ATTACHMENT 2 TO AEP:NRC:1071E

PROPOSED TECHNICAL SPECIFICATION CHANGES

DESIGN FLOW - 91,600 GPM/LOOP

DESCRIPTION OF SAFETY LIMITS

Pressure (psia)	Power (frac)	Tavg (°F)	Power (frac)	Tavg (°F)	Power (frac)	Tavg (°F)	Power (frac)	Tavg (°F)
1775	0.00	615.4	0.98	538.8	1.02	580.9	1.2	558.1
2000	0.00	631.8	0.86	605.8	0.96	597.5	1.2	568.5
2100	0.00	639.1	0.82	614.0	0.96	601.6	1.2	573.1
2250	0.00	649.2	0.72	628.6	0.98	605.2	1.2	580.4
2400	0.00	659.0	0.62	642.0	1.1	599.0	1.2	588.1

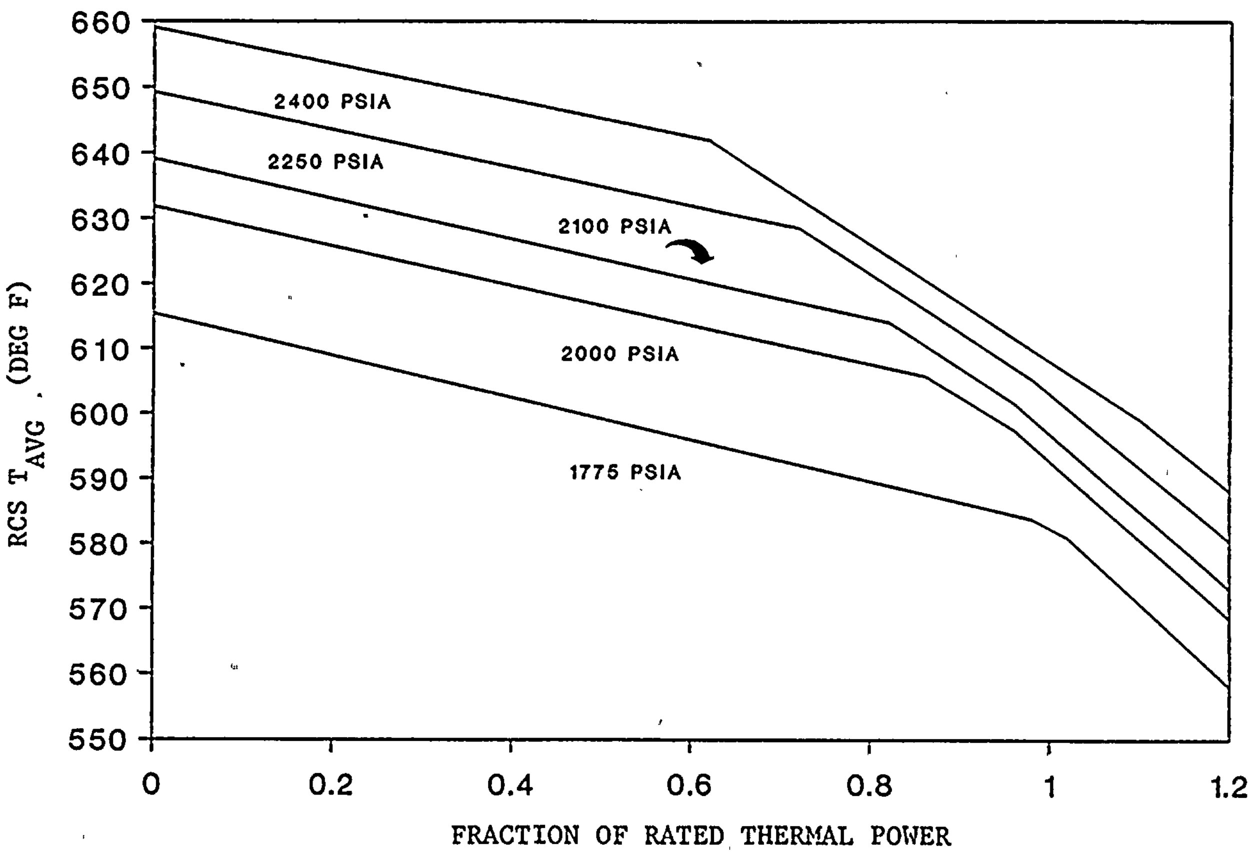

Figure 2.1-1 Reactor Core Safety Limits
Four Loops in Operation

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Power Range, Neutron Flux	Low Setpoint - Less than or equal to 25% of RATED THERMAL POWER High Setpoint - Less than or equal to 109% of RATED THERMAL POWER	Low Setpoint - Less than or equal to 26% of RATED THERMAL POWER High Setpoint - Less than or equal to 110% of RATED THERMAL POWER
3. Power Range, Neutron Flux, High Positive Rate	Less than or equal to 5% of RATED THERMAL POWER with a time constant greater than or equal to 2 seconds	Less than or equal to 5.5% of RATED THERMAL POWER with a time constant greater than or equal to 2 seconds
4. Power Range, Neutron Flux, High Negative Rate	Less than or equal to 5% of RATED THERMAL POWER with a time constant greater than or equal to 2 seconds	Less than or equal to 5.5% of RATED THERMAL POWER with a time constant greater than or equal to 2 seconds
5. Intermediate Range, Neutron Flux	Less than or equal to 25% of RATED THERMAL POWER	Less than or equal to 30% of RATED THERMAL POWER
6. Source Range, Neutron Flux	Less than or equal to 10^5 counts per second	Less than or equal to 1.3 x 10^5 counts per second
7. Overtemperature Delta T	See Note 1	See Note 3
8. Overpower Delta T	See Note 2	See Note 4
9. Pressurizer Pressure -- Low	Greater than or equal to 1950 psig	Greater than or equal to 1940 psig
10. Pressurizer Pressure -- High	Less than or equal to 2385 psig	Less than or equal to 2395 psig
11. Pressurizer Water Level -- High	Less than or equal to 92% of instrument span	Less than or equal to 93% of instrument span
12. Loss of Flow	Greater than or equal to 90% of design flow per loop*	Greater than or equal to 89.1% of design flow per loop*

* Design flow is 91,600 gpm per loop.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
13. Steam Generator Water Level-Low-Low	Greater than or equal to 21% of narrow range instrument span - each steam generator	Greater than or equal to 19.2% of narrow range instrument span - each steam generator
14. Steam/Feedwater Flow Mismatch and Low Steam Generator Water Level	Less than or equal to 1.47 x 10^6 lbs/hr of steam flow at RATED THERMAL POWER coincident with steam generator water level greater than or equal to 25% of narrow range instrument span - each steam generator	Less than or equal to 1.56 x 10^6 lbs/hr of steam flow at RATED THERMAL POWER coincident with steam generator water level greater than or equal to 24% of narrow range instrument span - each steam generator
15. Undervoltage - Reactor Coolant Pumps	Greater than or equal to 2905 volts - each bus	Greater than or equal to 2870 volts - each bus
16. Underfrequency - Reactor Coolant Pumps	Greater than or equal to 57.5 Hz - each bus	Greater than or equal to 57.4 Hz - each bus
17. Turbine Trip		
A. Low Trip System Pressure	Greater than or equal to 58 psig	Greater than or equal to 57 psig
B. Turbine Stop Valve Closure	Greater than or equal to 1% open	Greater than or equal to 1% open
18. Safety Injection Input from ESF	Not Applicable	Not Applicable
19. Reactor Coolant Pump Breaker Position Trip	Not Applicable	Not Applicable

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION

Note 1:

Overtemperature $\Delta T \leq \Delta T_o$ $[K_1 - K_2[(1 + \tau_1 S)/(1 + \tau_2 S)](T - T') + K_3(P - P') - f_1(\Delta I)]$

Where:	ΔT_o	- Indicated ΔT at RATED THERMAL POWER
	T	- Average temperature, ^oF
	T'	- Indicated T_{avg} at RATED THERMAL POWER less than or equal to 576.0 ^oF
	P	- Pressurizer Pressure, psig
	P'	- 2235 psig (indicated RCS nominal operating pressure)
	$\frac{1 + \tau_1 S}{1 + \tau_2 S}$	- The function generated by the lead-lag controller for T_{avg} dynamic compensation
	τ_1, τ_2	- Time constants utilized in the lead-lag controller for T_{avg}; τ_1 = 28 secs, τ_2 = 4 secs.
	S	- Laplace transform operator

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION (Continued)

4 Loops in Operation

K1 = 1.09

K2 = 0.01331

K3 = 0.00058

and $f_1(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) for $q_t - q_b$ between -33 percent and +6 percent, $f_1(\Delta I)=0$ (where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER).

(ii) for each percent that the magnitude of $(q_t - q_b)$ exceeds -33 percent, the ΔT trip setpoint shall be automatically reduced by 3.5 percent of its value at RATED THERMAL POWER.

(iii) For each percent that the magnitude of $(q_t - q_b)$ exceeds +6 percent, the ΔT trip setpoint shall be automatically reduced by 1.0 percent of its value at RATED THERMAL POWER.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATIONS (Continued)

Note 2: Overpower $\Delta T \leq \Delta T_o\ [K_4 - K_5[\tau_3 S/(1+\tau_3 S)]T - K_6[T-T''] - f_2(\Delta I)]$

Where:

ΔT_o	- Indicated ΔT at rated power
T	- Average temperature, ^oF
T''	- Indicated T_{avg} at RATED THERMAL POWER less than or equal to 576.0 ^oF
K_4	- 1.08
K_5	- 0.02/^oF for increasing average temperature and 0 for decreasing average temperature
K_6	- 0.00197 for T greater than T"; K_6 - 0 for T less than or equal to T"
$\tau_3 S/(1+\tau_3 S)$	- The function generated by the rate lag controller for T_{avg} dynamic compensation
τ_3	- Time constant utilized in the rate lag controller for T_{avg}; τ_3 - 10 secs.
S	- Laplace transform operator
$f_2(\Delta I)$	- 0.0

Note 3: The channel's maximum trip point shall not exceed its computed trip point by more than 1.3 percent ΔT span.

Note 4: The channel's maximum trip point shall not exceed its computed trip point by more than 3.0 percent ΔT span.

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 BORATION CONTROL

SHUTDOWN MARGIN - T_{AVG} GREATER THAN 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.1 The SHUTDOWN MARGIN shall be greater than or equal to 1.6% Delta k/k.

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

ACTION:

With the SHUTDOWN MARGIN less than 1.6% Delta k/k, immediately initiate and continue boration at greater than or equal to 10 gpm of a solution containing greater than or equal to 20,000 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.1.1 The SHUTDOWN MARGIN shall be determined to be greater than or equal to 1.6% Delta k/k:

a. Within one hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the above required SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s).

b. When in MODE 1 or MODE 2 with K_{eff} greater than or equal to 1.0, at least once per 12 hours by verifying that control bank withdrawal is within the limits of Specification 3.1.3.6.

c. When in MODE 2 with K_{eff} less than 1.0, within 4 hours prior to achieving reactor criticality by verifying that the predicted critical control rod position is within the limits of Specification 3.1.3.6.

d. Prior to initial operation above 5% RATED THERMAL POWER after each fuel loading, by consideration of the factors of e below, with the control banks at the maximum insertion limit of Specification 3.1.3.6.

*See Special Test Exception 3.10.1

SURVEILLANCE REQUIREMENTS (Continued)

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

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

4.1.1.1.2 The overall core reactivity balance shall be compared to predicted values to demonstrate agreement within plus or minus 1% Delta k/k at least once per 31 Effective Full Power Days (EFPD). This comparison shall consider at least those factors stated in Specification 4.1.1.1.1.e, above. The predicted reactivity values shall be adjusted (normalized) to correspond to the actual core conditions prior to exceeding a fuel burnup of 60 Effective Full Power Days after each fuel loading.

REACTIVITY CONTROL SYSTEMS

SHUTDOWN MARGIN - T_{AVG} LESS THAN OR EQUAL TO 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.2 The SHUTDOWN MARGIN shall be greater than or equal to 1.0% Delta k/k.

APPLICABILITY: MODE 5.

ACTION:

With the SHUTDOWN MARGIN less than 1.0% Delta k/k, immediately initiate and continue boration at greater than or equal to 10 gpm of a solution containing greater than or equal to 20,000 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN shall be determined to be greater than or equal to 1.0% Delta k/k:

a. Within one hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s).

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

   1. Reactor coolant system boron concentration,

   2. Control rod position,

   3. Reactor coolant system average temperature,

   4. Fuel burnup based on gross thermal energy generation,

   5. Xenon concentration, and

   6. Samarium concentration.

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BORATED WATER SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.8 Each of the following borated water sources shall be OPERABLE:

a. A boric acid storage system and associated heat tracing with:

1. A minimum contained borated water volume of 7715 gallons,

2. Between 20,000 and 22,500 ppm of boron, and

3. A minimum solution temperature of 145°F.

b. The refueling water storage tank with:

1. A minimum contained borated water volume of 350,000 gallons of water,

2. Between 2400 and 2600 ppm of boron, and

3. A minimum solution temperature of 80°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With the boric acid storage system inoperable, restore the storage system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and borated to a SHUTDOWN MARGIN equivalent to at least 1% Delta k/k at 200°F; restore the boric acid storage system to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

b. With the refueling water storage tank inoperable, restore the tank to OPERABLE status within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.8 Each borated water source shall be demonstrated OPERABLE:

ROD DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual full length (shutdown and control) rod drop time from the fully withdrawn position (228 steps) shall be less than or equal to 2.7 seconds from beginning of decay of stationary gripper coil voltage to dashpot entry with:

a. T_{avg} greater than or equal to 541°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 AND 2

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.1.3.4 The rod drop time of full length rods shall be demonstrated through measurement prior to entering MODE 2:

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

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

c. At least once per 18 months.

ACTION: (Continued)

b. THERMAL POWER shall not be increased above 90% or 0.9 x APL (whichever is less) of RATED THERMAL POWER unless the indicated AFD is within the target band and ACTION 2.a) 1), above has been satisfied.

c. THERMAL POWER shall not be increased above 50% of RATED THERMAL POWER unless the indicated AFD has not been outside of the target band for more than 1 hour penalty deviation cumulative during the previous 24 hours.

SURVEILLANCE REQUIREMENTS

4.2.1.1 The indicated AXIAL FLUX DIFFERENCE shall be determined to be within its limits during POWER OPERATION above 15% of RATED THERMAL POWER by:

a. Monitoring the indicated AFD for each OPERABLE excore channel:

1. At least once per 7 days when the AFD Monitor Alarm is OPERABLE, and

2. At least once per hour for the first 24 hours after restoring the AFD Monitor Alarm to OPERABLE status if the AFD has been outside of the target band for any period of time in the previous 24 hours of operation.

b. Monitoring and logging the indicated AXIAL FLUX DIFFERENCE for each OPERABLE excore channel at least once per hour for the first 24 hours and at least once per 30 minutes thereafter, when the AXIAL FLUX DIFFERENCE Monitor Alarm is inoperable. The logged values of the indicated AXIAL FLUX DIFFERENCE shall be assumed to exist during the interval preceding each logging.

POWER DISTRIBUTION LIMITS

DNB AND Tavg OPERATING PARAMETERS

LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB related parameters shall be maintained within the following operational indicated limits:

a. DNB

1. Reactor Coolant System T_{avg}	Less than or equal to 578.7°F*
2. Pressurizer Pressure	Greater than or equal to 2200 psig*/**
3. Reactor Coolant System Total Flow Rate	Greater than or equal to 366,400 gpm***

b. T_{avg}

1. Reactor Coolant System T_{avg}	Greater than or equal to 543.9°F*

APPLICABILITY: MODE 1

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.2.5.1 Each of the above parameters shall be verified to be within their limits at least once per 12 hours.

4.2.5.2 The indicators used to determine RCS total flow shall be subjected to a CHANNEL CALIBRATION at least once per 18 months.

4.2.5.3 The RCS total flow rate shall be determined by a power balance around the steam generators at least once per 18 months.

4.2.5.4 The provisions of Specification 4.0.4 shall not apply to primary flow surveillances.

---

* Indicated average of at least three OPERABLE instrument loops.

** Limit not applicable during either a THERMAL POWER ramp in excess of 5% of RATED THERMAL POWER per minute or a THERMAL POWER step in excess of 10% of RTP

*** Indicated value

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ALLOWABLE POWER LEVEL - APL

LIMITING CONDITION FOR OPERATION

3.2.6 THERMAL POWER shall be less than or equal to ALLOWABLE POWER LEVEL (APL), given by the following relationships:

Westinghouse Fuel

$$APL = \text{min over Z of } \frac{1.97\ K(Z)}{F_Q(Z) \times V(Z) \times F_p} \times 100\%, \text{ or } 100\%, \text{ whichever is less.}$$

Exxon Nuclear Fuel

$$APL = \text{min over Z of } \frac{2.10\ K(Z)}{F_Q(Z) \times V(Z) \times F_p} \times 100\%, \text{ or } 100\%, \text{ whichever is less.}$$

- $F_Q(Z)$ is the measured hot channel factor, including a 3% manufacturing tolerance uncertainty and a 5% measurement uncertainty.

- V(Z) is the function defined in Figure 3.2-3 which corresponds to the target band.

- $F_p = 1.00$ except when successive steady-state power distribution maps indicate an increase in max over Z of $\frac{F_Q(Z)}{K(Z)}$ with exposure.

  Then either of the following penalties, F_p, shall be taken:

  $F_p = 1.02$ or,

  $F_p = 1.00$ provided that Surveillance Requirement 4.2.6.2 is satisfied once per 7 Effective Full Power Days until 2 successive maps indicate that the max over Z of $\frac{F_Q(Z)}{K(Z)}$ is not increasing.

- The above limit is not applicable in the following core regions.

  1) Lower core region 0% to 10% inclusive.
  2) Upper core region 90% to 100% inclusive.

APPLICABILITY: MODE 1

TABLE 3.3-2

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
1. Manual Reactor Trip	NOT APPLICABLE
2. Power Range, Neutron Flux	Less than or equal to 0.5 seconds*
3. Power Range, Neutron Flux, High Positive Rate	NOT APPLICABLE
4. Power Range, Neutron Flux High Negative Rate	Less than or equal to 0.5 seconds*
5. Intermediate Range, Neutron Flux	NOT APPLICABLE
6. Source Range, Neutron Flux	NOT APPLICABLE
7. Overtemperature Delta T	Less than or equal to 6.0 seconds*
8. Overpower Delta T	NOT APPLICABLE
9. Pressurizer Pressure--Low	Less than or equal to 2.0 seconds
10. Pressurizer Pressure--High	Less than or equal to 2.0 seconds
11. Pressurizer Water Level--High	Less than or equal to 2.0 seconds

*Neutron detectors are exempt from response time testing. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input of first electronic component in channel.

TABLE 3.3-2 (Continued)
REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
12. Loss of Flow - Single Loop (Above P-8)	Less than or equal to 1.0 seconds
13. Loss of Flow - Two Loops (Above P-7 and below P-8)	Less than or equal to 1.0 seconds
14. Steam Generator Water Level--Low-Low	Less than or equal to 2.0 seconds
15. Steam/Feedwater Flow Mismatch and Low Steam Generator Water Level	NOT APPLICABLE
16. Undervoltage-Reactor Coolant Pumps	Less than or equal to 1.5 seconds
17. Underfrequency-Reactor Coolant Pumps	Less than or equal to 0.6 seconds
18. Turbine Trip	
A. Low Fluid Oil Pressure	NOT APPLICABLE
B. Turbine Stop Valve	NOT APPLICABLE
19. Safety Injection Input from ESF	NOT APPLICABLE
20. Reactor Coolant Pump Breaker Position Trip	NOT APPLICABLE

TABLE 3.3-3 (Continued)
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
Three Loops Operating	1 T_{avg}/operating loop	1### T_{avg} in any operating loop	1 T_{avg} in any two operating loops	3##	15
e. Steam Line Pressure-Low					
Four Loops Operating	1 pressure/loop	2 pressures any loops	1 pressure any 3 loops	1,2,3##	14*
Three Loops Operating	1 pressure/operating loop	1### pressure in any operating loop	1 pressure in any 2 operating loops	3##	15
5. TURBINE TRIP & FEEDWATER ISOLATION					
a. Steam Generator Water Level--High-High	3/loop	2/loop in any operating loop	2/loop in each operating loop	1,2 and 3	14*

TABLE 3.3-3 (Continued)
TABLE NOTATION

#Trip function may be bypassed in this MODE below P-11.

##Trip function may be bypassed in this MODE below P-12.

###The channel(s) associated with the protective functions derived from the out of service Reactor Coolant Loop shall be placed in the tripped mode.

####Manually trip all bistables which would be automatically tripped in the event pressure in the associated active loop were less than the pressure in the inactive loop. For example, if loop 1 is the inactive loop then the bistables which indicate low pressure in loops 2, 3, and 4 relative to loop 1 should be tripped.

*The provisions of Specification 3.0.4 are not applicable.

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINTS	ALLOWABLE VALUES
2. CONTAINMENT SPRAY		
a. Manual Initiation	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High-High	Less than or equal to 2.9 psig	Less than or equal to 3.0 psig
3. CONTAINMENT ISOLATION		
a. Phase "A" Isolation		
1. Manual	Not Applicable	Not Applicable
2. From Safety Injection Automatic Actuation Logic	Not Applicable	Not Applicable
b. Phase "B" Isolation		
1. Manual	Not Applicable	Not Applicable
2. Automatic Actuation Logic	Not Applicable	Not Applicable
3. Containment Pressure-High-High	Less than or equal to 2.9 psig	Less than or equal to 3.0 psig
c. Purge and Exhaust Isolation		
1. Manual	Not Applicable	Not Applicable
2. Containment Radio-activity--High Train A (VRS-2101, ERS-2301, ERS-2305)	See Table 3.3-6	Not Applicable
3. Containment Radio-activity--High Train B (VRS-2201, ERS-2401, ERS-2405)	See Table 3.3-6	Not Applicable

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINTS	ALLOWABLE VALUES
4. STEAM LINE ISOLATION		
a. Manual	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High-High	Less than or equal to 2.9 psig	Less than or equal to 3.0 psig
d. Steam Flow in Two Steam Lines--High Coincident with T_{avg}--Low-Low	Less than or equal to a function defined as follows: A Delta-p corresponding to 1.6×10^6 lbs/hr steam flow between 0% and 20% load and then a Delta-p increasing linearly to a Delta-p corresponding to 4.5×10^6 lbs/hr at full load.	Less than or equal to a function defined as follows: A Delta-p corresponding to 1.75×10^6 lbs/hr steam flow between 0% and 20% load and then a Delta-p increasing linearly to a Delta-p corresponding to 4.55×10^6 lbs/hr at at full load.
	T_{avg} greater than or equal to 541°F	T_{avg} greater than or equal to 539°F
e. Steam Line Pressure--Low	Greater than or equal to 600 psig steam line pressure	Greater than or equal to 585 psig steam line pressure
5. TURBINE TRIP AND FEEDWATER ISOLATION		
a. Steam Generator Water Level--High-High	Less than or equal to 67% of narrow range instrument span each steam generator	Less than or equal to 68% of narrow range instrument span each steam generator

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
6. MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS		
a. Steam Generator Water Level--Low-Low	Greater than or equal to 21% of narrow range instrument span each steam generator	Greater than or equal to 19.2% of narrow range instrument span each steam generator
b. 4 kV Bus Loss of Voltage	3196 volts with a 2 second delay	3196, +18, -36 volts with a 2 +/- 0.2 second delay
c. Safety Injection	Not Applicable	Not Applicable
d. Loss of Main Feedwater Pumps	Not Applicable	Not Applicable
7. TURBINE DRIVEN AUXILIATY FEEDWATER PUMPS		
a. Steam Generator Water Level--Low-Low	Greater than or equal to 21% of narrow range instrument span each steam generator	Greater than or equal to 19.2% of narrow range instrument span each steam generator
b. Reactor Coolant Pump Bus Undervoltage	Greater than or equal to 2750 Volts--each bus	Greater than or equal 2725 Volts--each bus
8. LOSS OF POWER		
a. 4 kV Bus Loss of Voltage	3196 volts with a 2 second delay	3196, +18, -36 volts with a 2 +/- 0.2 second delay
b. 4 kV Bus Degraded Voltage	3596 volts with a 2.0 minute time delay	3596,+36,-18 volts a 2.0 minute +/- 6 second time delay

TABLE 3.3-5

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION		RESPONSE TIME IN SECONDS
1. Manual		
a.	Safety Injection (ECCS)	Not Applicable
	Feedwater Isolation	Not Applicable
	Reactor Trip (SI)	Not Applicable
	Containment Isolation-Phase "A"	Not Applicable
	Containment Purge and Exhaust Isolation	Not Applicable
	Auxiliary Feedwater Pumps	Not Applicable
	Essential Service Water System	Not Applicable
	Containment Air Recirculation Fan	Not Applicable
b.	Containment Spray	Not Applicable
	Containment Isolation-Phase "B"	Not Applicable
	Containment Purge and Exhaust Isolation	Not Applicable
c.	Containment Isolation-Phase "A"	Not Applicable
	Containment Purge and Exhaust Isolation	Not Applicable
d.	Steam Line Isolation	Not Applicable
2. Containment Pressure-High		
a.	Safety Injection (ECCS)	Less than or equal to 27.0*
b.	Reactor Trip (from SI)	Less than or equal to 3.0
c.	Feedwater Isolation	Less than or equal to 8.0
d.	Containment Isolation-Phase "A"	Not Applicable
e.	Containment Purge and Exhaust Isolation	Not Applicable
f.	Auxiliary Feedwater Pumps	Not Applicable
g.	Essential Service Water System	Not Applicable

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
6. Steam Line Pressure--Low	
a. Safety Injection (ECCS)	Less than or equal to 12.0#/24.0##
b. Reactor Trip (from SI)	Less than or equal to 2.0
c. Feedwater Isolation	Less than or equal to 8.0
d. Containment Isolation-Phase "A"	Less than or equal to 18.0#/28.0##
e. Containment Purge and Exhaust Isolation	Not Applicable
f. Motor Driven Auxiliary Feedwater Pumps	Less than or equal to 60.0
g. Essential Service Water System	Less than or equal to 14.0#/48.0##
h. Steam Line Isolation	Less than or equal to 8.0
7. Containment Pressure--High-High	
a. Containment Spray	Less than or equal to 45.0
b. Containment Isolation-Phase "B"	Not Applicable
c. Steam Line Isolation	Less than or equal to 7.0
d. Containment Air Recirculation Fan	Less than or equal to 600.0
8. Steam Generator Water Level--High-High	
a. Turbine Trip	Less than or equal to 2.5
b. Feedwater Isolation	Less than or equal to 11.0
9. Steam Generator Water Level--Low-Low	
a. Motor Driven Auxiliary Feedwater Pumps	Less than or equal to 60.0
b. Turbine Driven Auxiliary Feedwater Pump	Less than or equal to 60.0
10. 4160 volt Emergency Bus Loss of Voltage	
a. Motor Driven Auxiliary Feedwater Pumps	Less than or equal to 60.0
11. Loss of Main Feedwater Pumps	
a. Motor Driven Auxiliary Feedwater Pumps	Less than or equal to 60.0
12. Reactor Coolant Pump Bus Undervoltage	
a. Turbine Driven Auxiliary Feedwater Pump	Less than or equal to 60.0

TABLE 4.3-2 (Continued)
ENGINEERED SAFETY FEATURED ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
1. SAFETY INJECTION, TURBINE TRIP, FEEDWATER ISOLATION, AND MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS				
a. Manual Initiation	N.A.	N.A.	M(1)	1,2,3,4
b. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
c. Containment Pressure-High	S	R	M(3)	1,2,3
d. Pressurizer Pressure-Low	S	R	M	1,2,3
e. Differential Pressure Between Steam Lines--High	S	R	M	1,2,3
f. Steam Line Pressure--Low	S	R	M	1,2,3
2. CONTAINMENT SPRAY				
a. Manual Initiation	N.A.	N.A.	M(1)	1,2,3,4
b. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
c. Containment Pressure-High-High	S	R	M(3)	1,2,3
3. CONTAINMENT ISOLATION				
a. Phase "A" Isolation				
1) Manual	N.A.	N.A.	M(1)	1,2,3,4
2) From Safety Injection Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
b. Phase "B" Isolation				
1) Manual	N.A.	N.A.	M(1)	1,2,3,4
2) Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3,4
3) Containment Pressure-High-High	S	R	M(3)	1,2,3

TABLE 4.3-2 (Continued)
ENGINEERED SAFETY FEATURED ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
c. Purge and Exhaust Isolation				
1) Manual	N.A.	N.A.	M(1)	1,2,3,4
2) Containment Radio activity-High	S	R	M	1,2,3,4
4. STEAM LINE ISOLATION				
a. Manual	N.A.	N.A.	M(1)	1,2,3
b. Automatic Actuation Logic	N.A.	N.A.	M(2)	1,2,3
c. Containment Press-ure--High-High	S	R	M(3)	1,2,3
d. Steam Flow in Two Steam Lines--High Coincident with Tavg--Low-Low	S	R	M	1,2,3
e. Steam Line Pressure--Low	S	R	M	1,2,3
5. TURBINE TRIP AND FEEDWATER ISOLATION				
a. Steam Generator Water Level--High-High	S	R	M	1,2,3
6. MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS				
a. Steam Generator Water Level--Low-Low	S	R	M	1,2,3
b. 4 kV Bus Loss of Voltage	S	R	M	1,2,3
c. Safety Injection	N.A.	N.A.	M(2)	1,2,3
d. Loss of Main Feed Pumps	N.A.	N.A.	R+	1,2

+The provisions of Specification 4.0.7 are applicable.

TABLE 4.3-2 (Continued)
ENGINEERED SAFETY FEATURED ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES IN WHICH SURVEILLANCE REQUIRED
7. TURBINE DRIVEN AUXILIARY FEEDWATER PUMP				
a. Steam Generator Water Level--Low-low	S	R	M	1,2,3
b. Reactor Coolant Pump Bus Undervoltage	N.A.	R	M	1,2,3
8. LOSS OF POWER				
a. 4 kv Bus Loss of Voltage	S	R	M	1,2,3,4
b. 4 kv Bus Degraded Voltage	S	R	M	1,2,3,4

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TABLE 4.3-2 (Continued)

TABLE NOTATION

(1) Manual actuation switches shall be tested at least once per 18 months during shutdown. All other circuitry associated with manual safeguards actuation shall receive a CHANNEL FUNCTIONAL TEST at least once per 31 days.

(2) Each train or logic channel shall be tested at least every other 31 days.

(3) The CHANNEL FUNCTIONAL TEST shall include exercising the transmitter by applying either a vacuum or pressure to the appropriate side of the transmitter.

TABLE 3.3-4

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINTS	ALLOWABLE VALUES
1. SAFETY INJECTION, TURBINE TRIP, FEEDWATER ISOLATION, AND MOTOR DRIVEN AUXILIARY FEEDWATER PUMPS		
a. Manual Initiation	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Containment Pressure--High	Less than or equal to 1.1 psig	Less than or equal to 1.2 psig
d. Pressurizer Pressure--Low	Greater than or equal to 1900 psig	Greater than or equal to 1890 psig
e. Differential Pressure Between Steam Lines--High	Less than or equal to 100 psi	Less than or equal to 112 psi
f. Steam Line Pressure--Low	Greater than or equal to 600 psig steam line pressure	Greater than or equal to 585 psig steam line pressure

REACTOR COOLANT SYSTEM

PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.4 The pressurizer shall be OPERABLE with a water volume less than or equal to 92% of span and at least 150 kW of pressurizer heaters.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

With the pressurizer inoperable due to an inoperable emergency power supply to the pressurizer heaters, either restore the inoperable emergency power supply within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 12 hours. With the pressurizer otherwise inoperable, be in at least HOT SHUTDOWN with the reactor trip breakers open within 12 hours.

SURVEILLANCE REQUIREMENTS

4.4.4.1 The pressurizer water volume shall be determined to be within its limit at least once per 12 hours.

4.4.4.2 The emergency power supply for the pressurizer heaters shall be demonstrated OPERABLE at least once per 18 months by transferring power from the normal to the emergency power supply and energizing the required capacity of heaters.

3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

ACCUMULATORS

LIMITING CONDITION FOR OPERATION

3.5.1 Each reactor coolant system accumulator shall be OPERABLE with:

a. The isolation valve open,

b. A contained borated water volume of between 921 and 971 cubic feet,

c. A boron concentration between 2400 ppm and 2600 ppm, and

d. A nitrogen cover-pressure of between 585 and 658 psig.

APPLICABILITY: MODES 1, 2, and 3.*

ACTION:

a. With one accumulator inoperable, except as a result of a closed isolation valve, restore the inoperable accumulator to OPERABLE status within one hour or be in HOT SHUTDOWN within the next 12 hours.

b. With one accumulator inoperable due to the isolation valve being closed, either immediately open the isolation valve or be in HOT STANDBY within one hour and be in HOT SHUTDOWN within the next 12 hours.

SURVEILLANCE REQUIREMENTS

4.5.1 Each accumulator shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1. Verifying the contained borated water volume and nitrogen cover-pressure in the tanks, and

2. Verifying that each accumulator isolation valve is open.

*Pressurizer Pressure above 1000 psig.

SURVEILLANCE REQUIREMENTS (Continued)

d. At least once per 18 months by:

1. Verifying automatic isolation and interlock action of the RHR system from the Reactor Coolant System when the Reactor Coolant System pressure is above 600 psig.*

2. A visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or corrosion.

e. At least once per 18 months, during shutdown, by:*

1. Verifying that each automatic valve in the flow path actuates to its correct position on a Safety Injection test signal.

2. Verifying that each of the following pumps start automatically upon receipt of a safety injection test signal:

a) Centrifugal charging pump

b) Safety injection pump

c) Residual heat removal pump

f. By verifying that each of the following pumps develops the indicated discharge pressure on recirculation flow when tested pursuant to Specification 4.0.5:

1.	Centrifugal charging pump	Greater than or equal to 2405 psig
2.	Safety Injection pump	Greater than or equal to 1409 psig
3.	Residual heat removal pump	Greater than or equal to 190 psig

g. By verifying the correct position of each mechanical stop for the following Emergency Core Cooling System throttle valves:

1. Within 4 hours following completion of each valve stroking operation or maintenance on the valve when the ECCS subsystems are required to be OPERABLE.

*The provisions of Specification 4.0.7 are applicable.

2. At least once per 18 months.

Boron Injection Throttle Valves	Safety Injection Throttle Valves
Valve Number	Valve Number
1. 2-SI-141 L1	1. 2-SI-121 N
2. 2-SI-141 L2	2. 2-SI-121 S
3. 2-SI-141 L3	
4. 2-SI-141 L4	

h. By performing a flow balance test during shutdown following completion of modifications to the ECCS subsystem that alter the subsystem flow characteristics and verifying the following flow rates:

Boron Injection System Single Pump*	Safety Injection System Single Pump**
Loop 1 Boron Injection Flow 117.5 gpm	Loop 1 and 4 Cold Leg Flow greater than or equal to 300 gpm
Loop 2 Boron Injection Flow 117.5 gpm	Loop 2 and 3 Cold Leg Flow greater than or equal to 300 gpm
Loop 3 Boron Injection Flow 117.5 gpm	**Combined Loop 1,2,3 and 4 Cold Leg Flow (single pump) less than or equal to 640 gpm. Total SIS (single pump) flow, including miniflow, shall not exceed 700 gpm.
Loop 4 Boron Injection Flow 117.5 gpm	

*The flow rate in each boron injection (BI) line should be adjusted to provide 117.5 gpm (nominal) flow into each loop. Under these conditions there is zero mini-flow and 80 gpm plus or minus 5 gpm simulated RCP seal injection line flow. The actual flow in each BI line may deviate from the nominal so long as:

a) the difference between the highest and lowest flow is 25 gpm or less.

b) the total flow to the four branch lines does not exceed 470 gpm.

c) the minimum flow through the three most conservative (lowest flow) branch lines must no be less than 300 gpm,

d) the charging pump discharge resistance (2.31*Pd/Qd^2) must not be less than 4.73E-3 ft/gpm^2 and must not be greater than 9.27E-3 ft/gpm^2, (Pd is the pump discharge pressure at runout; Qd is the total pump flow rate).

2.1 SAFETY LIMITS

BASES

2.1.1 REACTOR CORE

The restrictions of this safety limit prevent overheating of the fuel and possible cladding perforation which would result in the release of fission products to the reactor coolant. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Operation above the upper boundary of the nucleate boiling regime could result in excessive cladding temperatures because of the onset of departure from nucleate boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and reactor coolant temperature and pressure have been related to DNB through the WRB-2 correlation and W-3 correlation for conditions outside the range of WRB-2. The DNB correlations have been developed to predict the DNB flux and the location of DNB for axially uniform and nonuniform heat flux distributions. The local DNB heat flux ratio (DNBR) is defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, and is indicative of the margin to DNB.

The DNB design basis is as follows: there must be at least a 95 percent probability that the minimum DNBR of the limiting rod during Condition I and II events is greater than or equal to the DNBR limit of the DNB correlation being used (the WRB-2 correlation for Vantage-5 fuel, and the W-3 correlation for ANF fuel and conditions which fall outside the range of applicability of the WRB-2). The correlation DNBR limits are established based on the entire applicable experimental data set such that there is a 95 percent probability with 95 percent confidence that DNB will not occur when the minimum DNBR is at the DNBR limit (1.17 for WRB-2 and 1.3 for the W-3).

In meeting the DNB design basis, uncertainties in plant operating parameters, nuclear and thermal parameters, and fuel fabrication parameters are statistically combined with the DNBR correlation statistics such that there is at least a 95 percent probability with a 95 percent confidence level that the minimum DNBR for the limiting rod is greater than or equal to a calculated design limit DNBR. The uncertainties in the above plant parameters are used to determine the plant DNBR uncertainty. This DNBR uncertainty, combined with the DNBR correlation statistics, establishes a design DNBR value which must be met in plant safety analyses using values of input parameters without uncertainties. For Cook Nuclear Plant Unit 2, the design DNBR values are 1.23 and 1.22 for Vantage-5 fuel typical and thimble cells, respectively, and 1.39 and 1.36 for typical and thimble cells for the ANF fuel. In addition, margin has been maintained in both fuel types by performing safety analyses to a safety analysis limit DNBR. The margin between the design and safety analysis limit DNBR is used to offset known DNBR penalties (i.e., transition core penalties, rod bow, etc.) and provide DNBR margin for operating and design flexibility.

The curves of Figure 2.1-1 show the loci of points of THERMAL POWER, Reactor Coolant System pressure, and average temperature below which the calculated DNBR is no less than the design DNBR limit value or the average enthalpy at the vessel exit is less than the enthalpy of saturated liquid.

LIMITING SAFETY SYSTEM SETTINGS

BASES

The Power Range Negative Rate trip provides protection to ensure that the calculated DNBR is maintained above the design DNBR value for multiple control rod drop accidents. The analysis of a single control rod drop (or some multiple rod drops) accident indicates a return to full power may be initiated by the automatic control system in response to a continued full power turbine load demand or by the negative moderator temperature feedback.

Intermediate and Source Range, Nuclear Flux

The Intermediate and Source Range, Nuclear Flux trips provide reactor core protection during reactor startup. These trips provide redundant protection to the low setpoint trip of the Power Range, Neutron Flux channels. The Source Range Channels will initiate a reactor trip at about 10^{+5} counts per second unless manually blocked when P-6 becomes active. The Intermediate Range Channels will initiate a reactor trip at a current level proportional to approximately 25 percent of RATED THERMAL POWER unless manually blocked when P-10 becomes active. No credit was taken for operation of the trips associated with either the Intermediate or Source Range Channels in the accident analyses; however, their functional capability at the specified trip settings is required by this specification to enhance the overall reliability of the Reactor Protection System.

Overtemperature Delta T

The Overtemperature Delta T trip provides core protection to prevent DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided that the transient is slow with respect to piping transit delays from the core to the temperature detectors (about 4 seconds), and pressure is within the range between the High and Low Pressure reactor trips. This setpoint includes corrections for changes in density and heat capacity of water with temperature and dynamic compensation for piping delays from the core to the loop temperature detectors. This reactor trip limit is always below the core safety limit as shown in Figure 2.1-1. If axial peaks are more severe than design, as indicated by the difference between top and bottom power range nuclear detectors, the reactor trip is automatically reduced according to the notations in Table 2.2-1.

LIMITING SAFETY SYSTEM SETTINGS

BASES

Overpower Delta T

The Overpower Delta T reactor trip provides assurance of fuel integrity, e.g., no melting, under all possible overpower conditions, limits the required range for Overtemperature Delta T protection, and provides a backup to the High Neutron Flux trip. The setpoint includes corrections for changes in density and heat capacity of water with temperature, and dynamic compensation for piping delays from the core to the loop temperature detectors. No credit was taken for operation of this trip in the accident analyses; however, the functional capability of the Overpower Delta T trip at the specified trip setting is required by this specification to enhance the overall reliability of the Reactor Protection System.

Pressurizer Pressure

The Pressurizer High and Low Pressure trips are provided to limit the pressure range in which reactor operation is permitted. The High Pressure trip is backed up by the pressurizer code safety valves for RCS overpressure protection, and is therefore set lower than the set pressure for these valves (2485 psig). The High Pressure trip provides protection for a Loss of External Load event. The Low Pressure trip provides protection by tripping the reactor in the event of a loss of reactor coolant pressure.

Pressurizer Water Level

The Pressurizer High Water Level trip ensures protection against Reactor Coolant System overpressurization by limiting the water level to a volume sufficient to retain a steam bubble and prevent water relief through the pressurizer safety valves. The pressurizer high water level trip precludes water relief for the uncontrolled control rod assembly bank withdrawal at power event.

Undervoltage and Underfrequency - Reactor Coolant Pump Busses

The Undervoltage and Underfrequency Reactor Coolant Pump bus trips provide reactor core protection against DNB as a result of loss of voltage or underfrequency to more than one reactor coolant pump. The specified set points assure a reactor trip signal is generated before the low flow trip set point is reached. Time delays are incorporated in the underfrequency and undervoltage trips to prevent spurious reactor trips from momentary electrical power transients. For undervoltage, the delay is set so that the time required for a signal to reach the reactor trip breakers following the simultaneous trip of two or more reactor coolant pump bus circuit breakers shall not exceed 1.2 seconds. For underfrequency, the delay is set so that the time required for a signal to reach the reactor trip breakers after the underfrequency trip set point is reached shall not exceed 0.3 seconds. The total response times for these functional units include an additional 0.3 seconds for trip breaker operation and CRDM release.

Turbine Trip

A Turbine Trip causes a direct reactor trip when operating above P-7. Each of the turbine trips provide turbine protection and reduce the severity of the ensuing transient. No credit was taken in the accident analyses for operation of these trips. Their functional capability at the specified trip settings is required to enhance the overall reliability of the Reactor Protection System.

3/4.1 REACTIVITY CONTROL SYSTEMS

BASES

3/4.1.1 BORATION CONTROL

3/4.1.1.1 and 3/4.1.1.2 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that 1) the reactor can be made subcritical from all operating conditions, 2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and 3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

SHUTDOWN MARGIN requirements vary throughout core life as a function of fuel depletion, RCS boron concentration, and RCS T_{avg}. The most restrictive condition occurs at EOL, with T_{avg} at no load operating temperature, and is associated with a postulated steam line break accident and resulting uncontrolled RCS cooldown. In the analysis of this accident, a minimum SHUTDOWN MARGIN of 1.6% Delta k/k is initially required to control the reactivity transient and automatic ESF is assumed to be available.

With T_{avg} less than 200°F, the reactivity transients resulting from a postulated steam line break cooldown are minimal and a 1% Delta k/k SHUTDOWN MARGIN provides adequate protection for this event.

The SHUTDOWN MARGIN requirements are based upon the limiting conditions described above and are consistent with FSAR safety analysis assumptions.

3/4.1.1.3 BORON DILUTION

A minimum flow rate of at least 2000 GPM provides adequate mixing, prevents stratification and ensures that reactivity changes will be gradual during boron concentration reductions in the Reactor Coolant System. A flow rate of at least 2000 GPM will circulate an equivalent Reactor Coolant System volume of 12,612 cubic feet in approximately 30 minutes. The reactivity change rate associated with boron reductions will therefore be within the capability for operator recognition and control.

3/4.1 REACTIVITY CONTROL SYSTEMS

BASES

With the RCS average temperature above 200°F, a minimum of two separate and redundant boron injection systems are provided to ensure single functional capability in the event an assumed failure renders one of the systems inoperable. Allowable out-of-service periods ensure that minor component repair or corrective action may be completed without undue risk to overall facility safety from injection system failures during the repair period.

The limitation for a maximum of one centrifugal charging pump to be OPERABLE and the Surveillance Requirement to verify all charging pumps and safety injection pumps, except the required OPERABLE charging pump, to be inoperable below 152°F, unless the reactor vessel head is removed, provides assurance that a mass addition pressure transient can be relieved by the operation of a single PORV.

The boration capability of either system is sufficient to provide the required SHUTDOWN MARGIN from expected operating conditions after xenon decay and cooldown to 200°F. The maximum expected boration capability usable volume requirement is 7715 gallons of 20,000 ppm borated water from the boric acid storage tanks or 160,122 gallons of borated water from the refueling water storage tank. The required RWST volume is based on an assumed boron concentration of 2400 ppm. The minimum RWST boron concentration required by the post-LOCA long-term cooling analysis is 2400 ppm. The minimum contained RWST volume is based on ECCS considerations. See Section B 3/4.5.5.

With the RCS temperature below 200°F, one injection system is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the additional restrictions prohibiting CORE ALTERATIONS and positive reactivity change in the event the single injection system becomes inoperable.

