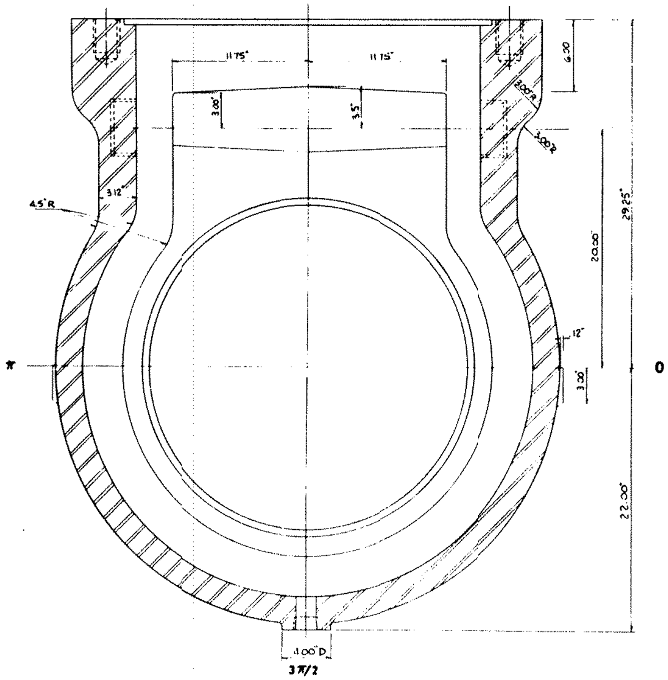
DETAIL A

SK-8770-M-255 (M-7,M-9)
SCALE: ¾"-1"



SECTION B-B

SK-8770 M 255 (H-1)



SECTION A-A

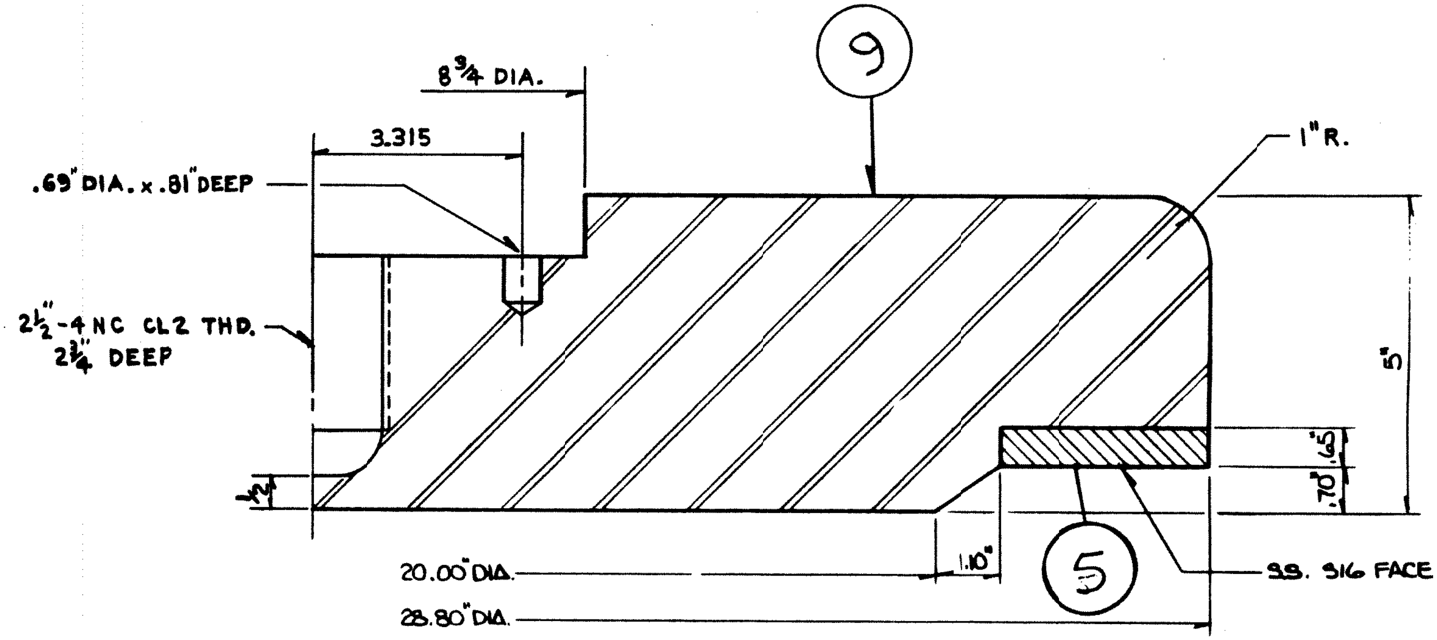
SK-8170 M-255 (E-5)

8770 – M-256

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MSIV SECTIONS AND DETAILS

FIGURE 10A-5

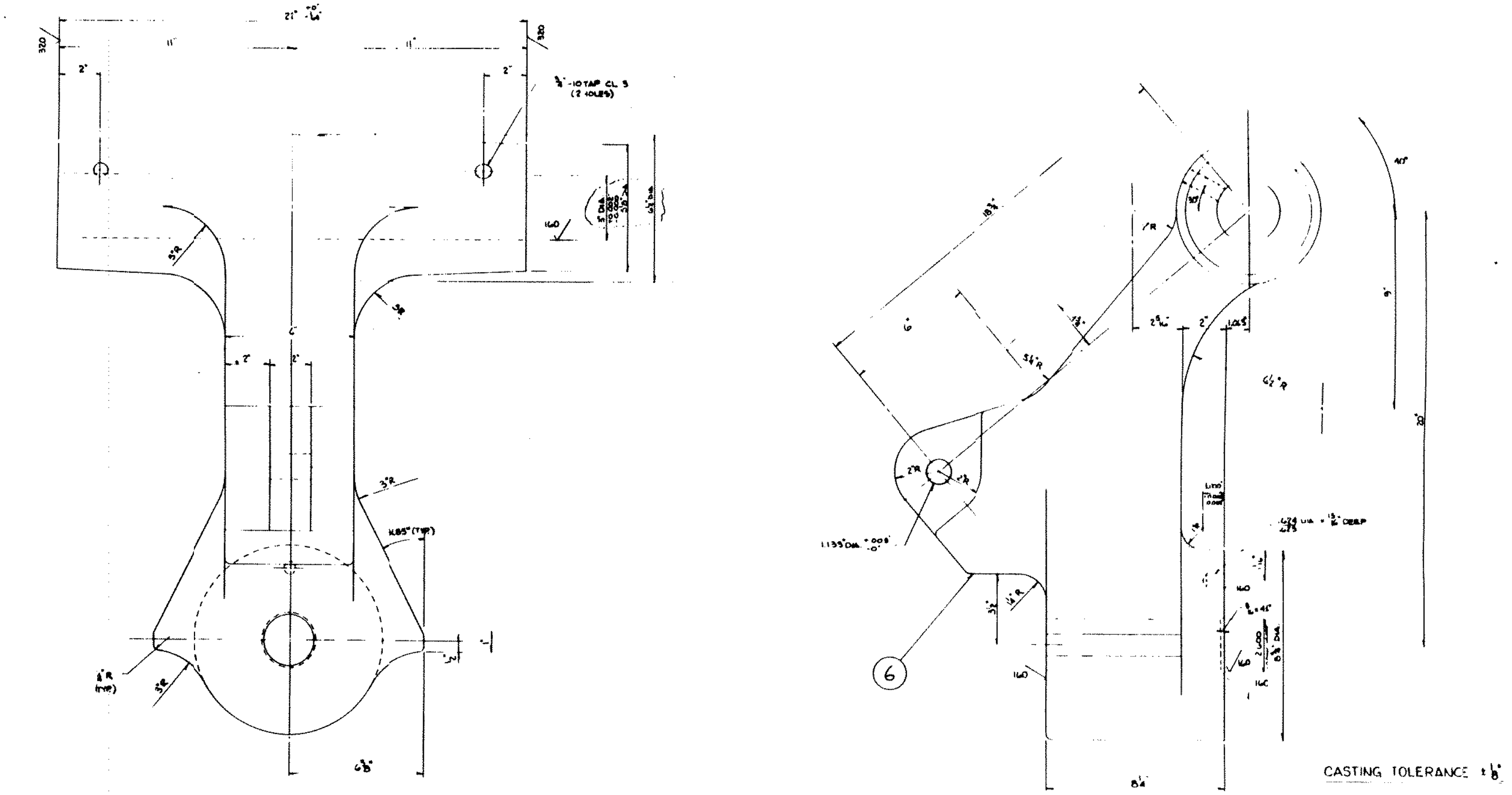


8770 – M-269

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

NEW DISC FOR MSCV

FIGURE 10A-6



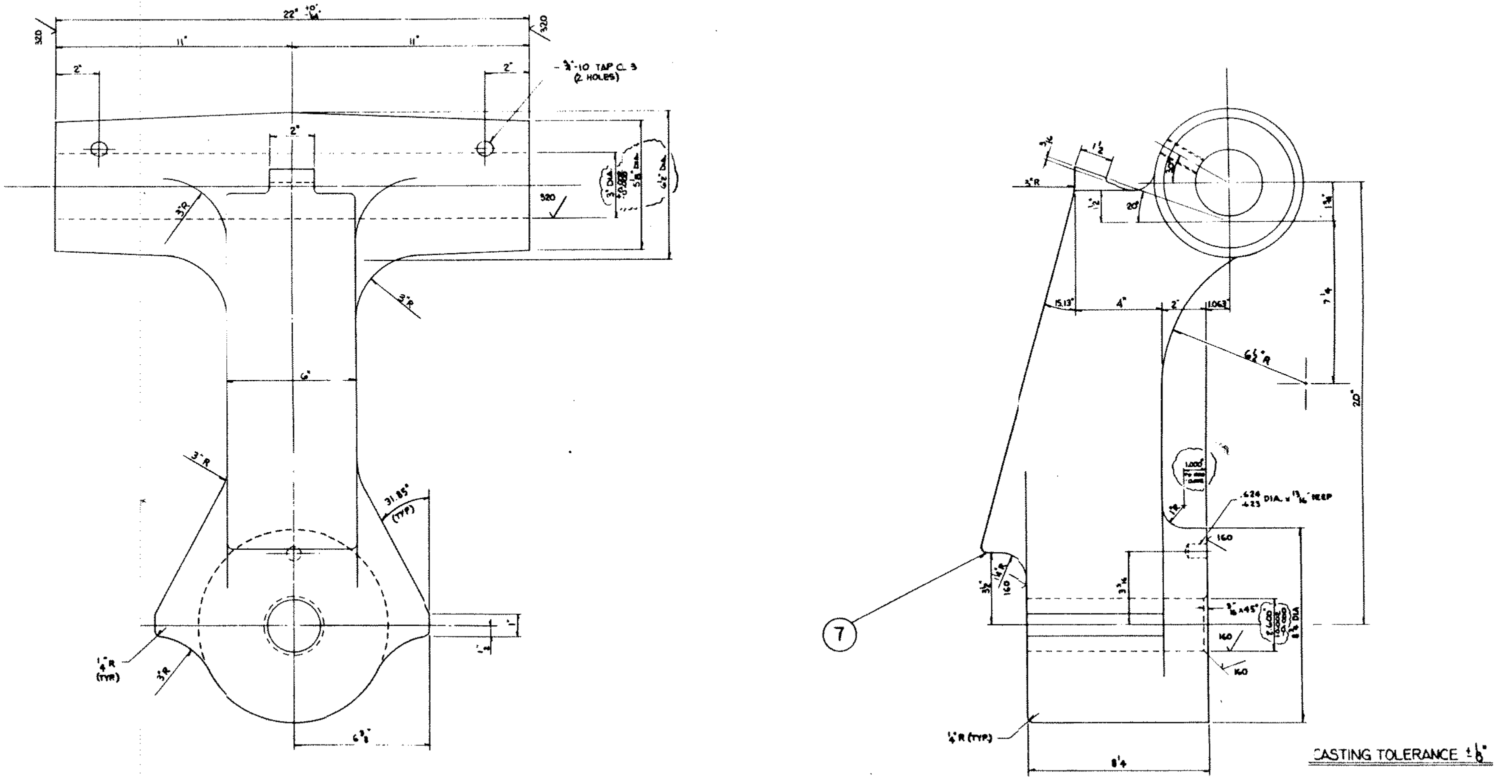
CASTING TOLERANCE ± 1/8"