The boron capability required below 200°F is sufficient to provide the required MODE 5 SHUTDOWN MARGIN after xenon decay and cooldown from 200°F to 140°F. This condition requires usable volumes of either 4300 gallons of 20,000 ppm borated water from the boric acid storage tanks or 90,000 gallons of borated water from the refueling water storage tank. The value for the boric acid storage tank volume includes sufficient boric acid to borate to 2190 ppm. The required RWST volume is based on an assumed boron concentration of 2400 ppm. The minimum RWST boron concentration required by the post-LOCA long-term cooling analysis is 2400 ppm.

The limits on contained water volume and boron concentration of the RWST also ensure a pH value of between 7.6 and 9.5 for the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components.

The OPERABILITY of boron injection system during REFUELING ensures that this system is available for reactivity control while in MODE 6.

target flux difference obtained under these conditions divided by the fraction of RATED THERMAL POWER is the target flux difference at RATED THERMAL POWER for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RATED THERMAL POWER value by the appropriate fractional THERMAL POWER level. The periodic updating of the target flux difference value is necessary to reflect core burnup considerations.

Although it is intended that the plant will be operated with the AXIAL FLUX DIFFERENCE within the target band about the target flux difference, during rapid plant THERMAL POWER reductions, control rod motion will cause the AFD to deviate outside of the target band at reduced THERMAL POWER levels. This deviation will not affect the xenon redistribution sufficiently to change the envelope of peaking factors which may be reached on a subsequent return to RATED THERMAL POWER (with the AFD within the target band) provided the time duration of the deviation is limited. Accordingly, a 1 hour penalty deviation limit cumulative during the previous 24 hours is provided for operation outside of the target band but within the limits of Figure 3.2-1 while at THERMAL POWER levels above 50% of RATED THERMAL POWER. For THERMAL POWER levels between 15% and 50% of RATED THERMAL POWER, deviations of the AFD outside of the target band are less significant. The penalty of 2 hours actual time reflects this reduced significance.

Provisions for monitoring the AFD on an automatic basis are derived from the plant process computer through the AFD Monitor Alarm. The computer determines the one minute average of each of the OPERABLE excore detector outputs and provides an alarm message if the AFD for at least 2 of 4 or 2 of 3 OPERABLE excore channels are outside the target band and the THERMAL POWER is greater than 90% or 0.9 x APL of RATED THERMAL POWER (whichever is less). During operation at THERMAL POWER levels between 50% and 90% or 0.9 x APL of RATED THERMAL POWER (whichever is less) and between 15% and 50% RATED THERMAL POWER, the computer outputs an alarm message when the penalty deviation accumulates beyond the limits of 1 hour and 2 hours, respectively.

Figure B 3/4 2-1 shows a typical monthly target band.

The basis and methodology for establishing these limits is presented in topical report WCAP-8385, "Power Distribution Control and Load Following Procedures."

3/4.2.2 and 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR, AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR

The limits on heat flux hot channel factor, and nuclear enthalpy rise hot channel factor ensure that 1) the design limits on peak local power density and minimum DNBR are not exceeded and 2) in the event of a LOCA the peak fuel clad temperature will not exceed the 2200°F ECCS acceptance criteria limit.

Each of these is measurable but will normally only be determined periodically as specified in Specifications 4.2.2.1, 4.2.2.2, 4.2.3, 4.2.6.1 and 4.2.6.2. This periodic surveillance is sufficient to ensure that the limits are maintained provided:

a. Control rods in a single group move together with no individual rod insertion differing by more than plus or minus 12 steps from the group demand position.

b. Control rod groups are sequenced with overlapping groups as described in Specification 3.1.3.6.

c. The control rod insertion limits of Specifications 3.1.3.5 and 3.1.3.6 are maintained.

d. The axial power distribution, expressed in terms of AXIAL FLUX DIFFERENCE, is maintained within the limits.

$F^N_{\Delta H}$ will be maintained within its limits provided conditions a. through d. above are maintained. The relaxation of $F^N_{\Delta H}$ as a function of THERMAL POWER allows changes in the radial power shape for all permissible rod insertion limits. The form of this relaxation for DNBR limits is discussed in Section 2.1.1 of this basis.

When an F_Q measurement is taken, both experimental error and manufacturing tolerance must be allowed for. 5% is the appropriate allowance on F_Q for a full core map taken with the incore detector flux mapping system and 3% in the appropriate allowance for manufacturing tolerance.

BASES: (Continued)

When RCS flow rate and $F^N_{\Delta H}$ are measured, no additional allowances are necessary prior to comparison with the limits of Specification 3.2.3. Measurement errors of 2.1% for RCS flow total flow rate and 4% for $F^N_{\Delta H}$ have been allowed for in determination of the design DNBR value and in the determination of the LOCA/ECCS limit.

Margin between the safety analysis DNBRs and the design limit DNBRs is maintained. (Safety analyses DNBRs: 1.69 and 1.61 for the Vantage 5 typical and thimble cells, respectively, and 1.43 and 1.40 for the ANF fuel typical and thimble cells. Design limit DNBRs: 1.23 and 1.22 for the Vantage 5 typical and thimble cells, respectively, and 1.39 and 1.36 for the ANF fuel typical and thimble cells.) A fraction of this margin is utilized to accomodate applicable transition core penalties and the appropriate fuel rod bow DNBR penalty for the Vantage 5 fuel (equal to 1.3% per WCAP-8691, Rev. 1). The remainder of the margin between design and safety analysis DNBR limits can be used for plant design flexibility.

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3/4.2.4 QUADRANT POWER TILT RATIO

The quadrant power tilt ratio limit assures that the radial power distribution satisfies the design values used in the power capability analysis. Radial power distribution measurements are made during startup testing and periodically during power operation.

The limit of 1.02 at which corrective action is required provides DNB and linear heat generation rate protection with x-y plane power tilts.

The two hour time allowance for operation with a tilt condition greater than 1.02 but less than 1.09 is provided to allow identification and correction of a dropped or misaligned rod. In the event such action does not correct the tilt, the margin for uncertainty on F_Q is reinstated by reducing the power by 3 percent from RATED THERMAL POWER for each percent of tilt in excess of 1.0.

3/4.2.5 DNB PARAMETERS

The limits on the DNB-related parameters ensure that each of the parameters are maintained within the normal steady-state envelope of operation assumed in the transient and accident analyses. The T_{avg} less than or equal to 578.7°F and pressurizer pressure greater than or equal to 2200 psig are consistent with the UFSAR assumptions and have been analytically demonstrated adequate to maintain the core at or above the design DNBR throughout each analyzed transient with allowance for measurement uncertainty. The T_{avg} greater than or equal to 543.9°F is conservative to a safety analysis performed to demonstrate that the plant may operate on a linear control program where the analytical limit of T_{avg} at 100% RATED THERMAL POWER may range from 541.4°F to 580.1°F. The limit of 543.9°F contains a margin of 1.1°F. The core may be operated with indicated vessel average temperature at any value between the upper and lower limits. Pressurizer pressure is limited to a single nominal setpoint, with the lower limit of the indicated value setpoint set forth in the specifications. The T/S value was selected for consistency with Unit 1 and contains a margin of 6 psi. The limits are consistent with the UFSAR assumptions and have been analytically demonstrated to be adequate to maintain the core at or above the applicable design limit DNBR values for each fuel type (which are listed in the bases for Section 2.1.1) throughout each analyzed transient.

The 12 hour periodic surveillance of these parameters through instrument readout is sufficient to ensure that the parameters are restored within their limits following load changes and other expected transient operation. The 12-hour surveillance of the RCS flow measurement is adequate to detect flow degradation. The CHANNEL CALIBRATION performed after refueling ensures the accuracy of the shiftly flow measurement. The total flow is measured after each refueling based on a secondary side calorimetric and measurements of primary loop temperatures.

3/4.2 POWER DISTIBUTION LIMITS

BASES

3/4.2.6 ALLOWABLE POWER LEVEL - APL

Constant Axial Offset Control (CAOC) operation manages core power distributions such that Technical Specification limits on $F_Q(Z)$ are not violated during normal operation and limits on MDNBR are not violated during steady-state, load-follow, and anticipated transients. The V(Z) factor given in the Peaking Factor Limit Report and applied by the Technical Specifications provides the means for predicting the maximum $F_Q(Z)$ distribution anticipated during operation using CAOC taking into account the incore measured equilibrium power distribution. A comparison of the maximum $F_Q(Z)$ with the Technical Specification limit determines the power level (APL) below which the Technical Specification limit can be protected by CAOC. This comparison is done by calculating APL, as defined in Specification 3.2.6.

3/4.7 PLANT SYSTEMS

BASES

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line code safety valves ensures that the secondary system pressure will be limited to within 110% of its design pressure of 1085 psig during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Code, 1971 Edition. The total relieving capacity of all safety valves on all of the steam lines is 17,153,800 lbs/hr which is at least 105 percent of the maximum secondary steam flow rate at 100% RATED THERMAL POWER. A minimum of 2 OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for the allowable THERMAL POWER restriction in Table 3.7-1.

STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in secondary system steam flow and THERMAL POWER required by the reduced reactor trip settings of the Power Range Neutron Flux channels. The reactor trip setpoint reductions are derived on the following bases:

For 4 loop operation

$$SP = \frac{(X) - (Y)(V)}{X} \times (109)$$

Where:

SP = reduced reactor trip setpoint in percent of RATED THERMAL POWER

V = maximum number of inoperable safety valves per steam line

X = total relieving capacity of all safety valves per steam line in lbs./hours = 4,288,450

Y = maximum relieving capacity of any one safety valve in lbs./hour = 857,690

109 = Power Range Neutron Flux-High Trip Setpoint for 4 loop operation

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 BORATION CONTROL

SHUTDOWN MARGIN - TAVG GREATER THAN 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.1 The SHUTDOWN MARGIN shall be greater than or equal to 1.6% Delta k/k.

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

ACTION:

With the SHUTDOWN MARGIN less than 1.6% Delta k/k, immediately initiate and continue boration at greater than or equal to 10 gpm of a solution containing greater than or equal to 20,000 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.1.1 The SHUTDOWN MARGIN shall be determined to be greater than or equal to 1.6% Delta k/k:

a. Within one hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the above required SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s).

b. When in MODE 1 or MODE 2 with Keff greater than or equal to 1.0, at least once per 12 hours by verifying that control bank withdrawal is within the limits of Specification 3.1.3.5.

c. When in MODE 2 with Keff less than 1.0, within 4 hours prior to achieving reactor criticality by verifying that the predicted critical control rod position is within the limits of Specification 3.1.3.5.

d. Prior to initial operation above 5% RATED THERMAL POWER after each fuel loading, by consideration of the factors of e below, with the control banks at the maximum insertion limit of Specification 3.1.3.5.

*See Special Test Exception 3.10.1.

SURVEILLANCE REQUIREMENTS (Continued)

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

   1. Reactor coolant system boron concentration,

   2. Control rod position,

   3. Reactor coolant system average temperature,

   4. Fuel burnup based on gross thermal energy generation,

   5. Xenon concentration, and

   6. Samarium concentration.

4.1.1.1.2 The overall core reactivity balance shall be compared to predicted values to demonstrate agreement within plus or minus 1% Delta k/k at least once per 31 days Effective Full Power Days (EFPD). This comparison shall consider at least those factors stated in Specification 4.1.1.1.1.e, above. The predicted reactivity values shall be adjusted (normalized) to correspond to the actual core conditions prior to exceeding a fuel burnup of 60 Effective Full Power Days after each fuel loading.

REACTIVITY CONTROL SYSTEMS

SHUTDOWN MARGIN - TAVG LESS THAN OR EQUAL TO 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.2 The SHUTDOWN MARGIN shall be greater than or equal to 1.0% Delta k/k.

APPLICABILITY: MODE 5.

ACTION:

With the SHUTDOWN MARGIN less than 1.0% Delta k/k, immediately initiate and continue boration at greater than or equal to 10 gpm of a solution containing greater than or equal to 20,000 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN shall be determined to be greater than or equal to 1.0% Delta k/k:

a. Within one hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s).

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

   1. Reactor coolant system boron concentration,

   2. Control rod position,

   3. Reactor coolant system average temperature,

   4. Fuel burnup based on gross thermal energy generation,

   5. Xenon concentration, and

   6. Samarium concentration.

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POWER DISTRIBUTION LIMITS

LIMITING CONDITION FOR OPERATION (Condition)

b. THERMAL POWER shall not be increased above 90% or 0.9 x APL (whichever is less) of RATED THERMAL POWER unless the indicated AFD is within the target band and ACTION 2.a) 1), above has been satisfied.

c. THERMAL POWER shall not be increased above 50% of RATED THERMAL POWER unless the indicated AFD has not been outside of the target band for more than 1 hour penalty deviation cumulative during the previous 24 hours.

SURVEILLANCE REQUIREMENTS

4.2.1.1 The indicated AXIAL FLUX DIFFERENCE shall be determined to be within its limits during POWER OPERATION above 15% of RATED THERMAL POWER by:

a. Monitoring the indicated AFD for each OPERABLE excore channel:

1. At least once per 7 days when the AFD Monitor Alarm is OPERABLE, and

2. At least once per hour for the first 24 hours after restoring the AFD Monitor Alarm to OPERABLE status if the AFD has been outside of the target bank for any period of time in the previous 24 hours of operation.

b. Monitoring and logging the indicated AXIAL FLUX DIFFERENCE for each OPERABLE excore channel at least once per hour for the first 24 hours and at least once per 30 minutes thereafter, when the AXIAL FLUX DIFFERENCE Monitor Alarm is inoperable. The logged values of the indicated AXIAL FLUX DIFFERENCE shall be assumed to exist during the interval preceding each logging.

SURVEILLANCE REQUIREMENTS (Continued)

d. At least once per 18 months by:*

1. Verifying automatic isolation and interlock action of the RHR system from the Reactor Coolant System when the Reactor Coolant System pressure is above 600 psig.

2. A visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or corrosion.

e. At least once per 18 months, during shutdown, by:*

1. Verifying that each automatic valve in the flow path actuates to its correct position on a Safety Injection test signal.

2. Verifying that each of the following pumps start automatically upon receipt of a safety injection test signal:

a) Centrifugal charging pump

b) Safety injection pump

c) Residual heat removal pump

f. By verifying that each of the following pumps develops the indicated discharge pressure on recirculation flow when tested pursuant to Specification 4.0.5 at least once per 31 days on a STAGGERED TEST BASIS.

1.	Centrifugal charging pump	Greater than or equal to 2405 psig
2.	Safety Injection pump	Greater than or equal to 1409 psig
3.	Residual heat removal pump	Greater than or equal to 190 psig

g. By verifying the correct position of each mechanical stop for the following Emergency Core Cooling System throttle valves:

1. Within 4 hours following completion of each valve stroking operation or maintenance on the valve when the ECCS subsystems are required to be OPERABLE.

*The provisions of Specification 4.0.6 are applicable.

3/4.1 REACTIVITY CONTROL SYSTEMS

BASES

3/4.1.1 BORATION CONTROL

3/4.1.1.1 and 3/4.1.1.2 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that 1) the reactor can be made subcritical from all operating conditions, 2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and 3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

SHUTDOWN MARGIN requirements vary throughout core life as a function of fuel depletion, RCS boron concentration, and RCS T_{avg}. The most restrictive condition occurs at EOL, with T_{avg} at no load operating temperature, and is associated with a postulated steam line break accident and resulting uncontrolled RCS cooldown. In the analysis of this accident, a minimum SHUTDOWN MARGIN of 1.6% Delta k/k is initially required to control the reactivity transient and automatic ESF is assumed to be available. With Tavg less than 200°F, the reactivity transients resulting from a postulated steam line break cooldown are minimal and a 1% Delta k/k SHUTDOWN MARGIN provides adequate protection for this event.

The SHUTDOWN MARGIN requirements are based upon the limiting conditions described above and are consistent with FSAR safety analysis assumptions.

3/4.1.1.3 BORON DILUTION

A minimum flow rate of at least 2000 GPM provides adequate mixing, prevents stratification and ensures that reactivity changes will be gradual during boron concentration reductions in the Reactor Coolant System. A flow rate of at least 2000 GPM will circulate an equivalent Reactor Coolant System volume of 12,612 plus or minus 100 cubic feet in approximately 30 minutes. The reactivity change rate associated with boron reductions will therefore be within the capability for operator recognition and control.

3/4.1.1.4 MODERATOR TEMPERATURE COEFFICIENT (MTC)

The limitations on MTC are provided to ensure that the assumptions used in the accident and transient analyses remain valid through each fuel cycle. The surveillance requirement for measurement of the MTC at the beginning, and near the end of each fuel cycle is adequate to confirm the MTC value since this coefficient changes slowly due principally to the reduction in the RCS boron

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DONALD C. COOK NUCLEAR PLANT UNITS 1 AND 2
SUMMARY OF PROPOSED TECHNICAL SPECIFICATION CHANGES

ATTACHMENT 3 TO AEP:NRC:1071E

SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
2-2	Figure 2.2-1	1	001	New reactor core safety limits	A new thermal design was performed for Cycle 8. See Attachment 4, Table 6.1; Attachment 4, Appendix A; and Attachment 4, Appendix B, Section B.2.2.1
2-5	Table 2.2-1 Footnote*	1	002	Design flow is changed to 91,600 gpm per loop	Design flow is loop flow. It is minimum measured flow (MMF) divided by 4; MMF - 366,400 gpm; 366,400/4 - 91,600 MMF is discussed in Attachment 4, Appendix B, Sections B.2.2.1, B.2.3 and B.3.5.1
		4	003	Rotate the printing on the page 90°	Administrative change
		4	004	Mathematical symbols replaced with words	Administrative change
2-6	Table 2.2-1	4	005	Rotate the balance of Table 2.2-1 90° consistent with page 2-5	Administrative change
		4	006	Mathematical symbols replaced with words	Administrative change
2-7	Table 2.2-1 Note 1	1	007	T' is changed to $\leq 576.0^{o}F$	Items 007 through 023 detail changes to the OTDeltaT and OPDeltaT setpoints. New setpoints were developed to protect the new core safety limits, item 001 above. See Attachment 4, Table 6.1; Attachment 4, Appendix A; and Attachment 4, Appendix B, Section B.2.2.1
		1	008	is changed to 28 seconds	

NOTES: - The number in the plus sign (+) column refers to applicable T/S change group of the significant hazards evaluations in Attachment 1.
- The number in the pound sign (#) column is a sequential identifier for each proposed change.

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
2-7	Table 2.2-1 Note 1	4	009	Rotate the printing on the page 90° and related formatting changes	Administrative change
		4	010	Mathematical symbols replaced with words	Administrative change
2-8	Table 2.2-1 Note 1	1	011	K_1 is changed to 1.09	
		1	012	K_2 is changed to 0.01331	
		1	013	K_3 is changed to 0.00058	
		1	014	Item (i), the range for f_1(DeltaI) is changed to -33.0% to +6%	
		1	015	Item (ii), the slope for the f_1(Delta I) penalty is changed to 3.5%/% for values lower than -33%	
		1	016	Item (iii), the slope for the f_1(DeltaI) penalty is changed to 1.0%/% for values higher than +6%	
2-8	Table 2.2-1 Note 1	4	017	Rotate the printing on the page 90°	Administrative change
		4	018	Mathematical symbols replaced with words	Administrative change
2-9	Table 2.2-1 Note 2	1	019	T" is changed to $\leq$ 576.0°F	
		1	020	K_4 is changed to 1.08	
		1	021	f_2(Delta I) is set equal to zero	

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
2-9	Table 2.2-1 Note 3	1	022	The OTDeltaT allowable value is set to 1.3% of DeltaT span	
2-9	Table 2.2-1 Note 4	1	023	The OPDeltaT allowable value is set to 3.0% of DeltaT span	
2-9	Table 2.2-1 Notes 2, 3	4	024	Rotate the printing on the page 90° and related formatting changes	Administrative change
		4	025	Mathematical symbols replaced with words	Administrative change
3/4 1-1	3.1.1.1	1	026	The value of the SHUTDOWN MARGIN is changed to 1.6% Delta k/k	The analyses performed for Unit 2 Cycle 8 and a new mass and energy releases analysis inside containment performed for both units use a SDM of 1.3% Delta k/k. The proposed T/S value is limited by the current current analysis of mass and energy releases outside of containment. See Attachment 4 of Appendix B, Section B.3.11.2; Attachment 5, p. S-3.3-12; and Attachment 4, Section 5.4.2.
3/4 1-1	3.1.1.1	2	027	T/Ss 3.1.1.1 and 3.1.1.2 are changed into the STS format	The current shutdown margin (SDM) T/Ss are grouped with APPLICABLE MODES 1, 2 and 3 in Specification 3/4.1.1.1 and APPLICABLE MODES 4 and 5 in Specification 3/4.1.1.2. This was done so that a special SDM LCO for operation on the residual heat removal (RHR) system could be included in. Specification 3/4.1.1.2. We propose to remove the SDM requirements for RHR operation to administrative control. See item 033. This

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
					change permits reformatting SDM T/Ss with APPLICABLE MODES 1, 2, 3 and 4 in Specification 3/4.1.1.1 and APPLICABLE MODE 5 in Specification 3/4.1.1.2 using the STS format. Proposed Specifications 3/4.1.1.1 and 3/4.1.1.2 are based on STS Rev. 4. This change is discussed in T/S Change Group 2b.
3/4 1-1	3/4.1.1.1	4	028	Mathematical symbols replaced with words	Administrative change
3/4 1-2	4.1.1.1	4	029	Mathematical symbols replaced with words	Administrative change
3/4 1-1 1-2	4.1.1.1.1.d	4	030	Section d moved from p. 3/4 1-2 to p. 3/4 1-1	Administrative change
3/4 1-2	4.1.1.1.3	2	031	Remove surveillance requirement	This surveillance was included by Amendment 82 to provide protection for increased steam loads in Mode 3. We propose to address this concern administratively. See Attachment 1, T/S Change Group 2c.
3/4 1-3 3/4 1-3a	3.1.1.2 3.1.1.2	2	032	T/Ss 3.1.1.1 and 3.1.1.2 are changed into the STS format. This specification is consolidated to one page.	See the remarks for item 027

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 1-3b	Figure 3.1-3	2	033	Remove Figure 3.1-3	The shutdown margin requirements for Mode 4 and Mode 5 when operating on RHR were added to the Unit 2 T/Ss by Amendment 82. This requirement ensures the operator has adequate time to respond to dilution transients when operating on RHR. We propose to address this concern administratively. See Attachment 1; T/S Change Group 2b
3/4 1-16	3.1.2.8	1	034	Item a1; the required volume of the 20,000 ppm boration source is increased to 7715 gallons	The new value is a value which is expected to accommodate uprating to a core thermal power of 3588 MWt, fuel of increased enrichment for increased cycle length, and changes in vendor methodology. This change is indicated in Attachment 4, Table 6.1 and Attachment 4, Appendix A.
		4	035	Mathematical symbols replaced with words	Administrative change
3/4 1-23	3.1.3.4	1	036	The rod drop time requirement is changed to less than or equal to 2.7 seconds	The pressure drop is larger in V5 than other fuel types requiring an increase in rod drop time to 2.7 seconds. See Attachment 4, Section 5.1.2; Attachment 4, Appendix B, Section B.2.4; and Attachment 4, Appendix C, Table C.3.2-1.
		4	037	Mathematical symbols replaced with words	Administrative change

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 2-2	3/4.2	4	038	ACTION d is removed	Administrative change. This ACTION is no longer appropriate. Section 6.9.1.9 of the T/Ss delineated reportability requirements prior to implementing the rule in 10 CFR 50.72 and 50.73.
3/4 2-2	4.2.1.1	5	039	Surveillance requirement 4.2.1.1.a.2 will be required only when the AFD has been outside the target band at any time during the 24 hours prior to restoring the AFD monitor alarm to operable status.	This will eliminate unnecessary surveillances of the AFD. If the axial power distribution is essentially stable for the 24 hours before the alarm is restored to operable status, there is no need for additional AFD monitoring. See Attachment 1, T/S Change Group 5.
		4	040	Spelling of "preceding" is corrected.	Administrative change
3/4 2-15	3.2.5	1	041	A range of reactor coolant system temperatures for operation are specified.	Unit 2 has been analyzed for a range of operating temperatures. All analyses use or bound the window shown in Table B.2-1. See Attachment 4, Appendix B, Section B.2.1; Attachment 4, Appendix C, Table C.3.1-1 and Section C.3.2; and Attachment 1, Change Group 1g.
3/4 2-15	3.2.5	1	042	The minimum pressurizer pressure is reduced to 2200 psig.	An increase in the allowances was made for this parameter. See Attachment 4, Appendix B, Section B.2.3, and Appendix C, Table C.3.1-1. SBLOCA used the same pressure assumptions shown for LBLOCA. See also Attachment 4, Table 6.1 and Appendix A.

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 2-15	3.2.5	1	043	The minimum measured flow is increased from 364,960 gpm to 366,400 gpm.	A small change was made in the analysis assumptions. See Attachment 4, Appendix B, Section B.2.3
3/4 2-15	3.2.5	4	044	Restructured format for ease of use. Values for reactor coolant system Tavg, pressurizer pressure, and reactor coolant system total flow rate from Table 3.2-1 incorporated into T/S. Mathematic symbols changed to words. LCO and surveillance requirements numbering changed to account for the removal of DNB T/S for Modes 2, 3, 4 and 5. Title changed to reflect retention of only Mode 1 DNB T/S.	Items 044, 045 and 046 are proposed for clarity and convenience of use. The changes are administrative in nature.
3/4 2-15	4.2.5.2	4	045	Surveillance requirement 4.2.5.2 is clarified.	Administrative change; surveillance requirement is revised to represent actual plant configuration. The plant does not have a "total flow rate indicator."
3/4 2-16	Table 3.2-1	4	046	Removed as part of administrative change described above.	This is an administrative change. See remarks for items 044 and 045.

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 2-17	3.2.5.2	2	047	Remove this T/S in its entirety	Existing T/S 3/4.2.5.2 defines DNB limits in Modes 2-5 which were added to the Unit 2 T/Ss by Amendment 82. This specification was intended to protect the analysis assumptions for the rod withdrawal from subcritical event. It is not standard in the sense of standard T/Ss. We believe it can be safely deleted. See Attachment 1; T/S Change Group 2d
3/4 2-18	Table 3.2-2	2	048	Remove this Table along with T/S 3.2.5.2	See the remarks for Item 047.
3/4 2-19	3.2.6	1	049	Change the formula for the F_p penalty	This change is a result of changing from Advanced Nuclear Fuels power distribution monitoring methodology to Westinghouse constant axial offset control methodology. See Attachment 10, p. B-4
3/4 3-9	Table 3.3-2	1	050	Functional Unit 11, pressurizer level-high, changed from not applicable to $\leq$ 2.0 seconds	This protective function is is needed to prevent pressurizer fill for certain uncontrolled rod assembly bank withdrawal at power cases. See Attachment 4, Appendix B, Sections B.3.2A.2, B.3.2A.3, and B.3.2.2A.4
		1	051	Functional Units 9 and 10 changed from 1 to 2 seconds	The new values reflect the values used in the analyses. See Attachment 4, Table 6.1 and Attachment 4, Appendix B, Tables B.2-2 and C.3.1-3.
3/4 3-9	Table 3.3-2	4	052	Rotate the printing on the page 90°	Administrative change.
		4	053	Mathematical symbols replaced with words	Administrative change.

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 3-10	Table 3.3-2	1	054	Functional Units 12, 13, 14 and 16 changed from 0.6, 0.6, 1.5 and 1.2 seconds respectively to 1.0, 1.0, 2.0 and 1.5 seconds respectively	The new values reflect the values used in the analyses. See Attachment 4, Table 6.1 and Appendix A; and Attachment 4, Appendix B, Table B.2-2.
3/4 3-10	Table 3.3-2	4	055	Rotate the printing on the page 90°	Administrative change.
		4	056	Mathematical symbols replaced with words	Administrative change.
3/4 3-20	Table 3.3-3	2	057	Functional Unit 5a has APPLICABLE MODE $ removed	APPLICABLE MODE $ was added to the Unit 2 T/Ss by Amendment 82. It was intended to provide protection from an increase in heat removal event in Modes 4 and 5. We believe this possibility is remote and can be addressed administratively as appropriate. See Attachment 1, T/S Change Group 2e.
3/4 3-21	Table 3.3-3	2	058	Footnotes # and ## revised	These footnotes presently include protection for increased steam loads in Mode 3. AEP proposes to address this concern administratively. See Attachment 1, T/S Change Group 2c.
		2	059	Footnote $ deleted	This footnote was added by Amendment 82. It is intended to provide protection from an increase in heat removal event in Modes 4 and 5. We believe this possibility is remote and can be addressed administratively as appropriate. See Attachment 1, T/S Change Group 2e.

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 3-23	Table 3.3-4	4	060	Rotate the printing on the page 90°	Administrative change
		4	061	Mathematical symbols replaced with words	Administrative change
3/4 3-24	Table 3.3-4	4	062	Rotate the printing on the page 90°	Administrative change
		4	063	Mathematical symbols replaced with words	Administrative change
3/4 3-25	Table 3.3-4	4	064	Rotate the printing on the page 90°	Administrative change
		4	065	Mathematical symbols replaced with words	Administrative change
3/4 3-25	Table 3.3-4	1	066	Functional Unit 4.d; steam flow in two steam lines--high coincident with Tavg--low low; new setpoints and allowable values for steam flow are proposed.	These setpoints are based on mass and energy releases inside containment. This is discussed in Attachment 1, T/S Change Group 1.1. The analysis is discussed in Attachment 5, particularly p. S-3.3-11. See also Attachment 4, Table 6.1 and Appendix A.
3/4 3-25a	Table 3.3-4	4	067	Rotate the printing on the page 90°	Administrative change
		4	068	Mathematical symbols replaced with words	Administrative change
3/4 3-26	Table 3.3-5	1	069	Initiating signal and Function 2.a; containment pressure-high safety injection response time changed from not applicable to $\leq$ 27.0 seconds	Items 069 through 071 propose the addition of response times for Engineered Safety Features Actuation on containment pressure high. The use of this feature for mass and energy releases inside containment is discussed on p. S-3.3-12 of WCAP 11902, Supplement 1 included in Attachment 5.

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
		1	070	Initiating signal and Function 2.b; containment pressure-high reactor trip (from SI) response time changed from not applicable to $\leq$ 3.0 seconds	
		1	071	Initiating signal and Function 2.c; containment pressure-high feedwater isolation response time changed from not applicable to $\leq$ 8.0 seconds	
3-28	Table 3.3-5	1	072	Initiating signal and Function 8.a; steam generator water level high-high turbine trip response time changed from not applicable to $\leq$ 2.5 seconds	Items 072 and 073 are required to terminate the feedwater system malfunctions causing an increase in feedwater flow event. See Attachment 4, Appendix B, Section B.3.8A.2.3
		1	073	Initiating signal and Function 8.b; steam generator water level high-high feedwater isolation response time changed from not applicable to $\leq$ 11.0 seconds	
		4	074	Mathematical symbols replaced with words	Administrative change

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 3-28	Table 3.3-5	4	075	In two places, references to the turbine driven auxiliary feedpump were changed from plural to singular	Administrative change
3/4 3-30	Table 4.3-2	4	076	Rotate the printing on the page 90^{o}	Administrative change
3/4 3-31	Table 4.3-2	4	077	Rotate the printing on the page 90^{o}	Administrative change
3/4 3-31	Table 4.3-2	2	078	Functional Unit 5a has surveillance Mode $ removed	Surveillance was required in Mode $ by Amendment 82. It was intended to provide protection from an increase in heat removal event in Modes 4 and 5. We believe this possibility is remote and can be addressed administratively as appropriate. See Attachment 1, T/S Change Group 2e.
		4	079	Reference to the turbine driven auxiliary feedpump was changed from plural to singular	Administrative change
3/4 3-32	Table 4.3-2	4	080	Rotate the printing on the page 90^{o}	Administrative change
3/4 3-32a	Table 4.3-2	4	081	Page is deleted	Administrative change; a result of consolidating the information on pages 3/4 3-30 and 3/4 3-31 onto page 3/4 3-30, and moving information on pages 3/4 3-32 and 3/4 3-32a to pages 3/4 3-31 and 3/4 3-32, respectively.

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 3-33	Table 4.3-2	2	082	Footnote $ deleted	This footnote was added by Amendment 82. It was intended to provide protection from an increase in heat removal event in Modes 4 and 5. We believe this possibility is remote and can be addressed administratively as appropriate. See Attachment 1, T/S Change Group 2e.
3/4 4-6	3.4.4	3	083	Pressurizer water level maximum volume changed to 92% of span	A new water level for pressurizer water level is proposed. This change was approved for Unit 1 by Amendment 126 to DPR-58. See Attachment 6
3/4 5-1	3.5.1	1	084	Accumulator borated water volume requirement changed to between 921 and 971 cubic feet	Items 084 and 085 are based on new LOCA analyses performed for Unit 2. The accumulator parameters used in the analyses are indicated in Tables C.3.1-2 and C.3.2-1 of Attachment 4, Appendix C. The limit values are provided in Attachment 4, Table 6.1 and Appendix A.
		1	085	Accumulator nitrogen cover pressure requirement is changed to between 585 and 658 psig	
3/4 5-5	4.5.2	1	086	Item f.2 safety injection pump discharge pressure requirement reduced from 1445 psig to 1409 psig	Items 086 and 087 are based on new LOCA analyses performed for Unit 2 and the containment integrity analysis described in WCAP 11908 which bounds both units. Discussion of this change and the development of the T/S limit are contained in T/S Change Group 1p.
		1	087	Item f.3 residual heat removal pump discharge pressure requirement reduced from 195 psig to 190 psig	
		4	088	Mathematical symbols replaced with words	Administrative change

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 5-6	4.5.2	1	089	Footnote* changed to reflect new analyses as follows: an uncertainty band of plus or minus 5 gpm is added to the 80 gpm simulated RCP seal injection line flow value; a flow imbalance of up to 25 gpm is permitted; the minimum flow through the three most conservative branch lines is not to be less than 300 gpm; and a new item reflecting the allowable range of the charging pump discharge resistance is provided	SBLOCA was analyzed assuming a safety injection flow consistent with the proposed T/S. See Attachment 4, Appendix C, Section C.3.2. The other analyses are not significantly affected by the proposed T/S. Also see Table 6.1 and Appendix A of Attachment 4.
		4	090	Mathematical symbols replaced with words	Administrative change
B 2-1	2.1.1		091	Bases description is changed to reflect correlations utilized in calculating DNBR	The changes were made to reflect the specific DNB correlations used. The design and safety analysis DNBR limits are described. The statement that Figure 2.1-1 includes errors was removed.
B 2-4	2.2.1		092	The words "(or some multiple rod drops)" added and the reference to "Interim criteria for single dropped rod" removed from power range, neutron flux, high rates description	The changes were made as a result of the analyses performed for Unit 2 Cycle 8.
			093	Mathematical symbols replaced with words	Administrative change

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
B 2-5	2.2.1		094	"its functional capability" is replaced with "the functional capability of the Overpower DeltaT trip" in the OPDeltaT section	Administrative change for clarity
			095	Reference to the f_2(DeltaI) penalty was deleted from the OPDeltaT section	The new analyses do not use f_2(DeltaI) in OPDeltaT trip
			096	Reference to use in control rod withdrawal at power was added to the pressurizer water level trip discussion.	This change reflects the analyses performed for Unit 2 Cycle 8
B 2-7	2.2.1		097	The delays in the discussion of the undervoltage trip were changed.	This change reflects the analyses performed for Unit 2 Cycle 8.
B 3/4 1-1	3/4.1.1.1 3/4.1.1.2		098	The required SDM for Modes 1, 2, 3 and 4 was changed from 2.0% to 1.6%. In addition, the references to SDM requirements prior to blocking safeguards on P-11 and P-12 and SDM requirements for RHR operation were deleted.	The SDM change from 2.0% to 1.6% reflects the analysis performed for Unit 2 Cycle 8. The other changes reflect our proposal to address transition mode concerns administratively. These proposals are discussed in Attachment 1 under T/S Change Group 2.
B 3/4 1-1	3/4.1.1.3		099	The minimum flow rate is changed to 2000 gpm.	This change reflects Amendment 107. That the bases were not changed at that time is an oversight.
			100	Mathematical symbols replaced with words	Administrative change

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
B 3/4 1-3	3/4.1.2		101	The required volumes for the BAST and the boron concentration basis for these calculations are changed.	The new values reflect the Unit 2 Cycle 8 analyses.
B 3/4 2-2	3/4.2.1		102	The methodology reference for the power distribution control methodology is changed to WCAP-8385.	This change reflects the Unit 2 Cycle 8 analyses.
B 3/4 2-4	3/4.2.2 3/4.2.3		103	The reference to $F^N_{\Delta H}$ measurement error is deleted.	The deleted information is redundant to information retained on p. B 3/4 2-4a.
			104	Mathematical symbols replaced with words	Administrative change
B 3/4 2-4a	3/4.2.2 3/4.2.3		105	The first three paragraphs on this page deleted.	The first and second paragraphs address a method of trading primary flow for $F^N_{\Delta H}$ and obsolete $F^N_{\Delta H}$, based on a LOCA analysis performed for Cycle 5 operation. Neither of these items is currently applicable. Therefore, these paragraphs are deleted. The third paragraph is redundant to information retained on p. B 3/4 2-4. It addresses allowances for F_Q.
B 3/4 2-4a	3/4.2.2 3/4.2.3		106	RCS flow total flow rate measurement error changed to 2.1%	This information reflects the Unit 2 Cycle 8 analysis.
B 3/4 2-4a	3/4 2.2 3/4 2.3		107	A discussion of DNBR margin allocation is added to the bases	This information reflects the Unit 2 Cycle 8 analysis.
B 3/4 2-4b	Figure B 3/4 2-2		108	The figure is deleted.	This figure is associated with the material at the top of page B 3/4 2-4a which was deleted because it was obsolete.

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
B 3/4 2-5	3/4 2.5		109	The discussion of DNB parameters is changed to reflect new analysis for mixed core	This information reflects the Unit 2 Cycle 8 analysis.
B 3/4 2-5	3/4 2.5		110	Delete paragraph with limits on pressurizer pressure and Tavg in Modes 2 and 3.	The applicable specification was removed in its entirety. See the remarks for item 047.
B 3/4 2-5	3/4.2.6		111	Section 3/4.2.6 was moved to page B 3/4 2-6	This resulted from the additional information relating to DNB parameters
B 3/4 2-6	3/4.2.6		112	The allowable power level basis, Section 3/4.2.6, was moved to this page	This resulted from the additional information relating to DNB parameters
			113	The allowable power level basis was revised to reflect the Westinghouse methodology	The methodology although similar to the methodology used in Cycles 4, 5, 6 and 7 rests on the reference added to Section B 3/4.2.1, WCAP-8385
B 3/4 7-1	3/4.7.1.1		114	The discussion of the relieving capacity of the steam generator safety valves is revised	The revised wording satisfies the ASME code and addresses all temperature and pressure operating conditions.

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 1 PROPOSED T/Ss RELATED TO UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 1-1 3/4 1-2	3.1.1.1	6	115	T/Ss 3.1.1.1 and 3.1.1.2 are changed into the STS format	The current SDM T/Ss are grouped with APPLICABLE MODES 1, 2 and 3 in Specification 3/4.1.1.1 and APPLICABLE MODES 4 and 5 in Specification 3/4.1.1.2. This was done so that a special SDM LCO for operation on the RHR system could be included in Specification 3/4.1.1.2. We propose to remove the SDM requirements for RHR operation to administrative control. See item 119. This change permits reformatting SDM T/Ss with APPLICABLE MODES 1, 2, 3 and 4 in Specification 3/4.1.1.1 and APPLICABLE MODE 5 in Specification 3/4.1.1.2 using the STS format
		4	116	Mathematical symbols replaced with words	Administrative change
3/4 1-3	3.1.1.2	6	117	T/Ss 3.1.1.1 and 3.1.1.2 are changed into the STS format. This specification is consolidated to one page.	See the remarks for item 115
3/4 1-3a	4.1.1.2.b	4	118	Section moved to page 3/4 1-3. Page is deleted.	Administrative change
3/4 1-3b	Figure 3.1-3	6	119	Remove Figure 3.1-3	The shutdown margin requirements for Mode 4 and Mode 5 when operating on RHR were added to the Unit 2 T/Ss by Amendment 82 and to Unit 1 T/Ss by Amendment 120. This requirement ensures the operator has adequate time to respond to dilution transients when operating on RHR. We propose to address this concern administratively. See Attachment 1, T/S Change Group 2b.

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SUMMARY DESCRIPTIONS FOR DONALD C. COOK NUCLEAR PLANT
UNIT 1 PROPOSED T/Ss RELATED TO UNIT 2 CYCLE 8 PROPOSED T/Ss

Page	Section	+	#	Description	Remarks
3/4 2-2	4.2.1.1	6	120	Surveillance requirement 4.2.1.1.a.2 will be required only when the AFD has been outside the target band at any time during the 24 hours prior to restoring the AFD monitor alarm to operable status.	This will eliminate unnecessary surveillances of the AFD. If the axial power distribution has been essentially stable for the 24 hours before the alarm was restored to operable status, there is no need for additional AFD monitoring. See Attachment 1, T/S Change Group 5.
3/4 5-5	4.5.2	6	121	Item f.2, safety injection pump discharge pressure requirement is increased from 1345 psig to 1409 psig.	Changes 121 and 122 correct errors in a previous submittal. The differential pressures are provided in Table S-3.13-2 of Attachment 5. The discharge pressures are calculated in Attachment 1, T/S Change Group 1o
3/4 5-5	4.5.2	6	122	Item f.3, residual heat removal pump discharge pressure requirement is increased from 165 psig to 190 psig.	
		4	123	Mathematical symbols replaced with words	Administrative change
B 3/4 1-1	3/4.1.1.1 3/4.1.1.2		124	SDM requirements for RHR operation were deleted	This change reflects our proposal to address transition mode concerns administratively. These proposals are discussed in Attachment 1 under T/S Change Group 2.
	3/4.1.1.3		125	Mathematical symbols replaced with words	Administrative change

ATTACHMENT 4 TO AEP:NRC:1071E

DESCRIPTIONS OF ANALYSES PERFORMED BY WESTINGHOUSE ELECTRIC CORPORATION FOR DONALD C. COOK NUCLEAR PLANT UNIT 2

APPENDIX B

NON-LOCA ANALYSES

FOR THE

DONALD C. COOK NUCLEAR PLANT UNIT 2

TRANSITION TO 17X17 VANTAGE 5 FUEL

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APPENDIX B

Non-LOCA Accident Analysis

B.1 INTRODUCTION

This section addresses the impact of the complete transition of the Donald C. Cook Nuclear Plant Unit 2 from ANF fuel to Westinghouse 17X17 VANTAGE 5 fuel on the FSAR Chapter 14 Non-LOCA accident analyses. The methods used for accident evaluation are discussed in Section 5.1.4 of this report.

The Cook Nuclear Plant Unit 2 licensing basis, as reported in the original FSAR, includes analyses or evaluations of the fifteen (15) Non-LOCA accidents. A complete list of these accidents is provided in Section 5.1.1 of this report.

All of the above Non-LOCA accidents, except Startup of an Inactive Reactor Coolant Loop, have been evaluated to address any impact resulting from the VANTAGE 5 reload. The specific design features associated with the VANTAGE 5 fuel and the modified safety analysis assumptions that were considered in the Non-LOCA safety analysis are described in Sections 5.1.2 and 5.1.3, respectively.

B.2 ACCIDENTS REANALYZED

B.2.1 General

All of the transients which are impacted by one or more of the VANTAGE 5 design features or modified safety analysis assumptions as discussed in Section 5.1 of this report were reanalyzed. These consist of the following fourteen (14) accidents:

1. Uncontrolled RCCA Bank Withdrawal From a Subcritical Condition
2. Uncontrolled RCCA Bank Withdrawal at Power
3. Rod Cluster Control Assembly (RCCA) Misalignment
4. Rod Cluster Control Assembly (RCCA) Drop

5. Uncontrolled Boron Dilution
6. Loss of Forced Reactor Coolant Flow
7. Loss of External Electric Load or Turbine Trip
8. Loss of Normal Feedwater
9. Excessive Heat Removal due to Feedwater System Malfunctions
10. Excessive Load Increase
11. Loss Of Offsite Power (LOOP) to the Station Auxiliaries
12. Rupture of a Steamline (Steamline Break)
13. Rupture of a Control Rod Drive Mechanism (CRDM) Housing (Rod Cluster Control Assembly Ejection)
14. Major Rupture of Main Feedwater Pipe (Feedline Break)

Table B.2-1 presents the "full window" (cases 2 through 7) of the range of key plant operating parameters considered in the analysis. However, because of the DNB constraints associated with the presence of the ANF fuel in the transition cycles, it was determined that the "full window" of the range of key plant parameters for the transition cycles (Cycles 8 and 9) must be limited as shown for cases 2 and 3 in Table B.2-1. Generating an acceptable nominal setpoint for the Overtemperature ΔT (OTΔT) reactor trip protection for the transition cycles has resulted in this limitation. Brief descriptions of cases 2 through 7 follows Table B.2-1.

As indicated in Section 5.1.3, the following DNB-related analyses are performed twice to include the variation in the core thermal safety limits and the Overtemperature and Overpower ΔT reactor trip setpoints between mixed core cycles and a full VANTAGE 5 core.

(a) Uncontrolled RCCA Withdrawal at Power
(b) Excessive Load Increase
(c) Excessive Heat Removal due to Feedwater System Malfunctions
(d) Loss of External Electric Load or Turbine Trip

For the remaining ten (10) Non-LOCA accidents, a bounding analysis is performed considering the "full window" (cases 2 through 7) of plant operating parameters as shown in Table B.2-1.

The Non-LOCA accident analyses presented in this report conservatively bound the current plant operating parameters shown in Table B.2-1 (case 1).

In accordance with Technical Specification 3/4.4.1 (Amendment 59), Cook Nuclear Plant Unit 2 operation during Modes 1 and 2 with less than four reactor coolant loops is not permitted. Since three loop operation during Modes 1 and 2 is prohibited, the Startup of an Inactive Reactor Coolant Loop event does not have to be considered for design changes associated with the transition to VANTAGE 5 fuel as discussed in Section B.1.

B.2.2 Reactor Protection System (RPS) and Engineered Safety Features (ESF) Setpoints Assumed in the Analysis

To provide adequate operating margin for the potential ranges of temperature and pressure operation and to accommodate the VANTAGE 5 transition, certain reactor trip and engineered safeguards features setpoints were revised. The revised RPS setpoints are the Overtemperature ΔT (OTΔT) and Overpower ΔT (OPΔT) reactor trips. The revised ESF setpoint is the low steamline pressure setpoint in the steamline break protection. The general equations for the OTΔT and OPΔT reactor trip setpoints are presented below. Section 6.0 provides the revised OTΔT, OPΔT and the low steamline pressure setpoints to be included in the Technical Specifications update.

Overtemperature ΔT equation:

$$\mathrm{OT\Delta T} \leq \Delta T_o \left[K_1 - K_2 \frac{1 + \tau_1 s}{1 + \tau_2 s} (T - T') + K_3 (P - P') - f_1(\Delta I)\right]$$

Overpower ΔT equation:

$$\mathrm{OP\Delta T} \leq \Delta T_o \left[K_4 - K_5 \left(\frac{\tau_3 s}{1 + \tau_3 s}\right) T - K_6 (T - T'') - f_2(\Delta I)\right]$$

B.2.2.1 Reactor Trip Setpoints

Revised OTΔT and OPΔT setpoints were calculated based on the new core thermal safety limits using the methodology described in Reference 1 (WCAP-8746). Because of the use of the W-3 correlation for ANF fuel in the transition cycles, the core thermal safety limits for transition cycles are limited by the ANF fuel. For a full VANTAGE 5 fuel, these core thermal safety limits are less restrictive. Two sets of OTΔT and OPΔT setpoints were calculated. The first set of these setpoints is calculated based on the most restrictive core thermal safety limits in the transition cycles (Cycles 8 and 9) and the second set is calculated for a full core of VANTAGE 5 fuel. Separate analyses for the appropriate accidents are performed to address these setpoint changes for a mixed core and a full VANTAGE 5 core.

Figure B.2-1a presents the allowable reactor coolant loop average temperature and vessel ΔT as a function of pressurizer pressure for the transition cycles (Cycles 8 and 9). This figure presents the most limiting operating configuration (nominal core power = 3588 MWt, nominal vessel T-avg = 576 °F, nominal pressure = 2250 psia) of the potential future rerating range of conditions described in Table B.2-1 (case 2) for the calculation of the OTΔT and OPΔT protection setpoints. A total Reactor Coolant System (RCS) flow rate of 366,400 gpm was assumed for generating these setpoints.

Figure B.2-1b presents the allowable reactor coolant loop average temperature and vessel ΔT as a function of pressurizer pressure for the cycles (Cycle 10 and beyond) with a full VANTAGE 5 core. This figure presents the most limiting operating configuration (nominal core power = 3588 MWt, nominal vessel T-avg = 581.3 °F, nominal pressure = 2100 psia) of the potential rerating range of conditions described in Table B.2-1 (case 5) for the calculation of the OTΔT and OPΔT protection setpoints. A total (RCS) flow rate of 366,400 gpm was assumed for generating these setpoints.

Figures B.2-1c through B.2-1f illustrate the OTΔT and OPΔT protection setpoints for the non-limiting endpoints of the range of operating conditions considered in generating these setpoints. Note that the core thermal safety limits on these figures are the same as shown in Figures B.2-1a or B.2-1b and the differences in the protection lines are due to the changes in full power nominal T-avg (T′ and T″) and/or nominal pressurizer pressure (P′).

The boundaries of operation defined by the OPΔT and OTΔT trips are represented as "protection lines" on these diagrams. The protection lines include all adverse instrumentation and setpoint errors so that under nominal conditions trip would occur within the area bounded by these lines. The utility of these diagrams is the fact that the limit imposed by any given DNBR can be represented as a line. The DNBR lines represent the locus of conditions for which DNBR equals the safety analysis limit value (1.40 for the thimble cell and 1.43 for the typical cell for ANF fuel and 1.61 for the thimble cell and 1.69 for the typical cell for VANTAGE 5 fuel). All points below and to the left of a DNB line for a given pressure have a DNBR greater than the safety analysis limit value. These diagrams show that DNB is prevented for all cases if the area enclosed with the maximum protection lines is not traversed by the applicable DNBR limit line at any point for a given pressure.

The area of permissible operation (power, pressure, and temperature) is bounded by a combination of reactor trips: high neutron flux (fixed setpoint); high pressure (fixed setpoint); low pressure (fixed setpoint); Overpower and Overtemperature ΔT (variable setpoints).

The safety analysis limit DNBR values of 1.43 (typical cell) and 1.40 (thimble cell) for ANF fuel and 1.69 (typical cell) and 1.61 (thimble cell) for VANTAGE 5 fuel are used for all DNB limited accidents analyzed with the RTDP (Reference 2). These safety analysis limit values are conservative compared to the actual design limit DNBR values (1.36 for the thimble cell and 1.39 for the typical cell for ANF fuel and 1.22 for the thimble cell and 1.23 for the typical cell for VANTAGE 5 fuel) required to meet the DNB design basis.

Table B.2-2 presents the limiting RPS trip setpoints assumed in the Non-LOCA accident analyses and the time delay assumed for each trip function. It should be noted that the high pressurizer water level reactor trip setpoint was assumed in the safety analysis. The differences between the limiting trip setpoint assumed for the analysis and the nominal trip setpoint represents an allowance for instrumentation channel error and setpoint error. Nominal trip setpoints are specified in the plant Technical Specifications. The protection system channels are calibrated and instrument response times determined periodically in accordance with the Technical Specifications.

The enclosed safety analyses/evaluations assume that the reference average temperature (T′ and T″) used in the OTΔT and OPΔT setpoint equations are rescaled to the full power vessel average

temperature each time the cycle vessel average temperature is changed. It is also assumed that the reference pressure (P′) in the OTΔT equation is set equal to the appropriate nominal primary system pressure (2250 or 2100 psia). P′ is 2250 psia for transition cycles (Cycles 8 and 9). The analysis also assumes recalibration of the NIS excore detectors to compensate for the changes in downcomer coolant density each time the downcomer operating conditions are changed by more than 4.0 °F.

B.2.2.2 ESF Setpoints

Table B.2-3 presents the limiting ESF setpoints assumed in the accident analyses and the time delay assumed for each trip function. The nominal value of the low steamline pressure setpoint was lowered from 600 psig to 500 psig. The revised low steamline pressure setpoint value provides operating margin for the potential reduced temperature operating conditions of Table B.2-1 (cases 3, 4, and 7). The total delay time for the steamline isolation was increased to 11 seconds to incorporate an allowance for increased valve closure time of 8 seconds as indicated in Section 6.0.

B.2.3 Initial Conditions

For most accidents which are DNB limited, nominal values of initial conditions and the RCS minimum measured flow (366,400 gpm total) are assumed. The allowances on power, temperature, pressure and flow are determined on a statistical basis and are included in the design limit DNBR as described in WCAP-11397 (Reference 2). This procedure is known as the Revised Thermal Design Procedure (RTDP).

For accidents that are not DNB limited or in which RTDP is not employed, the initial conditions are obtained by adding the maximum steady-state errors to nominal values. In addition, the RCS thermal design flow (354,000 gpm) is used. The following maximum steady-state errors are considered:

A. Core Power	+ 2% calorimetric error allowance
B. Average RCS Temperature	+ 4.1 °F/-5.6 °F controller and measurement error allowance
C. Pressurizer Pressure	± 62.6 psi steady-state fluctuations and measurement error allowance

Tables B.2-4 and B.2-5 summarize initial conditions and computer codes used in the accident analysis, and shows which accidents employed a DNB analysis using the RTDP.

B.2.4 Rod Cluster Control Assembly (RCCA) Insertion Characteristics

The negative reactivity insertion following a reactor trip is a function of the acceleration of the RCCA and the variation in rod worth as a function of rod position.

With respect to accident analyses, the critical parameter is from the start of insertion up to the dashpot entry or approximately 85% of the rod cluster travel. For accident analyses, the insertion time to dashpot entry is conservatively taken as 2.7 seconds. An exception to this is the Steamline Break Mass and Energy Releases Inside Containment analysis which used an insertion time to dashpot of 2.4 seconds. As described in Section 5.4.1, an evaluation has been performed that concluded that this difference would have an insignificant effect on the calculated Mass and Energy releases. The RCCA position versus time assumed in accident analyses is shown on Figure B.2-2.

Figure B.2-3 shows the fraction of total negative reactivity insertion versus normalized rod insertion for a core where the axial power distribution is skewed to the lower region of the core. This curve is used as input to all transient analysis point kinetics core models. There is inherent conservatism in the use of this curve in that it is based on a bottom skewed axial power distribution. For cases other than those associated with axial xenon oscillations, significant negative reactivity would have been inserted due to the more favorable axial power distribution existing prior to trip.

The normalized RCCA negative reactivity insertion versus time is shown on Figure B.2-4. The curve shown in this figure was obtained by combining Figures B.2-2 and B.2-3. A total negative reactivity insertion following a trip of 4.0 %Δk/k is assumed in the transient analyses except where specifically noted otherwise. This assumption is consistent with the core design.

The normalized RCCA negative reactivity insertion versus time curve for an axial power distribution skewed to the bottom (Figure B.2-4) is used in transient analyses.

For analyses requiring the use of a dimensional diffusion theory code (TWINKLE, Reference 6), the negative reactivity insertion resulting from reactor trip is calculated directly by the code and is not separable from other reactivity feedback effects. In this case, the RCCA position versus time of Figure B.2-2 is used as a code input.

B.2.5 Reactivity Coefficients

The transient response of the reactor coolant system is dependent on reactivity feedback effects, in particular the moderator temperature coefficient and the Doppler power coefficient. These reactivity coefficients and their values are discussed in detail in Section 3.0. In the analysis of certain events, conservatism requires the use of large reactivity coefficient values, whereas in the analysis of the other events, conservatism requires the use of small reactivity coefficients values. Some analyses, such as loss of reactor coolant from cracks or ruptures in the RCS, do not depend on reactivity feedback effects. The values used are given in Tables B.2-4 and B.2-5. Figure B.2-5 shows the upper and lower Doppler power coefficients, as a function of power, used in the transient analyses. The justification for use of conservatively large versus small reactivity coefficient values is treated on an event-by-event basis.

B.2.6 Residual Decay Heat

For the Non-LOCA analyses, conservative core residual heat generation based on long-term operation at the initial power level preceding the trip is assumed. The 1979 ANS decay heat standard (Reference 3) plus uncertainty was used for calculation of residual decay heat levels. Figure B.2-6 presents this curve as a function of time after shutdown.

B.2.7 Computer Codes Utilized

Summary descriptions of the principal computer codes used in the transient analyses are given below. The codes used in the analysis of each transient have been listed in Tables B.2-4 and B.2-5.

B.2.7.1 FACTRAN

FACTRAN calculates the transient temperature distribution in a cross-section of a metal clad UO2 fuel rod and the transient heat flux at the surface of the clad using as input the nuclear power and the time-dependent coolant parameters (pressure, flow, temperature, density). The code uses a fuel model which simultaneously exhibits the following features:

a. sufficiently large number of radial space increments to handle fast transients such as a rod ejection accidents.

b. Material properties which are functions of temperature and a sophisticated fuel-to-clad gap heat transfer calculation.

c. The necessary calculations to handle post-departure from nucleate boiling (DNB) transients: film boiling heat transfer correlations, Zircaloy-water reaction, and partial melting of the fuel.

FACTRAN is further discussed in Reference 4.

B.2.7.2 LOFTRAN

The LOFTRAN program is used for transient response studies of a pressurized water reactor (PWR) system to specified perturbations in process parameters. All 4 (four) reactor coolant loops are modeled in LOFTRAN program. This code simulates a multiloop system by a model containing the reactor vessel, hot and cold leg piping, steam generators (tube and shell sides), and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves are also considered in the program. Point model neutron kinetics and reactivity effects of the moderator, fuel, boron, and rods are included. The secondary side of the steam generator utilizes a homogeneous, saturated mixture for the thermal transients. The reactor protection system is simulated to include reactor trips on high neutron flux, overtemperature ΔT, overpower ΔT, high and low pressure, low flow, and high pressurizer level. Control systems are also simulated including rod control, steam dump, and pressurizer pressure control. The ECCS, including the accumulators, is also modeled.

LOFTRAN also has the capability of calculating the transient value of DNBR based on the input from the core thermal safety limits.

LOFTRAN is further discussed in Reference 5.

B.2.7.3 TWINKLE

The TWINKLE program is a multi-dimensional spatial neutron kinetics code, which was patterned after steady-state codes used for reactor core design. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed multi-region fuel-clad-coolant heat transfer model for calculating pointwise Doppler and moderator feedback effects. The code handles up to 2000 spatial points and performs its own steady-state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and others. Various edits are provided; e.g., channelwise power, axial offset, enthalpy, volumetric surge, pointwise power and fuel temperatures.

The TWINKLE code is used to predict the kinetic behavior of a reactor for transients which cause a major perturbation in the spatial neutron flux distribution.

TWINKLE is further described in Reference 6.

B.2.7.4 THINC

The THINC-IV computer program is used to perform thermal-hydraulic calculations. The THINC-IV code calculates coolant density, mass velocity, enthalpy, void fractions, static pressure, and DNBR distributions along flow channels within a reactor core under all expected operating conditions. The THINC-IV code is described in detail in References 7 and 8, including models and correlations used.

TABLE B.2-1

DESIGN POWER CAPABILITY PARAMETERS
USED IN NON-LOCA SAFETY ANALYSES*

Parameter	Case 1	Case 2	Case 3
NSSS Power, MWt	3423	3600	3600
Core Power, MWt	3411	3588	3588
RCS Flow,(gpm/loop)	87,450	88,500	88,500
Minimum Measured Flow, (total gpm)	364,960	366,400	366,400
RCS Temperatures, °F			
Core Outlet	-	613.5	585.8
Vessel Outlet	-	610.2	582.3
Core Average	575.5	579.5	550.1
Vessel Average	574.1	576.0	547.0
Vessel/Core Inlet	-	541.8	511.7
Steam Generator Outlet	547.0	541.6	511.4
Zero Load	547.0	547.0	547.0
RCS Pressure, psia	2250	2250	2250
Steam Pressure,psia	794.4	780.4	587.0
Steam Flow, (10^6 lb/hr total)	14.6	15.98	15.90
Feedwater Temp., °F	423.4	449.0	449.0
% SG Tube Plugging	10	10	10

* A brief description of each case follows Table B.2-1

TABLE B.2-1 (continued)

DESIGN POWER CAPABILITY PARAMETERS
USED IN NON-LOCA SAFETY ANALYSES*

Parameter	Case 4	Case 5	Case 6	Case 7
NSSS Power, MWt	3600	3600	3600	3600
Core Power, MWt	3588	3588	3588	3588
RCS Flow,(gpm/loop)	88,500	88,500	88,500	88,500
Minimum Measured Flow, (total gpm)	366,400	366,400	366,400	366,400
RCS Temperatures, °F				
Core Outlet	618.4	618.2	585.8	585.7
Vessel Outlet	615.2	615.0	582.3	582.2
Core Average	584.8	584.9	550.1	550.1
Vessel Average	581.3	581.3	547.0	547.0
Vessel/Core Inlet	547.3	547.6	511.7	511.8
Steam Generator Outlet	547.1	547.4	511.4	511.5
Zero Load	547.0	547.0	547.0	547.0
RCS Pressure, psia	2250	2100	2250	2100
Steam Pressure,psia	820.0	820.0	587.0	587.0
Steam Flow, (10^6 lb/hr total)	16.0	16.0	15.9	15.9
Feedwater Temp., °F	449.0	449.0	449.0	449.0
% SG Tube Plugging	10	10	10	10

* A brief description of each case follows Table B.2-1

A brief description of various cases listed in Table B.2-1

Case 1: These are the currently licensed design power capability parameters for Cook Nuclear Plant Unit 2 and are shown for comparison with revised parameters assumed in the Non-LOCA safety analyses for this report. Dashes in case 1 indicate information which was not contained in the FSAR.

Case 2: These parameters incorporate a core power level of 3588 MWt, an NSSS power level of 3600 MWt (which includes 12 MWt for reactor coolant pump heat), an average steam generator tube plugging level of 10%, primary pressure of 2250 psia, and an upper bound vessel average temperature of 576 °F. This parameter case was used to support high temperature operation during mixed core cycles (Cycles 8 and 9).

Case 3: These parameters incorporate a core power level of 3588 MWt, an NSSS power level of 3600 MWt (which includes 12 MWt for reactor coolant pump heat), an average steam generator tube plugging level of 10%, primary pressure of 2250 psia, and a lower bound vessel average temperature of 547 °F. This parameter case was used to support low temperature operation during mixed core cycles (Cycles 8 and 9).

Case 4: These parameters incorporate a core power level of 3588 MWt, an NSSS power level of 3600 MWt (which includes 12 MWt for reactor coolant pump heat), an average steam generator tube plugging level of 10%, primary pressure of 2250 psia, and an upper bound vessel average temperature of 581.3 °F. This parameter case was used to support high temperature and high primary pressure operation for a full VANTAGE 5 core (Cycle 10 and beyond).

Case 5: These parameters incorporate the same features as case 4, except the primary pressure is 2100 psia. This parameter case was used to support high temperature and low primary pressure operation for a full VANTAGE 5 core (Cycles 10 and beyond).

Case 6: These parameters incorporate the same features as case 4, except the lower bound temperature is 547 °F. This parameter case was used to support low temperature and high primary pressure operation for a full VANTAGE 5 core (Cycles 10 and beyond).

Case 7: These parameters incorporate the same features as case 6, except the primary pressure is 2100 psia. This parameter case was used to support low temperature and low primary pressure operation for a full VANTAGE 5 core (Cycles 10 and beyond).

TABLE B.2-2

RPS TRIP POINTS AND TIME DELAYS TO TRIP ASSUMED IN NON-LOCA SAFETY ANALYSIS

Trip Function	Limiting Trip Point Assumed In Analysis	Time Delay (Seconds)
Power range high neutron flux, high setting	118%	0.5
Power range high neutron flux, low setting	35%	0.5
Overtemperature ΔT	Variable, see Figures B.2-1a,1b	8.0[a]
Overpower ΔT	Variable,see Figures B.2-1a,1b	8.0[a]
High pressurizer pressure	2428 psig	2.0
Low pressurizer pressure	1907 psig	2.0
High pressurizer water level	100% span	2.0
Low reactor coolant flow (From loop flow detectors)	87% loop flow	1.0
Undervoltage trip	NA[b]	1.5
Underfrequency trip	57 Hz	0.6
Low-low steam generator level	0.0% of narrow range level span	2.0

a Time delay (including RTD bypass loop fluid transport delay, bypass loop piping thermal capacity, RTD time response, and trip circuit including channel electronics delay) from the time the temperature difference in the coolant loops exceeds the trip setpoint until the rods are free to fall. The time delay assumed in the analysis supports a total 6 second response time of the combined RTD time response, trip circuit delay, and channel electronics delay presented in the updated Technical Specifications.

b No explicit value assumed in the analysis. Undervoltage trip setpoint assumed reached at initiation of analysis.

TABLE B.2-3

ESF TRIP POINTS AND TIME DELAYS TO TRIP
ASSUMED IN NON-LOCA SAFETY ANALYSIS

ESF Actuation System	Limiting Trip Point Assumed In Analysis	Time Delay (Seconds)
Safety Injection (SI)		
- Low pressurizer pressure	1800 psig	27 w/ offsite power (Note 1) 37 w/o offsite power (Note 2)
- Low steamline pressure	344 psig	27 w/ offsite power (Note 1) 37 w/o offsite power (Note 2)
Auxiliary Feedwater (AFW)		
- Low-low steam generator water level	0.0% of narrow range level span	60[a]
High steam generator level Turbine Trip	82% of narrow range level span	2.5
Steamline Isolation on low steam line pressure	Not applicable	11[b]
Feedline Isolation on high steam generator water level	Not applicable	11[c]
Feedline Isolation on low steam line pressure	Not applicable	8[c]

TABLE B.2-3 (continued)

ESF TRIP POINTS AND TIME DELAYS TO TRIP
ASSUMED IN NON-LOCA SAFETY ANALYSIS

[a] For Loss of Normal Feedwater and Loss of Offsite Power to Station Auxiliaries events, the delay time assumed is 60 seconds from the initiation of the signals.

For Feedline Break event, the delay time assumed is 600 seconds (10 minute operator action delay) from the initiation of the break.

[b] Steamline isolation total delay time includes valve closure time, and electronics and sensor delay. Technical Specifications require 8.0 second valve closure time.

[c] Feedline isolation total delay time includes valve closure time and electronics and sensor delay time.

Note 1: Diesel generator starting and sequence loading delays NOT included. Offsite power available. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps. Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valve close) is included.

Note 2: Diesel generator starting and sequence loading delays included. Response time limit includes opening of valves to establish SI path and attainment of discharge pressure for centrifugal charging pumps. Sequential transfer of charging pump suction from the VCT to the RWST (RWST valves open, then VCT valve close) is included.

TABLE B.2-4

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Faults	Computer Codes Utilized	Reactivity Coefficients Assumed: Moderator Temperature (pcm/°F)	Reactivity Coefficients Assumed: Moderator Density (ΔK/gm/cc)	Reactivity Coefficients Assumed: Doppler	DNB Correlation	Revised Thermal Design Procedure	Initial NSSS Thermal Power Output(9) (MWt)	Reactor Vessel Coolant Flow (GPM)	Vessel Average Temperature (°F)	Pressurizer Pressure (PSIA)
Uncontrolled Rod Cluster Assembly Bank Withdrawal from a Subcritical Condition	TWINKLE FACTRAN THINC	See Section B.3.1.2	NA	(11)	W-3 ANF WRB-2 and W-3 V-5	No	0	162,840	547.0	2037.0(6)
Uncontrolled Rod Cluster Assembly Bank Withdrawal at Power (2), (3)	LOFTRAN	NA* +5	.54 NA	Max (4) Min (1)	W-3 ANF WRB-2 V-5	Yes	3608 2165 361	366,400	576.0 564.4 549.9	2250.0
Rod Cluster Control Assembly Misalignment	LOFTRAN THINC	NA	NA	NA	W-3 ANF WRB-2 V-5	Yes	3600	366,400	581.3	2100.0
Uncontrolled Boron Dilution	NA	NA	NA	NA	NA	NA	3600 0	NA	NA	NA
Loss of Forced Reactor Coolant Flow	LOFTRAN FACTRAN THINC	+5	NA	Max(4)	W-3 ANF WRB-2 V-5	Yes	3608	366,400	581.3(12)	2100.0(10)
Locked Rotor (Peak Pressure)	LOFTRAN	+5	NA	Max(4)	NA	NA	3680	354,000	585.4	2312.6
Locked Rotor (Peak Clad Temp)	LOFTRAN FACTRAN	+5	NA	Max(4)	NA	NA	3680	354,000	585.4	2037.4

*NA - Not Applicable

(1) Minimum Doppler power coefficient (pcm/%power) = -9.55 + 0.03732Q, where Q is in % power (see Figure B.2-5).

(2) Multiple power levels, Tavg, and reactivity feedback cases were examined.

(3) Initial conditions for the separate analysis to bound assumed operating conditions for full V-5 core are shown in Table B.2-5

(4) Maximum Doppler power coefficient (pcm/%power) = -19.4 + 0.07176Q, where Q is in % power (see Figure B.2-5).

(5) Minimum and maximum reactivity feedback cases were examined.

(6) Core Pressure.

(7) Full Power Doppler Power defect at BOL and EOL assumed to be -910 pcm and -840 pcm respectively.

(8) Core thermal power.

(9) Includes reactor coolant pump heat, if applicable.

(10) For transition cycles, pressurizer pressure is 2250 psia.

(11) Zero Power Doppler Power Defect at BOL assumed to be -1020 pcm

(12) For Transition Cycles, Vessel Average Temperature is 576°F.

TABLE B.2-4 (Cont'd)

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Faults	Computer Codes Utilized	Reactivity Coefficients Assumed: Moderator Temperature (pcm/°F)	Reactivity Coefficients Assumed: Moderator Density (ΔK/gm/cc)	Reactivity Coefficients Assumed: Doppler	DNB Correlation	Revised Thermal Design Procedure	Initial NSSS Thermal Power Output[9] (MWt)	Reactor Vessel Coolant Flow (GPM)	Vessel Average Temperature (°F)	Pressurizer Pressure (PSIA)
Loss of Electrical Load or Turbine Trip (3), (5)	LOFTRAN	NA	.54	Max (4)	W-3 ANF WRB-2 V-5	Yes	3600	366,400	576.0	2250.0
		+5	NA	Min (1)						
Loss of Normal Feedwater	LOFTRAN	+5	NA	Max (4)	NA	NA	3680	354,000	585.4	2312.6
Excessive Heat Removal Due to Feedwater System Malfunction	LOFTRAN	NA	.54	Min (1)	W-3 ANF WRB-2 V-5	Yes	3600 0	366,400	576.0 547.0	2250.0
Excess Load Increase (3)	LOFTRAN	NA	0	Min (1)	W-3 ANF WRB-2 V-5	Yes	3600	366,400	576.0	2250.0
		NA	.54	Max (4)						
Loss of Offsite Power to the Station Auxiliaries	LOFTRAN	+5	NA	Max (4)	NA	NA	3680	354,000	541.4	2312.6
Rupture of a Steam Pipe	LOFTRAN THINC	See Figure B.3-55	NA	See Figure B.3-56	W-3 ANF W-3 V-5	NO	0	354,000	547.0	2100 0
Rupture of a Control Rod Drive Mechanism Housing	TWINKLE FACTRAN	See Section B.3.12	NA	(7)	NA	NA	3660(8) 0	354,000 162,840	585 4 547.0	2037.4(6)
Rupture of Feedwater Pipe	LOFTRAN	NA	.54	Max (4)	NA	NA	3672	354,000	585 4	2162.6

*NA - Not Applicable
(1) Minimum Doppler power coefficient (pcm/%power) = -9.55 + 0 03732Q, where Q is in % power (see Figure B.2-5).
(2) Multiple power levels, Tavg, and reactivity feedback cases were examined.
(3) Initial conditions for the separate analysis to bound assumed operating conditions for full V-5 core are shown in Table B.2-5.
(4) Maximum Doppler power coefficient (pcm/%power) = -19 4 + 0 07176Q, where Q is in % power (see Figure B.2-5).
(5) Minimum and maximum reactivity feedback cases were examined
(6) Core Pressure.
(7) Full Power Doppler Power defect at BOL and EOL assumed to be -910 pcm and -840 pcm respectively.
(8) Core thermal power.
(9) Includes reactor coolant pump heat, if applicable.
(10) For transition cycles, pressurizer pressure is 2250 psia.
(11) Zero Power Doppler Power Defect at BOL assumed to be -1020 pcm
(12) For Transition Cycles, Vessel Average Temperature is 576°F,

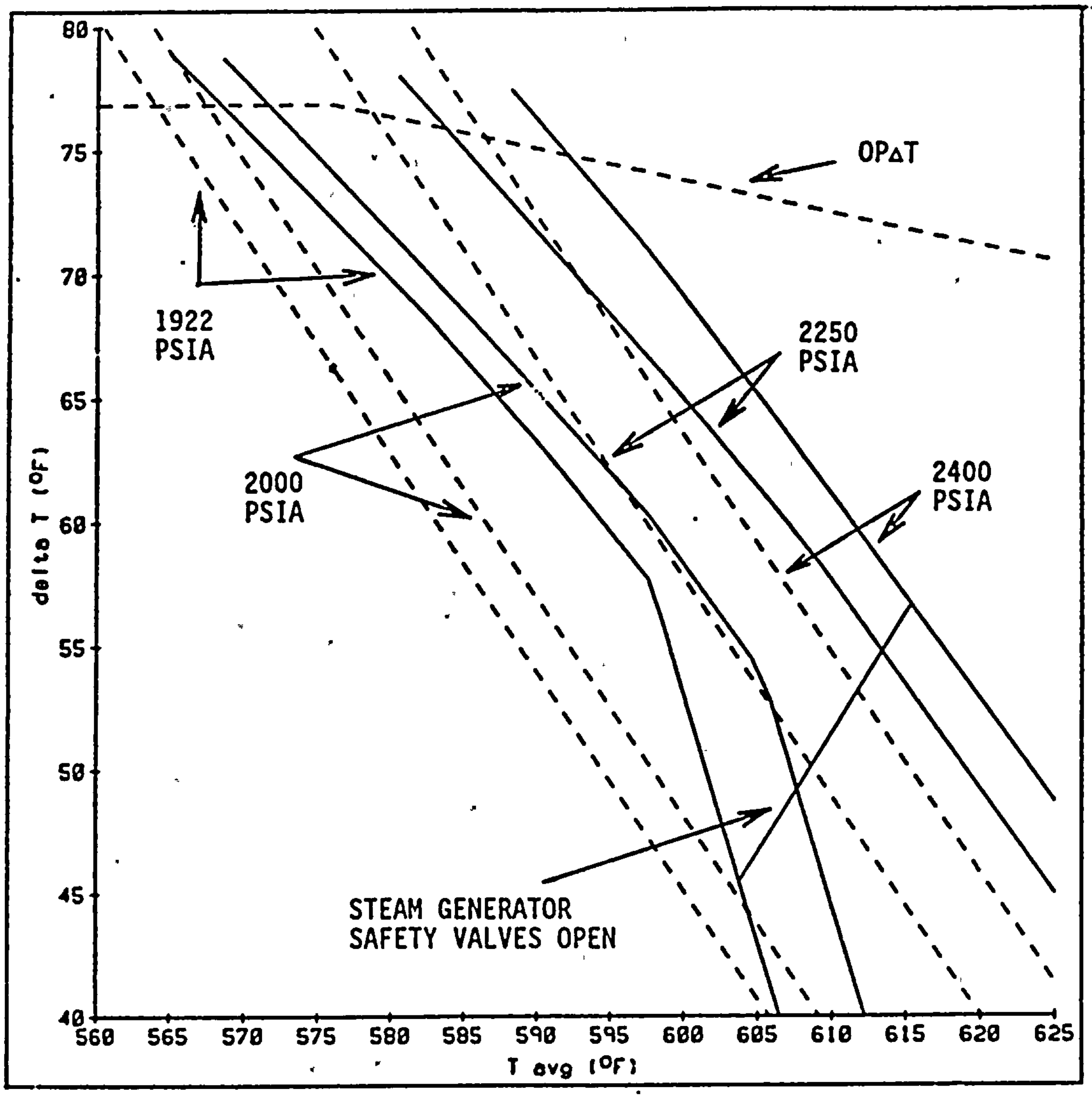
TABLE B.2-5

SUMMARY OF INITIAL CONDITIONS AND COMPUTER CODES USED

Faults	Computer Codes Utilized	Reactivity Coefficients Assumed: Moderator Temperature (pcm/°F)	Reactivity Coefficients Assumed: Moderator Density (ΔK/gm/cc)	Reactivity Coefficients Assumed: Doppler	DNB Correlation	Revised Thermal Design Procedure	Initial NSSS Thermal Power Output(9) (MWt)	Reactor Vessel Coolant Flow (GPM)	Vessel Average Temperature (°F)	Pressurizer Pressure (PSIA)
Uncontrolled Rod Cluster Assembly Bank Withdrawal At Power (2), (3)	LOFTRAN	NA*	.54	Max (4)	WRB-2	Yes	3608 2165 361	366,400	581.3 567.6 550.4	2100.0
		+5	NA	Min (1)						
Loss Of Electrical Load or Turbine Trip (3), (5)	LOFTRAN	NA	.54	Max (4)	WRB-2	Yes	3600	366,400	581.3	2100.0
		+5	NA	Min (1)						
Excessive Heat Removal Due to Feedwater System Malfunction	LOFTRAN	NA	.54	Min (1)	WRB-2	Yes	3600 0	366,400	581.3 547.0	2100.0
Excess Load Increas (3)	LOFTRAN	NA	0	Min (1)	WRB-2	Yes	3600	366,400	581.3	2100.0
		NA	.54	Max (4)						

*NA - Not Applicable

(1) Minimum Doppler power coefficient (pcm/%power) = -9.55 + 0.03732Q, where Q is in % power (see Figure B.2-5).
(2) Multiple power levels, Tavg, and reactivity feedback cases were examined.
(3) Initial conditions for the mixed core analysis are shown in Table B 2-4.
(4) Maximum Doppler power coefficient (pcm/%power) = -19.4 + 0.07176Q, where Q is in % power (see Figure B.2-5).
(5) Minimum and maximum reactivity feedback cases were examined.
(6) Core pressure.
(7) Full Power Doppler Power defect at BOL and EOL assumed to be -910 pcm and -840 pcm respectively.
(8) Core thermal power.
(9) Includes reactor coolant pump heat, if applicable.
(10) For transition cycles, pressurizer pressure is 2250 psia.
(11) Zero Power Doppler Power Defect at BOL assumed to be -1020 pcm
(12) For Transition Cycles, Vessel Average Temperature is 576°F.



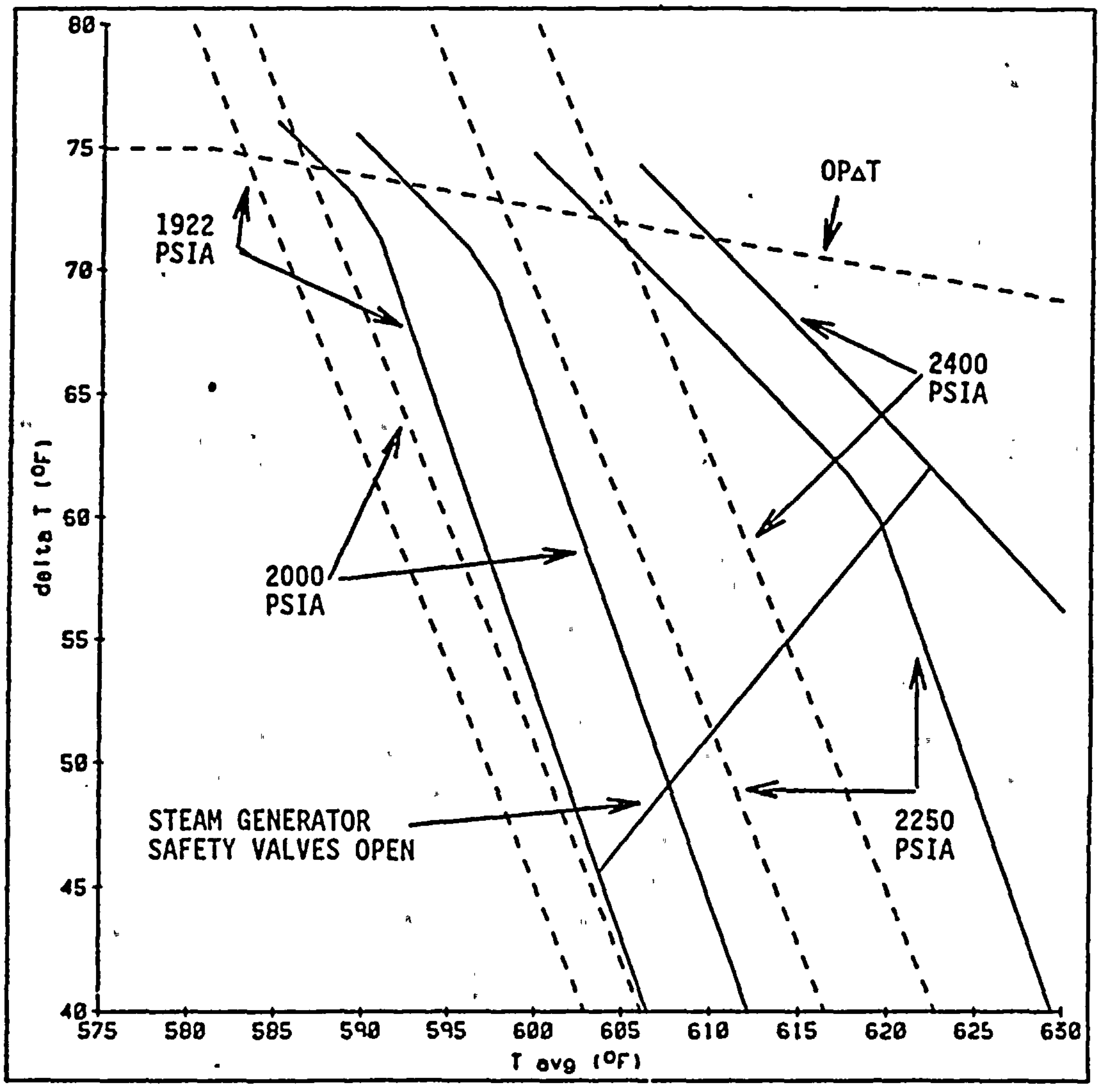
------OTΔT Protection Lines

______Core Thermal Safety Limits

Figure B.2-1a: Overtemperature and Overpower ΔT Protection

Core Conditions:

- Transition Cycles
- Nominal Vessel Average Temperature = 576°F
- Nominal Pressurizer Pressure = 2250 psia.



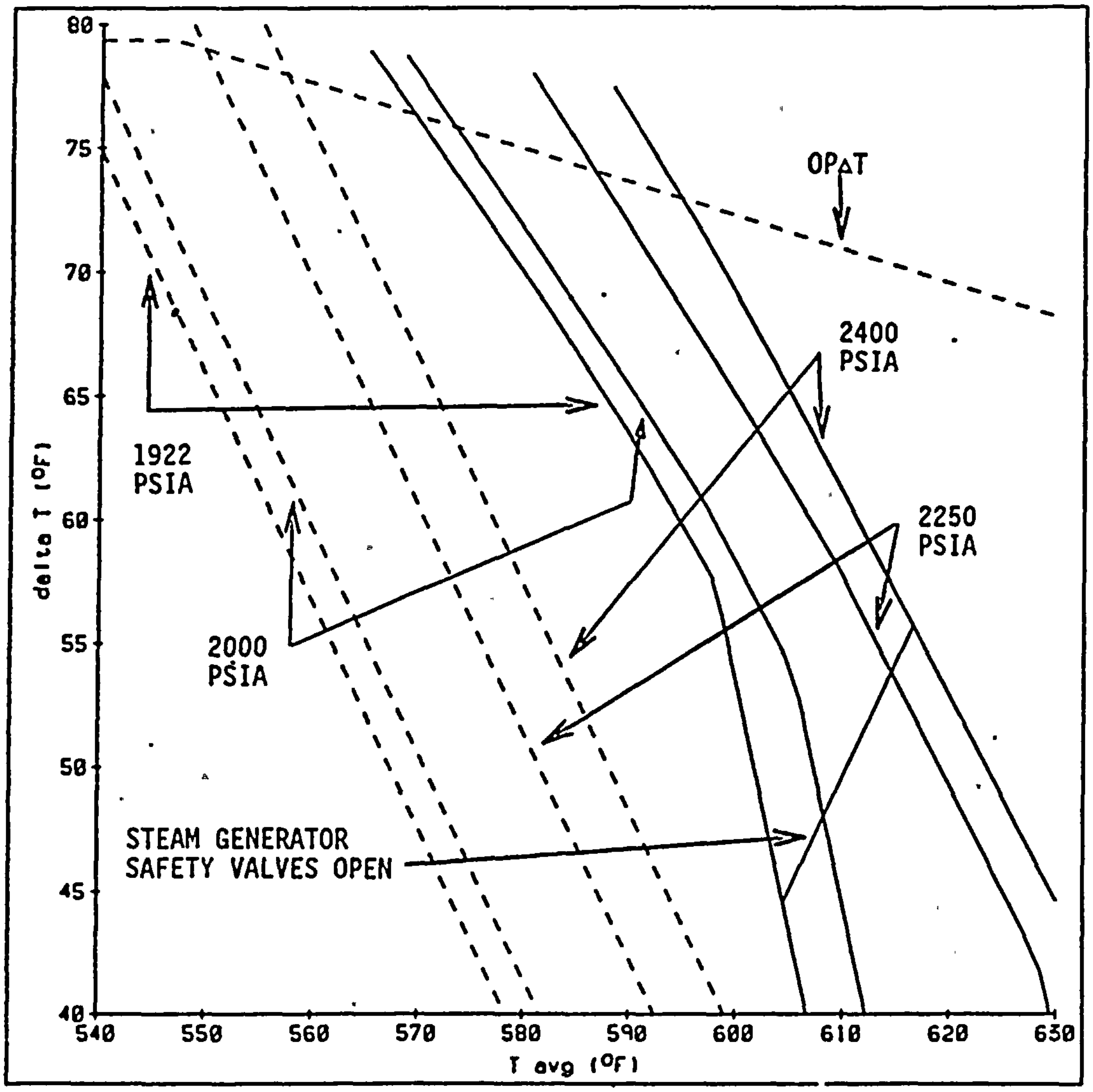
------OTΔT Protection Lines

______Core Thermal Safety Limits

Figure B.2-1b: Overtemperature and Overpower ΔT Protection

Core Conditions:

- Full VANTAGE 5 Core
- Nominal Vessel Average Temperature = 581.3°F
- Nominal Pressurizer Pressure = 2100 psia.



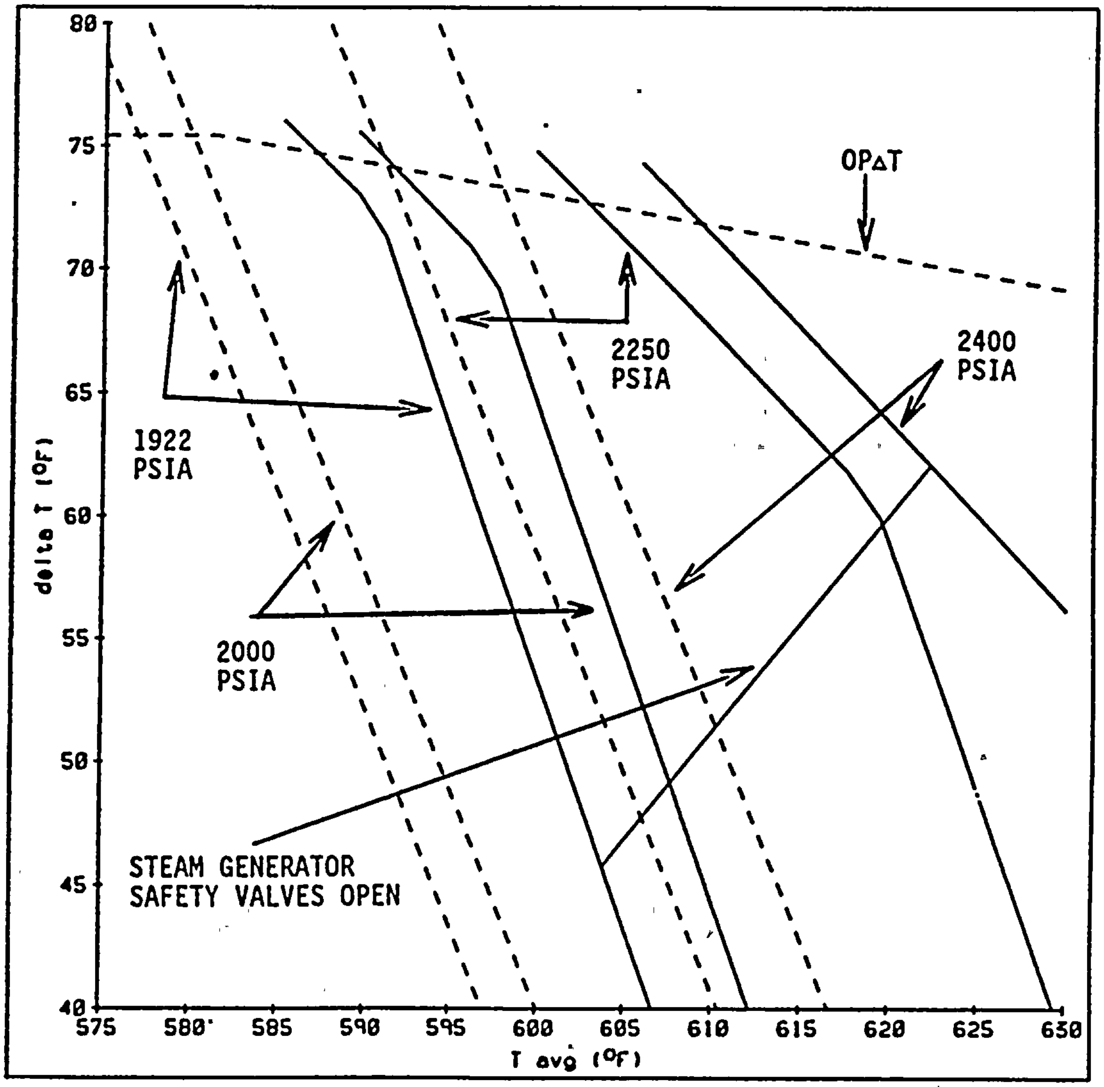
------OTΔT Protection Lines

______Core Thermal Safety Limits

Figure B.2-1c: Illustration of Overtemperature and Overpower ΔT Protection

Core Conditions:

- Transition Cycles
- Nominal Vessel Average Temperature = 547°F
- Nominal Pressurizer Pressure = 2250 psia.