8770 – M-264

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

NEW TAIL LINK FOR MSIV

FIGURE 10A-7



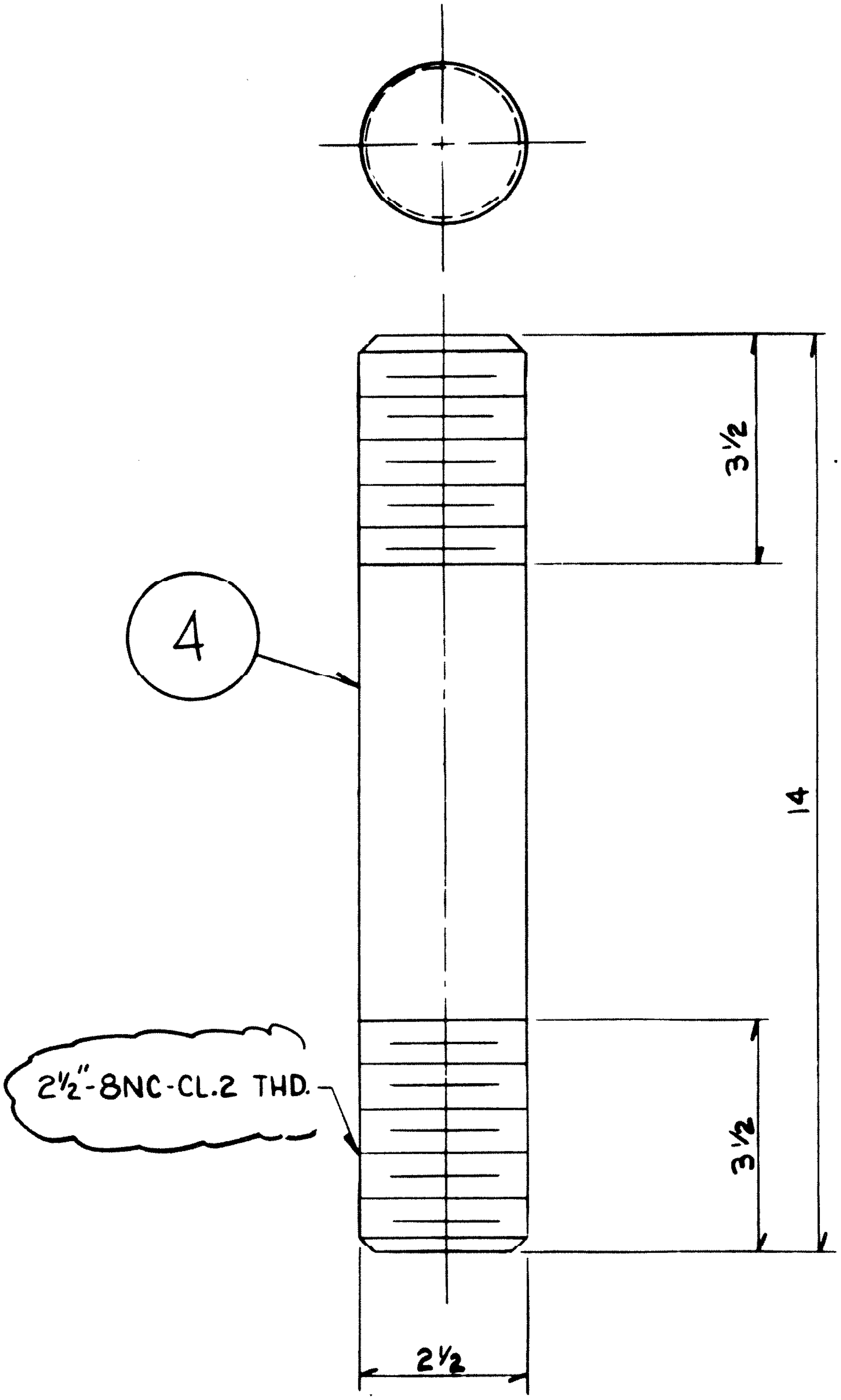
CASTING TOLERANCE ± 1/8"

8770 – M-265

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

NEW TAIL LINK FOR MSCV

FIGURE 10A-8

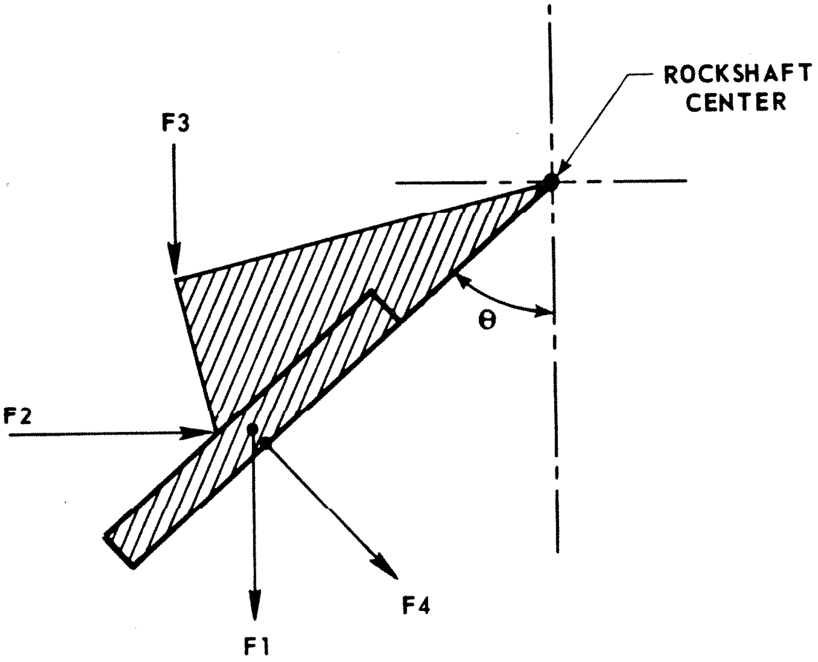


8770 – M-267

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MSIV AND MSCV STUDS

FIGURE 10A-9

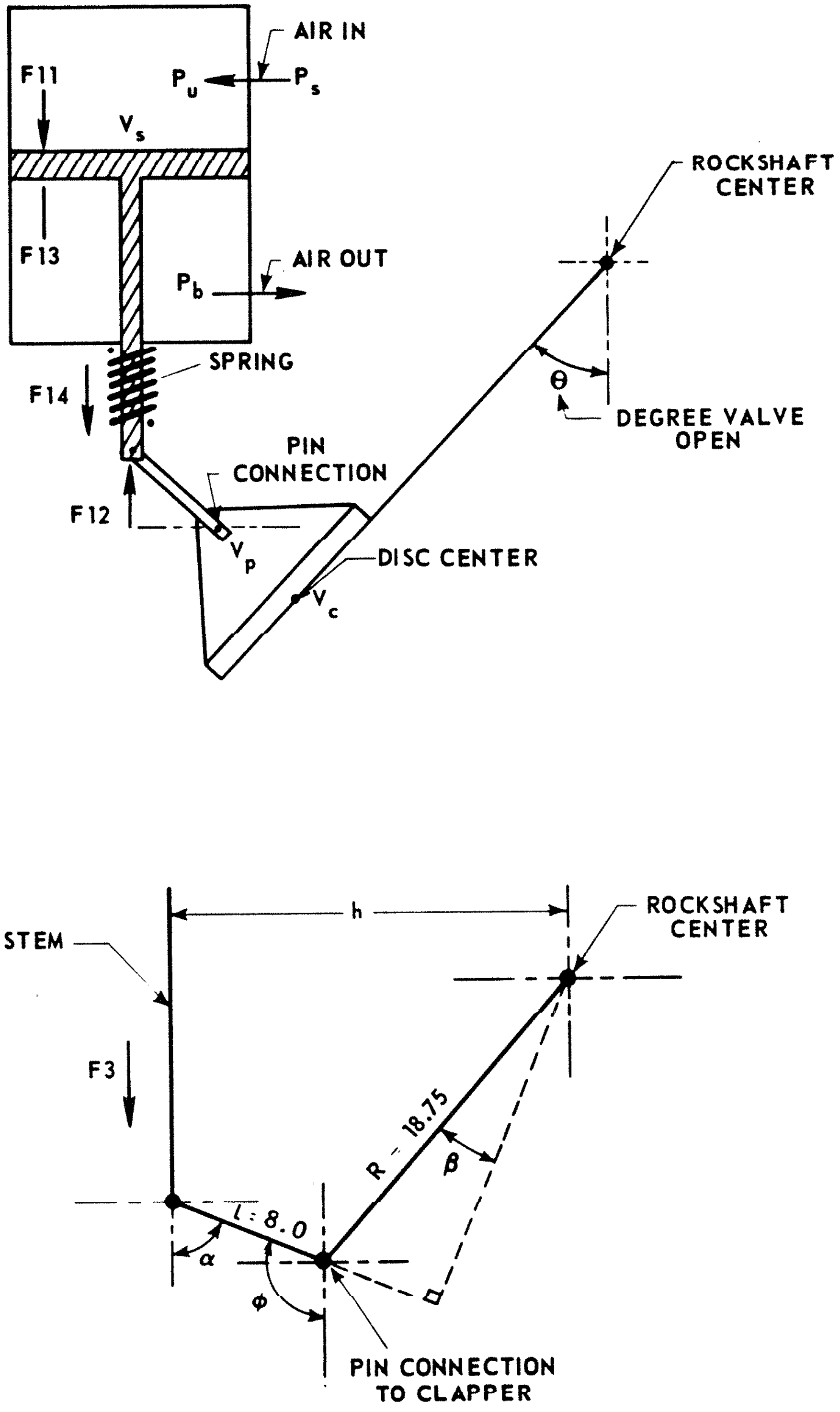


θ – ANGLE MSIV OPEN
F1 – WEIGHT OF VALVE COMPONENTS
F2 – DRAG FORCE
F3 – AIR CYLINDER AND SPRING FORCE
F4 – ΔP ACROSS VALVE

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

SYSTEM FREE BODY DIAGRAM

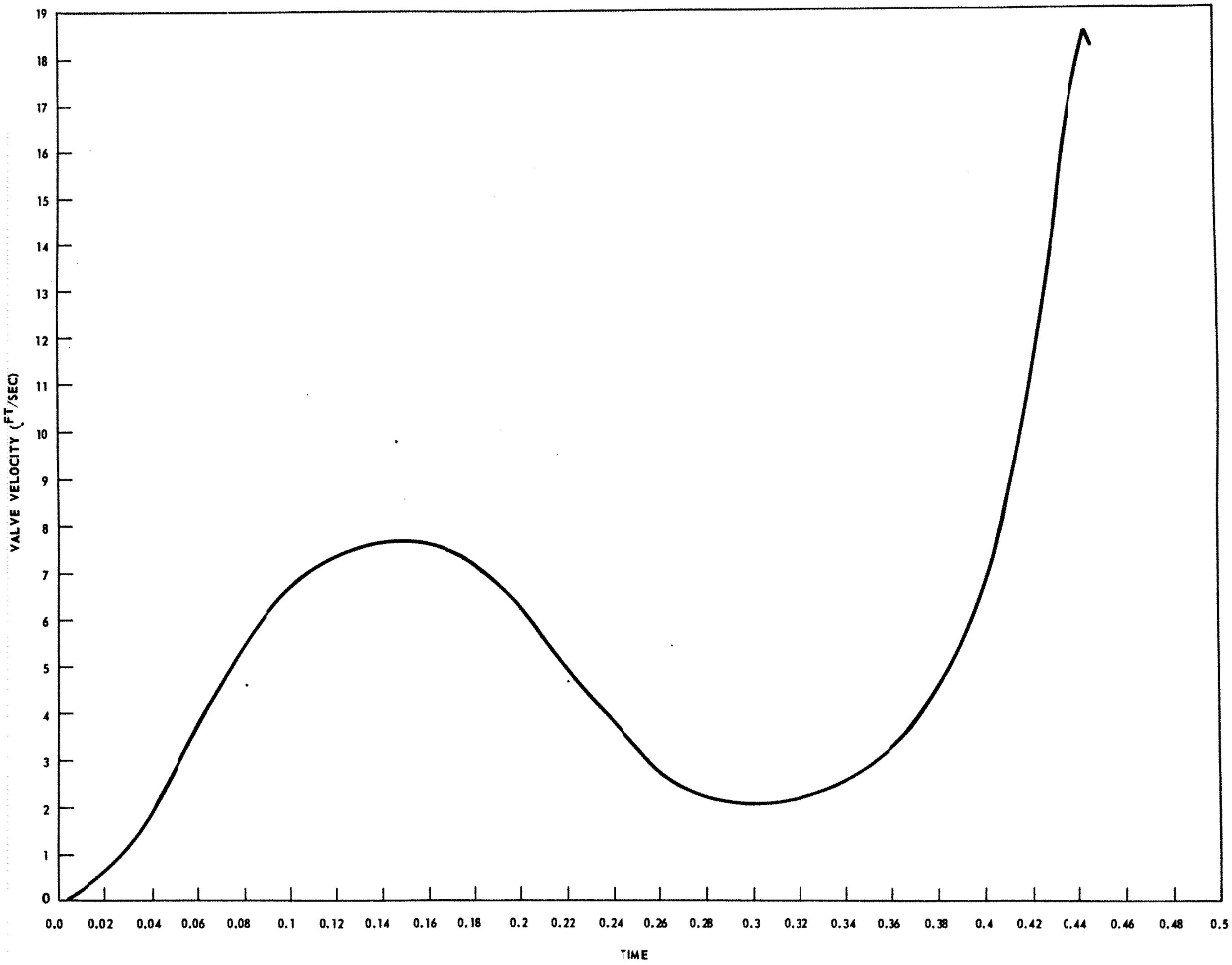
FIGURE 10A-10



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MECHANICAL MODELS FOR VELOCITY CALCULATIONS

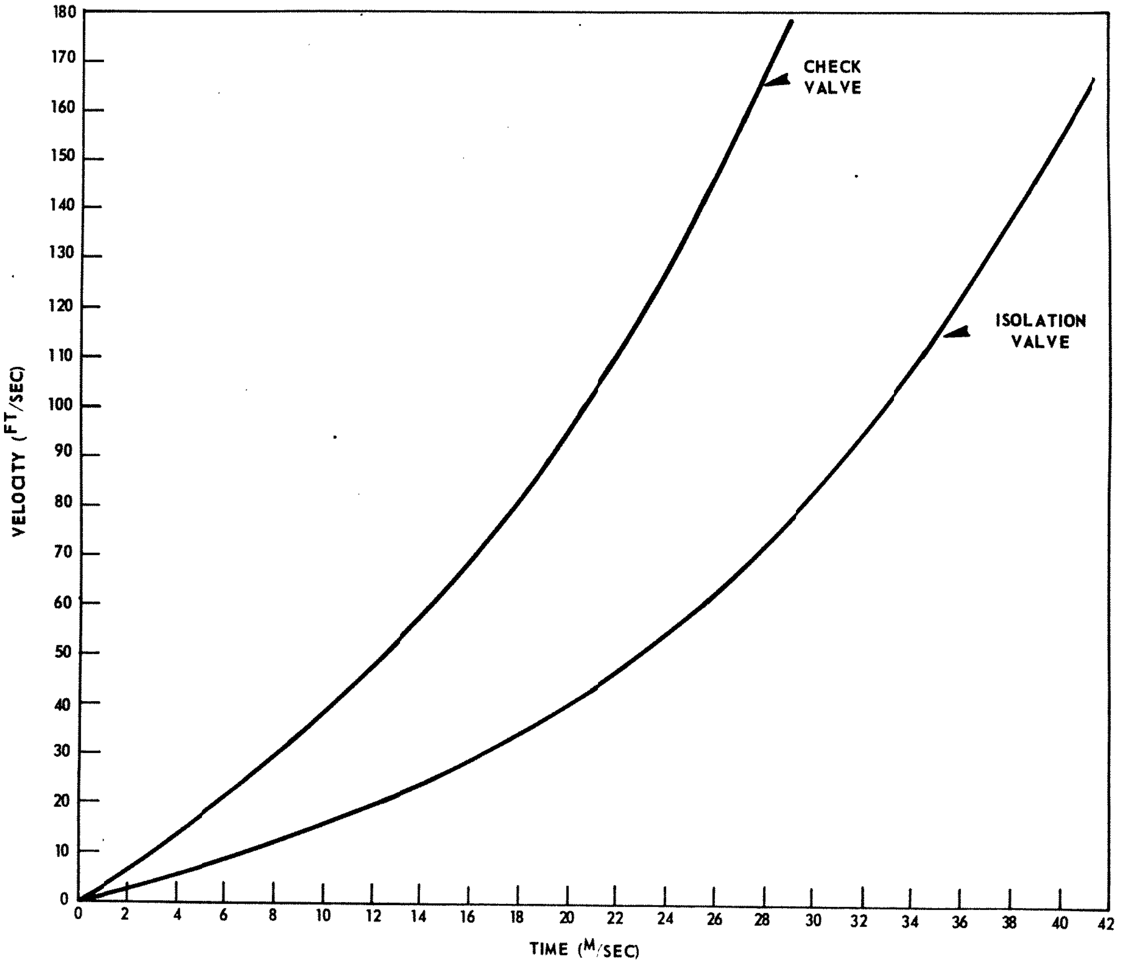
FIGURE 10A-11



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MSIV SPURIOUS SIGNAL VELOCITY