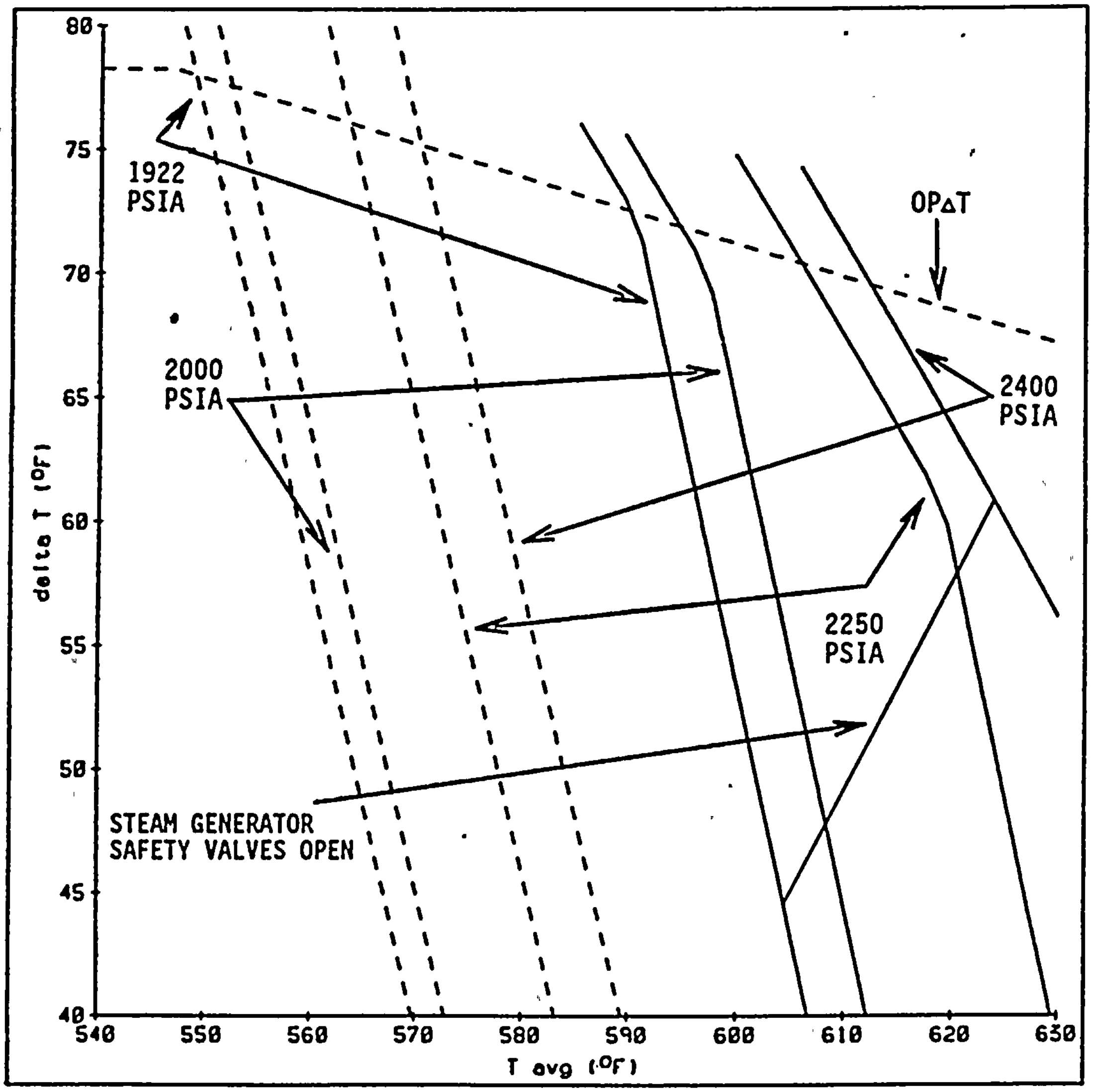
------OT∆T Protection Lines

______Core Thermal Safety Limits

Figure B.2-1d: Illustration of Overtemperature and Overpower ∆T Protection

Core Conditions:

- Full VANTAGE 5 Core
- Nominal Vessel Average Temperature = 581.3°F
- Nominal Pressurizer Pressure = 2250 psia.



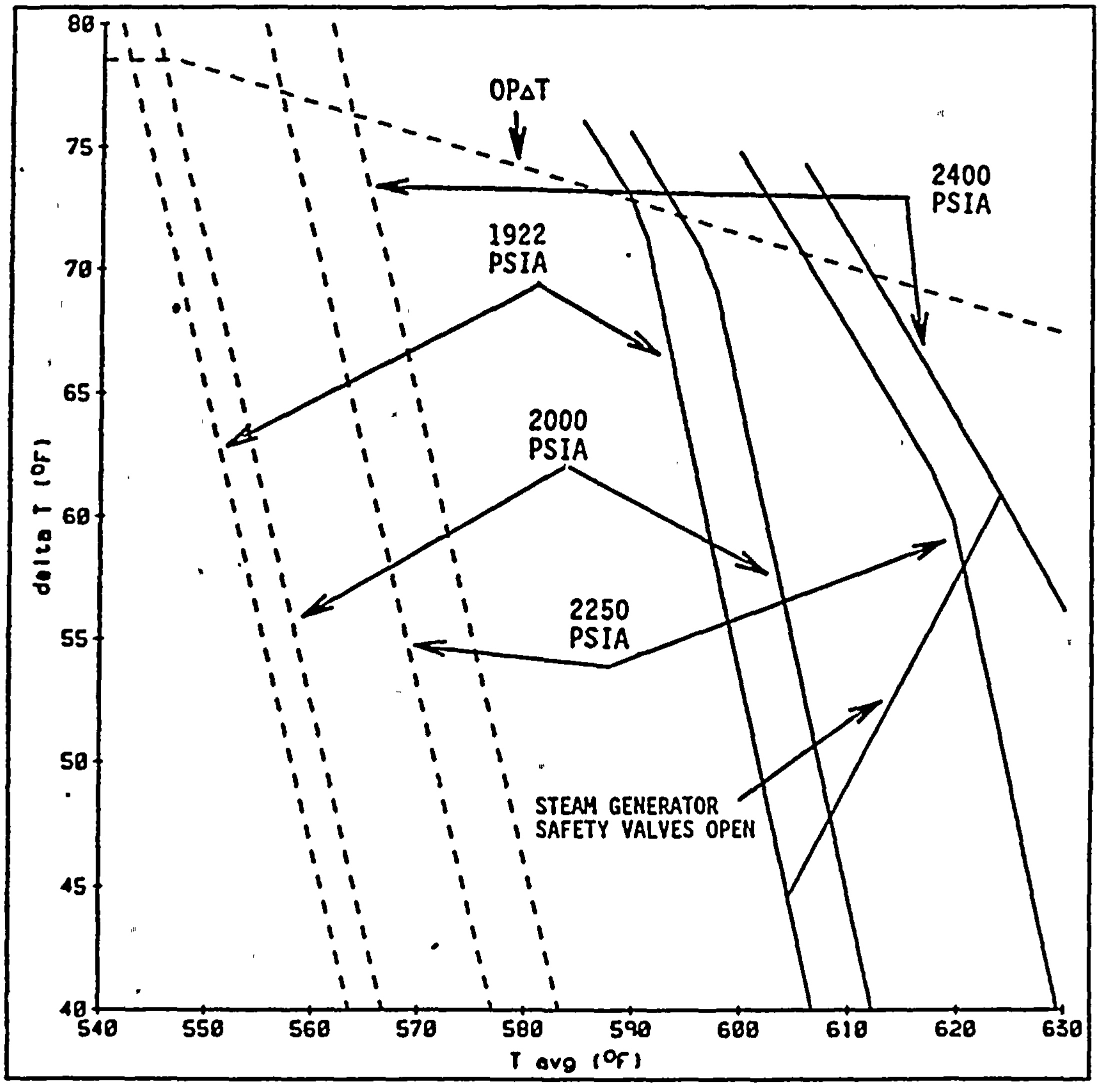
------OT∆T Protection Lines

______Core Thermal Safety Limits

Figure B.2-1e: Illustration of Overtemperature and Overpower ∆T Protection

Core Conditions:

- Full VANTAGE 5 Core
- Nominal Vessel Average Temperature = 547°F
- Nominal Pressurizer Pressure = 2100 psia.



------OTΔT Protection Lines

______Core Thermal Safety Limits

Figure B.2-1f: Illustration of Overtemperature and Overpower ΔT Protection

Core Conditions:

- Full VANTAGE 5 Core
- Nominal Vessel Average Temperature = 547°F
- Nominal Pressurizer Pressure = 2250 psia.

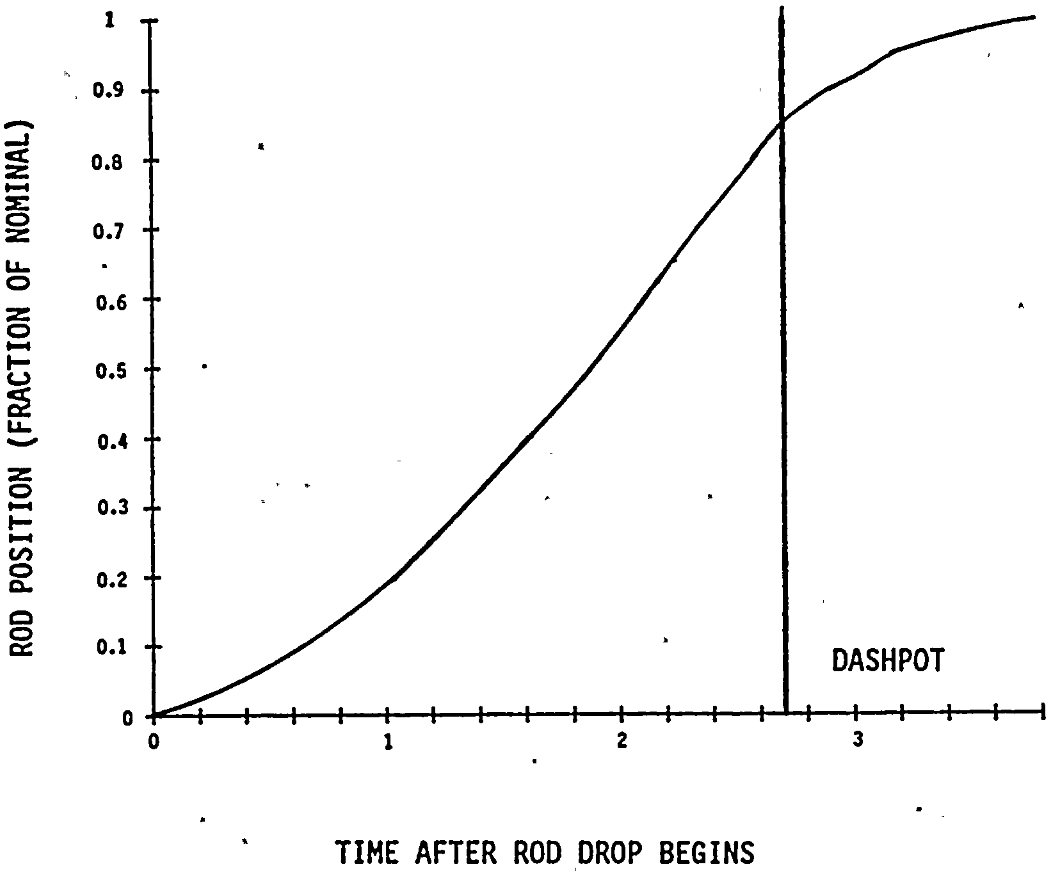


Figure B.2-2: Rod Position vs. Time After Rod Drop Begins

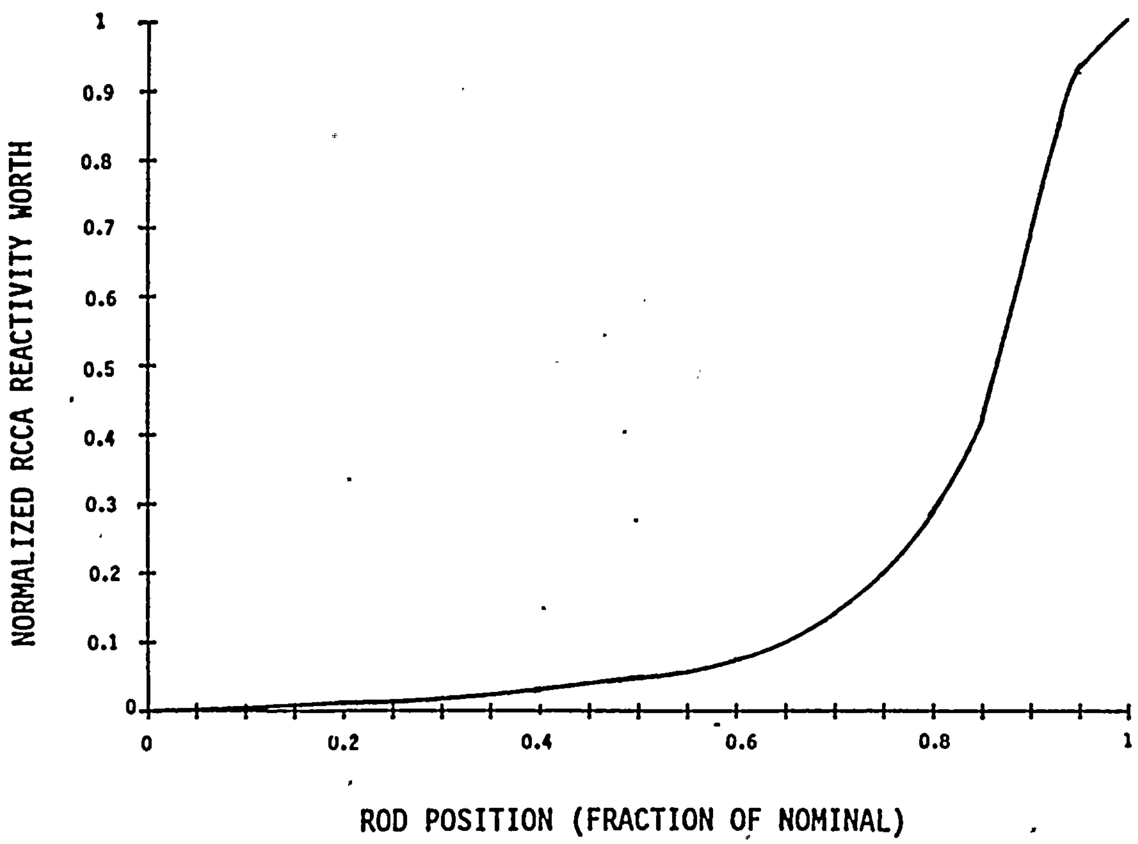


Figure B.2-3 Normalized RCCA Reactivity Worth vs. Rod Position

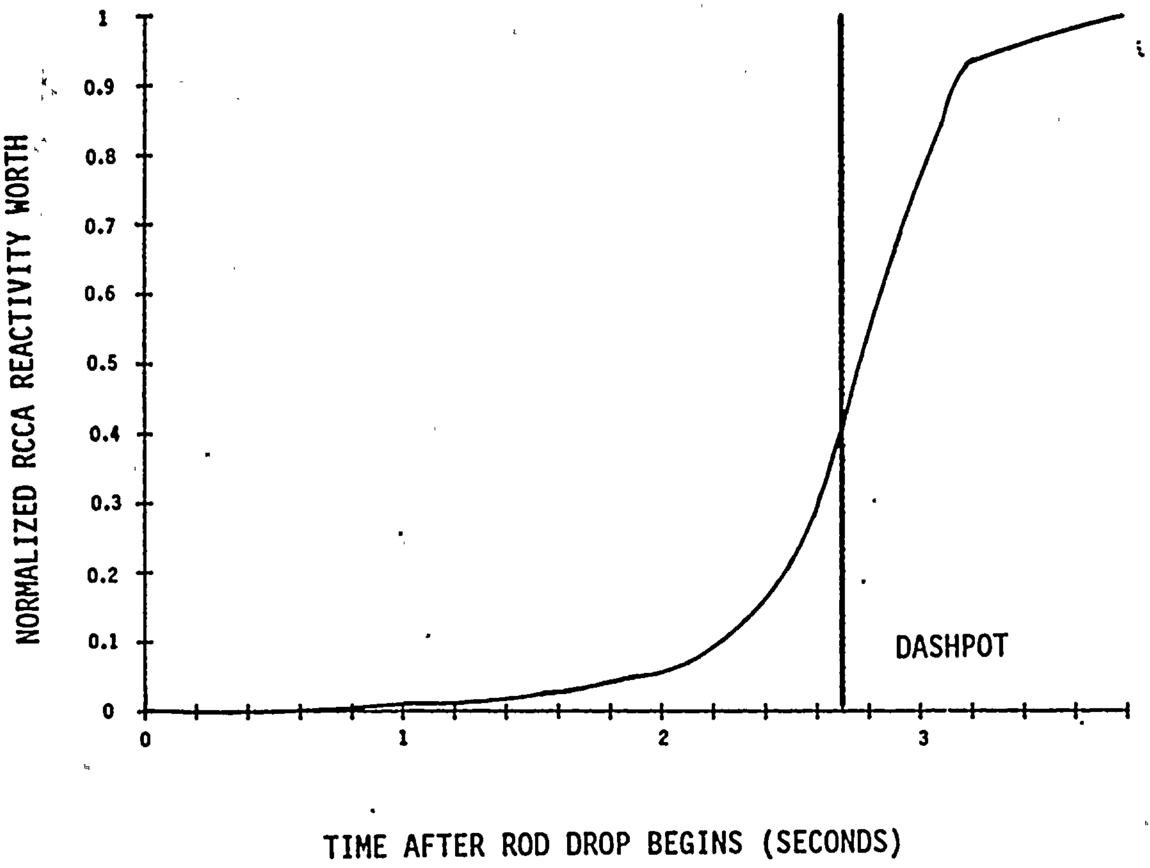


Figure B.2-4 Normalized RCCA Reactivity Worth vs. Time After Rod Drop Begins

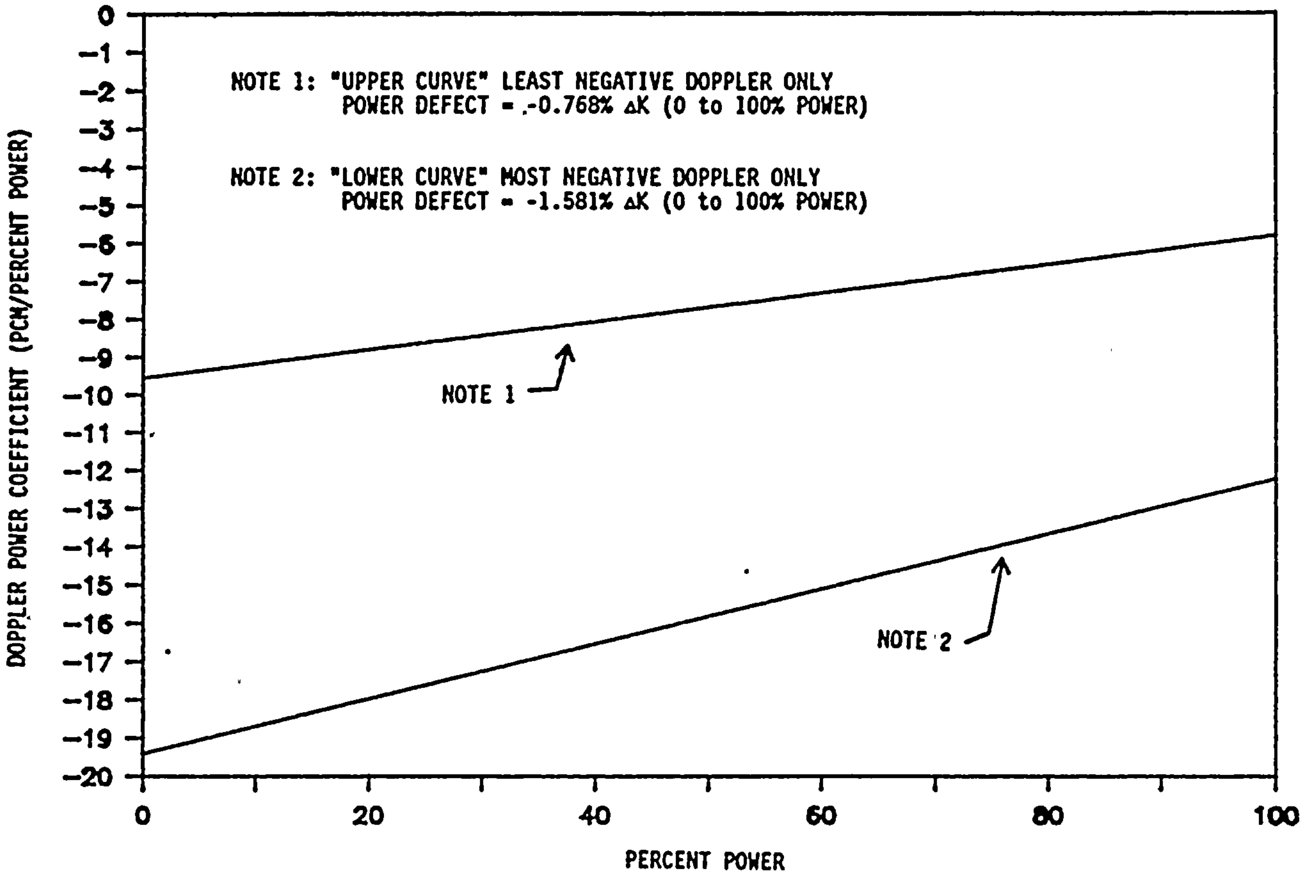


Figure B.2-5 Doppler Power Coefficient Used In Accident Analysis

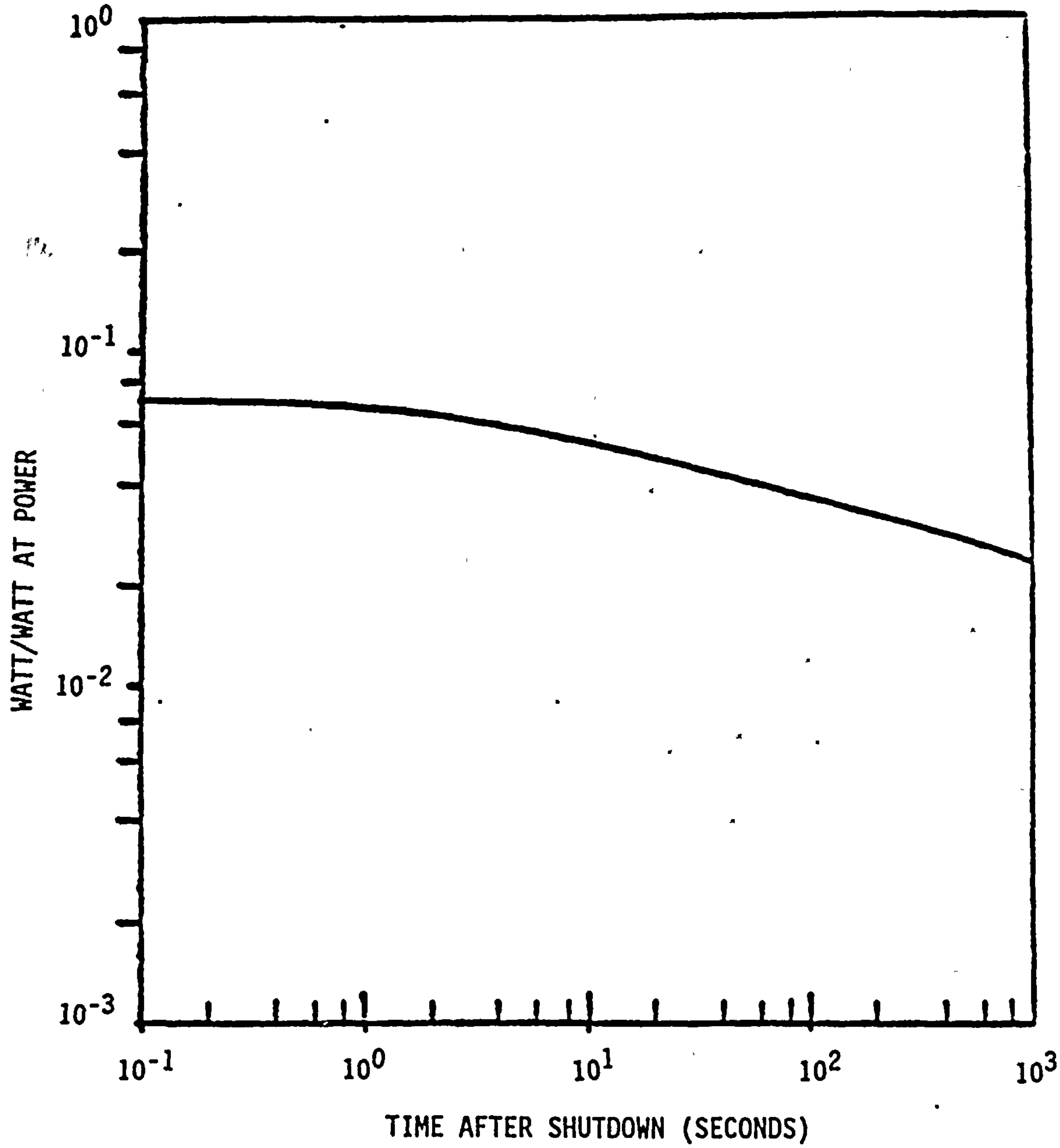


Figure B.2-6 1979 ANS Decay Heat Used In Accident Analyses

B.3 REANALYZED ACCIDENT DESCRIPTIONS

The following section contains the detailed descriptions of the reanalyzed accidents. As discussed in Section B.2.1, four DNB-related transients are analyzed twice. The detailed descriptions of these four Non-LOCA accidents are presented twice. For the remaining DNB-related accidents, a bounding analysis is presented. DNBR evaluations performed for these accidents verified that the applicable DNB limits are met for both a mixed core and a full VANTAGE 5 core. For the Non-DNB related accidents, a bounding analysis is presented below for both mixed and full VANTAGE 5 core.

In all cases the applicable UFSAR acceptance criteria are satisfied.

B.3.1 Uncontrolled RCCA Withdrawal From A Subcritical Condition

B.3.1.1 Introduction

The uncontrolled RCCA withdrawal from a subcritical condition event is analyzed to determine the impact of the design changes associated with the VANTAGE 5 transition as discussed in Section B.1. It is also analyzed because of the reduction in the nominal RCS pressure since a reduced RCS pressure is nonconservative with respect to the DNB transient.

An RCCA withdrawal incident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of RCCA banks resulting in a power excursion. While the occurrence of a transient of this type is highly unlikely, such a transient could be caused by a malfunction of the Reactor Control or Control Rod Drive Systems. This could occur with the reactor either subcritical or at power. The "at power" case is discussed in Section B.3.2.

Reactivity is added at a prescribed and controlled rate in bringing the reactor from a shutdown condition to a low power level during startup by RCCA bank withdrawal. Although the initial startup procedure uses the method of boron dilution, the normal startup is with RCCA bank withdrawal. RCCA bank motion can cause much faster changes in reactivity than can be made by changing boron concentration.

The control rod drive mechanisms are wired into preselected banks which are not altered during the core life. The RCCAs are therefore physically prevented from being withdrawn in other than

their respective banks. Power supplied to the rod banks is controlled such that no more than two banks can be withdrawn at any time. The RCCA drive mechanism is of the magnetic latch type and the coil actuation is sequenced to provide variable speed travel. The maximum reactivity insertion rate is analyzed by assuming the simultaneous withdrawal of the combination of the two banks of the maximum combined worth at maximum speed.

Should a continuous control rod assembly withdrawal be initiated, the transient will be terminated by the following reactor trip functions.

1. Source range neutron flux trip - actuated when either of two independent source range channels indicates a flux above a preselected, manually adjustable value. This trip function may be manually bypassed when either intermediate range flux channel indicates a flux above the source range cutoff level. It is automatically reinstated when both intermediate range channels indicate a flux below the source range cutoff level.

2. Intermediate range neutron flux trip - actuated when either of two independent intermediate range channels indicates a flux above a preselected, manually adjustable value. This trip function may be manually bypassed when two of the four power range channel are reading above approximately 10 percent of full power flux and is automatically reinstated when three of the four power range channels indicate a flux below this value.

3. Power range high neutron flux trip (low setting) - actuated when two out of the four power channels indicate a flux above approximately 25 percent of full power flux. This trip function may be manually bypassed when two of the four power range channels indicate a flux above approximately 10 percent of full power flux and is automatically reinstated when three of the four channels indicate a flux below this value.

4. Power range neutron flux level trip (high setting) - actuated when two out of the four power range channels indicate a flux level above a preset setpoint. This trip function is always active.

In addition, control rod stops on intermediate range flux and high power range flux serve to discontinue rod withdrawal and prevent the need to actuate the intermediate range flux trip and the power range flux trip, respectively.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast power rise terminated by the reactivity feedback effect of the negative fuel temperature coefficient. This self-limitation of the initial power burst results from a fast negative fuel temperature feedback (Doppler effect) and is of prime importance during a startup incident since it limits the power to a tolerable level prior to protective action. After the initial power burst, the neutron flux is momentarily reduced and then, if the incident is not terminated by a reactor trip, the neutron flux increases again, but at a much slower rate.

Termination of the startup incident by the previously discussed protection channels prevents core damage. In addition, the reactor trip from pressurizer high pressure serves as a backup to terminate the incident before an overpressure condition could occur.

B.3.1.2 Method of Analysis

The analysis of the uncontrolled RCCA bank withdrawal from subcritical accident is performed in three stages: first, an average core nuclear power transient calculation, then, an average core heat transfer calculation, and finally, the departure from nucleate boiling ratio (DNBR) calculation. The average core nuclear calculation is performed using spatial neutron kinetics methods (TWINKLE) to determine the average power generation with time including the various total core feedback effects, i.e., Doppler reactivity and moderator reactivity. The average heat flux and temperature transients are determined by performing a fuel rod transient heat transfer calculation in FACTRAN. The average heat flux is next used in THINC for transient DNBR calculations.

Analysis of this transient incorporates the neutron kinetics, including six delayed neutron groups and the core thermal and hydraulic equations. In addition to the neutron flux response, the average fuel, clad and water temperature, and also the heat flux response, are computed.

In order to give conservative results for a startup incident, the following additional assumptions are made concerning the initial reactor conditions:

1. Since the magnitude of the neutron flux peak reached during the initial part of the transient is strongly dependent on the Doppler power reactivity coefficient, a conservatively low value for Doppler power defect (-1020 pcm) is used for any given rate of reactivity insertion.

2. The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and the moderator is much longer than the neutron flux response time constant. However, after the initial neutron flux peak, the succeeding rate of power increase is affected by the moderator temperature reactivity coefficient. Although during normal operation (100% rated power), the moderator coefficient will not be positive at any time in core life, a highly conservative value has been used in the analysis to yield the maximum peak core heat flux. The analysis is based on a moderator coefficient which was at least +5 pcm/°F at the zero power nominal average temperature, and which became less positive for higher temperatures. This was necessary since the TWINKLE computer code used in the analysis is a diffusion theory code rather than a point-kinetics approximation and the moderator temperature feedback cannot be artificially held constant with temperature.

3. The reactor is assumed to be at hot zero power (547 °F). This assumption is more conservative than that of a lower initial system temperature. The higher initial system temperature yields a larger fuel-to-water heat transfer, a larger fuel thermal capacity, and a less-negative (smaller absolute magnitude) Doppler coefficient. The less-negative Doppler coefficient reduces the Doppler feedback effect thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel thermal capacity and larger thermal conductivity yields a larger peak heat flux. The initial multiplication factor (k_o) is assumed to be closely approaching 1.0 since this results in the maximum neutron flux peak.

4. Two reactor coolant pumps are assumed to be in operation. This is conservative with respect to the DNB transient.

5. The most adverse combination of instrumentation and setpoint errors, as well as delays for trip signal actuation and control rod assembly release, are taken into account. A 10% increase has been assumed for the power range flux trip, low setpoint raising it from the nominal value of 25% to a value of 35% in addition to taking no credit for the source and intermediate range protection. Reference to Figure B.3-1, however, shows that the rise in nuclear flux is so rapid that the effect of errors in the trip setpoint on the actual time at which the rods are released is negligible. In addition to the above, the rate of negative reactivity insertion corresponding to the trip action is based on the assumption that the highest worth control rod assembly is stuck in its fully withdrawn position.

The accident is analyzed using the Standard Thermal Design Procedure with the initial conditions shown in Table B.2-4. The analysis was performed for a reactivity insertion rate of 63 pcm/sec (1 pcm = 10^{-5} $\Delta k/k$). This reactivity insertion rate assumed is greater than that for the simultaneous withdrawal of the combination of the two sequential control banks having the greatest combined worth at maximum speed (45 inches/minute).

B.3.1.3 Results

The nuclear power, heat flux, fuel average temperature, and clad temperature versus time transients are shown in Figures B.3-1 and B.3-2. In addition, the time sequence of events is presented in Table B.3-1. The insertion rate of 63 pcm/sec, coupled with the reduced RCS pressure of 2100 psia, yields a minimum DNBR which remains above the safety analysis limit values for both a full VANTAGE 5 core and for a mixed core.

For the rod withdrawal from subcritical event, the core axial power distribution is severely peaked to the bottom of the core. The W-3 DNB correlation is used to evaluate DNBR in the span between the lower non-mixing vane grid and the first mixing vane grid. The WRB-2 correlation remains applicable for the rest of the fuel assembly. For all regions of the core, the DNB design bases are met.

B.3.1.4 Conclusions

The minimum DNBR remains above the safety analysis limit values for both a full VANTAGE 5 core and for a mixed core. In addition, the fuel and clad temperatures remain well below the limit

values. Therefore, the conclusions presented in the UFSAR remain applicable for both a mixed core and for a full VANTAGE 5 core, including the changes associated with the VANTAGE 5 transition, with the reduction in the nominal RCS pressure to 2100 psia.

B.3.2A Uncontrolled Control Rod Assembly Bank Withdrawal At Power (Mixed Core)

B.3.2A.1 Introduction

The uncontrolled control rod assembly bank withdrawal at power event is examined primarily to demonstrate core protection. An increase in core power is nonconservative with respect to the DNB transient whereas the reduction in full power average temperature for the reduced temperature operation is a benefit for the at power events. Also, as discussed previously, the core limits were revised for this analysis which required a new OTΔT setpoint equation. As such, the rod withdrawal at power incident was analyzed.

An uncontrolled Rod Control Cluster Assembly (RCCA) withdrawal at power results in an increase in core heat flux. Since the heat extraction from the steam generator lags behind the power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is a net increase in reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise would eventually result in DNB. Therefore, to minimize the possibility of breaching the cladding, the Reactor Protection System is designed to terminate any such transient before the DNBR falls below the limit value.

The automatic features of the Reactor Protection System which minimize adverse effects to the core in an RCCA Bank Withdrawal incident at power include the following:

1. Nuclear power range instrumentation actuates a reactor trip on high neutron flux if two out of four channels exceed an overpower setpoint.

2. Reactor trip is actuated if any two out of four ΔT channels exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with axial power distribution, coolant average temperature and pressure to protect against DNB.

3. Reactor trip is actuated if any two out of four ΔT channels exceed an overpower ΔT setpoint. This setpoint is automatically varied with coolant average temperature so that the allowable fuel power rating is not exceeded.

4. A high pressure reactor trip, actuated from any two out of four pressure channels, is set at a fixed point. This set pressure is less than the set pressure for the pressurizer safety valves.

5. A high pressurizer water level reactor trip, actuated from any two out of three level channels, is set at a fixed point.

In addition to the above listed reactor trips, there are the following RCCA Withdrawal blocks.

a. High neutron flux (one out of four)
b. Overpower ΔT (two out of four)
c. Overtemperature ΔT (two out of four)

The manner in which the combination of overpower ΔT and overtemperature ΔT trips provide protection over the full range of Reactor Coolant System conditions is illustrated in Figure B.2-1a. This figure represents the allowable conditions of reactor coolant loop average temperature and power with the design power capability in a two-dimensional plot.

The purpose of this analysis is to demonstrate the manner in which the above protective systems function for various reactivity insertion rates from different initial conditions. Reactivity insertion rates and initial conditions govern which protective function occurs first.

B.3.2A.2 Method of Analysis

This transient is analyzed using the LOFTRAN code (Reference 5). The core limits as illustrated in Figure B.2-1a are used as input to LOFTRAN to determine the minimum DNBR during the transient.

The analysis is performed to bound the reduced RCS temperature operation along with the range of conditions possible for the potential uprating of Cook Nuclear Plant Unit 2.

This accident is analyzed with the Revised Thermal Design Procedure described in Reference 2. Plant characteristics and initial conditions are shown in Table B.2-4. For an uncontrolled rod withdrawal at power accident, the following conservative assumptions are made:

A. Nominal values are assumed for the initial reactor power, pressure, and RCS temperatures (see Table B.2.4). Uncertainties in initial conditions are included in the limit DNBR as described in Reference 2.

B. Reactivity coefficients - two cases are analyzed:
   1. Minimum Reactivity Feedback. A +5 pcm/°F moderator temperature coefficient of reactivity and a least negative Doppler only power coefficient (see Table B.2-4) are assumed.

   2. Maximum Reactivity Feedback. A conservatively large positive moderator density coefficient (corresponding to a large negative moderator temperature coefficient) and a most negative Doppler only power coefficient (see Table B.2-4) are assumed.

C. The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 118 percent of nominal core power of 3588 MWt. The ΔT trips include all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation are assumed at their maximum values.

D. The RCCA trip insertion characteristic is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.

E. The maximum positive reactivity insertion rate is greater than that for the simultaneous withdrawal of the combinations of the two control banks having the maximum combined worth at maximum speed.

F. Reactor trip on high pressurizer water level is assumed available, with a delay of 2 seconds for rod motion, for cases analyzed to demonstrate that this trip will prevent the pressurizer from filling. It actuates earlier than either the OTΔT or high neutron flux trip functions to demonstrate this protection during pressurizer filling scenarios. Minimum DNBR calculations were conservatively performed without taking credit for the high pressurizer water level trip.

B.3.2A.3 Results

Figures B.3-3A through B.3-5A show the transient response for a rapid RCCA bank withdrawal incident starting from full power. Reactor trip on high neutron flux occurs shortly after the start of the accident. Since this is rapid with respect to the thermal time constants of the plant, small changes in T-avg and pressure result and margin to DNB is maintained.

The transient response for a slow RCCA bank withdrawal from full power is shown in Figures B.3-6A through B.3-8A. Reactor trip on overtemperature ΔT occurs after a longer period and the rise in temperature and pressure is consequently larger than for rapid RCCA bank withdrawal. Again, the minimum DNBR is greater than the limit value.

Figure B.3-9A shows the minimum DNBR as a function of reactivity insertion rate from initial full power operation for minimum and maximum reactivity feedback. It can be seen that two reactor trip channels provide DNB protection over the whole range of reactivity insertion rates. These are the high neutron flux and overtemperature ΔT channels. The minimum DNBR is always greater than the limit value.

Figures B.3-10A and B.3-11A show the minimum DNBR as a function of reactivity insertion rate for RCCA bank withdrawal incidents starting at 60 and 10 percent power respectively. The results are similar to the 100 percent power case, except as the initial power is decreased, the range over which the overtemperature ΔT trip is effective is increased. In neither case does the DNBR fall below the limit value. The minimum DNBR for the limiting case was verified using the detailed THINC code.

The shape of the curves of minimum DNBR versus reactivity insertion rate in the referenced figures is due both to reactor core and coolant system transient response and to protection system action in initiating a reactor trip.

The results of cases which examined a conservative pressurizer water volume transient due to the uncontrolled RCCA bank withdrawal at power accident showed that credit for the high pressurizer water level reactor trip was required to prevent the pressurizer from filling. An analysis value of 100% span was assumed for the high pressurizer water level reactor trip setpoint. A time delay of 2 seconds from actuation of the high pressurizer water level reactor trip signal until rod motion was determined adequate to terminate the transient and prevent the pressurizer from filling. For comparison purposes, the pressurizer fills at 1898 ft^3 (which includes the pressurizer surge line volume).

The calculated sequence of events for the uncontrolled RCCA bank withdrawal at power incident are shown in Table B.3-2A for large and small reactivity insertion rates. These sequence of events are for the cases initiated from full power assuming maximum reactivity feedback conditions.

B.3.2A.4 Conclusions

The high neutron flux and overtemperature ΔT trip channels provide adequate protection over the entire range of possible reactivity insertion rates (i.e., the minimum value of DNBR is always larger than the limit value for all fuel types). Also, the high pressurizer water level reactor trip prevents the pressurizer from filling.

B.3.2B Uncontrolled Control Rod Assembly Bank Withdrawal At Power (Full VANTAGE 5 Core)

B.3.2B.1 Introduction

The uncontrolled control rod assembly bank withdrawal at power event is examined primarily to demonstrate core protection. An increase in core power is nonconservative with respect to the DNB transient whereas the reduction in full power average temperature for the reduced temperature operation is a benefit for the at power events. The reduction in RCS pressure is nonconservative with respect to the DNB transient. Also, the impact of the new OTΔT setpoint equation needs to be addressed as well as other design changes associated with the complete transition to a VANTAGE 5 core. As a result, the rod withdrawal at power incident was analyzed.

An uncontrolled Rod Control Cluster Assembly (RCCA) withdrawal at power results in an increase in core heat flux. Since the heat extraction from the steam generator lags behind the power generation until the steam generator pressure reaches the relief or safety valve setpoint, there is

a net increase in reactor coolant temperature. Unless terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise would eventually result in DNB. Therefore, to minimize the possibility of breaching the cladding, the Reactor Protection System is designed to terminate any such transient before the DNBR falls below the limit value.

The automatic features of the Reactor Protection System which minimize adverse effects to the core in an RCCA Bank Withdrawal incident at power include the following:

1. Nuclear power range instrumentation actuates a reactor trip on high neutron flux if two out of four channels exceed an overpower setpoint.

2. Reactor trip is actuated if any two out of four ΔT channels exceed an overtemperature ΔT setpoint. This setpoint is automatically varied with axial power distribution, coolant average temperature and pressure to protect against DNB.

3. Reactor trip is actuated if any two out of four ΔT channels exceed an overpower ΔT setpoint. This setpoint is automatically varied with coolant average temperature so that the allowable fuel power rating is not exceeded.

4. A high pressure reactor trip, actuated from any two out of four pressure channels, is set at a fixed point. This set pressure is less than the set pressure for the pressurizer safety valves.

5. A high pressurizer water level reactor trip, actuated from any two out of three level channels, is set at a fixed point.

In addition to the above listed reactor trips, there are the following RCCA Withdrawal blocks.

a. High neutron flux (one out of four)
b. Overpower ΔT (two out of four)
c. Overtemperature ΔT (two out of four)

The manner in which the combination of overpower ΔT and overtemperature ΔT trips provide protection over the full range of Reactor Coolant System conditions is illustrated in Figure B.2-1b.

This figure represents the allowable conditions of reactor coolant loop average temperature and power with the design power capability in a two-dimensional plot.

The purpose of this analysis is to demonstrate the manner in which the above protective systems function for various reactivity insertion rates from different initial conditions. Reactivity insertion rates and initial conditions govern which protective function occurs first.

B.3.2B.2 Method of Analysis

This transient is analyzed using the LOFTRAN code (Reference 5). The core limits as illustrated in Figure B.2-1b are used as input to LOFTRAN to determine the minimum DNBR during the transient.

The analysis is performed to bound the reduced RCS temperature and decreased RCS pressure operation along with the range of conditions possible for the Cook Nuclear Plant Unit 2 core uprating and fuel upgrade.

This accident is analyzed with the Revised Thermal Design Procedure described in Reference 2. Plant characteristics and initial conditions are shown in Table B.2-5. For an uncontrolled rod withdrawal at power accident, the following conservative assumptions are made:

A. Nominal values are assumed for the initial reactor power, pressure, and RCS temperatures (see Table B.2.5). Uncertainties in initial conditions are included in the limit DNBR as described in Reference 2.

B. Reactivity coefficients - two cases are analyzed:

   1. Minimum Reactivity Feedback. A +5 pcm/°F moderator temperature coefficient of reactivity and a least negative Doppler only power coefficient (see Table B.2-5) are assumed.

   2. Maximum Reactivity Feedback. A conservatively large positive moderator density coefficient (corresponding to a large negative moderator temperature coefficient) and a most negative Doppler-only power coefficient (see Table B.2-5) are assumed.

C. The reactor trip on high neutron flux is assumed to be actuated at a conservative value of 118 percent of nominal core power of 3588 MWt. The ΔT trips include all adverse instrumentation and setpoint errors, while the delays for the trip signal actuation are assumed at their maximum values.

D. The RCCA trip insertion characteristic is based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.

E. The maximum positive reactivity insertion rate is greater than that for the simultaneous withdrawal of the combinations of the two control banks having the maximum combined worth at maximum speed.

F. Reactor trip on high pressurizer water level is assumed available, with a delay of 2 seconds for rod motion, for cases analyzed to demonstrate that this trip will prevent the pressurizer from filling. It actuates earlier than either the OTΔT or high neutron flux trip functions to demonstrate this protection during pressurizer filling scenarios. Minimum DNBR calculations were conservatively performed without taking credit for the high pressurizer water level trip.

B.3.2B.3 Results

Figures B.3-3B through B.3-5B show the transient response for a rapid RCCA bank withdrawal incident starting from full power. Reactor trip on high neutron flux occurs shortly after the start of the accident. Since this is rapid with respect to the thermal time constants of the plant, small changes in T-avg and pressure result and margin to DNB is maintained.

The transient response for a slow RCCA bank withdrawal from full power is shown in Figures B.3-6B through B.3-8B. Reactor trip on overtemperature ΔT occurs after a longer period and the rise in temperature and pressure is consequently larger than for rapid RCCA bank withdrawal. Again, the minimum DNBR is greater than the limit value.

Figure B.3-9B shows the minimum DNBR as a function of reactivity insertion rate from initial full power operation for minimum and maximum reactivity feedback. It can be seen that two reactor

trip channels provide DNB protection over the whole range of reactivity insertion rates. These are the high neutron flux and overtemperature ΔT channels. The minimum DNBR is always greater than the limit value.

Figures B.3-10B and B.3-11B show the minimum DNBR as a function of reactivity insertion rate for RCCA bank withdrawal incidents starting at 60 and 10 percent power respectively. The results are similar to the 100 percent power case, except as the initial power is decreased, the range over which the overtemperature ΔT trip is effective is increased. In neither case does the DNBR fall below the limit value.

The shape of the curves of minimum DNBR versus reactivity insertion rate in the referenced figures is due both to reactor core and coolant system transient response and to protection system action in initiating a reactor trip.

The results of cases which examined a conservative pressurizer water volume transient due to the uncontrolled RCCA bank withdrawal at power accident showed that credit for the high pressurizer water level reactor trip was required to prevent the pressurizer from filling. An analysis value of 100% span was assumed for the high pressurizer water level reactor trip setpoint. A time delay of 2 seconds from actuation of the high pressurizer water level reactor trip signal until rod motion was determined adequate to terminate the transient and prevent the pressurizer from filling. For comparison purposes, the pressurizer fills at 1898 ft^3 (which includes the pressurizer surge line volume).

The calculated sequence of events for the uncontrolled RCCA bank withdrawal at power incident are shown in Table B.3-2B for large and small reactivity insertion rates. These sequence of events are for the cases initiated from full power assuming maximum reactivity feedback conditions.

B.3.2B.4 Conclusions

The high neutron flux and overtemperature ΔT trip channels provide adequate protection over the entire range of possible reactivity insertion rates (i.e., the minimum value of DNBR is always larger than the limit value for all fuel types). Also, the high pressurizer water level reactor trip prevents the pressurizer from filling.

B.3.3 Rod Cluster Control Assembly (RCCA) Misalignment (Including RCCA Drop)

B.3.3.1 Introduction

Rod cluster control assembly (RCCA) misoperation accidents include:

A. One or more dropped RCCAs within the same group.

B. A dropped RCCA bank.

C. Statically misaligned RCCA.

Each RCCA has a position indicator channel which displays the position of the assembly. The displays of assembly positions are grouped for the convenience of the operator. Fully inserted assemblies are further indicated by a rod at bottom signal, which actuates a local alarm and a control room annunciator. Group demand position is also indicated.

RCCAs are moved in preselected banks, and the banks are moved in the same preselected sequence. Each bank of RCCAs is divided into two groups. The rods comprising a group operate in parallel through multiplexing thyristors. The two groups in a bank move sequentially such that the first group is always within one step of the second group in the bank. A definite schedule of actuation (or deactuation of the stationary gripper, movable gripper, and lift coils of a mechanism) is required to withdraw the RCCA attached to the mechanism. Mechanical failures are in the direction of insertion or immobility.

The dropped RCCAs, dropped RCCA bank, and statically misaligned RCCA events are considered incidents of moderate frequency.

A dropped RCCA or RCCA bank is detected by:

- Sudden drop in the core power level as seen by the nuclear instrumentation system.
- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples.
- Rod at bottom signal.
- Rod deviation alarm.
- Rod position indication.

Misaligned RCCAs are detected by:

- Asymmetric power distribution as seen on out-of-core neutron detectors or core exit thermocouples.
- Rod deviation alarm.
- Rod position indicators.

The resolution of the rod position indicator channel is ±5 percent of span (12 steps). Deviation of any RCCA from its group by twice this distance (10 percent of span or 24 steps) will not cause power distributions worse than the design limits. The deviation alarm alerts the operator to rod deviation with respect to the group position in excess of 5 percent of span. If the rod deviation alarm is not operable, the operator is required to take action as required by the Technical Specifications.

If one or more rod position indicator channels should be out of service, detailed operating instructions shall be followed to ensure the alignment of the non-indicated RCCAs. The operator is also required to take action, as required by the Technical Specifications.

B.3.3.2 Method of Analysis

A. One or More Dropped RCCAs Within the Same Group

For evaluation of the dropped RCCA event, the transient system response is calculated using the LOFTRAN Code. The code simulates the neutron kinetics, reactor coolant system (RCS), pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

Conservative nominal values for initial reactor power, temperature, and RCS pressure are assumed to bound the reduced temperature and pressure operation along with the range of conditions possible for the potential future rerating of Cook Nuclear Plant Unit 2. The initial conditions are presented in Table B.2-4.

Statepoints are calculated and nuclear models are used to obtain a hot channel factor consistent with the primary system conditions and reactor power. By incorporating the primary

conditions from the transient and the hot channel factor from the nuclear analysis, the departure from nucleate boiling(DNB) design basis is shown to be met using the THINC code. The transient response, nuclear peaking factor analysis, and DNB design basis confirmation are performed in accordance with the methodology described in Reference 9. Note that operation with automatic rod control is assumed for the analysis.

B. Dropped RCCA Bank

Analysis is not required since the dropped RCCA bank results in a trip.

C. Statically Misaligned RCCA

Steady-state power distributions are analyzed using the methodology as described in Reference 9. The peaking factors are then used as input to the THINC code to calculate the departure from nucleate boiling ratio (DNBR).

B.3.3.3 Results

A. One or More Dropped RCCAs Within the Same Group

Single or multiple dropped RCCAs within the same group result in a negative reactivity insertion which may be detected by the power range negative neutron flux rate trip circuitry. If detected, the reactor is tripped within approximately 2.5 seconds following the drop of the RCCAs. The core is not adversely affected during this period, since power is decreasing rapidly. Following reactor trip, normal shutdown procedures are followed. The operator may manually retrieve the RCCA by following approved operating procedures.

For those dropped RCCA events which do not result in a reactor trip, power may be re-established either by reactivity feedback or control bank withdrawal.

Following a dropped rod event in manual rod control, the plant will establish a new equilibrium condition. The equilibrium process without control system interaction is monotonic, thus removing power overshoot as a concern and establishing the automatic rod control mode of operation as the limiting case.

For a dropped RCCA event in the automatic rod control mode, the rod control system detects the drop in power and initiates control bank withdrawal. Power overshoot may occur due to this action by the automatic rod controller after which the control system will insert the control bank to restore nominal power. Figures B.3-12 and B.3-13 show a typical transient response to a dropped RCCA (or RCCAs) in automatic control. In all cases, the minimum DNBR remains above the limit value.

B. Dropped RCCA Bank

A dropped RCCA bank typically results in a negative reactivity insertion greater than 500 pcm (1 pcm = $10^{-5}\Delta k/k$), which will be detected by the power range negative neutron flux rate trip circuitry. The reactor is tripped within approximately 2.5 seconds following the drop of an RCCA bank. The core is not adversely affected during this period, since power is decreasing rapidly. Following reactor trip, normal shutdown procedures are followed to further cool down the plant.

C. Statically Misaligned RCCA

The most severe misalignment situations with respect to DNBR at significant power levels arise from cases in which one RCCA is fully inserted or where bank D is fully inserted with one RCCA fully withdrawn. Multiple independent alarms, including a bank insertion limit alarm, alert the operator well before the postulated conditions are approached. The bank can be inserted to its insertion limit with any one assembly fully withdrawn without the DNBR falling below the limit value.

The insertion limits in the Technical Specifications may vary from cycle to cycle, depending on a number of limiting criteria. The full-power insertion limits on control bank D must be chosen to be above that position which meets the minimum DNBR and peaking factors. The full power insertion limit is usually dictated by other criteria. Detailed results will vary from cycle to cycle depending on fuel arrangements.

For this RCCA misalignment, with bank D inserted to its full-power insertion limit and one RCCA fully withdrawn, DNBR does not fall below the limit value. This case is analyzed

assuming that the initial reactor power, pressure, and RCS temperature are at their nominal values (as given in Table B.2-4), with the increased radial peaking factor associated with the misaligned RCCA.

For RCCA misalignments with one RCCA fully inserted, the DNBR does not fall below the limit value. This case is analyzed assuming the initial reactor power, pressure, and RCS temperatures are at their nominal values (as given in Table B.2-4), with the increased radial peaking factor associated with the misaligned RCCA.

DNB does not occur for the RCCA misalignment incident, and thus the ability of the primary coolant to remove heat from the fuel rod is not reduced. The peak fuel temperature corresponds to a linear heat generation rate based on the radial peaking factor penalty associated with the misaligned RCCA and the design axial power distribution. The resulting linear heat generation is well below that which would cause fuel melting.

Following the identification of an RCCA group misalignment condition by the operator, the operator is required to take action as required by the plant Technical Specifications and operating instructions.

B.3.3.4 Conclusions

For cases of dropped RCCAs or dropped banks, for which the reactor is tripped by the power range negative neutron flux rate trip, there is no reduction in the margin to core thermal limits, and consequently the DNB design basis is met. It is shown for all cases which do not result in reactor trip that the DNBR remains greater than the limit value and, therefore, the DNB design is met.

For all cases of any RCCA fully inserted, or bank D inserted to its rod insertion limits with any single RCCA in that bank fully withdrawn (static misalignment), the DNBR remains greater than the limit value.

B.3.4 Uncontrolled Boron Dilution

B.3.4.1 Introduction

Reactivity can be added to the core by feeding primary grade water into the Reactor Coolant System via the reactor makeup portion of the Chemical and Volume Control System (CVCS).

Boron dilution is a manual operation. A boric acid blend system is provided to permit the operator to match the boron concentration of reactor coolant makeup water during normal charging to that in the Reactor Coolant System. The CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value which provides the operator sufficient time to correct the situation in a safe and orderly manner.

The opening of the Primary Water Makeup Control Valve supplies water to the Reactor Coolant System which can dilute the reactor coolant. Inadvertent dilution can be readily terminated by closing this valve. In order for makeup water to be added to the Reactor Coolant System, at least one charging pump must also be running in addition to the primary water pumps.

The rate of addition of unborated water makeup to the Reactor Coolant system is limited by the capacity of the primary water pumps. The maximum addition rate in this case is 225 gpm with both primary water pumps running. The 225 gpm reactor makeup water delivery rate is based on a pressure drop calculation comparing the pump curves with the system resistance curve. This is the maximum delivery based on the unit piping layout. Normally, only one primary water makeup pump is operating while the other is on standby.

The boric acid from the Boric Acid Storage Tank (BAST) is blended with primary grade water in the blender and the composition is determined by the preset flow rates of boric acid and primary grade water on the control board.

In order to dilute, two separate operations are required. First, the operator must switch from the automatic makeup mode to the dilute mode; second, the start button must be depressed. Omitting either step would prevent dilution. This makes the possibility of inadvertent dilution very remote.

Information on the status of reactor coolant makeup is continuously available to the operator. Lights are provided on the control board to indicate the operating condition of pumps in the Chemical and Volume Control System. Alarms are actuated to warn the operator if boric acid or demineralized water flow rates deviate from preset values as a result of system malfunction.

B.3.4.2 Method of Analysis

To cover the phases of the plant operation impacted by the reduced temperature and pressure operation as well as the other design changes associated with the VANTAGE 5 transition, boron dilution during refueling, startup and power operation were examined. Included in the analysis was the effect of the difference in the density of unborated makeup water and the density of the reactor coolant. The analysis is to show that, from initiation of the event, sufficient time is available to allow the operator to determine the cause of the addition and take corrective action before the shutdown margin is lost.

A. Dilution During Refueling

During refueling, the following conditions are assumed:

1. One Residual Heat Removal (RHR) System train is in operation.

2. A maximum dilution flow of 225 gpm, limited by the capacity of the two primary water makeup pumps, and uniform mixing in the reactor vessel are assumed.

3. The initial RCS boron concentration is 2000 ppm, corresponding to a shutdown margin of at least 5%Δk/k with all RCCAs in.

4. A minimum RCS water volume of 3527 ft^3 is assumed. This corresponds to the volume necessary to fill the reactor vessel to the mid-plane of the nozzle to ensure mixing via the RHR loop.

5. The critical boron concentration is assumed to be 1500 ppm, corresponding to all RCCAs in, no Xenon. The 500 ppm change from the initial condition noted above is a conservative minimum value.

B. Dilution During Startup

Prior to startup, the RCS is filled with borated water from the refueling water storage tank. Mixing of the reactor coolant is maintained by operation of the reactor coolant pumps.

Conditions assumed for the analysis are:

1. Conservatively high dilution flow capacity for the two primary water makeup pumps is considered, 225 gpm.

2. A minimum RCS water volume of 9595 ft^3. This corresponds to the active RCS volume excluding the pressurizer, surge line, reactor vessel dome and 10% of the steam generator tube volume. The RCS water mass is conservatively calculated at high temperature and reduced RCS pressure operation.

3. The initial boron concentration is assumed to be 1800 ppm, which is a conservative maximum value for the critical concentration at the condition of hot zero power, rods to insertion limits, and no Xenon.

4. The critical boron concentration following reactor trip is assumed to the 1550 ppm, corresponding to the hot zero power, all rods inserted (minus the most reactive RCCA), no Xenon condition. The 250 ppm change from the initial condition noted above is a conservative minimum value.

C. Dilution During Power Operation

During power operation, the plant may be operated in either automatic or manual rod control. Two cases are considered; the reactor in automatic rod control and the reactor in manual rod control. Conditions assumed for these two cases are:

1. Dilution flow at power is the maximum capacity of the makeup water pumps, 225 gpm.

2. A minimum RCS water volume of 9595 ft^3. This corresponds to the active RCS volume excluding the pressurizer, surge line, reactor vessel dome and 10% of the steam generator tube volume. The RCS water mass is conservatively calculated at high temperature and reduced RCS pressure operation.

3. The initial boron concentration is assumed to be 1900 ppm, which is a conservative maximum value for the critical concentration at the condition of hot full power, rods to insertion limits, and no Xenon.

4. The critical boron concentration following reactor trip is assumed to be 1550 ppm, corresponding to the hot zero power, all rods inserted (minus the most reactive RCCA), no Xenon condition. The 350 ppm change from the initial condition noted above is a conservative minimum value.

Plant characteristics and initial conditions are shown in Table B.2-4.

B.3.4.3 Results

A. Dilution During Refueling

For dilution during refueling, there are more than 33 minutes available for operator action from the time of initiation of the event to loss of shutdown margin (5 %Δk/k). The operator has prompt and definite indication of the boron dilution from the audible count rate Source Range Monitor (SRM) instrumentation. The SRM also gives a high count rate alarm in the reactor containment and the control room. The count rate increase is proportional to the subcritical multiplication factor.

B. Dilution During Startup

For dilution during startup, there are more than 35 minutes available for the operator action from the time of initiation of the event to loss of shutdown margin (1.3 %Δk/k).

C. Dilution During Power Operation

With the reactor in automatic control, the power and temperature increase from the boron dilution results in insertion of the control rods and a decrease in the available shutdown margin. The rod insertion limit alarms (low and low-low settings) alert the operator that a dilution event is in progress. There are more than 46 minutes from the time of alarm (low-low rod insertion limit) to loss of shutdown margin (1.3 %Δk/k).

With the reactor in manual control and no operator action taken to terminate the transient, the power and temperature rise will cause the reactor to reach the overtemperature ΔT trip setpoint

resulting in a reactor trip. The boron dilution transient in this case is essentially equivalent to an uncontrolled RCCA withdrawal at power. The maximum reactivity insertion rate for a boron dilution is conservatively estimated to be 2.5 pcm/sec which is within the range of insertion rates analyzed. There are more than 44 minutes available for operator action from the time of alarm (overtemperature ΔT) to loss of shutdown margin (1.3 %$\Delta k/k$). This operator action time is conservatively calculated to bound both sets of overtemperature ΔT setpoints discussed in Section B.2.2.1.

Table B.3-3 contains the time sequence of events for this accident.

B.3.4.4 Conclusions

Because of the steps involved in the dilution process, an erroneous dilution is considered unlikely. Nevertheless, if it does occur, numerous alarms and indications are available to alert the operator to the condition. The maximum reactivity addition due to the dilution is slow enough to allow the operator to determine the cause of the dilution and take corrective action before shutdown margin is lost.

B.3.5 Loss of Forced Reactor Coolant Flow (Including Locked Rotor)

B.3.5.1 Loss Of Reactor Coolant Flow

B.3.5.1.1 Introduction

A loss of forced reactor coolant flow may result from a simultaneous loss of electrical power to all reactor coolant pumps. If the reactor is at power at the time of the accident, the immediate effect of a loss of coolant flow is a rapid increase in the coolant temperature which is magnified by a positive MTC. This increase could result in DNB with subsequent adverse effects to the fuel if the reactor were not tripped promptly. The trip systems available to mitigate the consequences of this accident are discussed in the UFSAR.

Simultaneous loss of electrical power to all reactor coolant pumps at full power is the most severe credible loss of flow condition. For this condition reactor trip together with flow sustained by the inertia of the coolant and rotating pump parts will be sufficient to prevent RCS overpressurization and the DNBR from exceeding the limit values.

The decrease in reactor coolant system flow rate events are primarily examined to demonstrate core protection. Although the reduction in temperature associated with the reduced temperature and pressure operation is a benefit, the reduction in RCS pressure is non-conservative with respect to the DNB transient. As such, analyses are presented to address the impact of the reduced temperature and pressure operation. Also, included in the analysis is the effect of various fuel parameter changes due to the VANTAGE 5 fuel.

B.3.5.1.2 Method of Analysis

The following loss of flow cases reported in the UFSAR are analyzed:

1. Loss of four pumps from nominal full power conditions with four loops operating.
2. Loss of one pump from nominal full power conditions with four loops operating.

The normal power supplies for the pumps are four electrical buses connected to the generator. Each bus supplies power to one pump. When a generator trip occurs, the pumps are automatically transferred to a bus supplied from external power lines, and the pumps will continue to supply coolant flow to the core. The simultaneous loss of power to all reactor coolant pumps is an unlikely event. Since each pump is on a separate bus, a single bus fault would not result in the loss of more than one pump.

A full plant simulation is used in the analysis to compute the core average and hot spot heat flux transient responses, including flow coastdown, temperature, reactivity and control rod insertion effects. These data are then used in a detailed thermal-hydraulic computation to determine the margin to DNB. This computation solves the continuity, momentum, and energy equations of fluid flow and calculates DNBR using the W-3 (ANF) and WRB-2 (VANTAGE 5) correlations. This accident is analyzed with the RTDP.

The analyses are performed with the most limiting temperature and pressure conditions to bound the range of conditions possible for the potential rerating of Cook Nuclear Plant Unit 2. For the full VANTAGE 5 core analyses, the initial vessel average temperature of 581.3 °F and an RCS pressure of 2100 psia were assumed. The analyses performed for a mixed core assumed an initial vessel average temperature of 576 °F and an RCS pressure of 2250 psia. Uncertainties in initial

conditions are included in the limit DNBR as described in Reference 2. Conservative nominal values are assumed for the initial reactor power, pressure, and RCS temperatures. The initial conditions used are shown in Table B.2-4.

This transient is analyzed using three digital computer codes. First the LOFTRAN code is used to calculate the loop and core flow during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The FACTRAN code is then used to calculate the heat flux transient based on the nuclear power and flow from LOFTRAN.

Finally, the THINC code is used to calculate the DNBR during the transient based on the heat flux from FACTRAN and flow from LOFTRAN. The DNBR transients presented represent the minimum of the typical or thimble cell for each type of fuel.

B.3.5.1.3 Results

Figures B.3-14 through B.3-17 show the transient response for the loss of power to all RCPs with four loops in operation for a full VANTAGE 5 core. The reactor is assumed to be tripped on an undervoltage signal. Figure B.3-17 shows the DNBR to be always greater than the safety analysis limit value for the most limiting fuel assembly cell. In addition, the DNBR analysis for this event for a mixed core verified that the DNBR remains above the safety analysis limit value for the most limiting fuel assembly cell.

Figures B.3-18 through B.3-21 show the transient response for the loss of one RCP with four loop operation for a full VANTAGE 5 core. For this case, the reactor is tripped on low flow signal. Figure B.3-21 shows the DNBR to be always greater than the safety analysis limit value for the most limiting fuel assembly cell. In addition, the DNBR analysis for this event for a mixed core verified that the DNBR remains above the safety analysis limit value for the most limiting fuel assembly cell.

In addition to the complete loss of flow (loss of power to four pumps), an underfrequency event with a frequency decay rate of 5 Hz/sec was also analyzed for both a full VANTAGE 5 core and a mixed core. For this event, the reactor trip occurs on an underfrequency signal. The DNBR analysis of the underfrequency event verified that the DNBR remains above the safety analysis

limit value for both a full VANTAGE 5 core and a mixed core. The underfrequency event was determined to be the limiting event of all the loss of flow cases analyzed.

Since DNB does not occur, the ability of the primary coolant to remove heat from the fuel rod is not significantly reduced. Thus, the average fuel and clad temperature do not increase significantly above their respective initial values.

Time sequence of events is shown in Table B.3-4 for the UFSAR loss of flow cases.

B.3.5.1.4 Conclusions

For all cases, the analysis shows that the minimum DNBR remains above the limit value at all times during the transient. Thus, no adverse fuel effects or clad rupture is predicted, and all applicable acceptance criteria are met. For a mixed core, the full power vessel average temperature is limited to no greater than 576 °F at an RCS pressure of 2250 psia. For a full VANTAGE 5 core, the analysis supports a full power vessel average temperature of 581.3 °F at an RCS pressure of either 2250 psia or 2100 psia.

B.3.5.2 Locked Rotor Accident

B.3.5.2.1 Introduction

A transient analysis has been performed for the instantaneous seizure of a reactor coolant pump rotor. Flow through the affected reactor coolant loop is rapidly reduced, leading to a reactor trip on a low flow signal. Following the trip, heat stored in the fuel rods continues to pass into the core coolant, causing the coolant to expand. At the same time, heat transfer to the shell side of the steam generator is reduced, first because the reduced flow results in a decreased tube side film coefficient and then because the reactor coolant in the tubes cools down while the shell side temperature increases (turbine steam flow is reduced to zero upon plant trip). The rapid expansion of the coolant in the reactor core, combined with the reduced heat transfer in the steam generator causes an insurge into the pressurizer and a pressure increase throughout the Reactor Coolant System. The insurge into the pressurizer causes a pressure increase which in turn actuates the automatic spray system, opens the power-operated relief valves, and opens the pressurizer safety

valves, in a sequence dependent on the rate of insurge and pressure increase. The power-operated relief valves are designed for reliable operation and would be expected to function properly during the accident. However, for conservatism, their pressure-reducing affect as well as the pressure-reducing affect of the spray are not included in this analysis.

The locked rotor event is analyzed to demonstrate that the peak clad average temperature remains below the limit value (Reference 13) and the peak RCS pressure remains below a value that would cause the faulted condition stress limits to be exceeded. Included in the analysis are the design changes associated with the transition to V-5 fuel and other modified safety analysis assumptions as discussed in Section B.1.

B.3.5.2.2 Method of Analysis

Two digital-computer codes are used to analyze this transient. The LOFTRAN code is used to calculate 1) the resulting loop and core flow transients following the pump seizure, 2) the time of reactor trip based on the loop flow transients, 3) the nuclear power following reactor trip, and 4) the peak RCS pressure. The thermal behavior of the fuel located at the core hot spot is investigated using the FACTRAN code based on the core flow and the nuclear power calculated by LOFTRAN. The FACTRAN code includes the use of a film boiling heat transfer coefficient.

The analysis is conservatively performed to bound the range of pressure and temperature conditions as discussed in Section B.1. The plant characteristics and the initial conditions are shown in Table B.2-4. As in previous UFSAR Locked Rotor analyses for Cook Nuclear Plant Unit 2, the analysis assumes offsite power is available following the reactor trip and turbine trip.

<u>Evaluation of the Pressure Transient</u>

After pump seizure, the neutron flux is rapidly reduced by control rod insertion. Rod motion begins 1 second after the flow in the affected loop reaches 87 percent of nominal flow. No credit is taken for the pressure reducing effect of the pressurizer relief valves, pressurizer spray, steam dump or controlled feedwater flow after plant trip. Although these operations are expected to occur and would result in a lower peak RCS pressure, an additional degree of conservatism is provided by ignoring their effect.

The pressurizer safety valves are assumed to initially open at 2500 psia and achieve rated flow at 2575 psia. This analysis assumed a conservatively high initial pressurizer pressure of 2312.6 psia. Table B.2-4 presents the initial conditions assumed for the peak pressure transient.

Evaluation of the Peak Clad Temperature

In the analysis to determine the fuel rod thermal transients for this event, DNB is conservatively assumed to occur in the core at the initiation of the transient. This analysis also assumed a conservatively low initial pressurizer pressure of 2037.4 psia. Results obtained from analysis of this hot spot condition represent the upper limit with respect to clad temperature and zirconium water reaction. In the evaluation, the rod power at the hot spot is assumed to be 2.5 times the average rod power (i.e., $F_Q = 2.5$) at the initial core power level. Table B.2-4 presents the initial conditions assumed for the peak clad temperature transient.

Film Boiling Coefficient

To model the effect of DNB occurring, the film boiling coefficient is calculated in the FACTRAN code using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties are evaluated at film temperatures (average between wall and bulk temperatures). The program calculates the film coefficient at every time step based upon the actual heat transfer conditions at the time. The neutron flux, system pressure, bulk density, and mass flow rate as a function of time are used as program input.

For this analysis, the initial values of the pressure and the bulk density are used throughout the transient since they are the most conservative with respect to clad temperature response. As previously stated, for conservatism, DNB was assumed to start at the beginning of the accident to maximize the fuel rod thermal transient.

Fuel Clad Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and clad (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between pellet and clad. Based on investigations on the effect of the gap coefficient upon the maximum clad temperature during the transient, the gap

coefficient was assumed to increase from a steady state value consistent with initial fuel temperature to 10,000 BTU/hr-ft^2- °F at the initiation of the transient. Thus the large amount of energy stored in the fuel because of the small initial value is released to the clad at the initiation of the transient.

Zirconium-Steam Reaction

The zirconium-steam reaction can become significant above 1800 °F (clad temperature). In order to take this phenomenon into account, the following correlation, which defines the rate of the zirconium-steam reaction, was introduced into the models (Reference 10).

$$\frac{d(w^2)}{dt} = 33.3 \times 10^6 \times e^{-[(45000.)/(1.986\ T)]}$$

where: w = amount reacted, mg/cm^2

t = time, sec

T = temperature, K

The reaction heat is 1510 cal/gm

B.3.5.2.3 Results

The transient results for the locked rotor accident are shown in Figures B.3-22 through B.3-25. The peak RCS pressure (2619 psia) reached during the transient is less than that which would cause stresses to exceed the faulted condition stress limits. The pressure response shown in Figure B.3-23 is the response at the point in the Reactor Coolant System having the maximum pressure. Also, the peak clad surface temperature (1978 °F) is considerably less than 2700 °F (the temperature at which clad embrittlement may be expected).

The maximum zirconium-steam reaction at the core hot spot is 0.5% by weight.

The time sequence of events is presented in Table B.3-4.

B.3.5.2.4 Conclusions

A. Since the peak RCS pressure reached during any of the transients is less than that which would cause stresses to exceed the faulted conditions stress limits, the integrity of the primary coolant system is maintained.

B. Since the peak clad surface temperature calculated for the hot spot during the worst transient remains considerably less than 2700 °F, the core will remain in place and intact with no loss of core cooling capability.

B.3.6A Loss of External Electric Load or Turbine Trip (Mixed Core)

B.3.6A.1 Introduction

The complete loss of steam load from full power is examined primarily to show the adequacy of the pressure relieving devices and also to demonstrate core protection. This analysis examines the effects of the VANTAGE 5 transition and other design changes as discussed in Section B.1. Also, the impact of new OTΔT and OPΔT setpoints are examined. The full power vessel average temperature range of 547 °F to 576 °F at a primary pressure of 2250 psia was assumed under the mixed core scenario. Primary protection for this event is provided by the high pressurizer pressure and the OTΔT reactor trips.

A loss of external electrical load may result from an abnormal variation in network frequency or other adverse network operating conditions. It may also result from a trip of the turbine generator or in an unlikely opening of the main breaker from the generator which fails to cause a turbine trip but causes a rapid large NSSS load reduction by the action of the turbine control. For either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps. The case of loss of offsite power to the station auxiliaries is analyzed in Section B.3.10.

B.3.6A.2 Method of Analysis

The loss of load transients are analyzed by employing the detailed digital computer program LOFTRAN (Reference 5). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

The analysis is performed to bound the conditions of the high and reduced temperature operation along with other design changes associated with the V-5 transition as discussed in Section B.1. This accident is analyzed with RTDP. Plant characteristics and initial conditions are shown in Table B.2.4.

Major assumptions are summarized below:

A. Initial Operating Conditions - nominal conditions (RTDP) are assumed.

B. Moderator and Doppler Coefficients of Reactivity - the loss of load is analyzed with both maximum and minimum reactivity feedback. The maximum feedback cases assume a large positive moderator density coefficient (corresponding to a large negative moderator temperature coefficient) and the most negative Doppler power coefficient. The minimum feedback cases assume a positive moderator temperature coefficient and the least negative Doppler coefficients.

C. Reactor Control - from the standpoint of the maximum pressures attained it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

D. Pressurizer Spray and Power-Operated Relief Valves - two cases for both the minimum and maximum moderator feedback cases are analyzed:

    1. Full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are also available.

    2. No credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are available.

E. Steam Release - no credit is taken for the operation of the steam dump system or steam generator power-operated relief valves. The steam generator pressure rises to the safety valve setpoint where steam release through the safety valves limits secondary steam pressure at the setpoint value.

F. Feedwater Flow - main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow since a stabilized plant condition will be reached before auxiliary feedwater initiation is normally assumed to occur;

however, the auxiliary feedwater pumps would be expected to start on a trip of the main feedwater pumps. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

G. Reactor trip is actuated by the first Reactor Protection System trip setpoint reached. Trip signals are expected due to high pressurizer pressure, overtemperature ΔT, high pressurizer water level, and low-low steam generator water level.

B.3.6A.3 Results

The transient responses for a loss of load from full power operation are shown for four cases: two cases for minimum reactivity feedback and two cases for maximum reactivity feedback (Figures B.3-26A through B.3-37A).

Figures B.3-26A through B.3-28A show the transient responses for the loss of load with minimum reactivity feedback assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the steam dump. The reactor is tripped by the high pressurizer pressure signal.

The minimum DNBR remains well above the limit value. The pressurizer safety valves are not actuated for this case since primary system pressure remains well below the design value. The steam generator safety valves prevent overpressurization of the secondary system, maintaining pressure below 110 percent of design value.

Figures B.3-29A through B.3-31A show the responses for the total loss of steam load with maximum reactivity feedback. All other plant parameters are the same as the above. The DNBR increases throughout the transient and never drops below its initial value. Pressurizer relief valves and steam generator safety valves prevent overpressurization in primary and secondary systems, respectively. The reactor is tripped by the low-low steam generator water level signal. The pressurizer safety valves are not actuated for this case.

In the event that feedwater flow is not terminated at the time of turbine trip for this case, flow would continue under automatic control with the reactor at a reduced power. The operator would take action to terminate the transient and bring the plant to a stabilized condition. If no action

were taken by the operator the reduced power operation would continue until the condenser hotwell was emptied. A low-low steam generator water level reactor trip would be generated along with auxiliary feedwater initiation signals. Auxiliary feedwater would then be used to remove decay heat with the results less severe than those presented in Section B.3.7, Loss of Normal Feedwater Flow.

The loss of load accident was also studied assuming the plant to be initially operating at full power with no credit taken for the pressurizer spray, pressurizer power-operated relief values, or steam dump. The reactor is tripped on the high pressurizer pressure signal. Figures B.3-32A through B.3-34A show the transient responses with minimum reactivity feedback. The neutron flux remains essentially constant at full power until the reactor is tripped. The DNBR never goes below its initial value throughout the transient. In this case the pressurizer safety valves are actuated, and maintain system pressure below 110 percent of the design value.

Figures B.3-35A through B.3-37A show the transient responses with maximum reactivity feedback with the other assumptions being the same as in the preceding case. Again, the DNBR increases throughout the transient and the pressurizer safety valves are actuated to limit primary pressure.

The calculated sequence of events for the loss of load incident are shown in Table B.3-5A.

B.3.6A.4 Conclusions

Results of the analyses show that the plant design is such that a loss of load without a direct or immediate reactor trip presents no hazard to the integrity of the RCS or the main steam system. Pressure relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits. The integrity of the core is maintained by operation of the reactor protection system, i.e., the DNBR will be maintained above the limit value. Thus the conclusions presented in the UFSAR remain valid for the changes associated with the VANTAGE 5 transition for the mixed core cycles.

B.3.6B Loss of External Electric Load or Turbine Trip (Full VANTAGE 5 Core)

B.3.6B.1 Introduction

The complete loss of steam load from full power is examined primarily to show the adequacy of the pressure relieving devices and also to demonstrate core protection. This analysis examines the

effects of the VANTAGE 5 transition and other design changes as discussed in Section B.1. Also, the impact of new OTΔT and OPΔT setpoints are examined. The full power vessel average temperatures range of 547 °F to 581.3 °F at a primary pressure of either 2250 or 2100 psia was assumed under the full VANTAGE 5 core scenario. This analysis encompassed the most limiting combination of temperature and pressure conditions, namely high temperature (581.3 °F) and low pressure (2100 psia). Primary protection for this event is provided by the high pressurizer pressure and the OTΔT reactor trips.

A loss of external electrical load may result from an abnormal variation in network frequency or other adverse network operating conditions. It may also result from a trip of the turbine generator or in an unlikely opening of the main breaker from the generator which fails to cause a turbine trip but causes a rapid large NSSS load reduction by the action of the turbine control. For either case, offsite power is available for the continued operation of plant components such as the reactor coolant pumps. The case of loss of offsite power to the station auxiliaries is analyzed in Section B.3.10.

B.3.6B.2 Method of Analysis

The loss of load transients are analyzed by employing the detailed digital computer program LOFTRAN (Reference 5). The program simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level.

The analysis is performed to bound the conditions of the reduced temperature and pressure operation along with other design changes associated with the V-5 transition as discussed in Section B.1. This accident is analyzed with RTDP. Plant characteristics and initial conditions are shown in Table B.2.5.

Major assumptions are summarized below:

A. Initial Operating Conditions - nominal conditions (RTDP) are assumed.

B. Moderator and Doppler Coefficients of Reactivity - the loss of load is analyzed with both maximum and minimum reactivity feedback. The maximum feedback cases assume a large positive moderator density coefficient (corresponding to a large negative moderator temperature coefficient) and the most negative Doppler power coefficient. The minimum feedback cases assume a positive moderator temperature coefficient and the least negative Doppler coefficients.

C. Reactor Control - from the standpoint of the maximum pressures attained it is conservative to assume that the reactor is in manual control. If the reactor were in automatic control, the control rod banks would move prior to trip and reduce the severity of the transient.

D. Pressurizer Spray and Power-Operated Relief Valves - two cases for both the minimum and maximum moderator feedback cases are analyzed:

1. Full credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are also available.

2. No credit is taken for the effect of pressurizer spray and power-operated relief valves in reducing or limiting the coolant pressure. Safety valves are available.

E. Steam Release - no credit is taken for the operation of the steam dump system or steam generator power-operated relief valves. The steam generator pressure rises to the safety valve setpoint where steam release through the safety valves limits secondary steam pressure at the setpoint value.

F. Feedwater Flow - main feedwater flow to the steam generators is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater flow since a stabilized plant condition will be reached before auxiliary feedwater initiation is normally assumed to occur; however, the auxiliary feedwater pumps would be expected to start on a trip of the main feedwater pumps. The auxiliary feedwater flow would remove core decay heat following plant stabilization.

G. Reactor trip is actuated by the first Reactor Protection System trip setpoint reached. Trip signals are expected due to high pressurizer pressure, overtemperature ΔT, high pressurizer water level, and low-low steam generator water level.

B.3.6B.3 Results

The transient responses for a loss of load from full power operation are shown for four cases: two cases for minimum reactivity feedback and two cases for maximum reactivity feedback (Figures B.3-26B through B.3-37B).

Figures B.3-26B through B.3-28B show the transient responses for the loss of load with minimum reactivity feedback assuming full credit for the pressurizer spray and pressurizer power-operated relief valves. No credit is taken for the steam dump. The reactor is tripped by the high pressurizer pressure signal.

The minimum DNBR remains well above the limit value. The pressurizer safety valves are not actuated for this case since primary system pressure remains well below the design value. The steam generator safety valves prevent overpressurization of the secondary system, maintaining pressure below 110 percent of design value.

Figures B.3-29B through B.3-31B show the responses for the total loss of steam load with maximum reactivity feedback. All other plant parameters are the same as the above. The DNBR increases throughout the transient and never drops below its initial value. Pressurizer relief valves and steam generator safety valves prevent overpressurization in primary and secondary systems, respectively. The reactor is tripped by the low-low steam generator water level signal. The pressurizer safety valves are not actuated for this case.

In the event that feedwater flow is not terminated at the time of turbine trip for this case, flow would continue under automatic control with the reactor at a reduced power. The operator would take action to terminate the transient and bring the plant to a stabilized condition. If no action were taken by the operator the reduced power operation would continue until the condenser hotwell was emptied. A low-low steam generator water level reactor trip would be generated along

with auxiliary feedwater initiation signals. Auxiliary feedwater would then be used to remove decay heat with the results less severe than those presented in Section B.3.7, Loss of Normal Feedwater Flow.

The loss of load accident was also studied assuming the plant to be initially operating at full power with no credit taken for the pressurizer spray, pressurizer power-operated relief values, or steam dump. The reactor is tripped on the high pressurizer pressure signal. Figures B.3-32B through B.3-34B show the transient responses with minimum reactivity feedback. The neutron flux remains essentially constant at full power until the reactor is tripped. The DNBR never goes below its initial value throughout the transient. In this case the pressurizer safety valves are actuated, and maintain system pressure below 110 percent of the design value.

Figures B.3-35B through B.3-37B show the transient responses with maximum reactivity feedback with the other assumptions being the same as in the preceding case. Again, the DNBR increases throughout the transient and the pressurizer safety valves are actuated to limit primary pressure.

The calculated sequence of events for the loss of load incident are shown in Table B.3-5B.

B.3.6B.4 Conclusions

Results of the analyses show that the plant design is such that a loss of load without a direct or immediate reactor trip presents no hazard to the integrity of the RCS or the main steam system. Pressure relieving devices incorporated in the two systems are adequate to limit the maximum pressures to within the design limits. The integrity of the core is maintained by operation of the reactor protection system, i.e., the DNBR will be maintained above the limit value. Thus the conclusions presented in the UFSAR remain valid for the changes associated with the complete VANTAGE 5 transition for the loss of load event.

B.3.7 Loss of Normal Feedwater Flow

B.3.7.1 Introduction

A loss of normal feedwater (from pump failures, valve malfunctions, or loss of offsite AC power) results in a reduction in capability of the secondary system to remove the heat generated in the reactor core. If an alternative supply of feedwater were not supplied to the plant, core residual heat following reactor trip would heat the primary system water to the point where water relief

from the pressurizer would occur, resulting in a substantial loss of water from the RCS. Since the plant is tripped well before the steam generator heat transfer capability is reduced, the primary system variables never approach a DNB condition.

The reactor trip on low-low water level in any steam generator provides the necessary protection against a loss of normal feedwater. Other reactor protection functions available for this event are discussed in the UFSAR.

The auxiliary feedwater system is started automatically. The turbine driven auxiliary feedwater pump utilizes steam from the secondary system and exhausts to the atmosphere. The motor driven auxiliary feedwater pumps are supplied by power from the diesel generators if a loss of offsite power occurs. The pumps take suction directly from the condensate storage tank for delivery to the steam generators.

An analysis of the system transient is presented below to show that following a loss of normal feedwater, the auxiliary feedwater system is capable of removing the stored and residual heat, thus preventing either overpressurization of the RCS or uncovering the core, and returning the plant to a safe condition for the various temperature and pressure conditions possible for Cook Nuclear Plant Unit 2.

B.3.7.2 Method of Analysis

A detailed analysis using the LOFTRAN code (see Reference 5) is performed in order to obtain the plant transient following loss of normal feedwater. The simulation describes the plant thermal kinetics, RCS including the natural circulation, pressurizer, steam generators and feedwater system. The digital program computes pertinent variables including the steam generator level, pressurizer water level, and reactor coolant average temperature.

To ensure that the pressurizer does not overfill, the direction of conservatism in the initial conditions was examined. The initial nominal RCS temperature of 581.3 °F along with a nominal pressure of 2250 psia was found to produce the most conservative results.

Assumptions made in the analysis are:

A. The plant is initially operating at 102 percent of the Cook Nuclear Plant Unit 2 rerating power level (3608 MWt NSSS, which includes pump heat).

B. A conservative core residual heat generation based upon long term operation at the initial power level preceding the trip. The ANS 1979 Decay Heat Model plus two sigma uncertainty was assumed.

C. Reactor trip occurs on steam generator low-low level at 0.0% of narrow range span.

D. The worst single failure in the auxiliary feedwater system occurs (e.g., failure of turbine driven auxiliary feedwater pump).

E. Auxiliary feedwater is delivered to four steam generators at a rate of 450 gpm. The 450 gpm is assumed evenly split among the four steam generators and is delivered by two motor driven pumps at a steam generator pressure of 1123 psia. Automatic initiation of the auxiliary feedwater is assumed 60 seconds after a low-low steam generator signal is actuated.

F. Secondary system steam relief is achieved through the steam generator safety valves. First four safety valves at an actuation pressure of 1123 psia were assumed in the analysis.

G. The initial reactor coolant average temperature is 4.1 °F higher than the highest allowed full power temperature, and initial pressurizer pressure is 62.6 psi higher than the nominal pressure of 2250 psia.

H. The initial pressurizer water level is assumed to be at the maximum nominal setpoint (61.1% span) plus uncertainties (5% span).

I. Pressurizer Power Operated Relief Valves (PORVs) are assumed operable to maximize pressurizer water volume.

J. The maximum pressurizer spray flow rate is assumed to maximize pressurizer water volume.

K. An auxiliary feedwater line purge volume of 100 ft^3 per loop was assumed. This is the volume that needs to be purged before the relatively cold auxiliary feedwater reaches the steam generators.

Plant characteristics and initial conditions are shown in Table B.2-4.

B.3.7.3 Results

Figures B.3-38 through B.3-40 show the significant plant parameters following a loss of normal feedwater.

Following the reactor and turbine trip from full load, the water level in the steam generators will fall due to the collapse of voids and because steam flow through the safety valves continues to dissipate the stored and generated heat. One minute following the initiation of the low-low level trip, the motor driven auxiliary feedwater pumps are automatically started, reducing the rate of water level decrease.

The plot of pressurizer water volume clearly shows that the pressurizer does not fill. For comparison purposes, the pressurizer fills at 1889 ft^3 (which includes the pressurizer surge volume).

The plant parameter changes associated with the VANTAGE 5 reload as discussed in Section B.1 either were incorporated in the safety analysis or do not impact the analysis. The conservative direction for the moderator temperature coefficient for this event is to assume the most positive MTC. Also, the other plant parameter changes (i.e., degraded ECCS performance and increased MSIV closure time) do not impact the safety analysis since they are not modeled for the loss of normal feedwater transient.

The calculated sequence of events for this transient are shown in Table B.3-6.

B.3.7.4 Conclusions

Results of the analysis show that a loss of normal feedwater does not adversely affect the core, the RCS, or the steam system since the auxiliary feedwater capacity is such that reactor coolant water

is not relieved from the pressurizer relief or safety valves. Thus, the conclusions presented in the UFSAR remain valid for the Cook Nuclear Plant Unit 2 design changes associated with the VANTAGE 5 reload.

B.3.8A Excessive Heat Removal due to Feedwater System Malfunctions (Mixed Core)

Excessive heat removal events due to feedwater system malfunctions are examined primarily to demonstrate core protection. An increase in core power is nonconservative with respect to the DNB transient whereas the reduction in full power average temperature for the reduced temperature operation is a benefit for the at power events. The no load temperature does not change due to the reduced temperature operation. Also, the impact of the revised core limits as well as other design changes associated with the VANTAGE 5 transition as discussed in Section B.1 needs to be addressed. As a result, the excessive heat removal events due to feedwater system malfunctions were analyzed. Feedwater System Malfunctions causing a reduction in feedwater temperature as well as an increase in feedwater flow are considered.

B.3.8A.1 Feedwater System Malfunctions Causing a Reduction in Feedwater Temperature

B.3.8A.1.1 Introduction

Reductions in feedwater temperature will result in an increase in core power by initially decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and of the RCS. The high neutron flux trip, overtemperature ΔT trip, and overpower ΔT trip prevent any power increase which could lead to a Departure from Nucleate Boiling Ratio (DNBR) less than the limit value. A reduction in feedwater temperature may be caused by the accidental opening of a feedwater heater bypass valve which diverts flow around a portion of the feedwater heaters. In the event of an accidental opening of the bypass valve, there is a sudden reduction in feedwater inlet temperature to the steam generators. At power, this increased subcooling will create a greater load demand on the RCS.

With the plant at no load (Hot Zero Power) conditions, the addition of cold feedwater will cause a decrease in RCS temperature and, thus, a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity. However, the rate of energy change is reduced as load and feedwater flow decrease so the transient is less severe than the full power case. The net effect on the RCS due to a reduction in feedwater temperature is that the reactor will reach a new equilibrium condition at a power level corresponding to the new steam generator ΔT.

B.3.8A.1.2 Method of Analysis

This transient is analyzed by computing conditions at the feedwater pump inlet following opening of the heater bypass valve. These feedwater conditions are then used to perform a heat balance through the high pressure heaters. This heat balance gives the new feedwater conditions at the steam generator inlet.

The following assumptions are made:

1. Plant initial power level corresponding to guaranteed NSSS thermal output.

2. Simultaneous actuation of either a low pressure heater bypass valve or a high pressure heater bypass valve and isolation of one string of feedwater heaters.