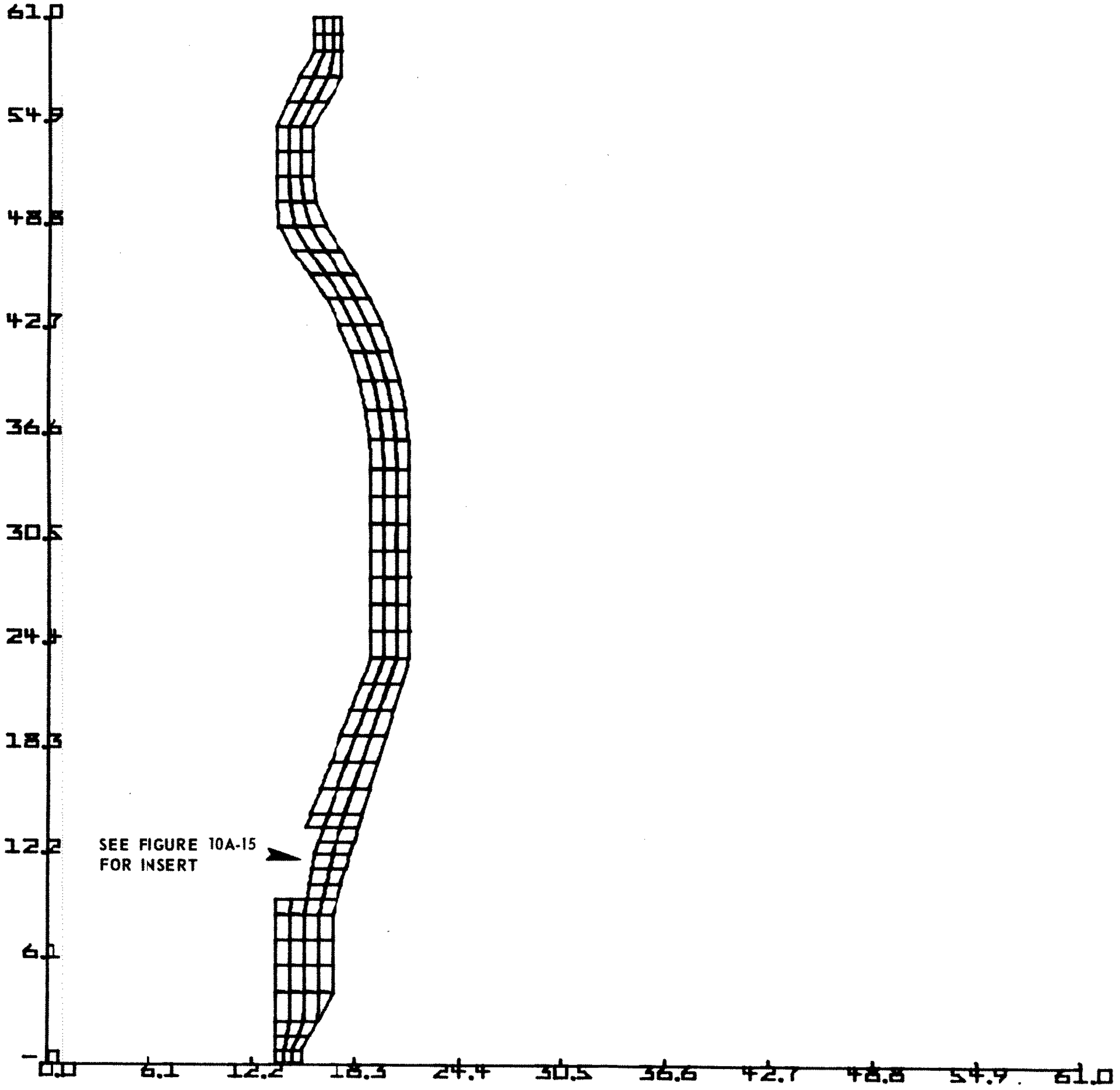
FIGURE 10A-12



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MSCV RUPTURE VELOCITY PROFILE

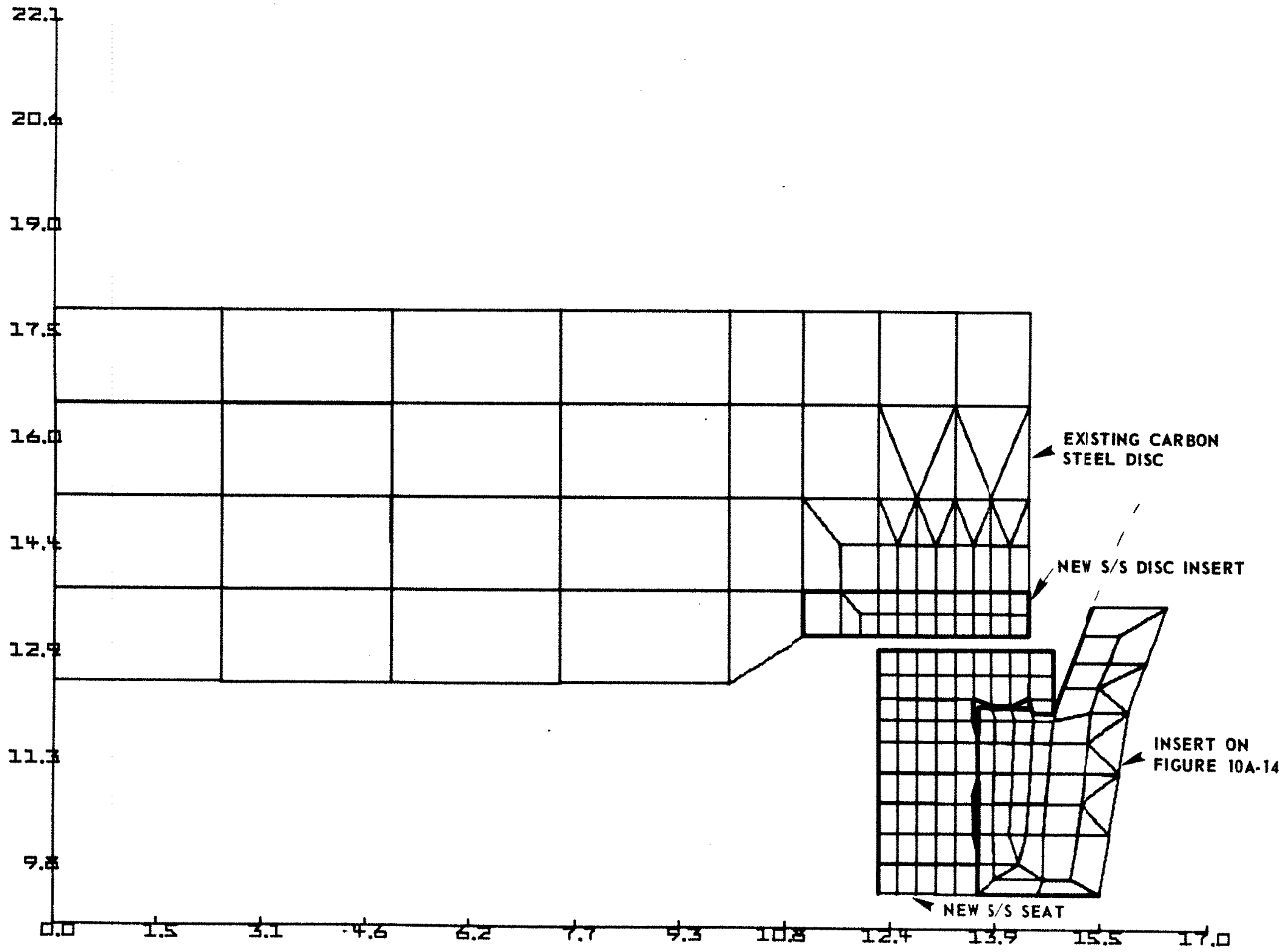
FIGURE 10A-13



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FINITE ELEMENT MESH FOR AXISYMMETRIC VALVE BODY FOR REGION 0, 3π/2, π