B.3.8A.1.3 Results

Opening of either a low pressure heater bypass valve or a high pressure heater bypass valve causes a reduction in feedwater temperature which increases the thermal load on the primary system. The calculated reduction in feedwater temperature due to opening of a high pressure heater bypass valve is higher than that of the opening of a low pressure heater bypass valve and is less than 60 °F. This reduction in feedwater temperature results in an increase in heat load on the primary system of less than 10 percent of full power. The increased thermal load, due to opening of a high pressure heater bypass valve, would result in a transient very similar (but of reduced magnitude) to that presented in Section B.3.9A for an Excessive Increase in Secondary Steam Flow incident, which evaluates the consequences of a 10 percent step load increase. Therefore, the results of this analysis are not presented.

B.3.8A.1.4 Conclusions

The decrease in feedwater temperature transient is less severe than the increase in secondary steam flow event (Section B.3.9A). Based on results presented in Section B.3.9A, the applicable acceptance criteria for the decrease in feedwater temperature event have been met.

B.3.8A.2 Feedwater System Malfunctions Causing an Increase in Feedwater Flow

B.3.8A.2.1 Introduction

Addition of excessive feedwater is a means of increasing core power above full power. Such transients are attenuated by the thermal capacity of the secondary plant and of the Reactor Coolant System. The high neutron flux trip, overpower ΔT trip and overtemperature ΔT trip prevent any power increase which could lead to DNBR less than the minimum allowable value in the event that the steam generator high level protection has not be actuated.

Excessive feedwater flow may be caused by the full opening of a feedwater control valve due to a Feedwater Control system malfunction or an operator error. At power conditions, this excess flow causes a greater load demand on the Reactor Coolant System due to increased subcooling in the steam generator. With the plant at no load conditions, the addition of cold feedwater will cause a decrease in Reactor Coolant System temperature and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity.

B.3.8A.2.2 Method of Analysis

The excessive heat removal due to a feedwater system malfunction transient is analyzed by using the detailed digital computer code LOFTRAN (Reference 5). This code simulates the neutron kinetics of the reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The system is analyzed to demonstrate acceptable consequences in the event of an excessive feedwater addition, due to a control system malfunction or operator error which allows a feedwater control valve to open fully. The following cases have been analyzed:

1. Accidental full opening of one feedwater control valve with the reactor at power assuming automatic and manual rod control and a conservatively large negative moderator temperature coefficient of reactivity.

2. Accidental full opening of a feedwater control valve with the reactor at no load (Hot Zero Power) conditions and assuming a conservatively large negative moderator temperature coefficient of reactivity.

The analyses are performed to bound the reduced RCS temperature operation along with the range of conditions possible for the uprating of Cook Nuclear Plant Unit 2. This accident is analyzed using the Revised Thermal Design Procedure with the initial conditions shown in Table B.2-4.

The reactivity insertion rate following a feedwater system malfunction is calculated with the following assumptions:

A. Initial reactor power, pressure, and RCS temperatures are assumed to be at their conservative nominal valves. Uncertainties in initial conditions are included in the limit DNBR.

B. For the feedwater control valve accident at full power, one feedwater control valve is assumed to malfunction resulting in a step increase to 150% of nominal feedwater flow to one steam generator.

C. For the feedwater control valve accident at no load conditions, feedwater control valve malfunction occurs which results in an increase in flow to one steam generator from zero to 100 percent of the nominal full load value.

D. For the zero load condition, feedwater temperature is at a value of 70 °F.

E. No credit is taken for the heat capacity of the RCS and steam generator thick metal in attenuating the resulting plant cooldown.

F. The feedwater flow resulting from a fully open control valve is terminated by a steam generator high-high level trip signal which closes all feedwater control and isolation valves, trips the main feedwater pumps and trips the turbine.

Normal reactor control system and engineered safety systems are not required to function. The reactor protection system may function to trip the reactor due to overpower or turbine trip on high-high steam generator water level conditions.

B.3.8A.2.3 Results

In the case of an accidental full opening of one feedwater control valve with the reactor at zero power and the above mentioned assumptions, the maximum reactivity insertion rate is less than the maximum reactivity insertion rate assumed in the analysis in Section B.3.1, Uncontrolled RCCA Withdrawal From a Subcritical Condition, and therefore, the results of the analysis are not presented here. It should be noted that if the incident occurs with the unit just critical at no load, the reactor may be tripped by the power range high neutron flux trip (low setting) set at approximately 25 percent of nominal full power.

The full power case (maximum reactivity feedback coefficients with manual rod control) gives the largest reactivity feedback and results in the greatest power increase. Assuming the reactor to be in the automatic rod control mode results in a slightly less severe transient. The rod control system is not required to function for an excessive feedwater flow event.

For all excessive feedwater cases, continuous addition of cold feedwater is prevented by automatic closure of all feedwater isolation valves on a steam generator high-high water level signal. In addition, a turbine trip is initiated. A reactor trip on turbine trip was then assumed as a means of terminating the transient analysis. The reactor trip prevents reactor coolant heatup consistent with the cooldown characteristics of the feedwater malfunction event. The reactor trip on turbine trip was assumed as an anticipatory trip. If the reactor trip was not assumed, the transient would progress into a heatup event, in particular, a loss of normal feedwater due to the isolation which occurs on the high-high steam generator water level signal. A reactor trip would then be provided by a low-low steam generator water level signal. The reactor trip on turbine trip is not required for core protection for this event. The results (minimum DNBR) of the feedwater malfunction analysis would be essentially unchanged if the reactor trip was not assumed to occur on turbine trip.

Following reactor trip and feedwater isolation, the plant will approach a stabilized condition at hot standby. Normal plant operating procedures may then be followed. The operating procedures would call for operator action to control RCS boron concentration and pressurizer level using the CVCS and to maintain steam generator level through control of the main or auxiliary feedwater system. Any action required of the operator to maintain the plant in a stabilized condition will be in a time frame in excess of ten minutes following reactor trip.

Transient results, Figures B.3-41A through B.3-44A, show the nuclear power, T-avg, pressurizer pressure and DNBR for the full power cases (with and without Rod Control). The DNBR does not drop below the safety analysis limit value.

Since the power level rises during the excessive feedwater flow incident, the fuel temperatures will also rise until after reactor trip occurs. The core heat flux lags behind the neutron flux response due to the fuel rod thermal time constant; hence, the peak heat flux does not exceed 118 percent of its nominal value (i.e., the assumed high neutron flux trip setpoint). The peak fuel temperature will thus remain below the fuel melting temperature.

The transient results show that DNB does not occur at any time during the excessive feedwater flow incident; thus, the ability of the primary coolant to remove heat from the fuel rods is not reduced. The fuel cladding temperature therefore does not rise significantly above its initial value during the transient.

The calculated sequence of events for the increase in feedwater flow for the full power cases are shown in Table B.3-7A.

B.3.8A.2.4 Conclusions

The results of the analysis show that the DNB ratios encountered for an excessive feedwater addition at power are above the limit value; hence, no fuel or clad damage is predicted. Additionally, it has been shown that the reactivity insertion rate which occurs at no load conditions following excessive feedwater addition is less than the maximum value considered in the analysis of the rod withdrawal from a subcritical condition event (Section B.3.1).

B.3.8B Excessive Heat Removal due to Feedwater System Malfunctions (Full VANTAGE 5 Core)

Excessive heat removal events due to feedwater system malfunctions are examined primarily to demonstrate core protection. An increase in core power is nonconservative with respect to the DNB transient whereas the reduction in full power average temperature for the reduced temperature operation is a benefit for the at power events. The no load temperature does not change due to the reduced temperature and pressure operation. The reduction in RCS pressure is nonconservative with respect to the DNB transient. Also, the impact of the revised core limits

as well as other design changes associated with the VANTAGE 5 transition as discussed in Section B.1 needs to be addressed. As a result, the excessive heat removal events due to feedwater system malfunctions were analyzed. Feedwater System Malfunctions causing a reduction in feedwater temperature as well as an increase in feedwater flow are considered.

B.3.8B.1 Feedwater System Malfunctions Causing a Reduction in Feedwater Temperature

B.3.8B.1.1 Introduction

Reductions in feedwater temperature will result in an increase in core power by initially decreasing reactor coolant temperature. Such transients are attenuated by the thermal capacity of the secondary plant and of the RCS. The high neutron flux trip, overtemperature ΔT trip, and overpower ΔT trip prevent any power increase which could lead to a Departure from Nucleate Boiling Ratio (DNBR) less than the limit value.

A reduction in feedwater temperature may be caused by the accidental opening of a feedwater heater bypass valve which diverts flow around a portion of the feedwater heaters. In the event of an accidental opening of the bypass valve, there is a sudden reduction in feedwater inlet temperature to the steam generators. At power, this increased subcooling will create a greater load demand on the RCS.

With the plant at no load (Hot Zero Power) conditions, the addition of cold feedwater will cause a decrease in RCS temperature and, thus, a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity. However, the rate of energy change is reduced as load and feedwater flow decrease so the transient is less severe than the full power case. The net effect on the RCS due to a reduction in feedwater temperature is that the reactor will reach a new equilibrium condition at a power level corresponding to the new steam generator ΔT.

B.3.8B.1.2 Method of Analysis

This transient is analyzed by computing conditions at the feedwater pump inlet following opening of the heater bypass valve. These feedwater conditions are then used to perform a heat balance through the high pressure heaters. This heat balance gives the new feedwater conditions at the steam generator inlet.

The following assumptions are made:

1. Plant initial power level corresponding to guaranteed NSSS thermal output.
2. Simultaneous actuation of either a low pressure heater bypass valve or a high pressure heater bypass valve and isolation of one string of feedwater heaters.

B.3.8B.1.3 Results

Opening of either a low pressure heater bypass valve or a high pressure heater bypass valve causes a reduction in feedwater temperature which increases the thermal load on the primary system. The calculated reduction in feedwater temperature due to opening of a high pressure heater bypass valve is higher than that of the opening of a low pressure heater bypass valve and is less than 60 °F. This reduction in feedwater temperature results in an increase in heat load on the primary system of less than 10 percent of full power. The increased thermal load, due to opening of the high pressure heater bypass valve, would result in a transient very similar (but of reduced magnitude) to that presented in Section B.3.9B for an Excessive Increase in Secondary Steam Flow incident, which evaluates the consequences of a 10 percent step load increase. Therefore, the results of this analysis are not presented.

B.3.8B.1.4 Conclusions

The decrease in feedwater temperature transient is less severe than the increase in secondary steam flow event (Section B.3.9B). Based on results presented in Section B.3.9B, the applicable acceptance criteria for the decrease in feedwater temperature event have been met.

B.3.8B.2 Feedwater System Malfunctions Causing an Increase in Feedwater Flow

B.3.8B.2.1 Introduction

Addition of excessive feedwater is a means of increasing core power above full power. Such transients are attenuated by the thermal capacity of the secondary plant and of the Reactor Coolant System. The high neutron flux trip, overpower ΔT trip and overtemperature ΔT trip prevents any power increase which could lead to DNBR less than the minimum allowable value in the event that the steam generator high level protection has not be actuated.

Excessive feedwater flow may be caused by the full opening of a feedwater control valve due to a Feedwater Control system malfunction or an operator error. At power conditions, this excess

flow causes a greater load demand on the Reactor Coolant System due to increased subcooling in the steam generator. With the plant at no load conditions, the addition of cold feedwater will cause a decrease in Reactor Coolant System temperature and thus a reactivity insertion due to the effects of the negative moderator temperature coefficient of reactivity.

B.3.8B.2.2 Method of Analysis

The excessive heat removal due to a feedwater system malfunction transient is analyzed by using the detailed digital computer code LOFTRAN (Reference 5). This code simulates the neutron kinetics of the reactor coolant system, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The system is analyzed to demonstrate acceptable consequences in the event of an excessive feedwater addition, due to a control system malfunction or operator error which allows a feedwater control valve to open fully. The following cases have been analyzed:

1. Accidental full opening of one feedwater control valve with the reactor at power assuming automatic and manual rod control and a conservatively large negative moderator temperature coefficient of reactivity.

2. Accidental full opening of a feedwater control valve with the reactor at no load (Hot Zero Power) conditions and assuming a conservatively large negative moderator temperature coefficient of reactivity.

The analyses are performed to bound the reduced RCS temperature and decreased RCS pressure operation along with the range of conditions possible for the Cook Nuclear Plant Unit 2 core uprating and fuel upgrade. This accident is analyzed using the Revised Thermal Design Procedure with the initial conditions shown in Table B.2-5.

The reactivity insertion rate following a feedwater system malfunction is calculated with the following assumptions:

A. Initial reactor power, pressure, and RCS temperatures are assumed to be at their conservative nominal valves. Uncertainties in initial conditions are included in the limit DNBR.

B. For the feedwater control valve accident at full power, one feedwater control valve is assumed to malfunction resulting in a step increase to 150% of nominal feedwater flow to one steam generator.

C. For the feedwater control valve accident at no load conditions, feedwater control valve malfunction occurs which results in an increase in flow to one steam generator from zero to 100% of the nominal full load value.

D. For the no load condition, feedwater temperature is at a value of 70 °F.

E. No credit is taken for the heat capacity of the RCS and steam generator thick metal in attenuating the resulting plant cooldown.

F. The feedwater flow resulting from a fully open control valve is terminated by a steam generator high-high level trip signal which closes all feedwater control and isolation valves, trips the main feedwater pumps and trips the turbine.

Normal reactor control system and engineered safety systems are not required to function. The reactor protection system may function to trip the reactor due to overpower or turbine trip on high-high steam generator water level conditions.

B.3.8B.2.3 Results

In the case of an accidental full opening of one feedwater control valve with the reactor at zero power and the above mentioned assumptions, the maximum reactivity insertion rate is less than the maximum reactivity insertion rate assumed in the analysis in Section B.3.1, Uncontrolled RCCA Withdrawal From A Subcritical Condition, and therefore, the results of the analysis are not presented here. It should be noted that if the incident occurs with the unit just critical at no load, the reactor may be tripped by the power range high neutron flux trip (low setting) set at approximately 25 percent of nominal full power.

The full power case (maximum reactivity feedback coefficients with manual rod control) gives the largest reactivity feedback and results in the greatest power increase. Assuming the reactor to be in the automatic rod control mode results in a slightly less severe transient. The rod control system is not required to function for an excessive feedwater flow event.

For all excessive feedwater cases, continuous addition of cold feedwater is prevented by automatic closure of all feedwater isolation valves on a steam generator high-high water level signal. In addition, a turbine trip is initiated. A reactor trip on turbine trip was then assumed as a means of terminating the transient analysis. The reactor trip prevents reactor coolant heatup consistent with the cooldown characteristics of the feedwater malfunction event. The reactor trip on turbine trip was assumed as an anticipatory trip. If the reactor trip was not assumed, the transient would progress into a heatup event, in particular, a loss of normal feedwater due to the isolation which occurs on the high-high steam generator water level signal. A reactor trip would then be provided by a low-low steam generator water level signal. The reactor trip on turbine trip is not required for core protection for this event. The results (minimum DNBR) of the feedwater malfunction analysis would be essentially unchanged if the reactor trip was not assumed to occur on turbine trip.

Following reactor trip and feedwater isolation, the plant will approach a stabilized condition at hot standby. Normal plant operating procedures may then be followed. The operating procedures would call for operator action to control RCS boron concentration and pressurizer level using the CVCS and to maintain steam generator level through control of the main or auxiliary feedwater system. Any action required of the operator to maintain the plant in a stabilized condition will be in a time frame in excess of ten minutes following reactor trip.

Transient results, Figures B.3-41B through B.3-44B, show the nuclear power, T-avg, pressurizer pressure and DNBR for the full power cases (with and without Rod Control). The DNBR does not drop below the safety analysis limit value.

Since the power level rises during the excessive feedwater flow incident, the fuel temperatures will also rise until after reactor trip occurs. The core heat flux lags behind the neutron flux response due to the fuel rod thermal time constant; hence, the peak heat flux does not exceed 118 percent of its nominal value (i.e., the assumed high neutron flux trip setpoint). The peak fuel temperature will thus remain below the fuel melting temperature.

The transient results show that DNB does not occur at any time during the excessive feedwater flow incident; thus, the ability of the primary coolant to remove heat from the fuel rods is not reduced. The fuel cladding temperature therefore does not rise significantly above its initial value during the transient.

The calculated sequence of events for the increase in feedwater flow for the full power cases are shown in Table B.3-7B.

B.3.8B.2.4 Conclusions

The results of the analysis show that the DNB ratios encountered for an excessive feedwater addition at power are above the limit value; hence, no fuel or clad damage is predicted. Additionally, it has been shown that the reactivity insertion rate which occurs at no load conditions following excessive feedwater addition is less than the maximum value considered in the analysis of the rod withdrawal from a subcritical condition event (Section B.3.1).

B.3.9A Excessive Load Increase (Mixed Core)

B.3.9A.1 Introduction

The excessive increase in secondary steam flow is examined primarily to demonstrate core protection. Since the OTΔT setpoint is changed for the VANTAGE 5 transition, the impact of the revised OTΔT setpoint needs to be examined for this event. As such, the excessive increase in secondary steam flow is analyzed to determine the impact of VANTAGE 5 transition and other design changes as discussed in Section B.1.

An excessive load increase incident is defined as a rapid increase in steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a ten percent (10%) step load increase and a five percent (5%) per minute ramp load increase in the range of 15 to 100 percent of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the reactor protection system.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control.

During power operation, steam dump to the condenser is controlled by reactor coolant condition signals, i.e., high reactor coolant temperature indicates a need for steam dump. A single controller malfunction does not cause steam dump; an interlock is provided which blocks the opening of the valves unless a large turbine load decrease or turbine trip has occurred.

Protection against an excessive load increase accident is provided by the following reactor protection system signals:

- Overpower ΔT
- Overtemperature ΔT
- Power range high neutron flux
- Low pressurizer pressure

B.3.9A.2 Method of Analysis

This accident is analyzed using the LOFTRAN Code (Reference 5). This code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, steam generator safety valves, and feedwater system. The code computes pertinent plant variables including temperatures, pressures, and power level.

Four cases are analyzed to demonstrate the plant behavior following a 10 percent step load increase from rated load. These cases are as follows:

A. Manual rod control with minimum moderator reactivity feedback
B. Manual rod control with maximum moderator reactivity feedback
C. Automatic rod control with minimum moderator reactivity feedback
D. Automatic rod control with maximum moderator reactivity feedback

For the minimum moderator feedback cases, it was assumed that the core has a zero moderator temperature coefficient of reactivity and the least negative Doppler only power coefficient curve. This results in the least inherent transient response capability. The zero moderator temperature coefficient of reactivity bounds a positive moderator temperature coefficient for this cooldown

event. For the maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its highest absolute value and the most negative Doppler only power coefficient curve. This results in the largest amount of reactivity feedback due to changes in coolant temperature.

A conservative limit on the turbine valve opening is assumed, and all cases are studied without credit being taken for pressurizer heaters.

An analysis is performed to bound the conditions of the high and reduced temperature operation along with the other design changes associated with the VANTAGE 5 transition as discussed in Section B.1. This accident is analyzed with the RTDP as described in Reference 2. Conservative nominal values are assumed for the initial reactor power, pressure, and RCS temperature. Uncertainties in initial conditions are included in the limit DNBR. Plant characteristics and initial conditions are shown in Table B.2-4.

Normal reactor control systems and engineered safety systems are not required to function. The reactor protection system is assumed to be operable; however, reactor trip is not encountered for most cases due to the error allowances assumed in the setpoints.

The cases which assume automatic rod control are analyzed to ensure that the worst case is presented. The automatic function is not required.

B.3.9A.3 Results

Figures B.3-45A through B.3-48A illustrate the transient with the reactor in the manual control mode. As expected, for the minimum moderator feedback case there is a slight power increase, and the average core temperature shows a large decrease. This results in a DNBR which increases above its initial value. For the maximum moderator feedback, manually controlled case there is a large increase in reactor power due to the moderator feedback. A reduction in DNBR is experienced but DNBR remains above the limit value.

Figures B.3-49A through B.3-52A illustrate the transient assuming the reactor is in the automatic control mode. Both the minimum and maximum moderator feedback cases show that core power increases, thereby reducing the rate of decrease in coolant average temperature and pressurizer pressure. For both of these cases, the minimum DNBR remains above the limit value.

For all cases, the plant rapidly reaches a stabilized condition at the higher power level. Normal plant operating procedures would then be followed to reduce power.

The excessive load increase incident is an overpower transient for which the fuel temperatures will rise. Reactor trip does not occur for the cases analyzed, and the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

The calculated sequence of events for the excessive load increase incident are shown in Table B.3-8A.

B.3.9A.4 Conclusions

The analysis presented above shows that for a ten percent (10%) step load increase, the DNBR remains above the limit value, thereby precluding fuel or clad rupture. The plant reaches a stabilized condition rapidly following the load increase.

B.3.9B Excessive Load Increase (Full VANTAGE 5 Core)

B.3.9B.1 Introduction

The excessive increase in secondary steam flow is examined primarily to demonstrate core protection. The reduction in RCS pressure is non-conservative with respect to the DNB transient. Since the OTΔT setpoint is changed for the reduced temperature and pressure operation, the impact of the revised OTΔT setpoint also needs to be examined for this event. As such the excessive increase in secondary steam flow is analyzed to determine the impact of complete VANTAGE 5 transition and other design changes as discussed in Section B.1.

An excessive load increase incident is defined as a rapid increase in steam flow that causes a power mismatch between the reactor core power and the steam generator load demand. The reactor control system is designed to accommodate a ten percent (10%) step load increase and a five percent (5%) per minute ramp load increase in the range of 15 to 100 percent of full power. Any loading rate in excess of these values may cause a reactor trip actuated by the reactor protection system.

This accident could result from either an administrative violation such as excessive loading by the operator or an equipment malfunction in the steam dump control or turbine speed control.

During power operation, steam dump to the condenser is controlled by reactor coolant condition signals, i.e., high reactor coolant temperature indicates a need for steam dump. A single controller malfunction does not cause steam dump; an interlock is provided which blocks the opening of the valves unless a large turbine load decrease or turbine trip has occurred.

Protection against an excessive load increase accident is provided by the following reactor protection system signals:

- Overpower ΔT
- Overtemperature ΔT
- Power range high neutron flux
- Low pressurizer pressure

B.3.9B.2 Method of Analysis

This accident is analyzed using the LOFTRAN Code (Reference 5). This code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, steam generator safety valves, and feedwater system. The code computes pertinent plant variables including temperatures, pressures, and power level.

Four cases are analyzed to demonstrate the plant behavior following a 10 percent step load increase from rated load. These cases are as follows:

A. Manual rod control with minimum moderator reactivity feedback
B. Manual rod control with maximum moderator reactivity feedback
C. Automatic rod control with minimum moderator reactivity feedback
D. Automatic rod control with maximum moderator reactivity feedback

For the minimum moderator feedback cases, it was assumed that the core has a zero moderator temperature coefficient of reactivity and the least negative Doppler only power coefficient curve. This results in the least inherent transient response capability. The zero moderator temperature coefficient of reactivity bounds a positive moderator temperature coefficient for this cooldown

event. For the maximum moderator feedback cases, the moderator temperature coefficient of reactivity has its highest absolute value and the most negative Doppler only power coefficient curve. This results in the largest amount of reactivity feedback due to changes in coolant temperature.

A conservative limit on the turbine valve opening is assumed, and all cases are studied without credit being taken for pressurizer heaters.

An analysis is performed to bound the conditions of the reduced temperature and pressure operation along with the other design changes associated the VANTAGE 5 transition and modified safety analysis assumptions as discussed in Section B.1. This accident is analyzed with the RTDP as described in Reference 2. Conservative nominal values are assumed for the initial reactor power, pressure, and RCS temperature. Uncertainties in initial conditions are included in the limit DNBR. Plant characteristics and initial conditions are shown in Table B.2-5.

Normal reactor control systems and engineered safety systems are not required to function. The reactor protection system is assumed to be operable; however, reactor trip is not encountered for most cases due to the error allowances assumed in the setpoints.

The cases which assume automatic rod control are analyzed to ensure that the worst case is presented. The automatic function is not required.

B.3.9B.3 Results

Figures B.3-45B through B.3-48B illustrate the transient with the reactor in the manual control mode. As expected, for the minimum moderator feedback case there is a slight power increase, and the average core temperature shows a large decrease. This results in a DNBR which increases above its initial value. For the maximum moderator feedback, manually controlled case there is a large increase in reactor power due to the moderator feedback. A reduction in DNBR is experienced but DNBR remains above the limit value.

Figures B.3-49B through B.3-52B illustrate the transient assuming the reactor is in the automatic control mode. Both the minimum and maximum moderator feedback cases show that core power increases, thereby reducing the rate of decrease in coolant average temperature and pressurizer pressure. For both of these cases, the minimum DNBR remains above the limit value.

For all cases, the plant rapidly reaches a stabilized condition at the higher power level. Normal plant operating procedures would then be followed to reduce power.

The excessive load increase incident is an overpower transient for which the fuel temperatures will rise. Reactor trip does not occur for the cases analyzed, and the plant reaches a new equilibrium condition at a higher power level corresponding to the increase in steam flow.

The calculated sequence of events for the excessive load increase incident are shown in Table B.3-8B.

B.3.9B.4 Conclusions

The analysis presented above shows that for a ten percent (10%) step load increase, the DNBR remains above the limit value; thereby precluding fuel or clad rupture. The plant reaches a stabilized condition rapidly following the load increase.

B.3.10 Loss Of Offsite Power (LOOP) to the Station Auxiliaries

B.3.10.1 Introduction

A concern presented by the reduced temperature and pressure operation is the possibility of pressurizer overfill for the loss of all AC power to plant auxiliaries event. This event, along with the loss of normal feedwater incident (Section B.3.7), is a limiting transient with respect to pressurizer overfill. The decrease in primary temperature increases the density of the coolant and, during any heatup transient, increases the potential for filling the pressurizer. As such, the loss of all AC power to the plant auxiliaries is analyzed for the Cook Nuclear Plant Unit 2 VANTAGE 5 reload, including other design changes discussed in Section B.1.

A complete loss of all (non-emergency) AC power (e.g. offsite power) may result in the loss of all power to the plant auxiliaries, i.e., the RCPs, condensate pumps, etc. The loss of power may be caused by a complete loss of the offsite grid accompanied by a turbine generator trip at the station, or by a loss of the onsite AC distribution system.

This transient is analyzed to show the adequacy of the heat removal capability of the auxiliary feedwater system. This transient is more severe than the loss of external electric load or turbine trip event (Section B.3.6) analyzed because in this case the decrease in heat removal by the

secondary system is accompanied by a flow coastdown which further reduces the capacity of the primary coolant to remove heat from the core. The reactor will trip due to: (1) turbine trip; (2) upon reaching one of the trip setpoints in the primary and secondary systems as a result of the flow coastdown and decrease in secondary heat removal; or (3) due to loss of power to the control rod drive mechanisms as a result of the loss of AC power to the plant.

Following a loss of power with turbine and reactor trips, the sequence described below will occur:

A. Plant vital instruments are supplied from emergency DC power sources.

B. As the steam system pressure rises following the trip, the steam generator power-operated relief valves may be automatically opened to the atmosphere. The condenser is assumed not to be available for steam dump. If the steam flow rate through the power relief valves is not available, the steam generator safety valves may lift to dissipate the sensible heat of the fuel and coolant plus the residual decay heat produced in the reactor.

C. As the no load temperature is approached, the steam generator power-operated relief valves (or safety valves, if the power operated relief valves are not available) are used to dissipate the residual decay heat and to maintain the plant at the hot standby condition.

D. The standby diesel generators, started on loss of voltage on the plant emergency buses, begin to supply plant vital loads.

The motor driven auxiliary feedwater pumps are supplied power by the diesels and the turbine-driven pump utilizes steam from the main steam system. Both type pumps are designed to supply rated flow within one minute of the initiating signal even if a loss of all non-emergency AC power occurs simultaneously with loss of normal feedwater. The turbine exhausts the used steam to the atmosphere. The auxiliary feedwater pumps take suction from the condensate storage tank for delivery to the steam generators.

Following the RCP coastdown caused by the loss of AC power, the natural circulation capability of the RCS will remove residual and decay heat from the core, aided by auxiliary feedwater in the secondary system. Although there is no RCP heat to remove, an analysis is presented here to show

that the natural circulation flow in the RCS following a loss of AC power event is sufficient to remove residual heat from the core.

B.3.10.2 Method of Analysis

A detailed analysis using the LOFTRAN Code (Reference 5) is performed to obtain the plant transient following a loss of all AC power. The simulation describes the plant thermal kinetics, RCS including the natural circulation, pressurizer, steam generators and feedwater system. The digital program computes pertinent variables including the steam generator level, pressurizer water level, and reactor coolant average temperature.

The direction of conservatism in the initial conditions was examined relative to the pressurizer overfill. Since a maximum water mass in the primary system, given a constant volume, is desired, the nominal average temperature at full power was assumed to be the no-load temperature and the initial pressurizer pressure was assumed to correspond to a nominal pressure of 2250 psia. These assumptions maximize the density of the primary system coolant. The pressurizer pressure control system was assumed to be available as well.

The assumptions used in the analysis are as follows:

A. The plant is initially operating at 102% of the Cook Nuclear Plant Unit 2 rerating power level (3608 MWt NSSS, which includes pump heat).

B. A conservative core residual heat generation based upon long term operation at the initial power level preceding the trip. The ANS 1979 Decay Heat model plus two sigma uncertainty was assumed.

C. A heat transfer coefficient in the steam generator associated with RCS natural circulation following the RCP coastdown.

D. Reactor trip occurs on steam generator low-low level at 0% of narrow range span. No credit is taken for immediate release of the control rod drive mechanisms caused by a loss of offsite power.

E. Auxiliary feedwater is delivered to four steam generators at a rate of 430 gpm. The 430 gpm is assumed evenly split among four steam generators and is delivered by two motor driven pumps at a steam generator safety valve actuation pressure of 1133 psia. Automatic initiation of the auxiliary feedwater is assumed 60 seconds after a low-low steam generator signal is actuated. The failure of the turbine driven auxiliary feedwater pump is assumed as the limiting single failure for this event.

F. Secondary system steam relief is achieved through the steam generator safety valves. These safety valves are assumed to be actuated at 1133 psia.

G. The initial reactor coolant average temperature is 5.6 °F lower than the nominal value of 547 °F, and initial pressurizer pressure is 62.6 psi higher than nominal pressure of 2250 psia.

H. The initial pressurizer water level is assumed to be at the maximum nominal setpoint of 61.1% span plus uncertainties (5% span).

I. Pressurizer Power Operated Relief Valves (PORVs) are assumed operable to maximize pressurizer water volume.

J. The maximum pressurizer spray flow rate is assumed to maximize pressurizer water volume.

K. An auxiliary feedwater line purge volume of 100 ft^3 per loop was assumed. This is the volume that needs to be purged before the relatively cold auxiliary feedwater reaches the steam generators.

Plant characteristics and initial conditions are shown in Table B.2-4.

B.3.10.3 Results

The transient response of the RCS following a loss of AC power is shown in Figures B.3-53 and B.3-54.

The LOFTRAN code results show that the natural circulation flow available is sufficient to provide adequate core decay heat removal following reactor trip and RCP coastdown. The plot of

pressurizer water volume shows that the pressurizer does not fill. For comparison purposes, the pressurizer fills at 1889 ft^3 (which includes the pressurizer surge volume).

The plant parameter changes associated with the VANTAGE 5 reload as discussed in Section B.1 either were incorporated in the safety analysis or do not impact the analysis. The conservative direction for the moderator temperature coefficient for this event is to assume the most positive MTC. Also, the other plant parameter changes (i.e., degraded ECCS performance and increased MSIV closure time) do not impact the safety analysis since they are not modeled for the loss of AC power transient.

The calculated sequence of events for tis transient are shown in Table B.3-9.

B.3.10.4 Conclusions

Analysis of the natural circulation capability of the RCS has demonstrated that sufficient heat removal capability exists following RCP coastdown to prevent fuel or clad rupture. Thus, a loss of AC power to station auxiliaries does not adversely affect the core, the RCS, or the steam system, and the auxiliary feedwater capability is sufficient to preclude water relief through the pressurizer relief or safety valves.

B.3.11 Rupture of a Steamline (Steamline Break)

B.3.11.1 Introduction

Although the no load temperature does not change due to the plant rerating and VANTAGE 5 fuel, the impact of the various fuel parameter changes as well as various temperature and pressure operation was addressed. Also, the nominal low steam pressure setpoint for steamline isolation and safety injection actuation is revised (lowered from 600 psig to 500 psig) to provide operating margin. As such, the rupture of a steam pipe event was analyzed. Included in the analysis are the design changes associated with the VANTAGE 5 transition and other modified safety analysis assumptions as discussed in Section B.1.

A rupture of a steam pipe results in an uncontrolled steam release from a steam generator. The steam release results in an initial increase in steam flow which decreases during the accident as the steam pressure falls. The energy removal from the Reactor Coolant System causes a reduction of coolant temperature and pressure. In the presence of a negative coolant temperature coefficient,

the cooldown results in a reduction of core shutdown margin. If the most reactive RCCA is assumed stuck in its fully withdrawn position, there is an increased possibility that the core will become critical and return to power. A return to power following a steam pipe rupture is a potential concern mainly because of the high hot channel factors which exist when the most reactive RCCA is assumed stuck in its fully withdrawn position. The core is ultimately shut down by boric acid delivered by the Emergency Core Cooling System.

The analysis of a steam pipe rupture is performed to demonstrate that:

A. Assuming a stuck RCCA, with or without offsite power, and assuming a single failure in the engineered safety features, there is no consequential damage to the core and the core remains in place and intact.

B. Although DNB and possible clad perforation following a steam pipe rupture are not necessarily unacceptable, the following analysis, in fact, shows that no DNB occurs for any rupture assuming the most reactive RCCA stuck in its fully withdrawn position.

B.3.11.2 Method of Analysis

The analysis of the steam pipe rupture has been performed to determine:

A. The core heat flux and RCS temperature and pressure resulting from the cooldown following the steam line break. The LOFTRAN Code (Reference 5) has been used.

B. The thermal and hydraulic behavior of the core following a steam line break. A detailed thermal and hydraulic digital computer code, THINC, has been used to determine if DNB occurs for the limiting core conditions computed in item A above.

The following conditions were assumed to exist at the time of a main steam line break accident:

A. End-of-life shutdown margin (1.3 $\%\Delta k/k$) at no load, equilibrium xenon conditions, and the most reactive RCCA stuck in its fully withdrawn position.

B. A negative moderator temperature coefficient corresponding to the end-of-life rodded core with the most reactive RCCA in the fully withdrawn position: The variation of the coefficient with temperature and pressure has been included. The keff versus temperature at 1050 psia corresponding to the negative moderator temperature coefficient used plus the Doppler temperature effect, is shown in Figure B.3-55. The Doppler power feedback assumed for this analysis is presented in Figure B.3-56.

The core properties associated with the sector nearest the affected steam generator and those associated with the remaining sector were conservatively combined to obtain average core properties for reactivity feedback calculation. Further, it was conservatively assumed that the core power distribution was uniform. These two conditions cause underprediction of the reactivity feedback in the high power region near the stuck rod. To verify the conservatism of this method, the reactivity as well as the power distribution was checked for the limiting conditions for the cases analyzed. This core analysis considered the Doppler reactivity from the high fuel temperature near the stuck RCCA, moderator feedback from the high enthalpy water near the stuck RCCA, power redistribution and non-uniform core inlet temperature effects. For cases in which steam generation occurs in the high flux regions of the core, the effect of void formation was also included. It was determined that the reactivity employed in the kinetics analysis was always larger than the reactivity calculated including the above local effects for the statepoints. These results verify conservatism; i.e., underprediction of negative reactivity feedback from power generation.

C. Minimum capability for injection of boric acid (2400 ppm) solution from the RWST corresponding to the most restrictive single failure in the safety injection system. The Emergency Core Cooling System (ECCS) consists of the following systems: 1) the passive accumulators, 2) the low head safety injection (residual heat removal) system, 3) the intermediate head safety injection system, and 4) the high head safety injection (charging) system. Only the high head safety injection (charging) system and the passive accumulators are modeled for the steam line break accident analysis. Centrifugal Charging pump flow degradation of 10% was assumed.

The modeling of the safety injection system in LOFTRAN is described in Reference 5. Figure B.3-57 presents the safety injection flow rates as a function of RCS pressure assumed in the

analysis. The flow corresponds to that delivered by one charging pump delivering its full flow to the cold leg header. No credit has been taken for the low concentration borated water which must be swept from the lines downstream of the RWST isolation valves prior to the delivery of boric acid to the reactor coolant loops. For this analysis, a boron concentration of 0 ppm for the boron injection tank is assumed.

For the cases where offsite power is assumed, the sequence of events in the safety injection system is the following. After the generation of the safety injection signal (appropriate delays for instrumentation, logic, and signal transport included), the appropriate valves begin to operate and the high head safety injection pump starts. In 27 seconds, the valves are assumed to be in their final position and the pump is assumed to be at full speed and to draw suction from the RWST. The volume containing the low concentration borated water is swept into core before the 2400 ppm borated water reaches the core. This delay, described above, is inherently included in the modeling.

In cases where offsite power is not available, an additional 10 second delay is assumed to start the diesel generators and to commence loading the necessary safety injection equipment onto them.

D. Design value of the steam generator heat transfer coefficient.

E. Four combinations of break sizes and initial plant conditions have been considered in determining the core power transient which can result from large area pipe breaks.

   a. Complete severance of a pipe downstream of the steam flow restrictor with the plant initially at no load conditions and all reactor coolant pumps running.

   b. Complete severance of a pipe inside the containment at the outlet of the steam generator (upstream of the steam flow restrictor) with the same plant conditions as above.

   c. Case (a) above with loss of off-site power simultaneous with the generation of the Safety Injection Signal (loss of AC power results in reactor coolant pump coastdown).

d. Case (b) above with the loss of offsite power simultaneous with the Safety Injection Signal.

A fifth case was analyzed to show that the DNBR remains above the limit value in the event of the spurious opening of a steam dump or relief valve.

e. A break equivalent to a steam flow of 265 lbs per second at 1100 psia from one steam generator with offsite power available.

F. Power peaking factors corresponding to one stuck RCCA are determined at end of core life assuming non-uniform core inlet coolant temperatures. The coldest core inlet temperatures are assumed to occur in the sector with the stuck rod. The power peaking factors account for the effect of the local void in the region of the stuck control assembly during the return to power phase following the steam line break. This void in conjunction with the large negative moderator coefficient partially offsets the effect of the stuck assembly. The power peaking factors depend upon the core power, temperature, pressure, and flow, and are thus different for each case studied.

The analyses assumed initial hot shutdown conditions at time zero since this represents the most pessimistic initial condition. Should the reactor be just critical or operating at power at the time of a steam line break, the reactor will be tripped by the normal overpower protection system when power level reaches a trip point. Following a trip at power the reactor coolant system contains more stored energy than at no-load, the average coolant temperature is higher than at no-load and there is appreciable energy stored in the fuel. Thus, the additional stored energy is removed via the cooldown caused by the steam line break before the no-load conditions of RCS temperature and shutdown margin assumed in the analyses are reached. After the additional stored energy has been removed, the cooldown and reactivity insertions proceed in the same manner as in the analysis which assumes no-load conditions at time zero.

In addition, since the initial steam generator water inventory is greatest at no-load, the magnitude and duration of RCS cooldown are more severe than steam line breaks occurring at power.

G. In computing the steam flow during a steam line break, the Moody Curve (Reference 11) for fL/D = 0 is used.

H. The total delay time assumed for the steamline isolation is 11 seconds from receipt of actuation signal. The 11 second steamline isolation time includes valve closure time, and electronics and sensor delay. The Technical Specifications require a maximum 8 second valve closure time. For breaks downstream of the isolation valves, closure of all valves would completely terminate the blowdown. For any break, in any location following steamline isolation, no more than one steam generator would experience an uncontrolled blowdown even if one of the isolation valves fails to close.

Plant characteristics and initial conditions are shown in Table B.2.4.

B.3.11.3 Results

The limiting case for Cases a through e was shown to be the double-ended rupture located upstream of the flow restrictor with offsite power available (case b). Table B.3-10 lists the limiting statepoint for this worst case. The results presented are a conservative indication of the events which would occur assuming a steam line rupture.

Figures B.3-58 through B.3-60 show the RCS transient and core heat flux following a main steam line rupture (complete severance of a pipe) upstream of the flow restrictor at initial no-load conditions.

Offsite power is assumed available so that full reactor coolant flow exists. The transient shown assumes an uncontrolled steam release from only one steam generator. Should the core be critical at near zero power when the rupture occurs the initiation of safety injection by high differential pressure between any steamline and the remaining steamlines or by low steam line pressure in two steamlines will trip the reactor. Steam release from more than one steam generator will be prevented by automatic trip of the fast acting isolation valves in the steam lines by high-high containment pressure signals or low steamline pressure or high steam flow coincident with low-low T-avg. Even with the failure of one valve, release from the other steam generators is terminated by steamline isolation while the one generator blows down. The steam line stop valves are assumed to be fully closed in less than 11 seconds from receipt of a closure signal.

As shown in Figure B.3-60, the core attains criticality with the RCCAs inserted (with the design shutdown margin assuming one stuck RCCA) before boron solution (2400 ppm from RWST) enters the RCS. A peak core power less than the nominal full power value is attained.

The calculation assumes the boric acid is mixed with, and diluted by, the water flowing in the RCS prior to entering the reactor core. The concentration after mixing depends upon the relative flow rates in the RCS and in the safety injection system. The variation of mass flow rate in the RCS due to water density changes is included in the calculation as is the variation of flow rate in the safety injection system due to changes in the RCS pressure. The safety injection system flow calculation includes the line losses in the system as well as the pump head curve.

The assumed steam release for an accidental depressurization of the main steam system (case e) is the maximum capacity of any single steam dump, relief, or safety valve. Safety injection is initiated automatically by low pressurizer pressure. Operation of one centrifugal charging pump is assumed. Boron solution at 2400 ppm enters the RCS providing sufficient negative reactivity to prevent core damage. The transient is quite conservative with respect to cooldown, since no credit is taken for the energy stored in the system metal other than that of the fuel elements or the energy stored in the other steam generators. Since the transient occurs over a period of about 5 minutes, the neglected stored energy is likely for this event to have a significant effect in slowing the cooldown. The DNB transient is bounded by the limiting case for a steamline rupture.

The DNB analysis for the limiting case (double-ended rupture located upstream of the flow restrictor) showed that the minimum DNBR remained above the limit value. The DNBR design basis limit for the hypothetical steamline break event is 1.45. The pressures for this event fall in the low pressure range (500-1000 psia) where the W-3 based DNB correlation is used with a 1.45 limit DNBR. This design limit for low pressure applications of the W-3 correlation has been approved by the NRC in Reference 15. Although the low pressure limit was approved in conjunction with WCAP-9227-NP, which is not referenced in the Cook Nuclear Plant Unit 2 UFSAR, the SER is an applicable reference for reload designs.

The calculated sequence of events for the limiting case (double-ended rupture located upstream of the flow restrictor) are shown in Table B.3-11.

B.3.11.4 Conclusions

The analysis has shown that the criteria stated earlier are satisfied.

Although DNB and possible clad perforation following a steam pipe rupture can be acceptable and is not precluded by the criteria, the above analysis, in fact, shows that no DNB occurs for the rupture (including an accidental depressurization of the main steam system) assuming the most reactive RCCA stuck in its fully withdrawn position.

B.3.12 Rupture of Control Rod Drive Mechanism (CRDM) Housing (RCCA Ejection)

B.3.12.1 Introduction

This accident is defined as the mechanical failure of a control rod mechanism pressure housing resulting in the ejection of a RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage. This accident is discussed further in UFSAR Section 14.5.8.

The limiting criteria is described in References 12 and 13 and summarized below:

A. Average fuel pellet enthalpy at hot spot below 225 cal/g for unirradiated fuel and 200 cal/g for irradiated fuel.

B. Peak reactor coolant pressure less than that which could cause stresses to exceed the faulted condition stress limits.

C. Fuel melting will be limited to less than ten percent 10% of the fuel volume at the hot spot even if the average fuel pellet enthalpy is below the limits of criterion A above.

The RCCA ejection accident was analyzed to assure that the above criteria would not be violated by the design changes associated with VANTAGE 5 fuel reload as discussed in Section B.1. For the reduced temperature and pressure operation, the reduction in full power average temperature is a benefit for the rod ejection transient. However, a reduction in RCS pressure is nonconservative for this transient. As a result, RCCA ejection incident was analyzed.

The analysis performed is to bound the reduced temperature and pressure operation as well as the range of conditions possible for the potential rerating of Cook Nuclear Plant Unit 2.

B.3.12.2 Method of Analysis

The calculation of the RCCA ejection transient is performed in two stages, first an average core channel calculation and then a hot region calculation. The average core calculation is performed using spatial neutron kinetics methods to determine the average power generation with time including the various total core feedback effects, i.e., Doppler reactivity and moderator reactivity. Enthalpy and temperature transients in the hot spot are then determined by multiplying the average core energy generation by the hot channel factor and performing a fuel rod transient heat transfer calculation. The power distribution calculated without feedback is pessimistically assumed to persist throughout the transient. A detailed discussion of the method of analysis can be found in Reference 12.

<u>Average Core Analysis</u>

The spatial kinetics computer code, TWINKLE, is used for the average core transient analysis. This code solves the two group neutron diffusion theory kinetic equation in one, two or three spatial dimensions (rectangular coordinates) for six delayed neutrongroups and up to 2000 spatial points. The computer code includes a detailed multiregion, transient fuel-clad-coolant heat transfer model for calculation of pointwise Doppler and moderator feedback effects. In this analysis, the code is used as a one dimensional axial kinetics code since it allows a more realistic representation of the spatial effects of axial moderator feedback and RCCA movement. However, since the radial dimension is missing, it is still necessary to employ very conservative methods (described below) of calculating the ejected rod worth and hot channel factor. Further description of TWINKLE appears in Section B.2.7.3.

<u>Hot Spot Analysis</u>

In the hot spot analysis, the initial heat flux is equal to the nominal times the design hot channel factor. During the transient, the heat flux hot channel factor is linearly increased to the transient value in 0.1 second, the time for full ejection of the rod. Therefore, the assumption is made that the hot spot before and after ejection are coincident. This is very conservative since the peak after ejection will occur in or adjacent to the assembly with the ejected rod, and prior to ejection the power in this region will necessarily be depressed.

The hot spot analysis is performed using the detailed fuel and clad transient heat transfer computer code, FACTRAN. This computer code calculates the transient temperature distribution in a cross section of a metal clad UO_2 fuel rod, and the heat flux at the surface of the rod, using as input the nuclear power versus time and the local coolant conditions. The zirconium-water reaction is explicitly represented, and all material properties are represented as functions of temperature. A conservative radial power distribution is used within the fuel rod.

FACTRAN uses the Dittus-Boelter or Jens-Lottes correlation to determine the film heat transfer before DNB, and the Bishop-Sandberg-Tong correlation (Reference 14) to determine the film boiling coefficient after DNB. The Bishop-Sandberg-Tong correlation is conservatively used assuming zero bulk fluid quality. The DNB ratio is not calculated, instead the code is forced into DNB by specifying a conservative DNB heat flux. The gap heat transfer coefficient can be calculated by the code; however, it is adjusted in order to force the full power steady-state temperature distribution to agree with the fuel heat transfer design codes. Further description of FACTRAN appears in Section B.2.7.1.

System Overpressure Analysis

Because safety limits for fuel damage specified earlier are not exceeded, there is little likelihood of fuel dispersal into the coolant. The pressure surge may therefore by calculated on the basis of conventional heat transfer from the fuel and prompt heat generation in the coolant.

The pressure surge is calculated by first performing the fuel heat transfer calculation to determine the average and hot spot heat flux versus time. Using this heat flux data, a THINC calculation is conducted to determine the volume surge. Finally, the volume surge is simulated in the LOFTRAN computer code (Reference 5). This code calculates the pressure transient taking into account fluid transport in the RCS and heat transfer to the steam generators. No credit is taken for the possible pressure reduction caused by the assumed failure of the control rod pressure housing.

Input parameters for the analysis are conservatively selected on the basis of values calculated for this type of core. The more important parameters are discussed below. Table B.3-12 presents the parameters used in this analysis.

Ejected Rod Worths and Hot Channel Factors

The values for ejected rod worths and hot channel factors are calculated using either three dimensional static methods or by a synthesis method employing one dimensional and two dimensional calculations. Standard nuclear design codes are used in the analysis. No credit is taken for the flux flattening effects of reactivity feedback. The calculation is performed for the maximum allowed bank insertion at a given power level, as determined by the rod insertion limits. Adverse xenon distributions are considered in the calculation to provide worst case results.

Appropriate margins are added to the ejected rod worth and hot channel factors to account for any calculational uncertainties, including an allowance for nuclear power peaking due to densification.

Power distribution before and after ejection for a worst case can be found in Reference 12. During plant startup physics testing, ejected rod worths and power distributions are measured in the zero and full power configurations and compared to values used in the analysis. Experience has shown that the ejected rod worth and power peaking factors are consistently overpredicted in the analysis.

Reactivity Feedback Weighting Factors

The largest temperature rises, and hence the largest reactivity feedbacks occur in channels where the power is higher than average. Since the weight of a region is dependent on flux, these regions have high weights. This means that the reactivity feedback is larger than that indicated by a simple channel analysis. Physics calculations have been carried out for temperature changes with a flat temperature distribution, and with a large number of axial and radial temperature distributions. Reactivity changes were compared and effective weighting factors determined. These weighting factors take the form of multipliers which, when applied to single channel feedbacks, correct them to effective whole core feedbacks for the appropriate flux shape. In this analysis, since a one dimensional (axial) spatial kinetics method is employed, axial weighting is not necessary if the initial condition is made to match the ejected rod configuration. In addition, no weighting is applied to the moderator feedback. A conservative radial weighting factor is applied to the transient fuel temperature to obtain an effective fuel temperature as a function of time accounting for the missing spatial dimension. These weighting factors have also been shown to be conservative compared to three dimensional analysis (Reference 12).

Moderator and Doppler Coefficient

The critical boron concentrations at the beginning of life and end of life are adjusted in the nuclear code in order to obtain moderator density coefficient curves which are conservative compared to actual design conditions for the plant. As discussed above, no weighting factor is applied to these results. The resulting moderator temperature coefficient is at least +5 pcm/°F at the appropriate zero or full power nominal average temperature, and becomes less positive for higher temperatures. This is necessary since the TWINKLE computer code utilized in the analyses is a diffusion-theory code rather than a point-kinetics approximation and the moderator temperature feedback cannot be artificially held constant with temperature.

The Doppler reactivity defect is determined as a function of power level using a one dimensional steady-state computer code with a Doppler weighting factor of 1.0. The Doppler weighting factor will increase under accident conditions, as discussed above.

Delayed Neutron Fraction, βeff

Calculations of the effective delayed neutron fraction (βeff) typically yield values no less than 0.70% at beginning of life and 0.50% at end of life. The accident is sensitive to βeff if the ejected rod worth is equal to or greater than βeff as in zero power transients. In order to allow for future cycles, pessimistic estimates of βeff of 0.50% at beginning of a cycle and 0.40% at end of a cycle were used in the analysis.

Trip Reactivity Insertion

The trip reactivity insertion assumed is given in Table B.3-12 and includes the effect of one stuck RCCA adjacent to the ejected rod. These values are reduced by the ejected rod reactivity. The shutdown reactivity was simulated by dropping a rod of the required worth into the core. The start of rod motion occurred 0.5 second after the high neutron flux trip point is reached. The curve of trip rod insertion versus time is shown in Figure B.2-2 which assumed that insertion to dashpot does not occur until 2.7 seconds after the start of fall. The choice of such a conservative insertion rate means that there is over one second after the trip point is reached before significant shutdown reactivity is inserted into the core. This is particularly important conservatism for hot full power accidents.

The minimum design shutdown margin available for this plant at hot zero power (HZP) may be reached only at end of life in the equilibrium cycle. This value includes an allowance for the worst stuck rod, an adverse xenon distribution, conservative Doppler and moderator defects, and an allowance for calculational uncertainties. Physics calculations have shown that the effect of two stuck RCCAs (one of which is the worst ejected rod) is to reduce the shutdown by about an additional 1 %Δk/k. Therefore, following a reactor trip resulting from an RCCA ejection accident, the reactor will be subcritical when the core returns to HZP.

Depressurization calculations have been performed assuming the maximum possible size break (2.75 inch diameter) located in the reactor pressure vessel head. The results show a rapid pressure drop and a decrease in system water mass due to the break. The Emergency Core Cooling System (ECCS) is actuated on low pressurizer pressure within one minute after the break. The RCS pressure continues to drop and reaches saturation (1100 to 1300 psi depending on the system temperature) in about two to three minutes. Due to the large thermal inertia of the primary and secondary system, there has been no significant decrease in the RCS temperature below no-load by this time, and the depressurization itself has caused an increase in shutdown margin by about 0.2 %Δk/k due to the pressure coefficient. The cooldown transient could not absorb the available shutdown margin until more than 10 minutes after the break. The addition of borated safety injection flow (supplied from the RWST) starting one minute after the break is much more than sufficient to ensure that the core remains subcritical during the cooldown.

Reactor Protection

Reactor protection for a rod ejection is provided by high neutron flux trip (high and low setting) and high rate of neutron flux increase trip although the analysis modeled the high neutron flux trip (high and low setting) only. These protection functions are part of the reactor trip system. No single failure of the reactor trip system will negate the protection functions required for the rod ejection accident, or adversely affect the consequences of the accident.

B.3.12.3 Results

Table B.3-12 summarizes the results. Cases are presented for both beginning and end of life at zero and full power.

A. Beginning of Cycle, Full Power

Control Bank D was assumed to be inserted to its insertion limit. The worst ejected rod worth and hot channel factor were conservatively calculated to be 0.15 %Δk/k and 7.0 respectively. The peak spot fuel center temperature reached melting, conservatively assumed at 4900 °F. However, melting was restricted to less than 10% of the pellet.

B. Beginning of Cycle, Zero Power

For this condition, Control Bank D was assumed to be fully inserted and banks B and C were at their insertion limits. The worst ejected rod is located in Control Bank D and has a worth of 0.75 %Δk/k and a hot channel factor of 12.0. The fuel center temperature was 3922 °F.

C. End of Cycle, Full Power

Control Bank D was assumed to be inserted to its insertion limit. The ejected rod worth and hot channel factors were conservatively calculated to be 0.19 %Δk/k and 7.3 respectively. The peak hot spot fuel center temperature reached melting at 4800 °F. However, melting was restricted to less than 10% of the pellet.

D. End of Cycle, Zero Power

The ejected rod worth and hot channel factor for this case were obtained assuming Control Bank D to be fully inserted and banks B and C at their insertion limits. The results were 0.78 %Δk/k and 21.0 respectively. The fuel center temperature was 3721 °F. The Doppler weighting factor for this case is significantly higher than for the other cases due to the very large transient hot channel factor.

For all the cases analyzed, average fuel pellet enthalpy at the hot spot remains below 200 cal/g.

The nuclear power and hot spot fuel and clad temperature transients for the worst case in terms of fuel melt (BOL full power) are presented in Figure B.3-61. The same transients for the worst case in terms of clad temperature (BOL zero power) are presented in Figure B.3-62.

The ejection of an RCCA constitutes a break in the RCS, located in the reactor pressure vessel head. Following the RCCA ejection, the operator would follow the same emergency instructions as for any other LOCA to recover from the event.

Pressure Surge

A detailed calculation of the pressure surge for an ejection worth of one dollar at beginning of life, hot full power, indicates that the peak pressure does not exceed that which would cause stress to exceed the faulted condition stress limits (Reference 12). Since the severity of the present analysis does not exceed the "worst case" analysis, the accident for this plant will not result in an excessive pressure rise or further adverse effects to the RCS.

Lattice Deformations

A large temperature gradient will exist in the region of the hot spot. Since the fuel rods are free to move in the vertical direction, differential expansion between separate rods cannot produce distortion. However, the temperature gradients across individual rods may produce a differential expansion tending to bow the midpoint of the rods toward the hotter side of the rod. Calculations have indicated that this bowing would result in a negative reactivity effect at the hot spot since Westinghouse cores are under-moderated, and bowing will tend to increase the under-moderation at the hot spot. In practice, no significant bowing is anticipated, since the structural rigidity of the core is more than sufficient to withstand the forces produced. Boiling in the hot spot region would produce a net flow away from that region. However, the heat from the fuel is released to the water relatively slowly, and it is considered inconceivable that cross flow will be sufficient to produce significant lattice forces. Even if massive and rapid boiling, sufficient to distort the lattice, is hypothetically postulated, the large void fraction in the hot spot region would produce a reduction in the total core moderator to fuel ratio, and a large reduction in this ratio at the hot spot. The net effect would therefore be a negative feedback. It can be concluded that no conceivable mechanism exists for a net positive feedback resulting from lattice deformation. In fact, a small negative feedback may result. The effect is conservatively ignored in the analysis.

B.3.12.4 Conclusions

Even on a pessimistic basis, the analyses indicate that the described fuel and clad limits are not exceeded. It is concluded that there is no likelihood of sudden fuel dispersal into the coolant. Since the peak pressure does not exceed that which would cause stresses to exceed the faulted condition stress limits, it is concluded that there is no likelihood of further consequence to the RCS. The analyses have demonstrated the fission product release as a result of fuel rods entering DNB is limited to less than 10% of the fuel rods in the core.

B.3.13 Major Rupture of Main Feedwater Pipe (Feedline Break)

B.3.13.1 Introduction

A major feedwater line rupture is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to the steam generators to maintain shell side fluid inventory in the steam generators. If the break is postulated in a feedwater line between the check valve and the steam generator, fluid from the steam generator may also be discharged through the break. Further, a break in this location could preclude the subsequent addition of emergency feedwater to the affected steam generator. (A break upstream of the feedwater line check valve would affect the nuclear steam supply system only as a loss of normal feedwater.)

Depending upon the size of the break and the plant operating conditions at the time of the break, the break could cause either a RCS cooldown (by excessive energy discharge through the break) or a RCS heatup. Potential RCS cooldown resulting from a secondary pipe rupture is evaluated in the steamline break event. Therefore, only the RCS heatup effects are evaluated for a feedwater line rupture.

A feedwater line rupture reduces the ability to remove heat generated by the core from the RCS for the following reasons:

a. Feedwater flow to the steam generators is reduced. Since feedwater is subcooled, its loss may cause reactor coolant temperatures to increase prior to reactor trip.

b. Fluid in the steam generator may be discharged through the break, and would then not be available for decay heat removal after trip.

c. The break may be large enough to prevent the addition of any main feedwater after trip.

An auxiliary feedwater system is provided to assure that adequate feedwater will be available such that:

a. No substantial overpressurization of the RCS shall occur.

b. Sufficient liquid in the RCS shall be maintained so that the core remains inplace and geometrically intact with no loss of core cooling capability.

The severity of the feedwater line rupture transient depends on a number of system parameters including break size, initial reactor power, and credit taken for the functioning of various control and safety systems. Sensitivity studies have shown that the most limiting feedwater line rupture is a double-ended rupture of the largest feedwater line. Analyses have been performed at full power with and without loss of offsite power.

The following provides the protection for a main feedwater line rupture:

a. A reactor trip on any of the following conditions:
    1. High pressurizer pressure
    2. Overtemperature ΔT
    3. Low-low steam generator water level in any steam generator
    4. Safety injection signal

b. An auxiliary feedwater system to provide an assured source of feedwater to the steam generators for decay heat removal.

B.3.13.2 Method of Analysis

A detailed analysis using the LOFTRAN Code (see Reference 5) is performed in order to determine the plant transient following a feedwater line rupture. The code describes the plant thermal kinetics, RCS including natural circulation, pressurizer, steam generators and feedwater system, and computes pertinent variables including the pressurizer pressure, pressurizer water level, and reactor coolant average temperature. The code also calculates pump coastdown flow and natural circulation flow during a feedline rupture.

The cases analyzed assume a double-ended rupture of the largest feedwater pipe at full power. Major assumptions used in the analysis are as follows:

A. The plant is initially operating at 102 percent of the Cook Nuclear Plant Unit 2 rerating power level (3608 Mwt, which includes pump heat).

B. The initial reactor coolant average temperature is 4.1 °F higher than the nominal value of 581.3 °F, and initial pressurizer pressure is 62.6 psi higher than the nominal pressure of 2100 psia.

C. No credit is taken for rod control or pressurizer spray.

D. Credit is taken for the Pressurizer Relief Valves to minimize the RCS subcooling margin.

E. Initial pressurizer level is assumed to be at the maximum nominal setpoint (61.1% span) plus uncertainties (5% span). Initial steam generator water level is at the nominal value plus 5% in the faulted steam generator, and at the nominal value minus 5% in the intact steam generators.

F. Reactor trip is assumed to be initiated when the low-low steam generator level trip setpoint in the ruptured steam generator is reached.

G. Main feedwater to all steam generators is assumed to stop at the time the break occurs (all main feedwater spills out through the break).

H. The worst break area of 0.717 ft^2 is assumed to minimize the RCS subcooling margin.

I. The auxiliary feedwater system is actuated by operator action 10 minutes after the break occurs. A total of 600 gpm was assumed, evenly split between the 3 intact steam generators. This auxiliary feedwater flow was assumed to be delivered by one turbine driven pump and one motor driven pump.

J. For the case without offsite power, there will be a flow coastdown (when the reactor trips) until flow in the loops reaches the natural circulation value.

Plant characteristics and initial conditions are shown in Table B.2-4.

B.3.13.3 Results

Calculated plant parameters following a major feedwater line rupture are shown in Figures B.3-63 through B.3-70. Results for the case with offsite power available are presented in Figures B.3-63 through B.3-64. Results for the case where offsite power is lost are presented in Figures B.3-67 through B.3-70.

The plot of pressurizer water volume clearly shows that the pressurizer does not fill. For comparison purposes, the pressurizer fills at 1889 ft^3 (which includes the pressurizer surge volume).

The calculated sequence of events for this accident is shown in Table B.3-13.

B.3.13.4 Conclusions

Results of the analysis show that for the postulated main feedwater line rupture, the assumed auxiliary feedwater system capacity is adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core. Thus, all applicable acceptance criteria are met.

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TABLE B.3-1

TIME SEQUENCE OF EVENTS

Accident	Event	Time (sec)
Uncontrolled RCCA Withdrawal From A Subcritical Condition		
	Initiation of uncontrolled RCCA withdrawal (63 pcm/sec)	0.0
	High Neutron Flux Reactor Trip Setpoint (low setting) reached	12.2
	Rods begin to fall into core	12.7
	Minimum DNBR occurs	14.8
	Peak Clad Average Temperature occurs	15.2
	Peak Fuel Average Temperature occurs	15.5
	Peak Fuel Centerline Temperature occurs	15.9

TABLE B.3-2A

TIME SEQUENCE OF EVENTS

(Mixed Core)

Accident	Event	Time (sec)
Uncontrolled RCCA Bank Withdrawal At Full Power		
Case A (high insertion rate, max feedback)	Initiation of uncontrolled RCCA bank withdrawal at a high reactivity insertion rate (80 pcm/sec)	0
	Power range high neutron flux high trip signal initiated	5.4
	Rods begin to fall into core	5.9
	Minimum DNBR occurs	6.0
Case B (small insertion rate, max feedback)	Initiation of uncontrolled RCCA bank withdrawal at a small reactivity insertion rate (4 pcm/sec)	0
	Overtemperature ΔT reactor trip signal initiated	298.7
	Rods begin to fall into core	300.7
	Minimum DNBR occurs	300.2

TABLE B.3-2B

TIME SEQUENCE OF EVENTS

(Full VANTAGE 5 Core)

Accident	Event	Time (sec)
Uncontrolled RCCA Bank Withdrawal At Full Power		
Case A (high insertion rate, max feedback)	Initiation of uncontrolled RCCA bank withdrawal at a high reactivity insertion rate (80 pcm/sec)	0
	Power range high neutron flux high trip signal initiated	5.8
	Rods begin to fall into core	6.3
	Minimum DNBR occurs	6.4
Case B (small insertion rate, max feedback)	Initiation of uncontrolled RCCA bank withdrawal at a small reactivity insertion rate (4 pcm/sec)	0
	Overtemperature ΔT reactor trip signal initiated	314.5
	Rods begin to fall into core	316.5
	Minimum DNBR occurs	316.2

TABLE B.3-3
TIME SEQUENCE OF EVENTS

Accident	Event	Time (sec)
Uncontrolled Boron Dilution		
1. Dilution during Refueling	Dilution begins	0
	Shutdown margin lost	1980
2. Dilution during startup	Dilution begins	0
	Shutdown margin lost	2100
3. Dilution during full power operation		
a. Automatic reactor control	Dilution begins	0
	Shutdown margin list	2760
b. Manual reactos control	Dilution begins	0
	Overtemperature ΔT reactor trip	90
	shutdown margin lost	2760

TABLE B.3-4

TIME OF SEQUENCE OF EVENTS

Accident	Event	Time (sec)
Loss of Forced Reactor Coolant Flow		
Four loops in operation, four pumps coasting down	All operating pumps lose power and begin coasting down	0.0
	Reactor coolant pump under-voltage trip point reached	0.0
	Rods begin to drop	1.5
	Minimum DNBR occurs	3.7
Four loops in operation, one pump coasting down	Coastdown begins	0.0
	Low flow reactor trip	1.28
	Rods begin to drop	2.28
	Minimum DNBR occurs	3.40

TABLE B.3-4 (continued)

TIME SEQUENCE OF EVENTS

Accident	Event	Time (sec)
Single Reactor Coolant Pump Locked Rotor		
Four loops in operation, one locked rotor	Rotor in one pump locks	0.00
	Low flow trip point reached	0.02
	Rods begin to drop	1.02
	Maximum RCS pressure occurs	3.0
	Maximum clad temperature occurs	3.60

TABLE B.3-5A
TIME SEQUENCE OF EVENTS
(Mixed Core)

Accident	Event	Time (sec)
Loss of External Electric Load or Turbine Trip		
1. With pressurizer control (min fdbk)	Loss of electric load	0.0
	High pressurizer pressure reactor trip point reached	10.6
	Rods begin to drop	12.6
	Peak pressurizer pressure occurs	13.0
	Minimum DNBR Occurs	14.5
2. With pressurizer control (max fdbk)	Loss of electrical load	0.0
	Peak pressurizer pressure occurs	7.0
	Low-low steam generator water level reactor trip point reached	59.6
	Rods begin to drop	61.6
	Minimum DNBR occurs	*

TABLE B.3-5A (continued)

TIME SEQUENCE OF EVENTS

Accident	Event	Time (sec)
3. Without pressurizer control (min fdbk)	Loss of electrical load	0.00
	High pressurizer pressure reactor trip point reached	5.5
	Rods begin to drop	7.5
	Peak pressurizer pressure occurs	9.5
	Minimum DNBR occurs	*
4. Without pressurizer control (max fdbk)	Loss of electrical load	0.0
	High pressurizer pressure reactor trip point reached	5.5
	Rods begin to drop	7.5
	Peak pressurizer pressure occurs	9.0
	Minimum DNBR occurs	*

*DNBR never decreases below initial value

TABLE B.3-5B

TIME SEQUENCE OF EVENTS

(Full VANTAGE 5 Core)

Accident	Event	Time (sec)
Loss of External Electric Load or Turbine Trip		
1. With pressurizer control (min fdbk)	Loss of electric load	0.00
	High pressurizer pressure reactor trip point reached	11.4
	Rods begin to drop	13.4
	Peak pressurizer pressure occurs	14.5
	Minimum DNBR occurs	15.0
2. With pressurizer control (max fdbk)	Loss of electrical load	0.0
	Peak pressurizer pressure occurs	7.5
	Low-low steam generator water level reactor trip point reached	51.9
	Rods begin to drop	53.9
	Minimum DNBR occurs	*

TABLE B.3-5B (continued)

TIME SEQUENCE OF EVENTS

Accident	Event	Time (sec)
3. Without pressurizer control (min fdbk)	Loss of electrical load	0.00
	High pressurizer pressure reactor trip point reached	7.5
	Rods begin to drop	9.5
	Peak pressurizer pressure occurs	10.5
	Minimum DNBR occurs	*
4. Without pressurizer control (max fdbk)	Loss of electrical load	0.0
	High pressurizer pressure reactor trip point reached	7.6
	Rods begin to drop	9.6
	Peak pressurizer pressure occurs	10.0
	Minimum DNBR occurs	*

*DNBR never decreases below initial value

TABLE B.3-6

TIME SEQUENCE OF EVENTS

Accident	Event	Time (sec)
Loss of Normal Feedwater		
	Main feedwater flow stops	10.0
	Low-low steam generator water level trip signal initiated	55.7
	Rods begin to fall into core	57.7
	Two Motor-Driven Auxiliary Feedwater Pumps Start and Supply the Steam Generators	115.7
	Cold Auxiliary Feedwater is Delivered to the Steam Generators	515.0
	Peak water level in pressurizer occurs	4672
	Core decay heat plus RCP heat decreases to auxiliary feedwater heat removal capacity	~4800

TABLE B.3-7A

TIME SEQUENCE OF EVENTS

(Mixed Core)

Accident	Event	Time (sec)
Feedwater System Malfunctions		
Excessive feedwater flow at full power (Automtic Rod Control)	One main feedwater control valve fails fully open	0
	Minimum DNBR occurs	59.0
	Hi-hi steam generator water level signal generated	61.2
	Turbine trip occurs due to hi-hi steam generator water level	63.7
	Reactor trip occurs due to turbine trip	65.7
	Feedwater isolation valves fully closed	72.2

TABLE B.3-7A

TIME SEQUENCE OF EVENTS

(Mixed Core)

Accident	Event	Time (sec)
Feedwater System Malfunctions		
Excessive feedwater flow at full power (Manual Rod Control)	One main feedwater control valve fails fully open	0
	Minimum DNBR occurs	63.0
	Hi-hi steam generator water level signal generated	61.3
	Turbine trip occurs due to hi-hi steam generator water level	63.8
	Reactor trip occurs due to turbine trip	65.8
	Feedwater isolation valves fully closed	72.3

TABLE B.3-7B

TIME SEQUENCE OF EVENTS

(Full VANTAGE 5 Core)

Accident	Event	Time (sec)
Feedwater System Malfunctions		
Excessive feedwater flow at full power (Automatic Rod Control)	One main feedwater control valve fails fully open	0
	Minimum DNBR occurs	51.5
	Hi-hi steam generator water level signal generated	60.6
	Turbine trip occurs due to hi-hi steam generator water level	63.1
	Reactor trip occurs due to turbine trip	65.1
	Feedwater isolation valves fully closed	71.6

TABLE B.3-7B (continued)
TIME SEQUENCE OF EVENTS
(Full VANTAGE 5 Core)

Accident	Event	Time (sec)
Feedwater System Malfunctions		
Excessive feedwater flow at full power (Manual Rod Control)	One main feedwater control valve fails fully open	0
	Minimum DNBR occurs	63.5
	Hi-hi steam generator water level signal generated	60.7
	Turbine trip occurs due to hi-hi steam generator water level	63.2
	Reactor trip occurs due to turbine trip	65.2
	Feedwater isolation valves fully closed	71.7

TABLE B.3-8A

TIME SEQUENCE OF EVENTS

(Mixed Core)

Accident	Events	Time (sec)
Excessive Load Increase		
1. Manual reactor control (Min fdbk)	10% step load increase	0.0
	Equilibrium conditions reached	160.0
2. Manual reactor control (max fdbk)	10% step load increase	0.0
	Equilibrium conditions reached	40.0
3. Automatic reactor control (Min fdbk)	10% step load increase	0.0
	Equilibrium conditions reached	160.0
4. Automatic reactor control (Max fdbk)	10% step load increase	0.0
	Equilibrium conditions reached	70.0

TABLE B.3-8B

TIME SEQUENCE OF EVENTS

(Full VANTAGE 5 core)

Accident	Events	Time (sec)
Excessive Load Increase		
1. Manual reactor control (Min fdbk)	10% step load increase	0.0
	Equilibrium conditions reached	160.0
2. Manual reactor control (max fdbk)	10% step load increase	0.0
	Equilibrium conditions reached	40.0
3. Automatic reactor control (Min fdbk)	10% step load increase	0.0
	Equilibrium conditions reached	160.0
4. Automatic reactor control (Max fdbk)	10% step load increase	0.0
	Equilibrium conditions reached	70.0

TABLE B.3-9

TIME SEQUENCE OF EVENTS

Accident	Event	Time (sec)
Loss of Offsite Power to the Station Auxiliaries		
	AC power is lost	10.0
	Main feedwater flow stops	10.0
	Low-low steam generator water level trip signal initiated	56.0
	Rods begin to fall into core	58.0
	Reactor coolant pumps begin to coastdown	58.0
	Two Motor-Driven Auxiliary Feedwater Pumps Start and Supply the Steam Generators	117.0
	Cold Auxiliary Feedwater is Delivered to the Steam Generators	534.0
	Core decay heat decreases to auxiliary feedwater heat removal capacity	~800.0
	Peak water level in pressurizer occurs	1406.0

TABLE B.3-10

LIMITING STEAMLINE BREAK STATEPOINT

DOUBLE ENDED RUPTURE INSIDE CONTAINMENT

WITH OFFSITE POWER AVAILABLE

Time	Pressure	Heat Flux	Inlet Temp Cold	Inlet Temp Hot	Flow	Boron	Reactivity	Density
Sec	Psia	Fraction	°F	°F	Frac	PPM	Percent	GM/CC
100.2	598.7	0.107	330.2	441.8	1.0	1.51	0.044	0.863

TABLE B.3-11

TIME SEQUENCE OF EVENTS

Accidents	Events	Time (sec)
Rupture of a Steamline		
1. Inside Containment With Offsite Power available	Steam line ruptures	0.0
	Low steamline pressure setpoint reached	0.26
	Feedwater Isolation (All loops)	8.26
	Steamline Isolation (Loops 2, 3 and 4)	11.26
	Pressurizer empties	13.8
	SI flow starts	27.26
	Criticality attained	29.4
	Boron from SI reaches cores	38.2
	Peak heat flux attained	100.2
	Core becomes subcritical	116.2

TABLE B.3-11
(continued)
TIME SEQUENCE OF EVENTS

Accidents	Events	Time (sec)
Rupture of a Steamline		
2. Inside Containment Without Offsite Power available	Steam line ruptures	0.0
	Low steamline pressure setpoint reached	0.26
	Feedwater Isolation (All loops)	8.26
	Steamline Isolation (Loops 2, 3 and 4)	11.26
	Pressurizer empties	15.4
	Criticality attained	37.0
	SI flow starts	37.26
	Boron from SI reaches cores	51.4
	Peak heat flux attained	236.0
	Core becomes subcritical	291.7

TABLE B.3-12

PARAMETERS USED IN THE ANALYSIS OF THE ROD CLUSTER CONTROL ASSEMBLY EJECTION ACCIDENT

	Time of Cycle			
Accident Parameters	HZP Beginning	HFP Beginning	HZP End	HFP End
Power level (%)	0	102	0	102
Ejected Rod Worth (%Δk)	0.75	0.15	0.78	0.19
Delayed Neutron Fraction (%)	0.50	0.50	0.40	0.40
Feedback Reactivity Weighting	2.071	1.30	3.190	1.30
Trip Reactivity (%Δk)	2.	4.	2.	4.
F_Q Before Rod Ejection	2.50	2.50	2.50	2.50
F_Q After Rod Ejection	12.	7.0	21.0	7.3
Number of Operational Pumps	2.	4.	2.	4.
Results				
Maximum Fuel Pellet Average Temperature (°F)	3439	4268	3310	4159
Maximum Fuel Center Temperature (°F)	3922	4983	3721	4910
Maximum Fuel Stored Enthalpy (cal/gm)	145.6	188.6	139.2	182.8
Fuel-Melt in Hot Pellet, %	0	<10	0	<10

TABLE B.3-13

TIME SEQUENCE OF EVENTS

Accident	Event	Time (sec)
Main Feedwater Line Rupture (With Power)		
	Main feedwater line rupture occurs	10.00
	Low-low steam generator water level trip signal initiated	16.0
	Rods begin to fall into core	18.0
	SIS low pressurizer pressure setpoint reached	78.0
	Feedwater isolation (Loops 2,3,4)	86.0
	SIS flow starts	106.0
	SIS low steamline pressure setpoint reached in two loops	239.8
	Steamline isolation (All loops)	250.8
	Auxiliary feedwater started to deliver to intact steam generators	610.00

TABLE B.3-13 (cont)

TIME SEQUENCE OF EVENTS

Accidents	Events	Time (sec)
	Steam generator safety valve setpoint reached in intact steam generators	910.0
	Core decay heat plus RCP heat decreases to auxiliary feedwater heat removal capacity	~1500.0
	Pressurizer safety valve setpoint reached	Never reached
Main Feedwater Line Rupture (Without Power)		
	Main feedwater line rupture occurs	10.0
	Low-low steam generator water level trip signal initiated	16.0
	Rods begin to fall into core	18.0
	RCS pumps begin to coastdown	20.0

TABLE B.3-13 (continued)

TIME SEQUENCE OF EVENTS

Accident	Events	Time (sec)
	SIS low steamline pressure setpoint reached in two loops	150.6
	Feedwater isolation (Loops 2,3,4)	158.6
	Steamline isolation (All loops)	161.6
	SIS flow starts	189.0
	Auxiliary feedwater started to deliver to intact steam generators	610.0
	Steam generator safety valve setpoint reached in intact steam generators	668.0
	Core decay heat decreases to auxiliary feedwater heat removal capacity	~1200.00
	Pressurizer safety valve setpoint reached	Never reached

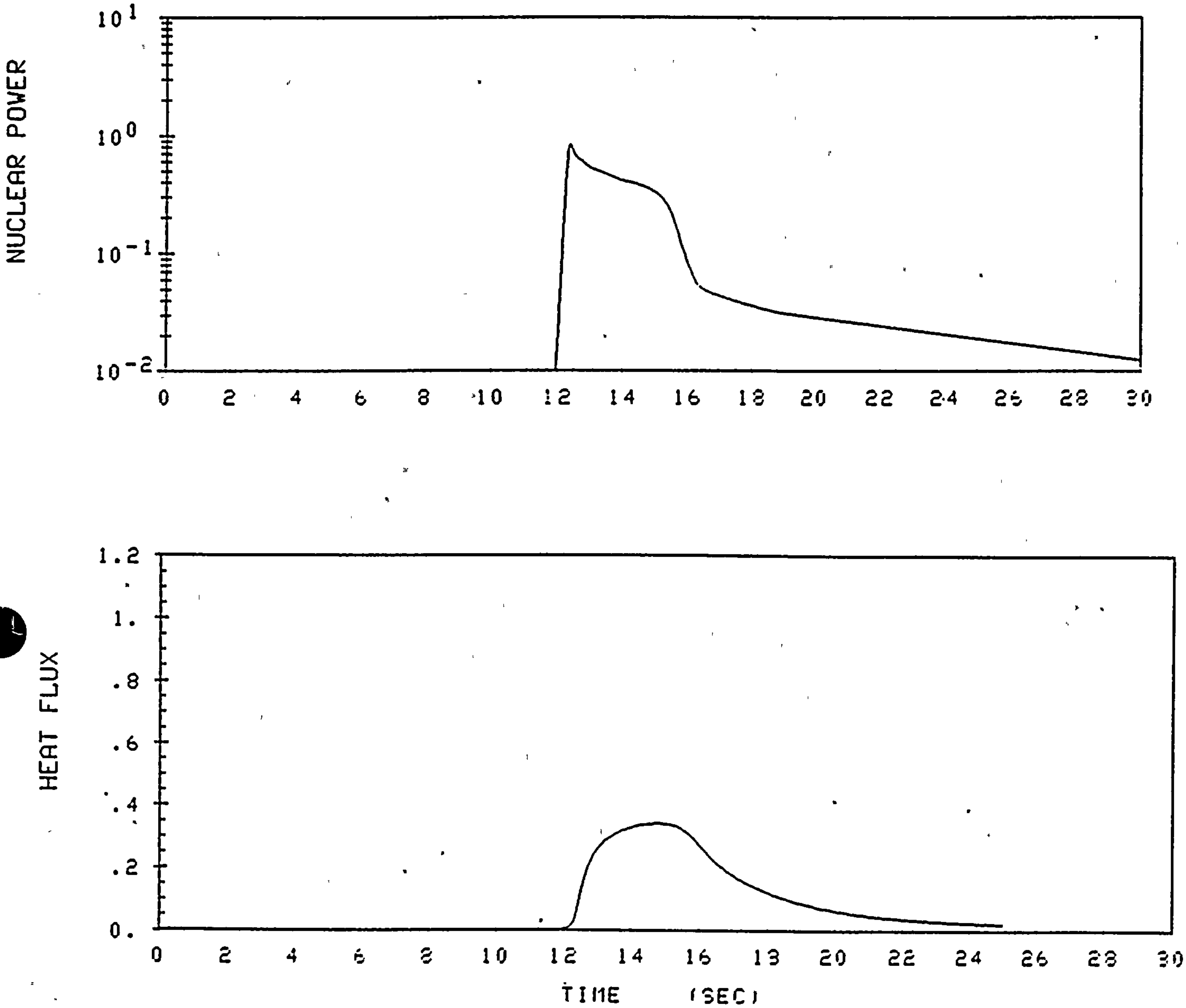


Figure B.3-1 Rod Withdrawal from Subcritical
Nuclear Power and Heat Flux Versus Time

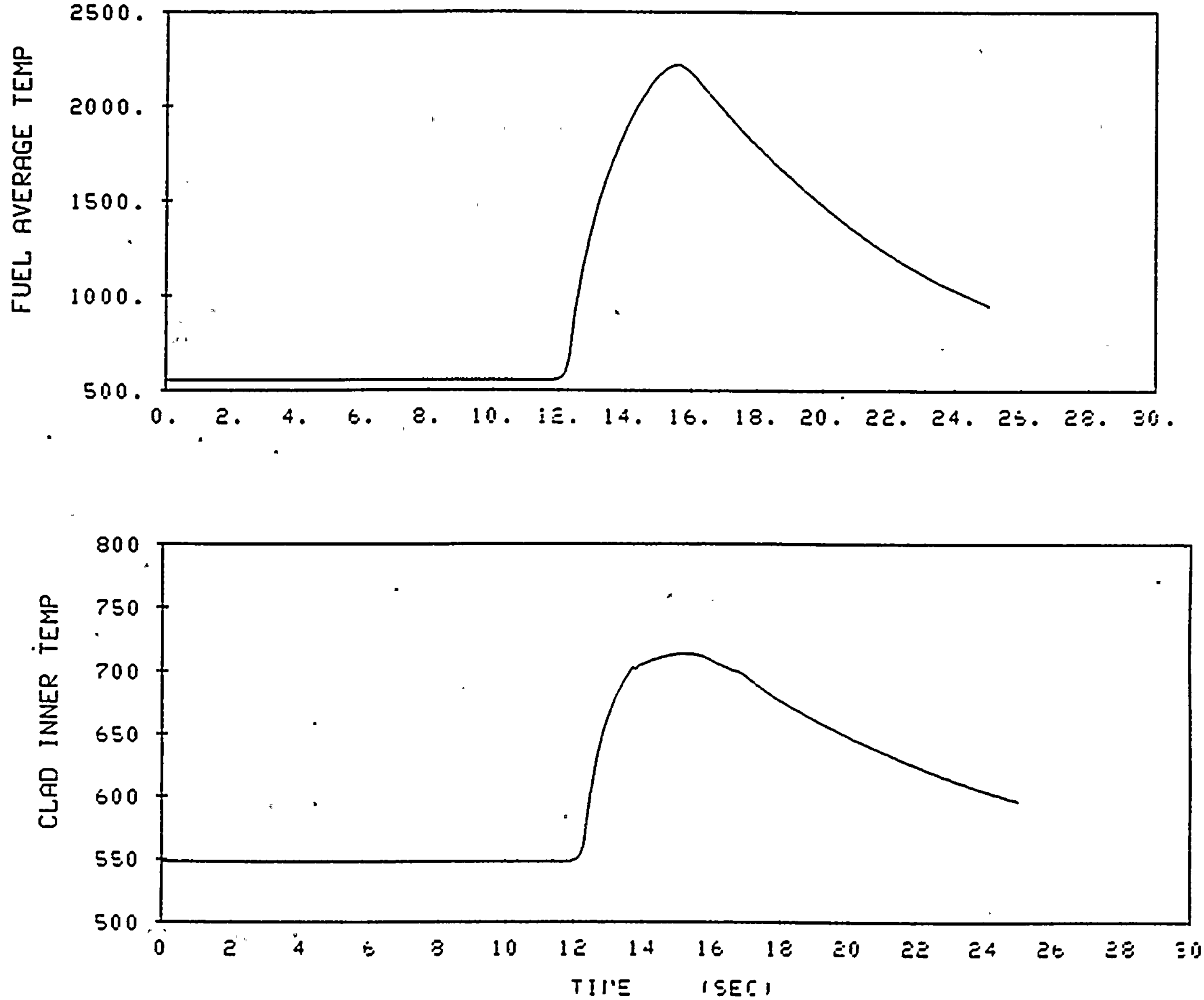


Figure B.3-2 Rod Withdrawal from Subcritical
Fuel Average and Clad Temperatures Versus Time

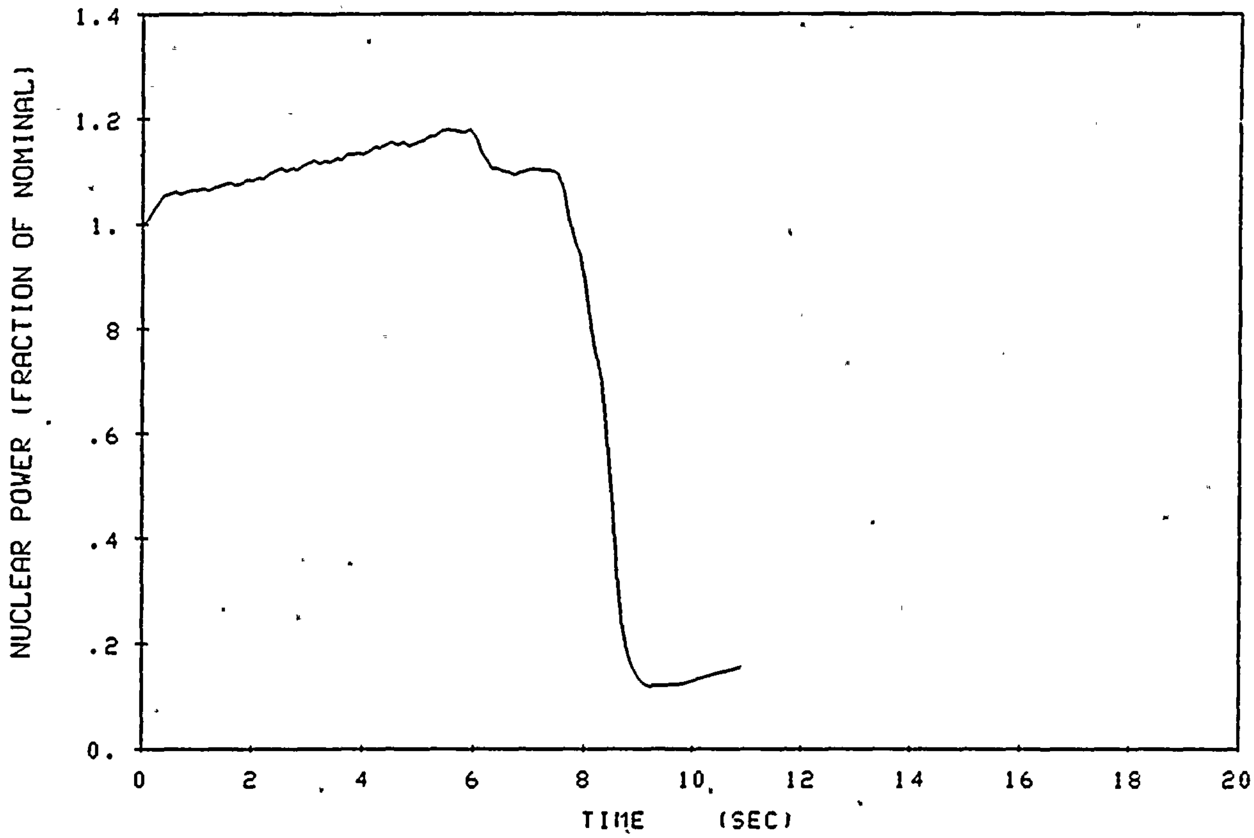


Figure B.3-3A Rod Withdrawal at Power
Nuclear Power Versus Time for Full Power, 80 PCM/Sec Insertion Rate, Maximum Reactivity Feedback

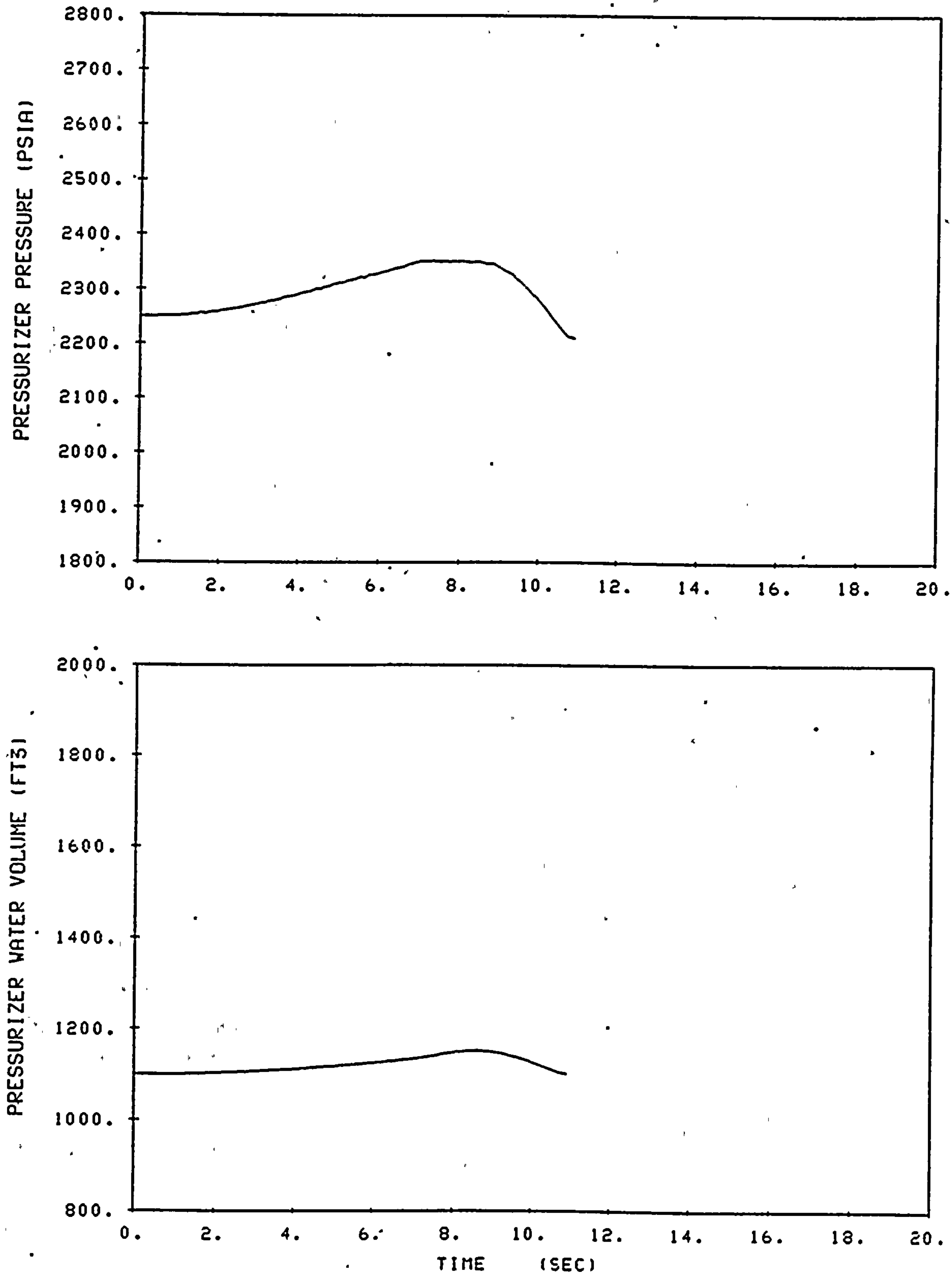


Figure B.3-4A Rod Withdrawal at Power
Pressurizer Pressure and Water Volume Versus Time for Full Power, 80 PCM/Sec Insertion Rate, Maximum Reactivity Feedback