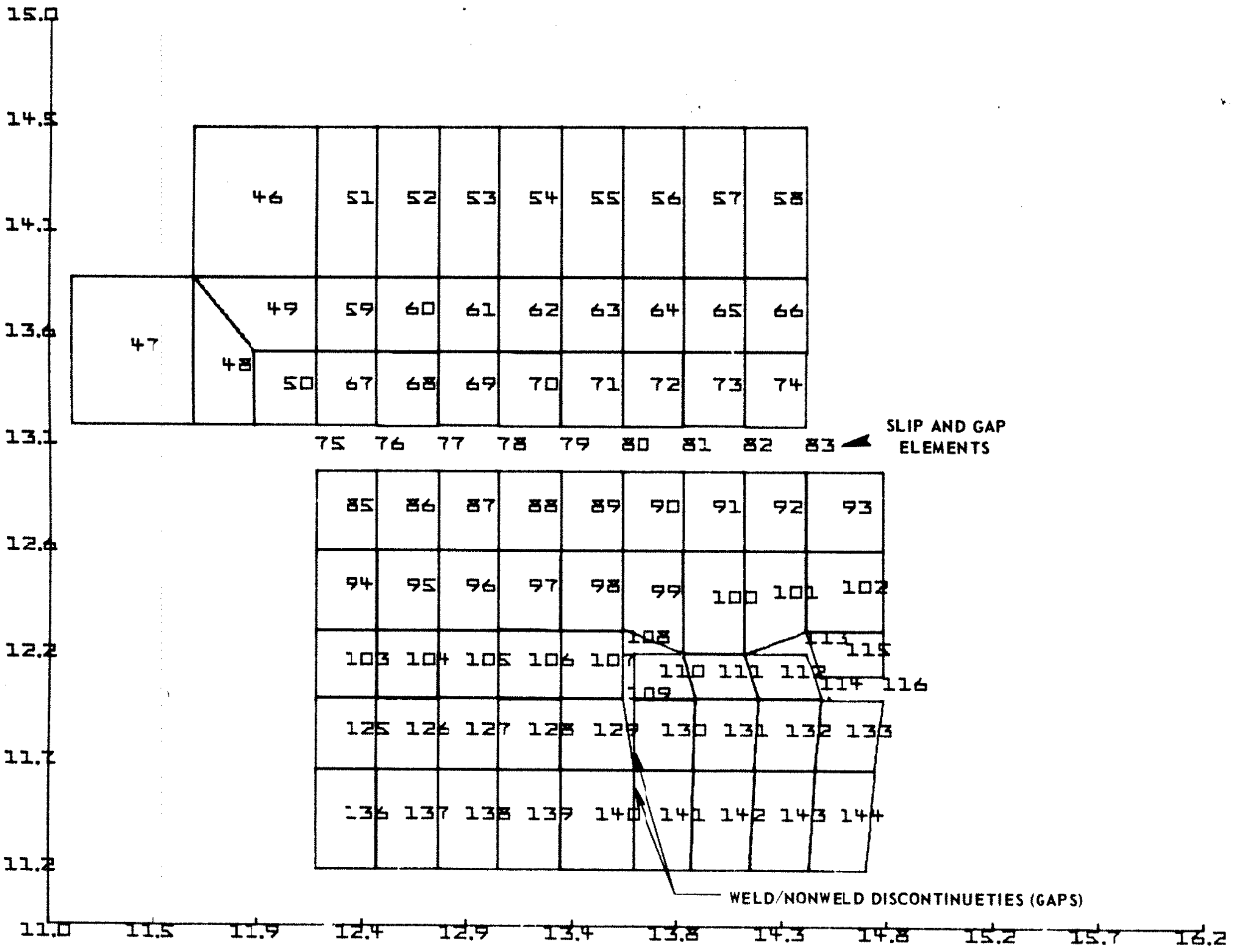
FIGURE 10A-14



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FINITE ELEMENT MESH OF
DISC, SEAT AND VALVE BODY

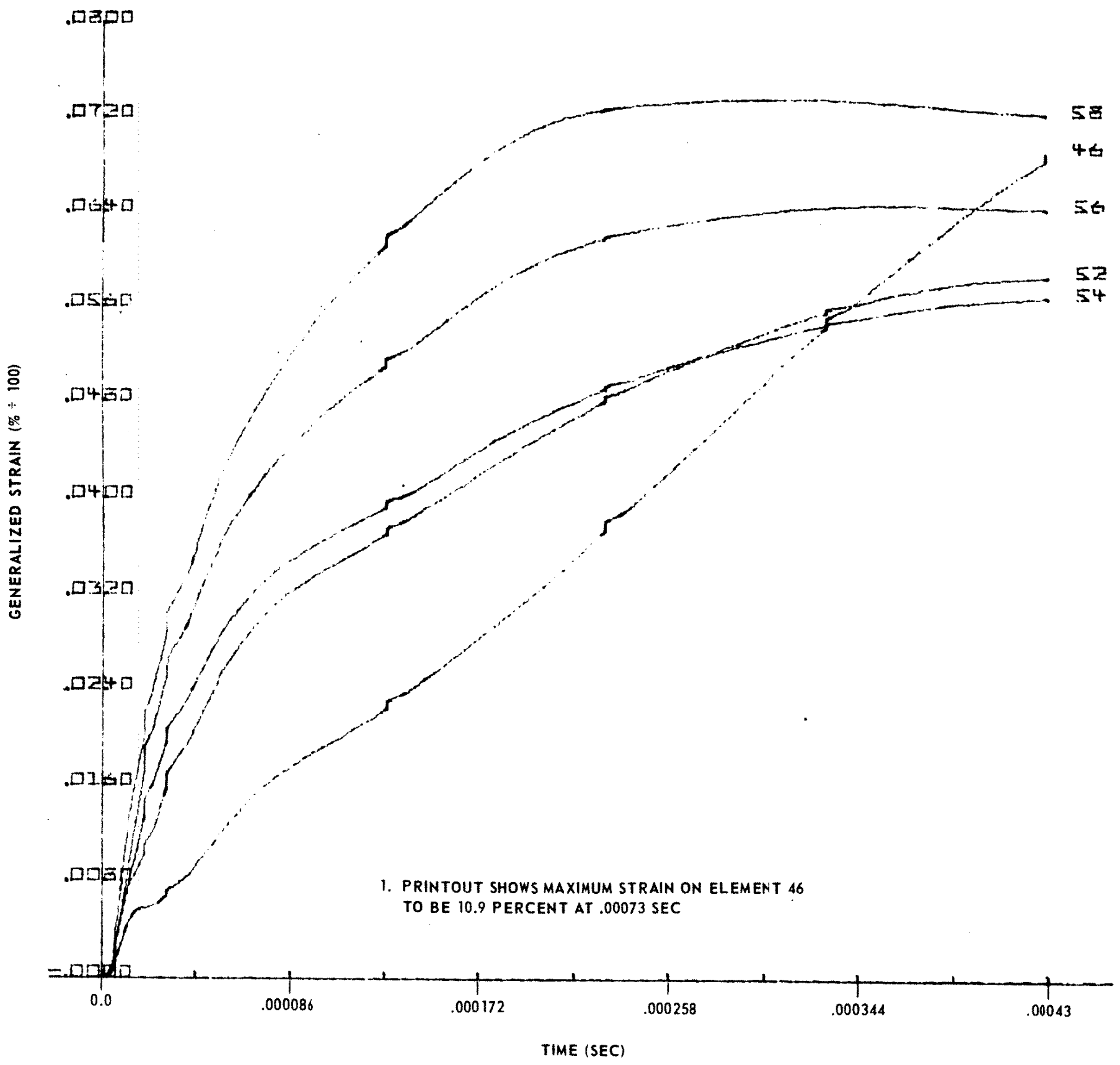
FIGURE 10A-15



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

FINITE ELEMENT MESH OF
SEAT AREA

FIGURE 10A-16

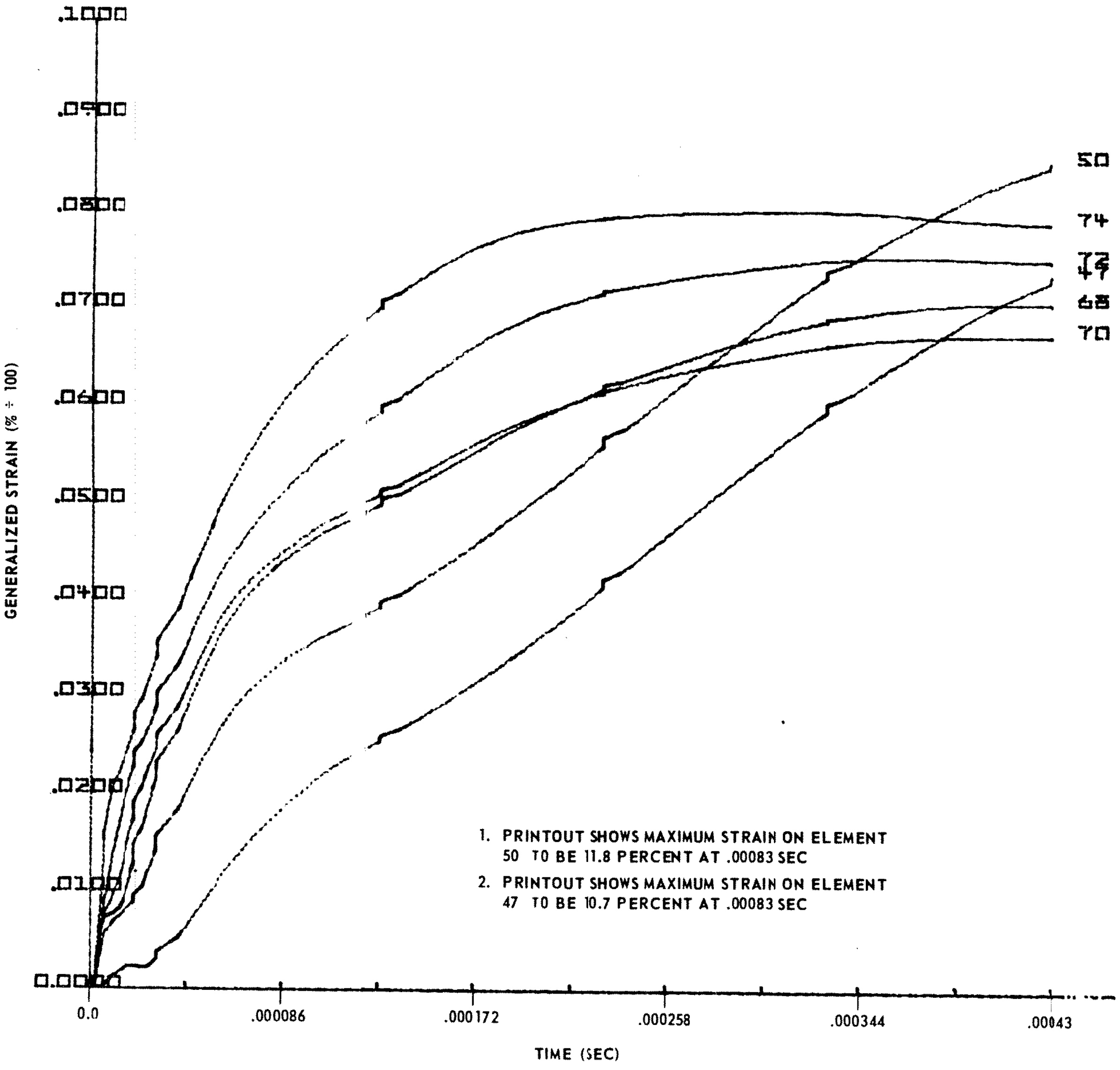


1. PRINTOUT SHOWS MAXIMUM STRAIN ON ELEMENT 46 TO BE 10.9 PERCENT AT .00073 SEC

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

GENERALIZED STRAIN FOR
RUPTURE CASE – POST IMPACT

FIGURE 10A-17

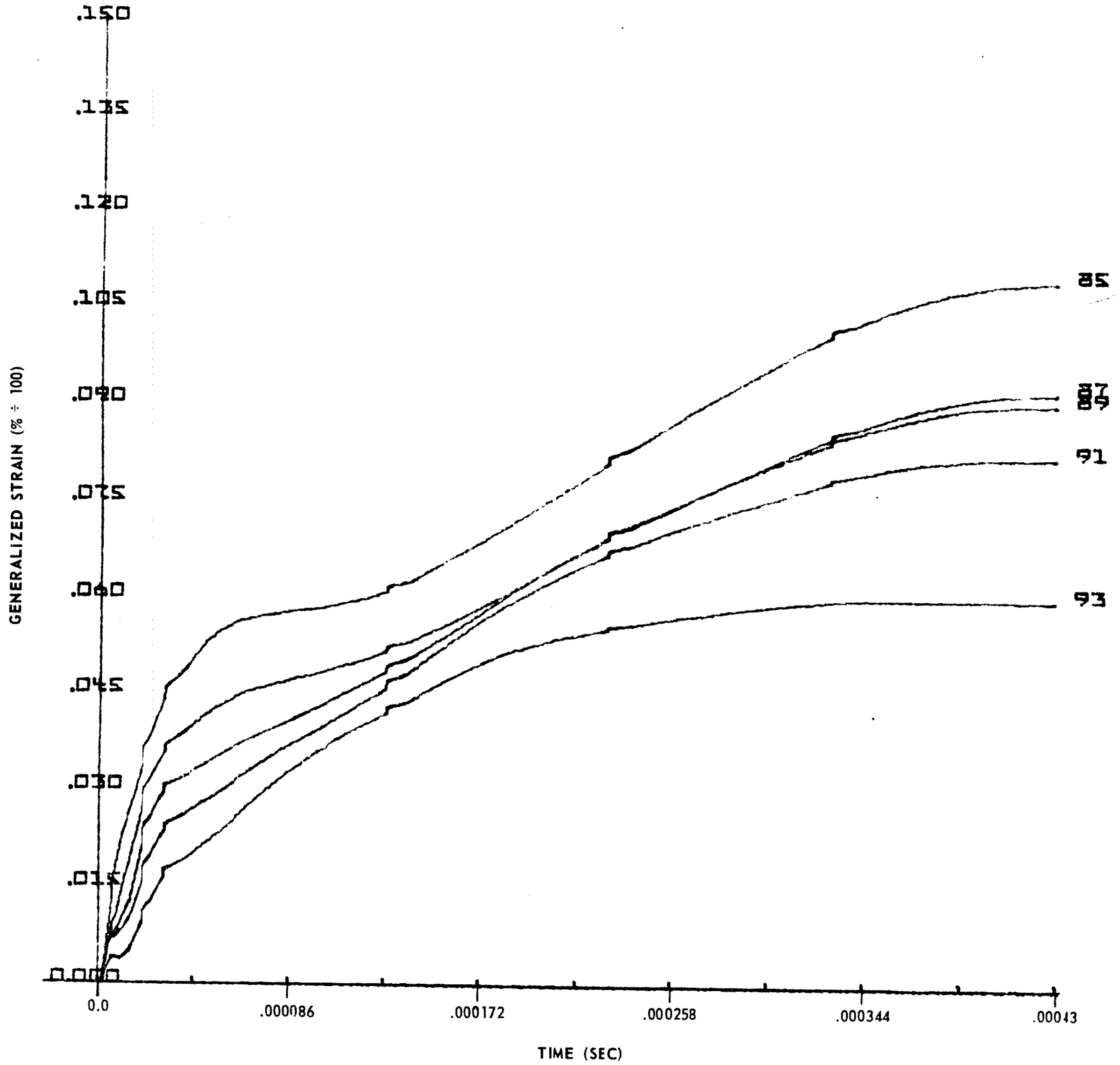


1. PRINTOUT SHOWS MAXIMUM STRAIN ON ELEMENT 50 TO BE 11.8 PERCENT AT .00083 SEC
2. PRINTOUT SHOWS MAXIMUM STRAIN ON ELEMENT 47 TO BE 10.7 PERCENT AT .00083 SEC

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

GENERALIZED STRAIN FOR
RUPTURE CASE - POST IMPACT

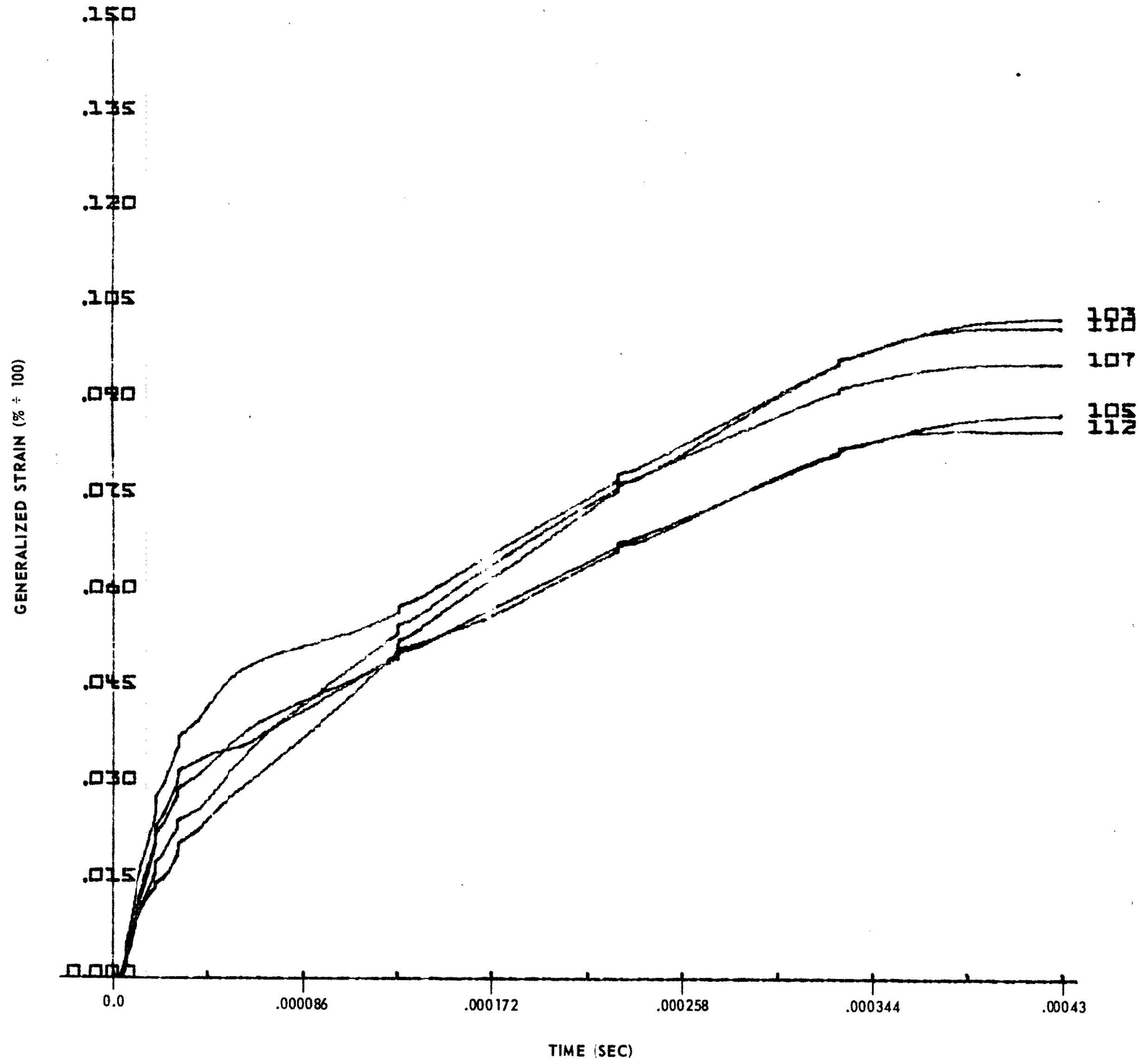
FIGURE 10A-18



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

GENERALIZED STRAIN FOR
RUPTURE CASE – POST IMPACT

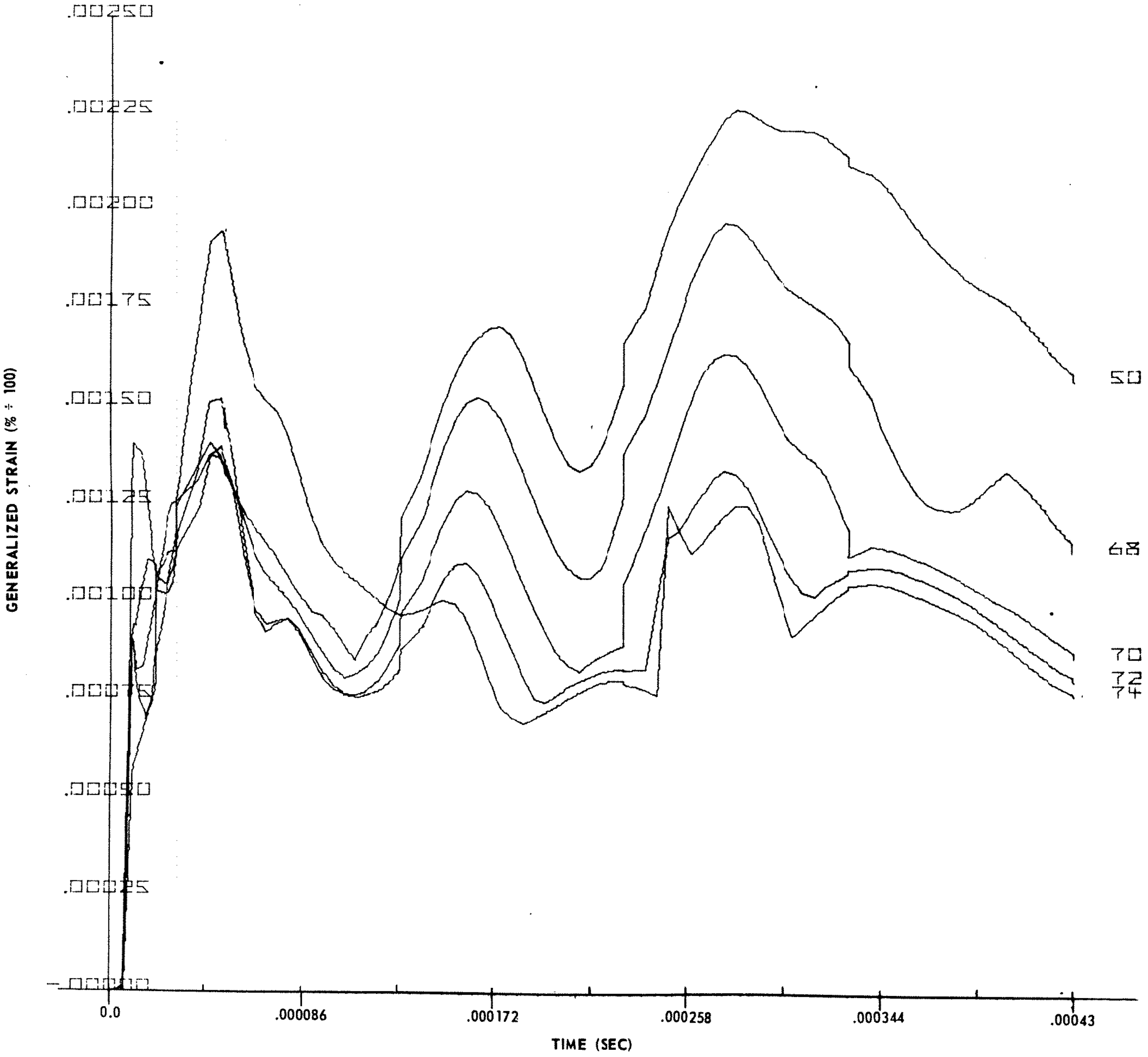
FIGURE 10A-19



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

GENERALIZED STRAIN FOR RUPTURE CASE – POST IMPACT

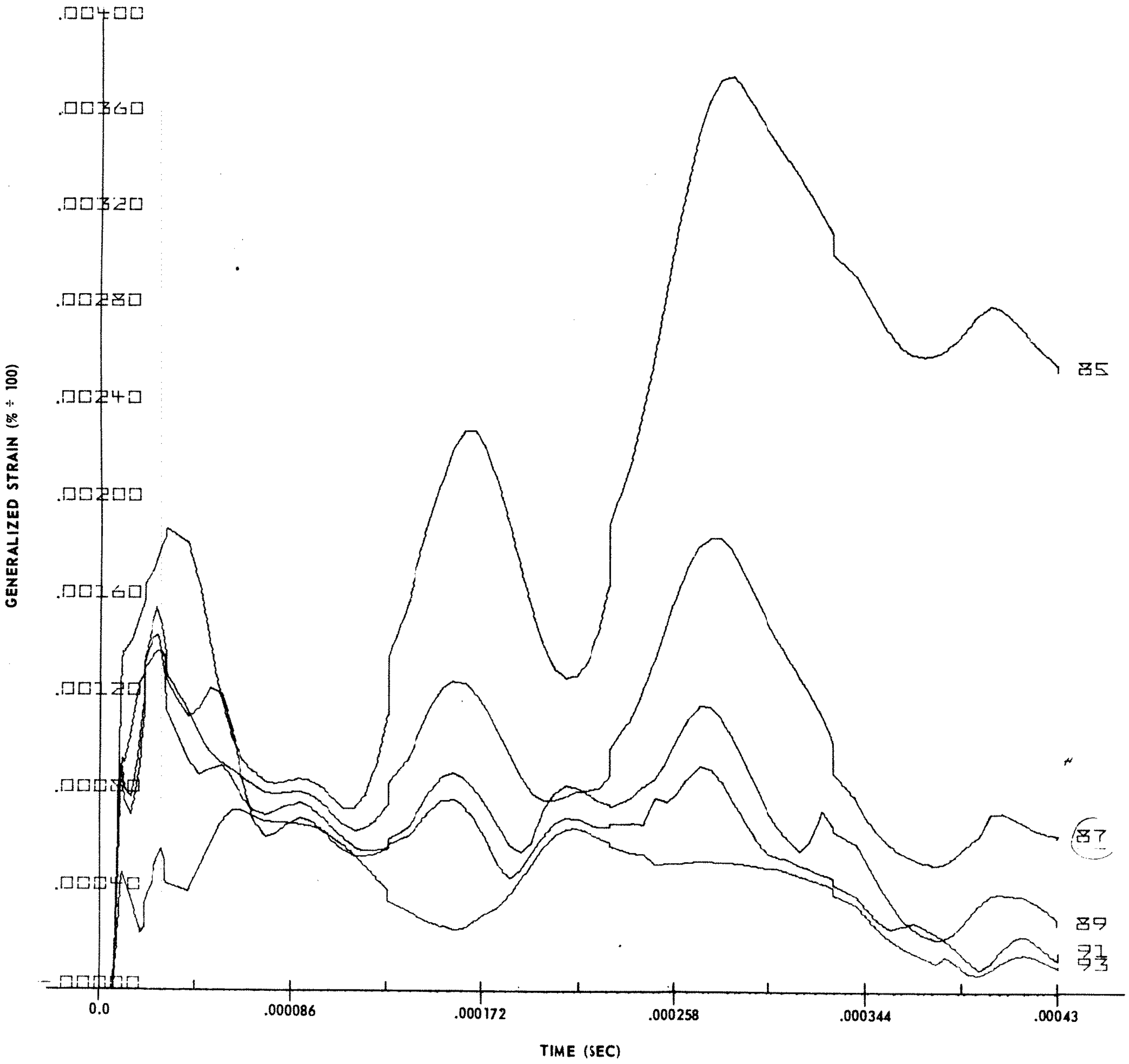
FIGURE 10A-20



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

GENERALIZED STRAIN FOR SPURIOUS SIGNAL - POST IMPACT

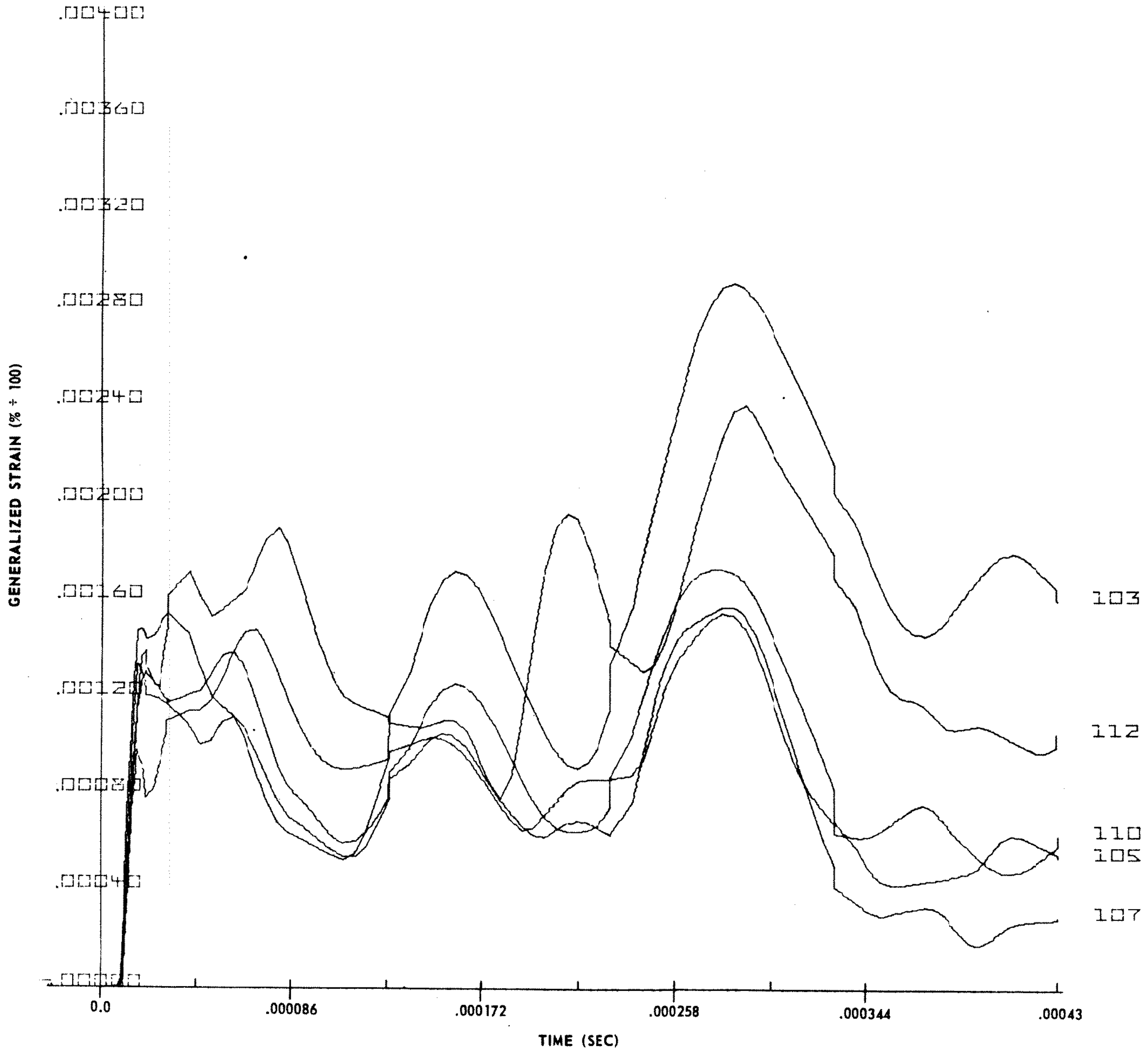
FIGURE 10A-21



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

GENERALIZED STRAIN FOR SPURIOUS SIGNAL – POST IMPACT

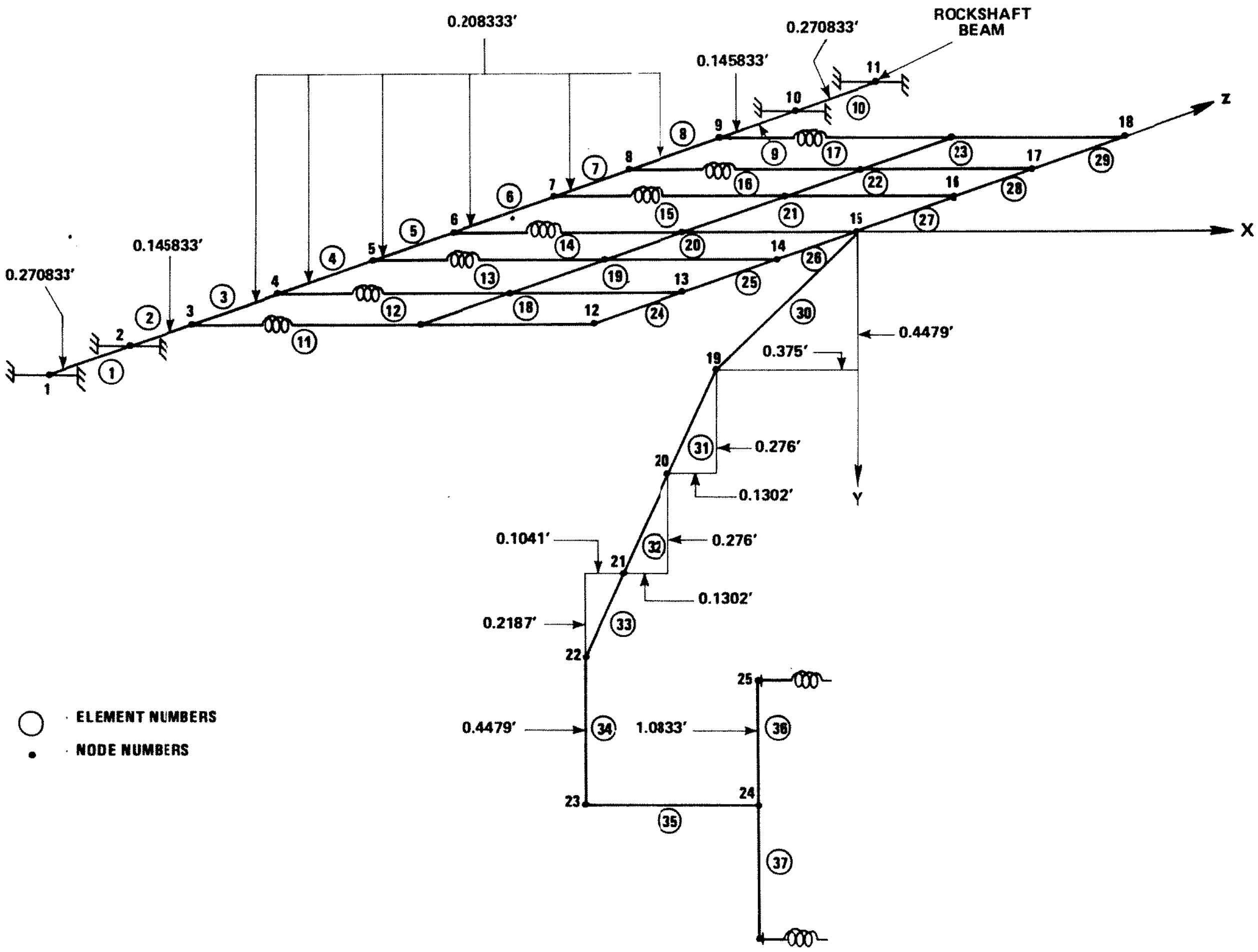
FIGURE 10A-22



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

GENERALIZED STRAIN FOR SPURIOUS SIGNAL – POST IMPACT

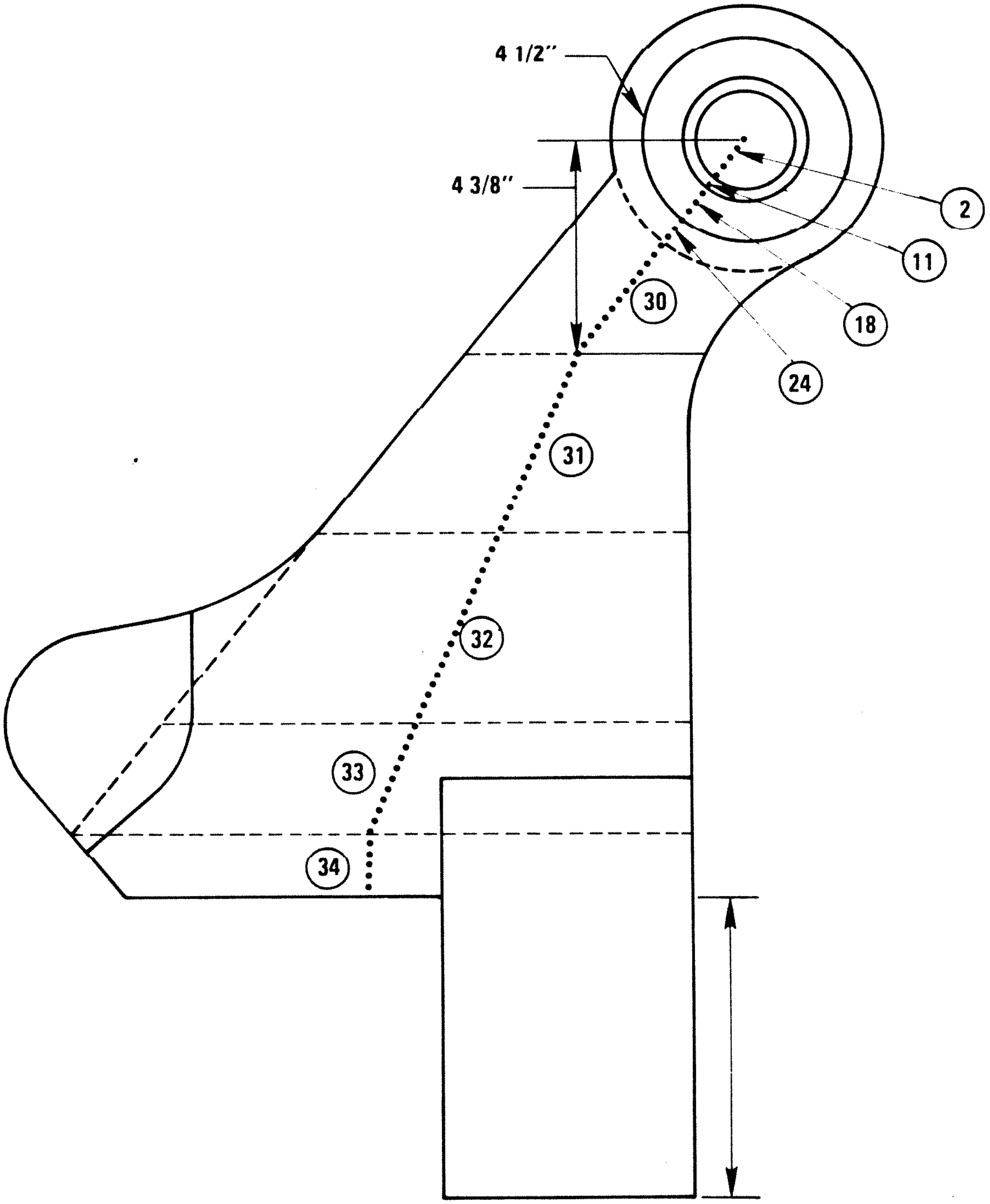
FIGURE 10A-23



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

PLAST MODEL – MSIV RUPTURE CASE – POST IMPACT

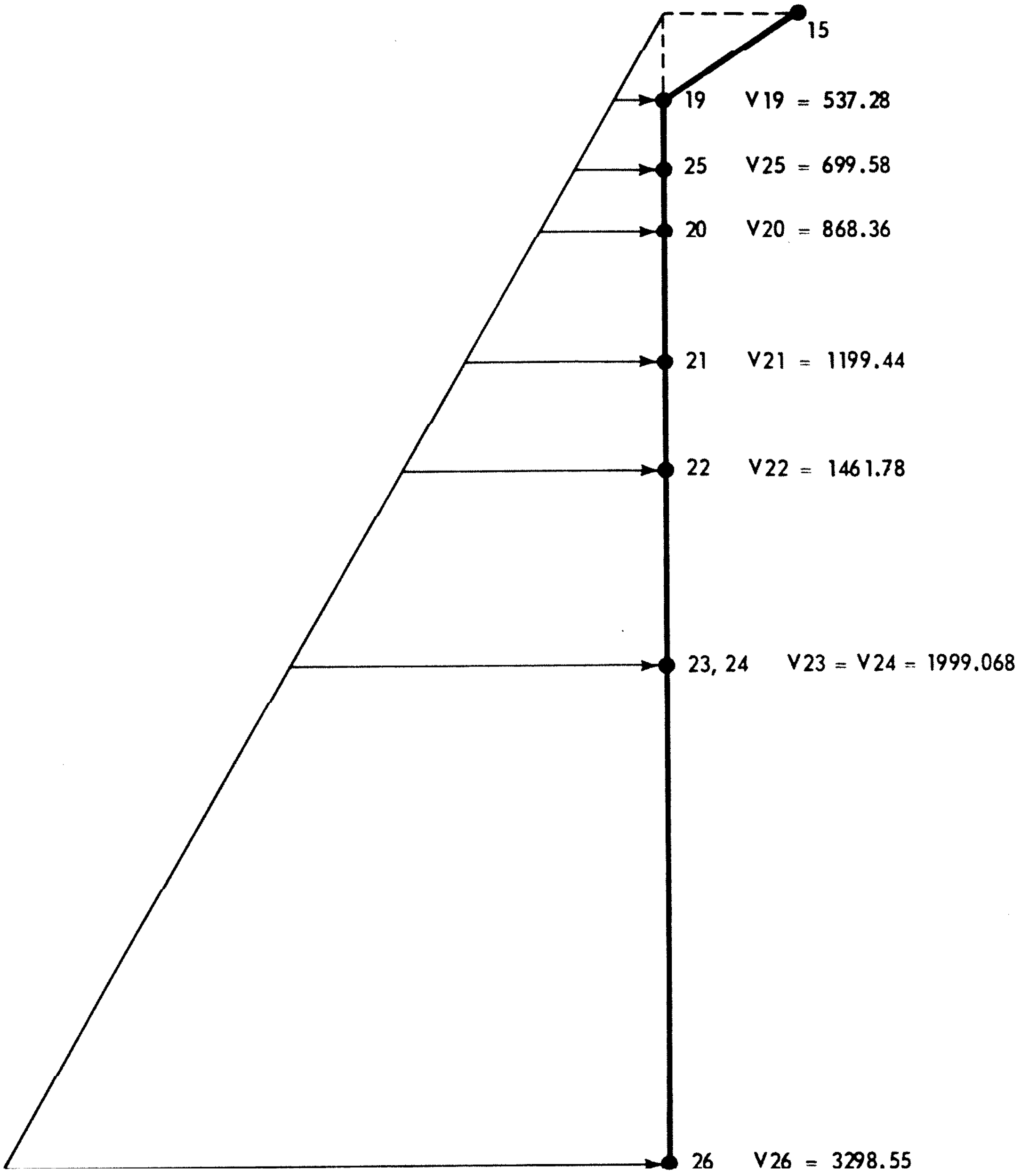
FIGURE 10A-24



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MSIV – PLAST MODEL GRAPHIC

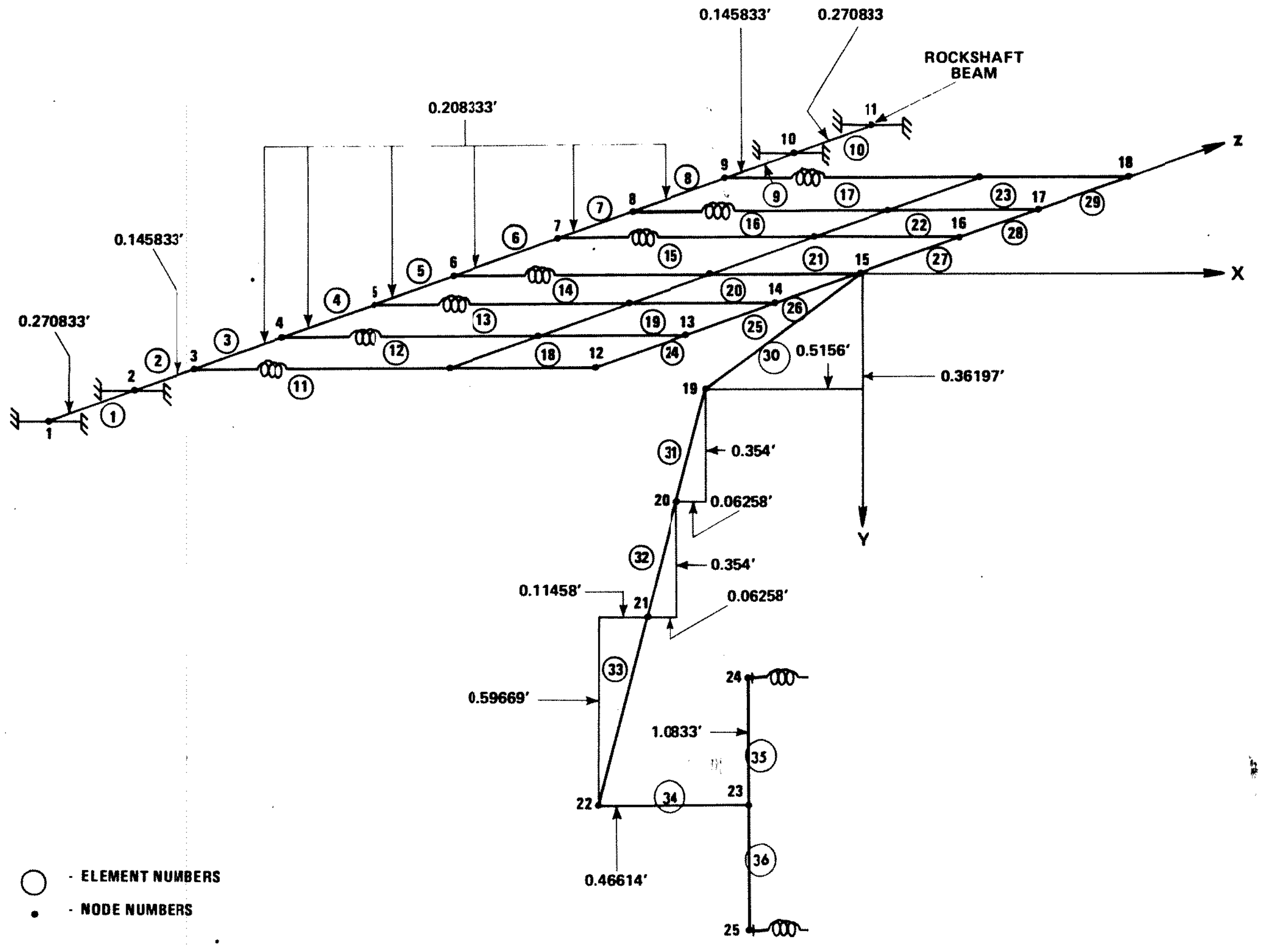
FIGURE 10A-25



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MSIV – VELOCITY PROFILE
(IN-SEC)

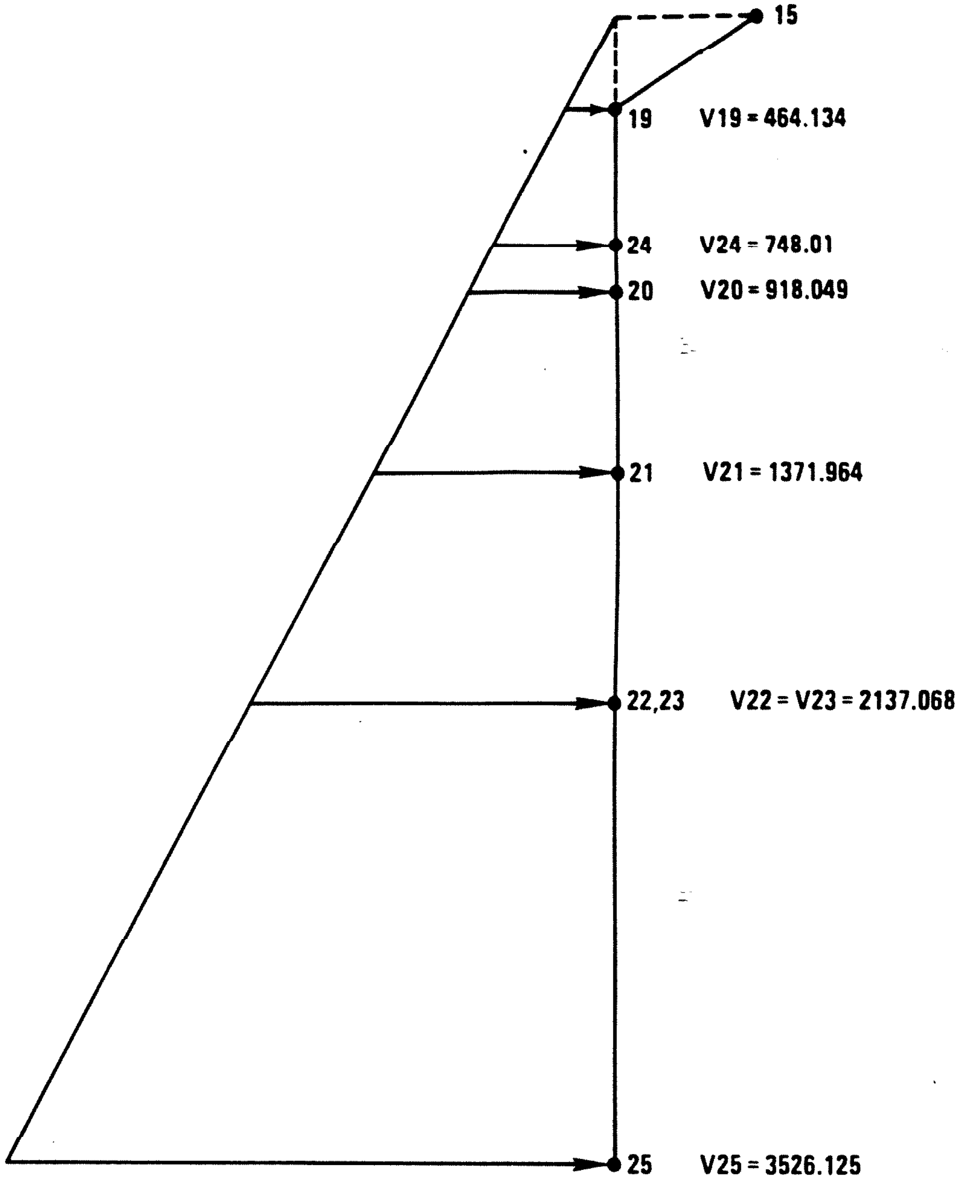
FIGURE 10A-26



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

PLAST MODEL – MSCV RUPTURE CASE – POST IMPACT

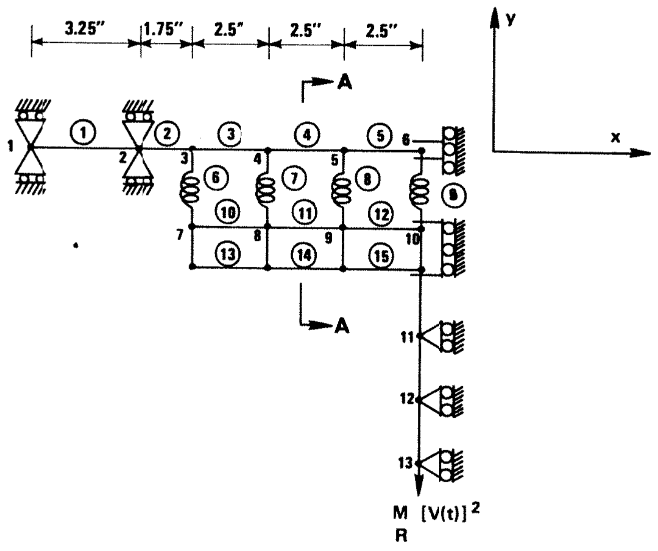
FIGURE 10A-27

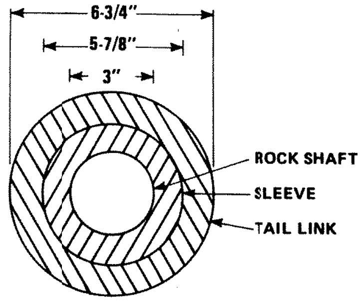


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MSCV – VELOCITY PROFILE
(IN-SEC)

FIGURE 10A-28



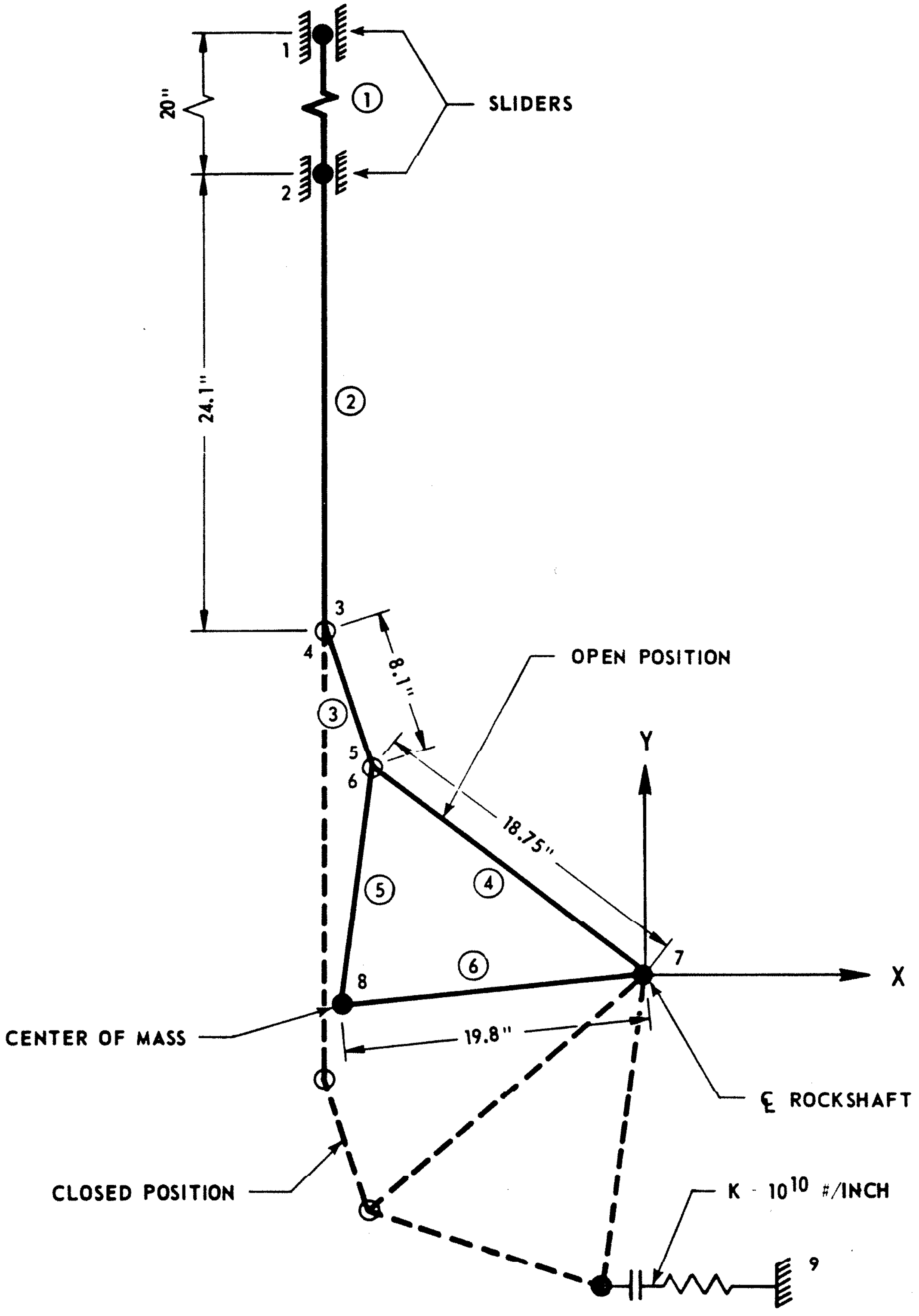


SECTION A-A

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

ROCKSHAFT RUPTURE
CASE – PRE-IMPACT

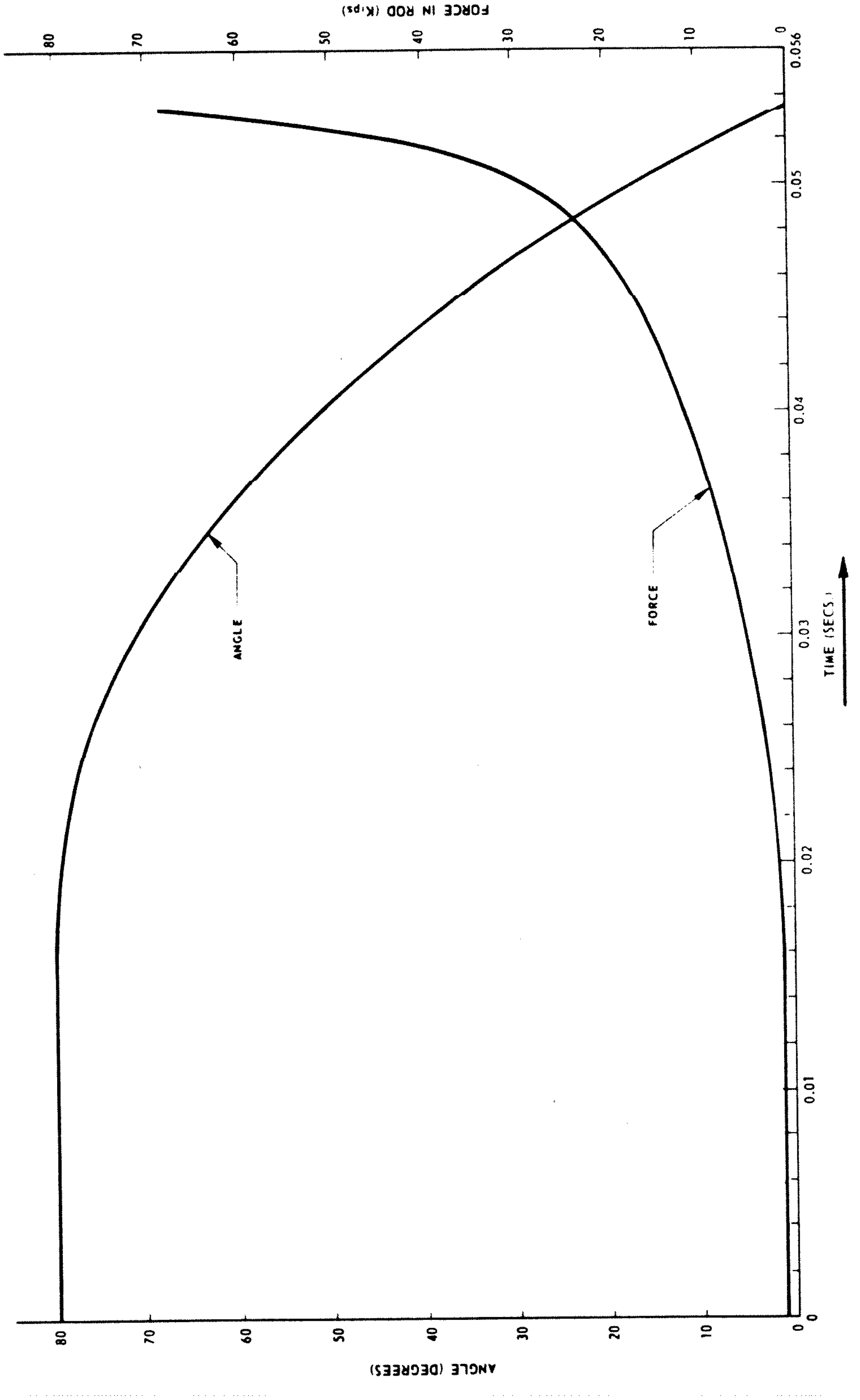
FIGURE 10A-29



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

MSIV - AIR CYLINDER
LINKAGE MODEL

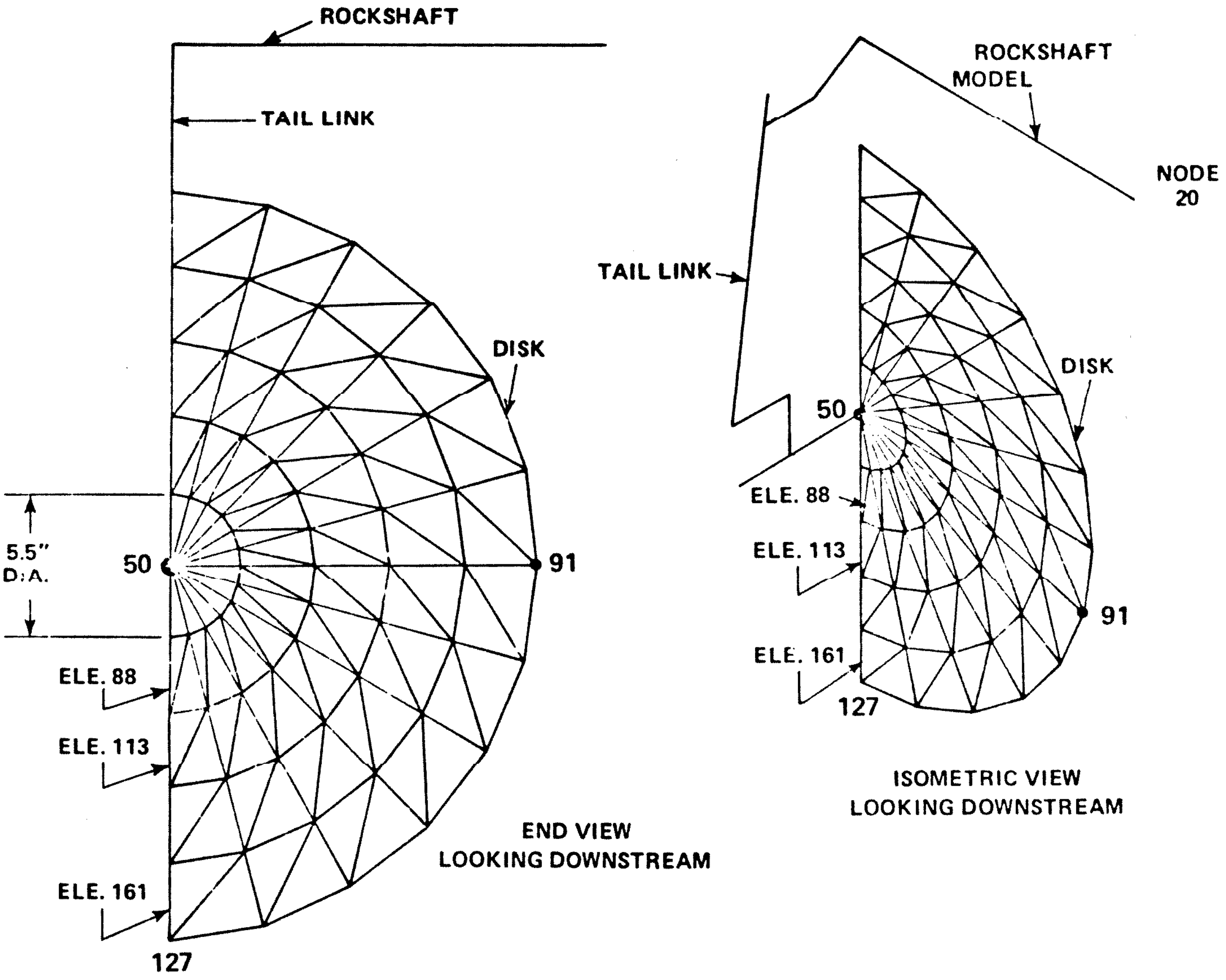
FIGURE 10A-30



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

RUPTURE CASE
MSIV VALVE OPENING ANGLE AND FORCE
ON AIR CYLINDER STEM VERSUS TIME

FIGURE 10A-31



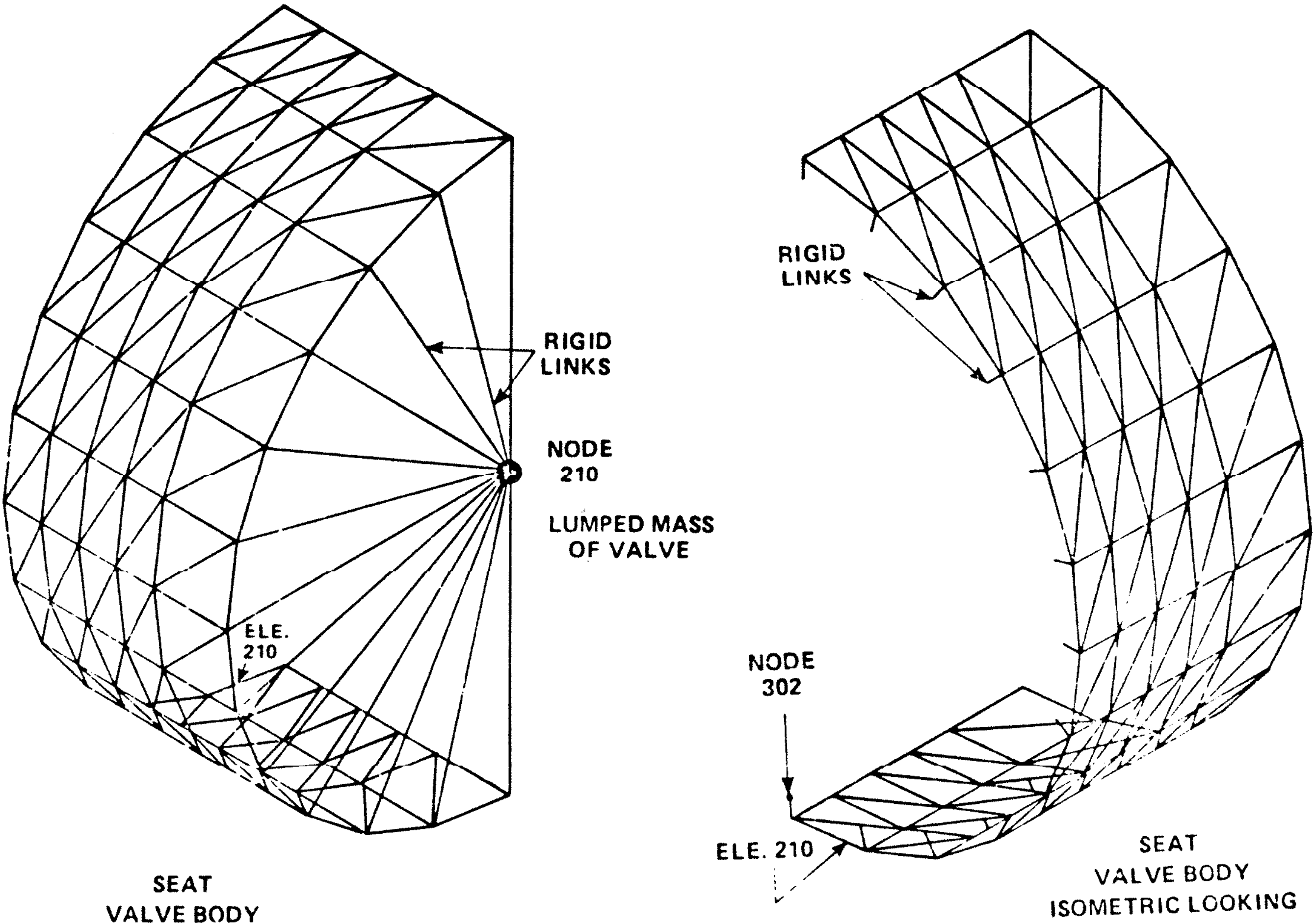
END VIEW
LOOKING DOWNSTREAM

ISOMETRIC VIEW
LOOKING DOWNSTREAM

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 1

VIEWS OF DISK, TAIL LINK AND
ROCKSHAFT 3-D FINITE ELEMENT MODEL

FIGURE 10A-32



SEAT
VALVE BODY
ISOMETRIC LOOKING
UPSTREAM*

SEAT
VALVE BODY
ISOMETRIC LOOKING
DOWNSTREAM*

*DOWNSTREAM
WITH RESPECT TO
THE BLOW DOWN
FLOW.

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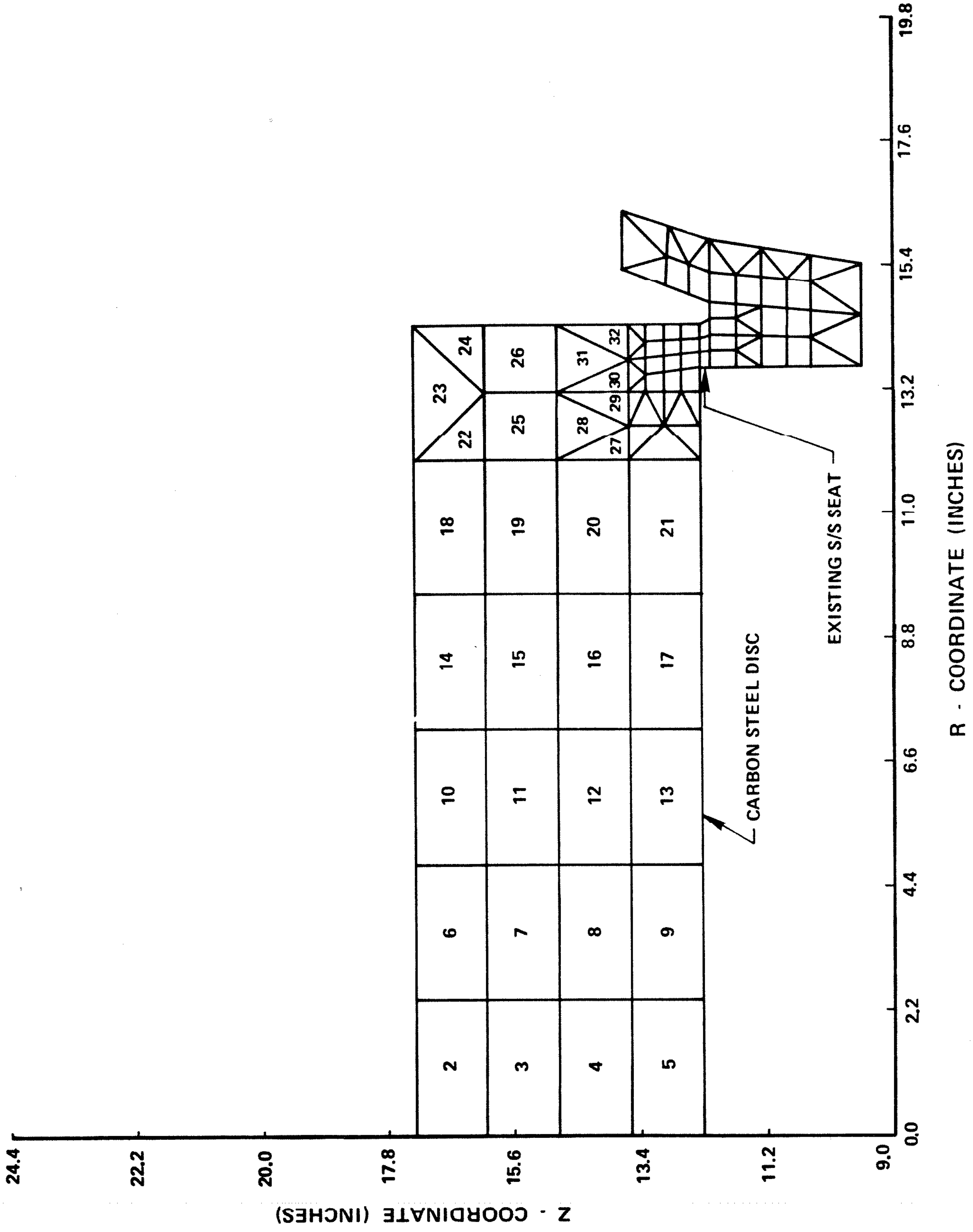
ISOMETRIC VIEWS OF SEAT-VALVE
BODY 3-D FINITE ELEMENT MODEL

FIGURE 10A-33



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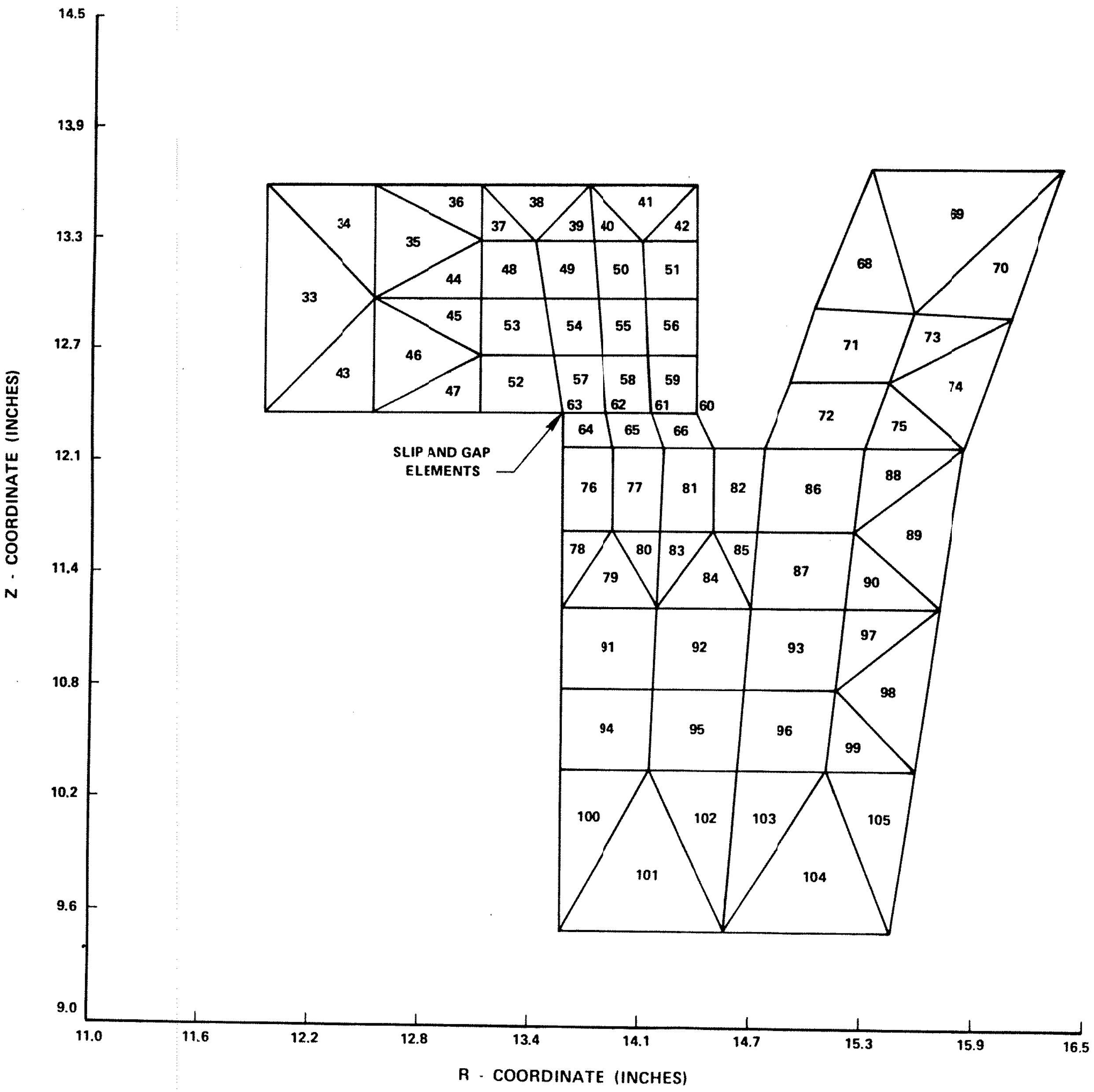
FINITE ELEMENT MESH
OF DISC, SEAT AND VALVE
BODY – ORIGINAL CONFIGURATION

FIGURE 10A-34



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FINITE ELEMENT MESH
OF SEAT AREA
ORIGINAL CONFIGURATION
FIGURE 10A-35