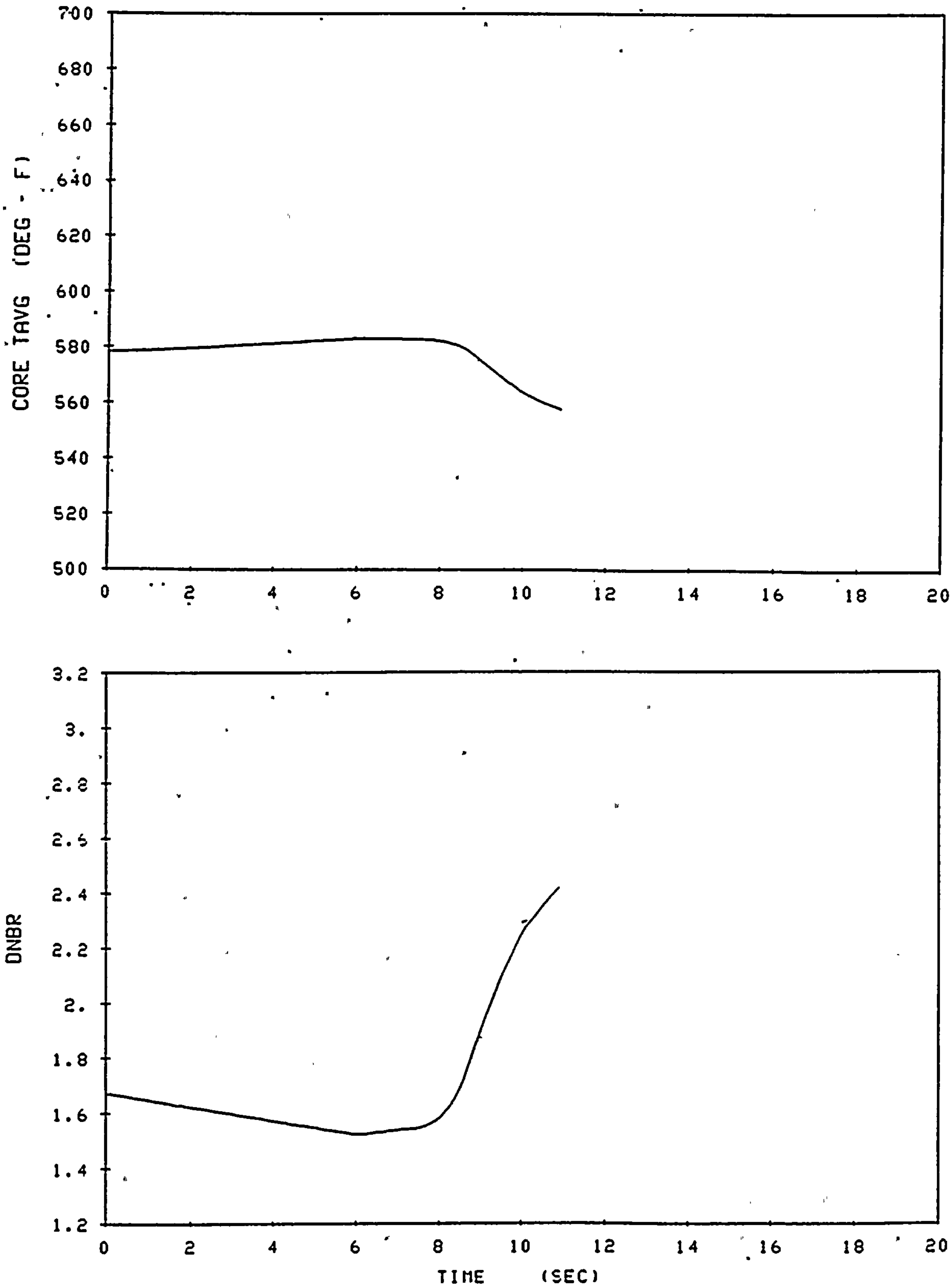


Figure B.3-5A Rod Withdrawal at Power
Core Average Temperature and DNBR Versus Time for Full Power, 80 PCM/Sec Insertion Rate, Maximum Reactivity Feedback

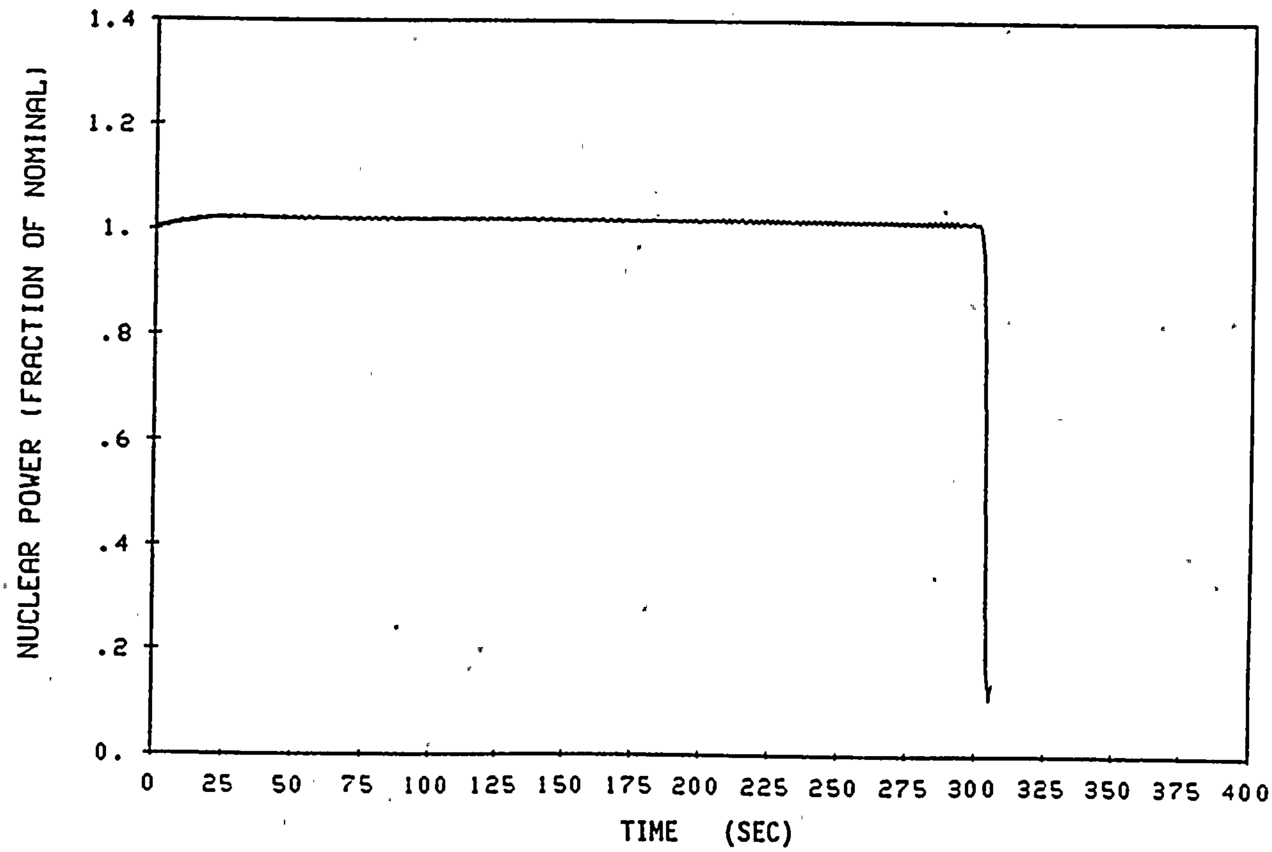


Figure B.3-6A Rod Withdrawal at Power
Nuclear Power Versus Time for Full Power, 4 PCM/Sec Insertion Rate, Maximum Reactivity Feedback

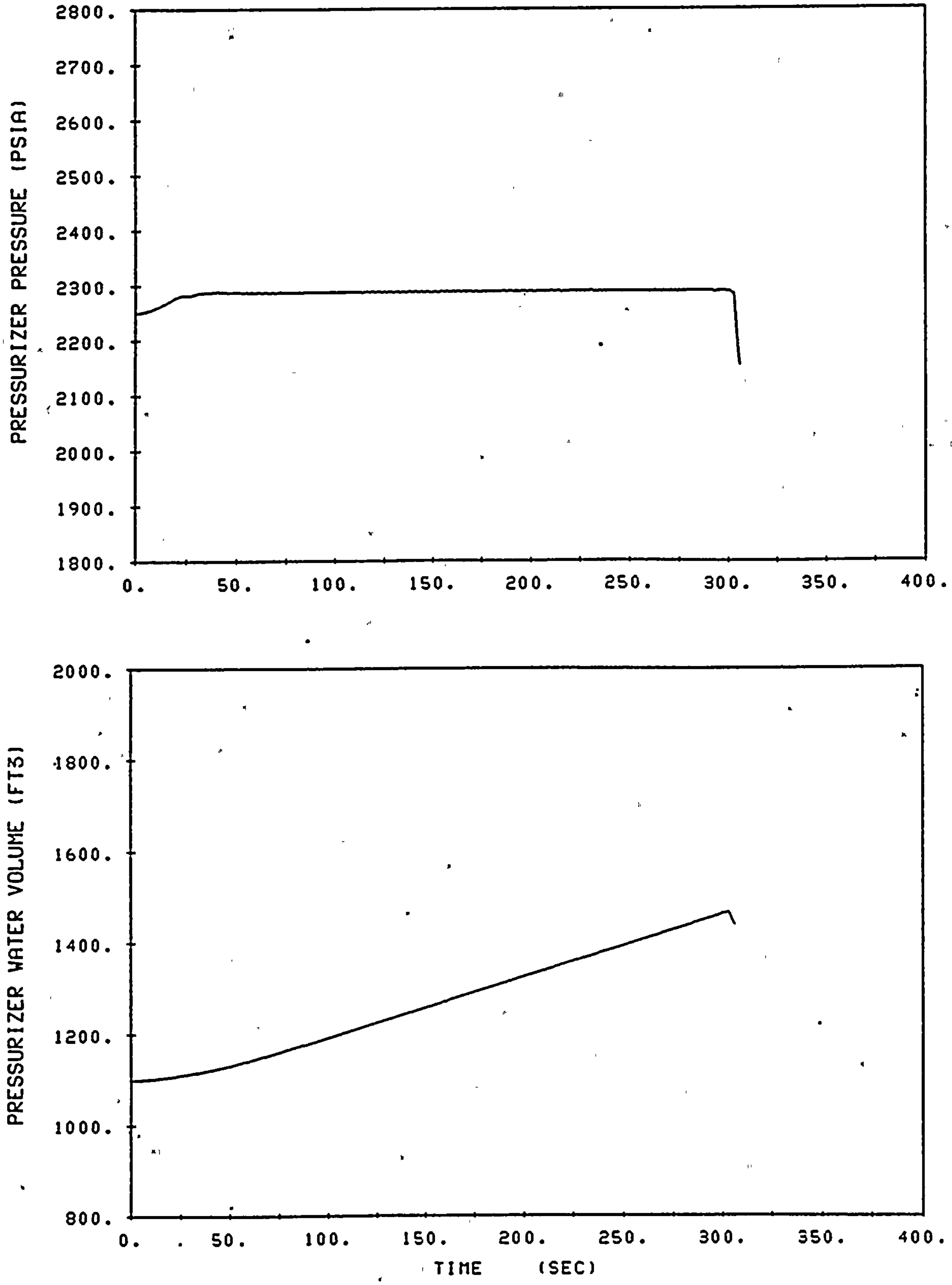


Figure B.3-7A Rod Withdrawal at Power
Pressurizer Pressure and Water Volume Versus Time for Full Power, 4 PCM/Sec Insertion Rate, Maximum Reactivity Feedback

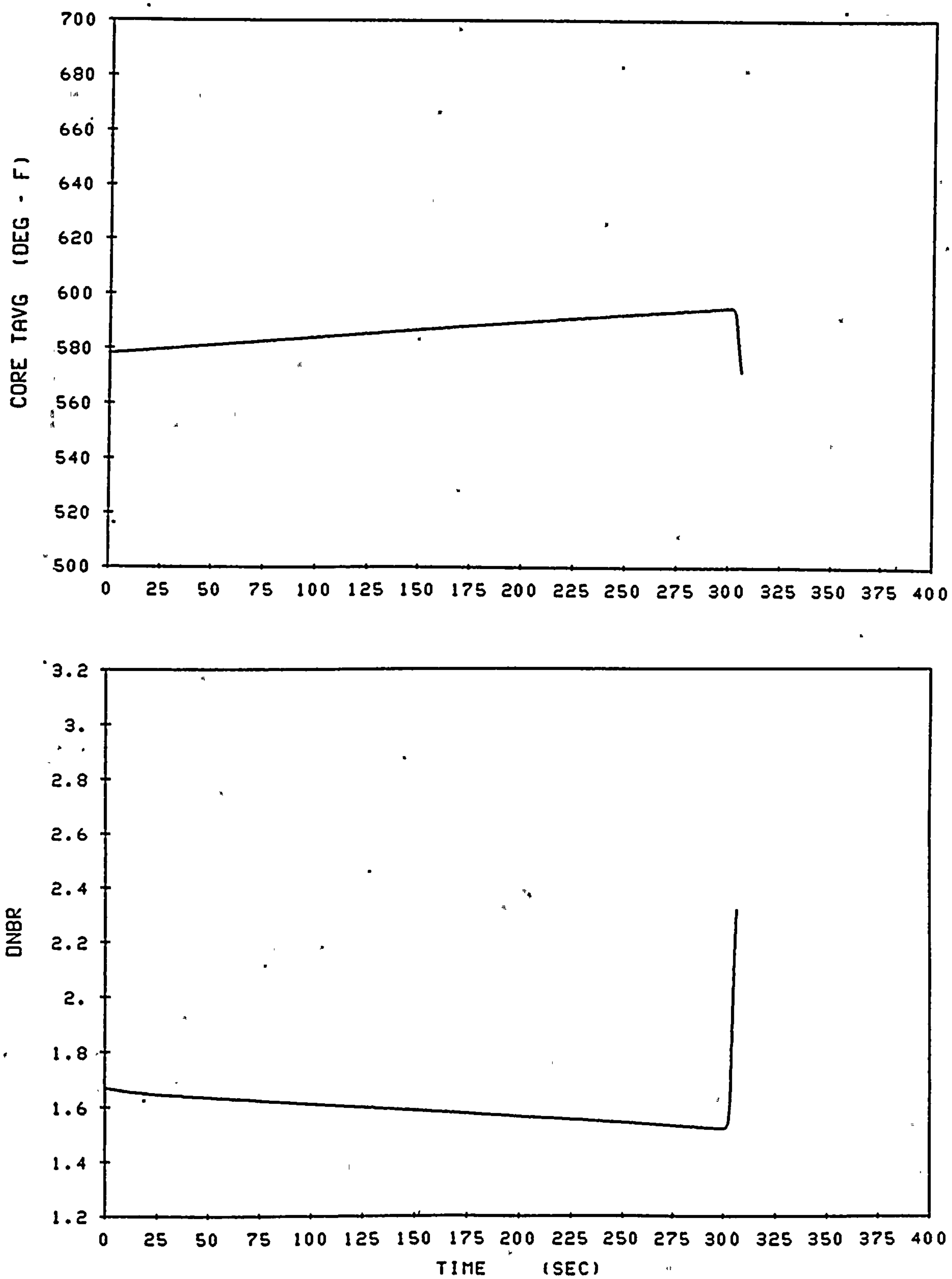


Figure B.3-8A Rod Withdrawal at Power
Core Average Temperature and DNBR Versus Time for Full Power, 4 PCM/Sec Insertion Rate, Maximum Reactivity Feedback

Figure B.3-9A Rod Withdrawal at Power
100% Power, Minimum DNBR Versus Reactivity Insertion Rate

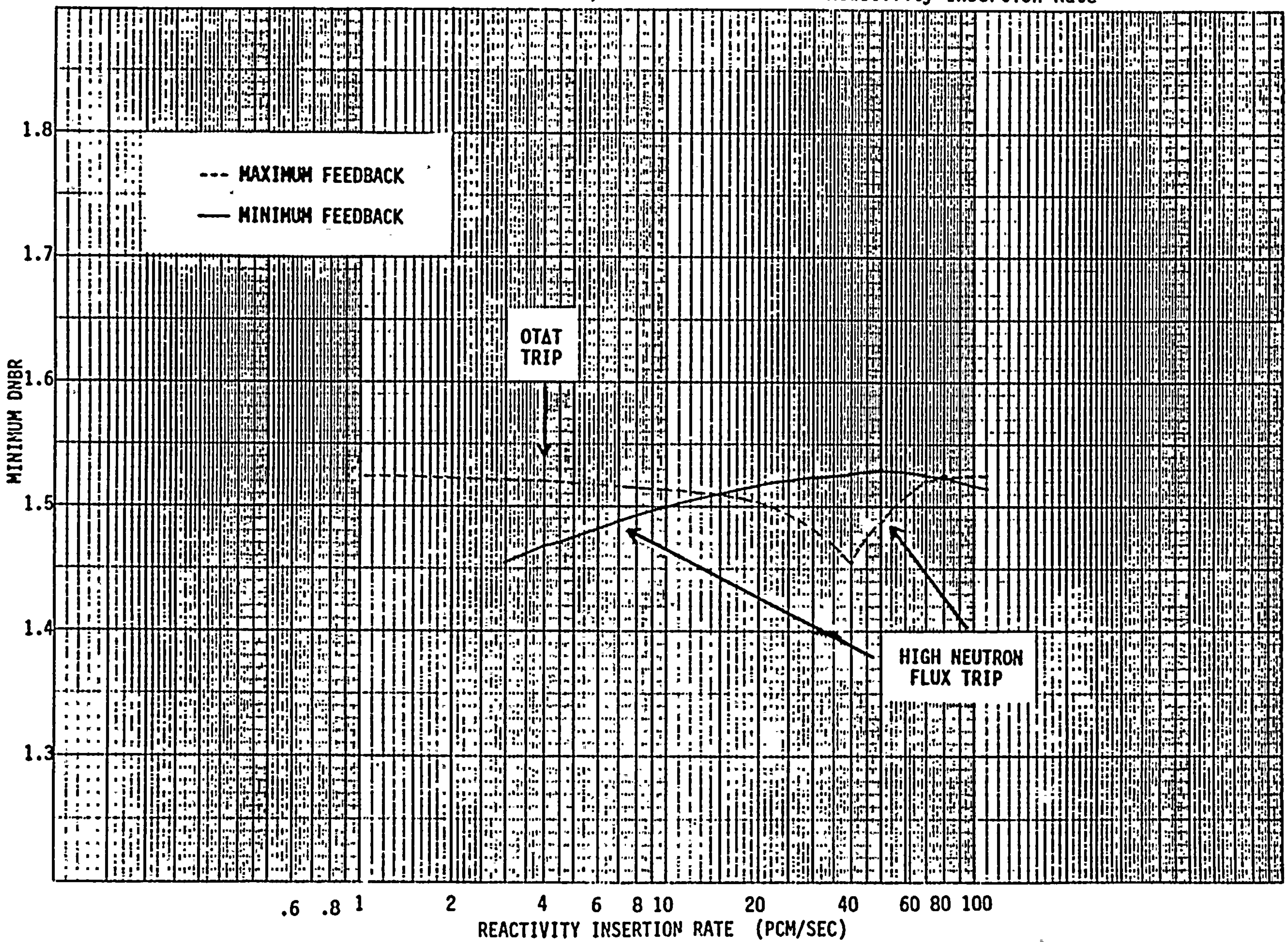


Figure B.3-10A Rod Withdrawal at Power
60% Power, Minimum DNBR Versus Reactivity Insertion Rate

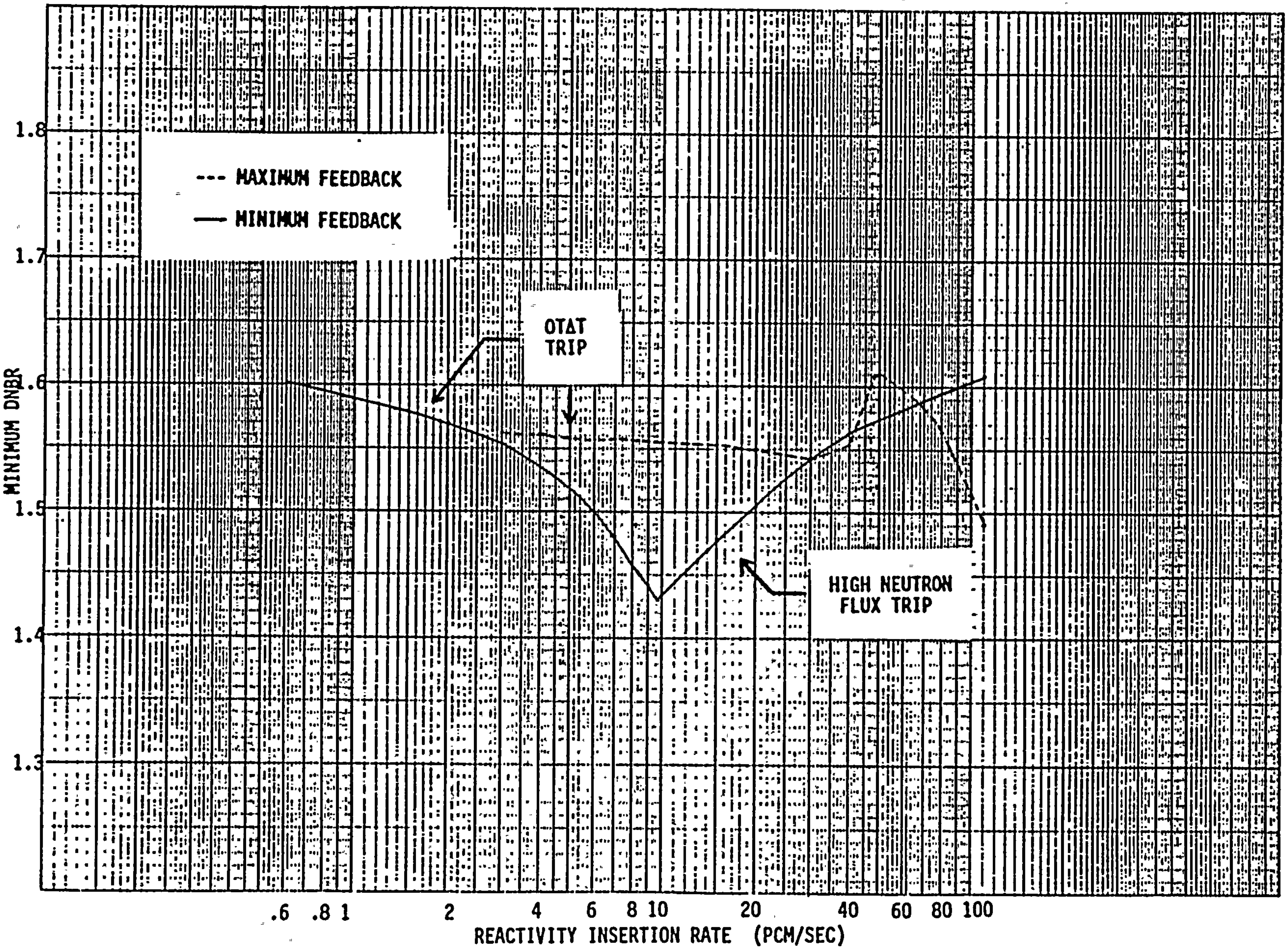
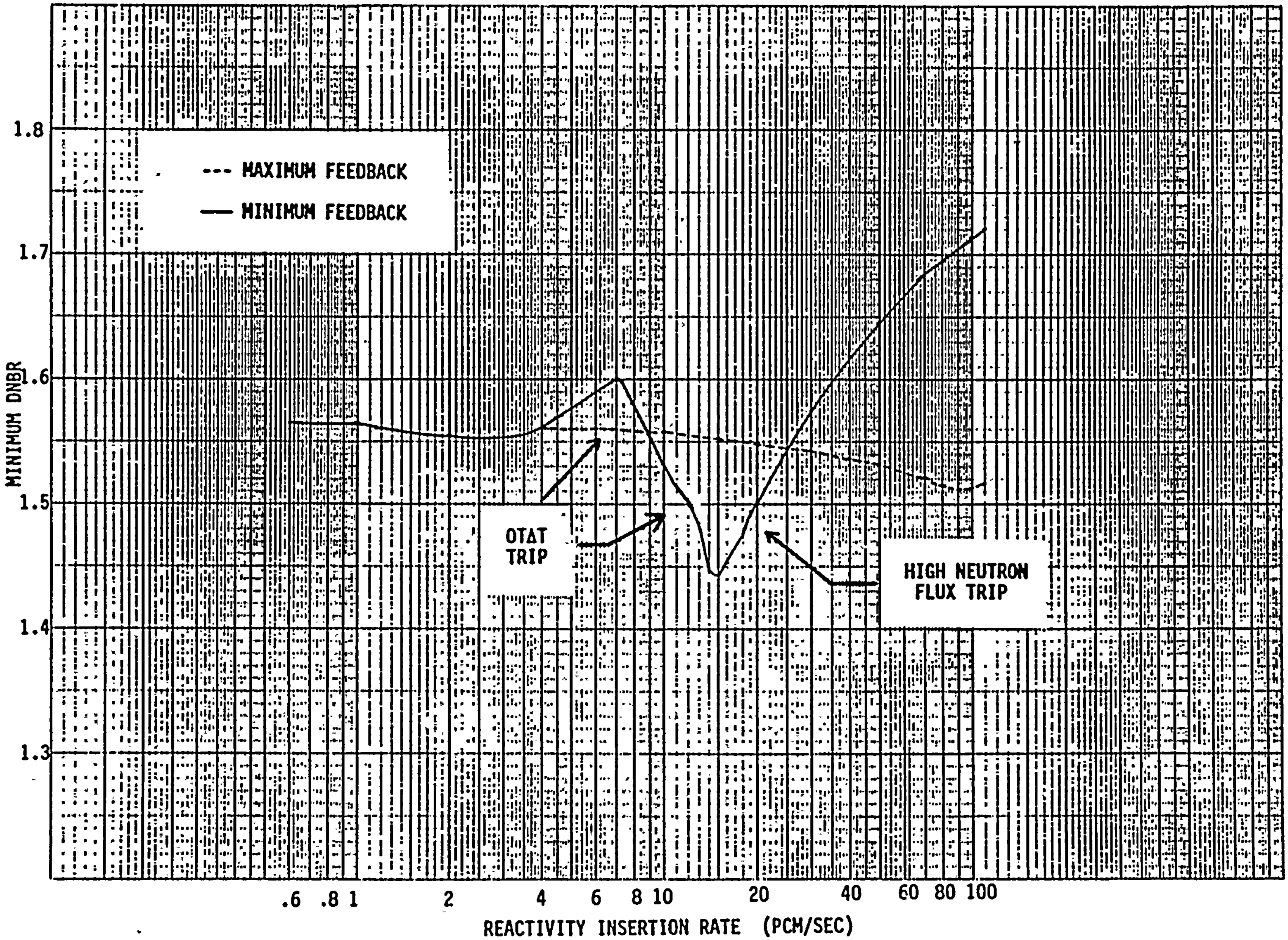


Figure B.3-11A Rod Withdrawal at Power
10% Power, Minimum DNBR Versus Reactivity Insertion Rate



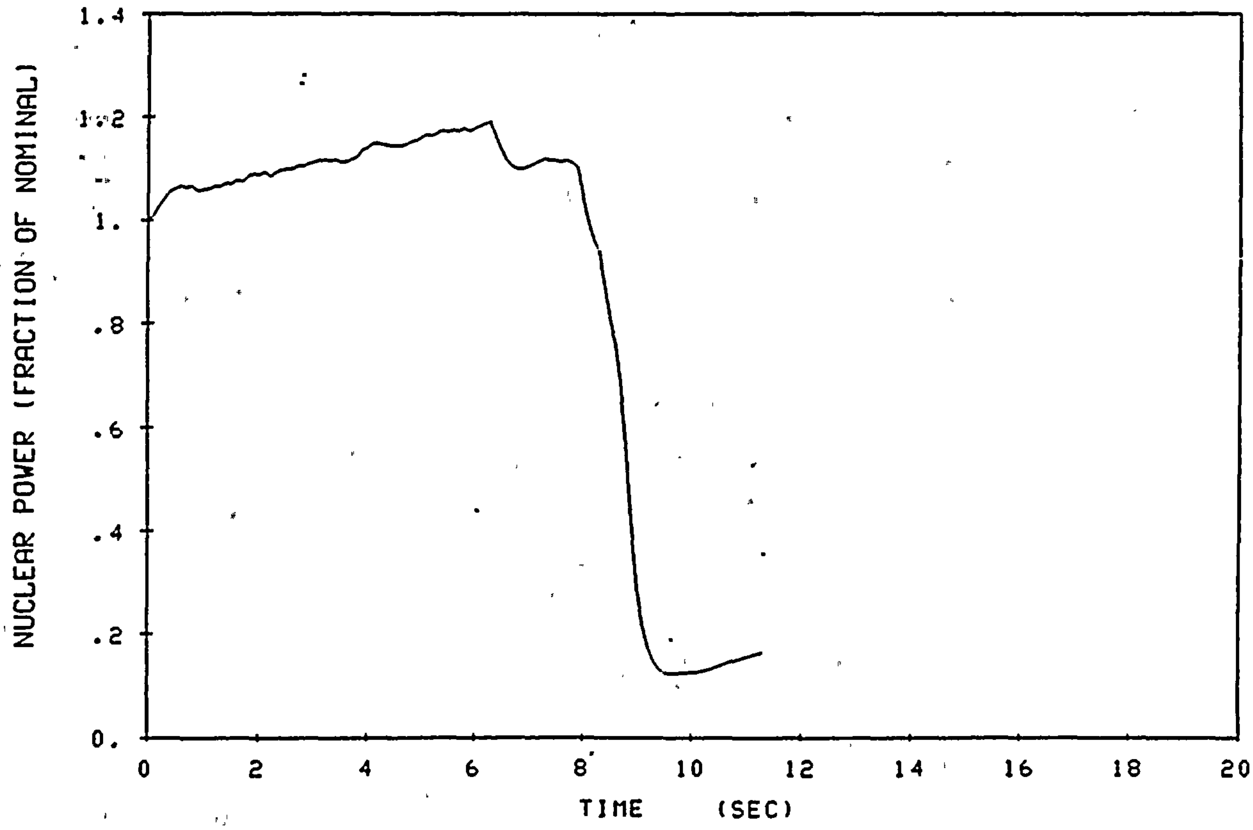


Figure B.3-3B Rod Withdrawal at Power
Nuclear Power Versus Time for Full Power, 80 PCM/Sec
Insertion Rate, Maximum Reactivity Feedback

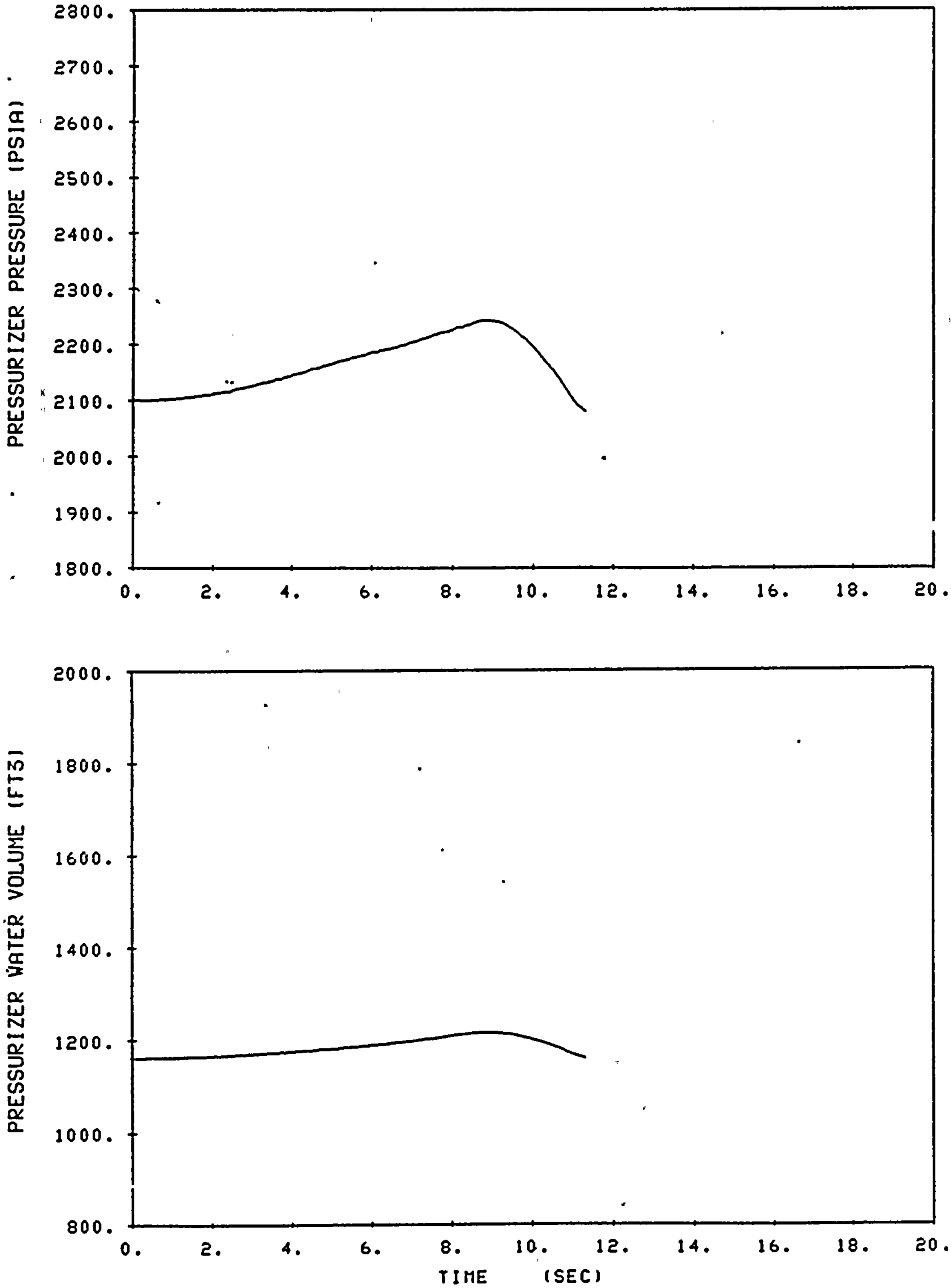


Figure B.3-4B Rod Withdrawal at Power
Pressurizer Pressure and Water Volume Versus Time for Full Power, 80 PCM/Sec Insertion Rate, Maximum Reactivity Feedback

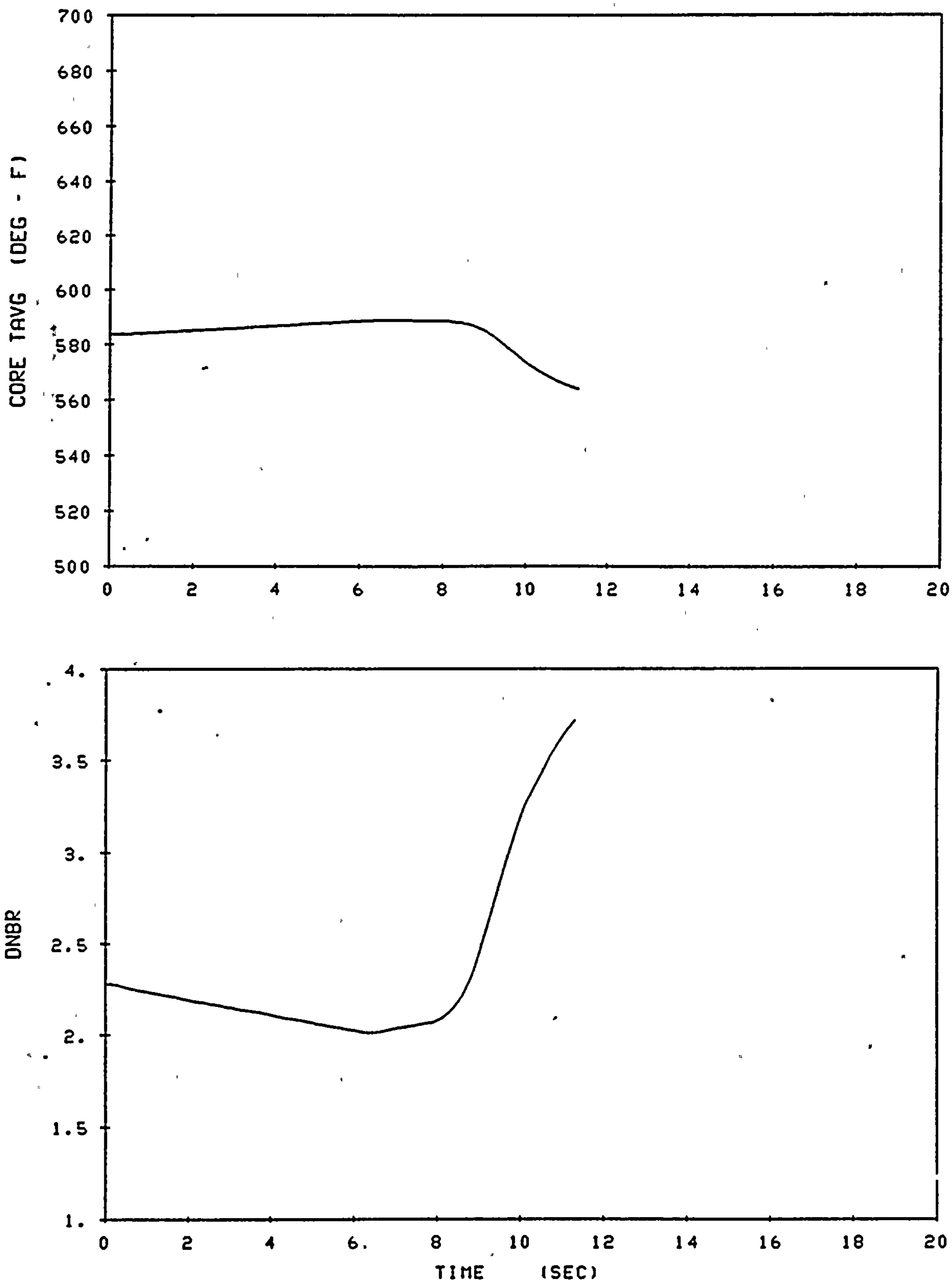


Figure B.3-5B Rod Withdrawal at Power
Core Average Temperature and DNBR Versus Time for Full Power, 80 PCM/Sec Insertion Rate, Maximum Reactivity Feedback

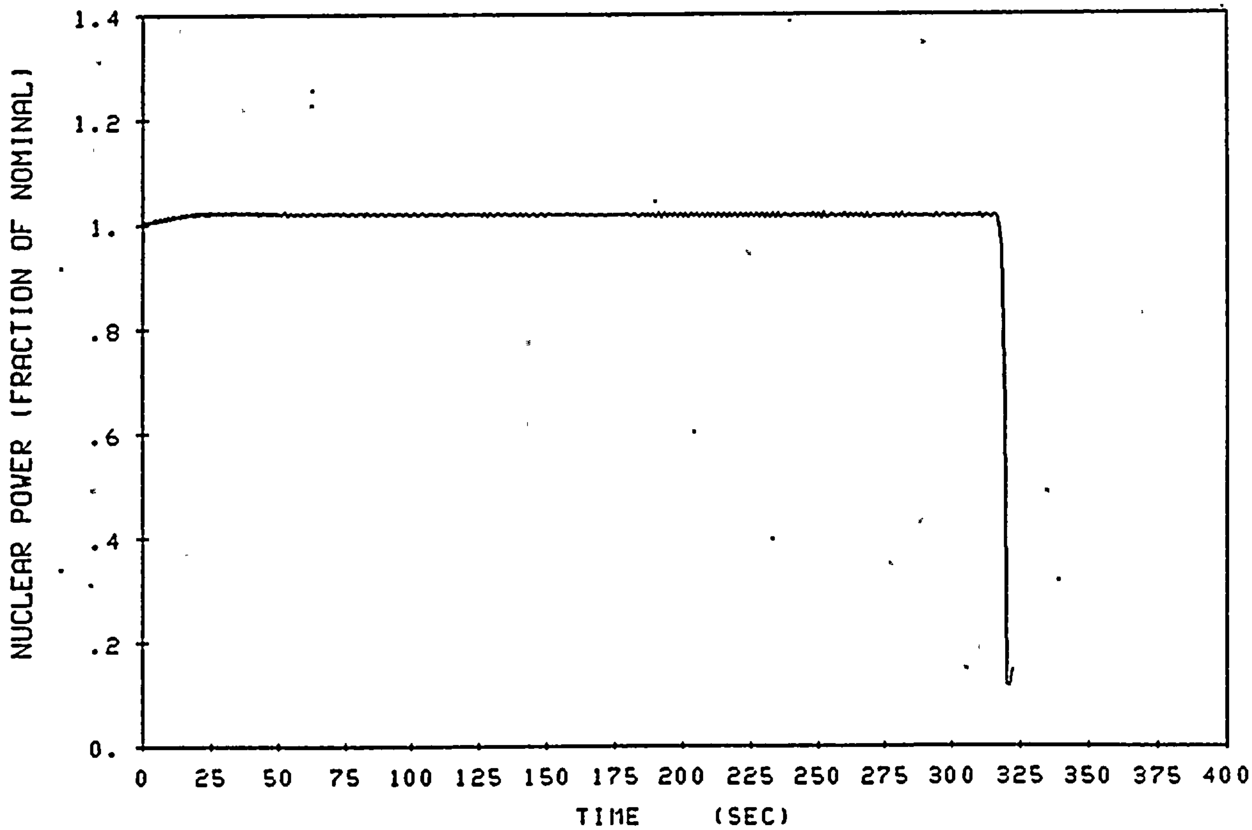
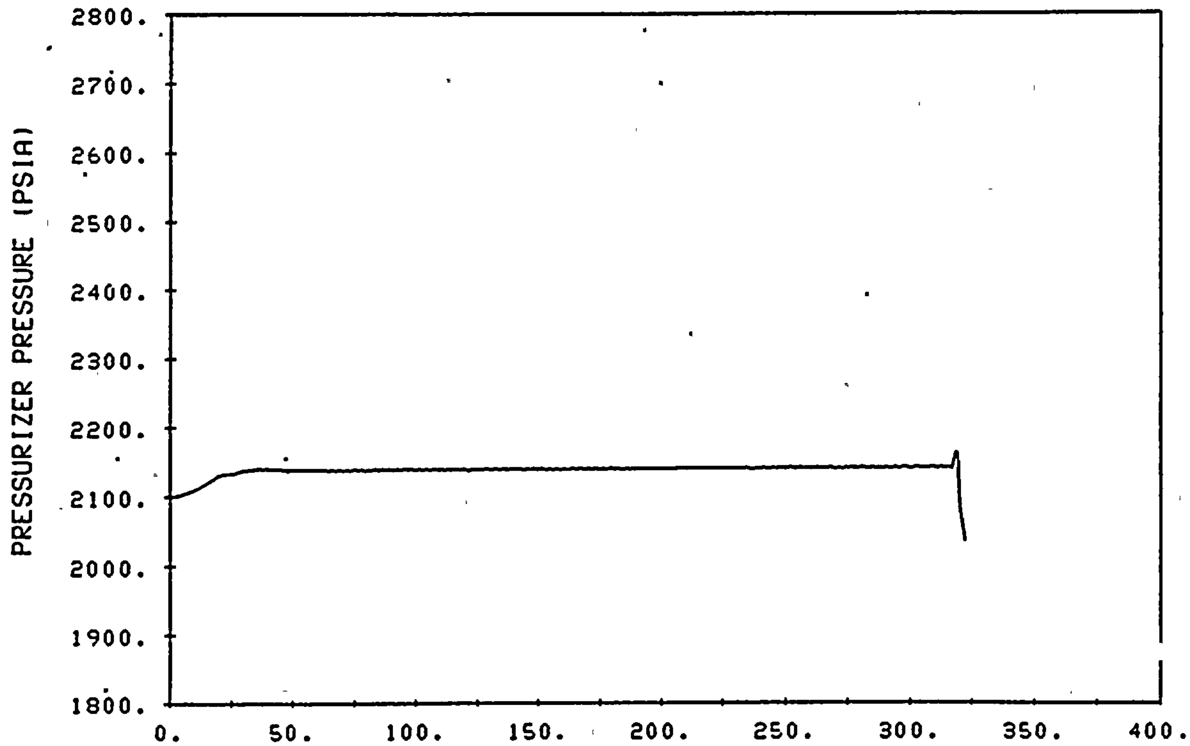


Figure B.3-6B Rod Withdrawal at Power
Nuclear Power Versus Time for Full Power, 4 PCM/Sec Insertion Rate, Maximum Reactivity Feedback



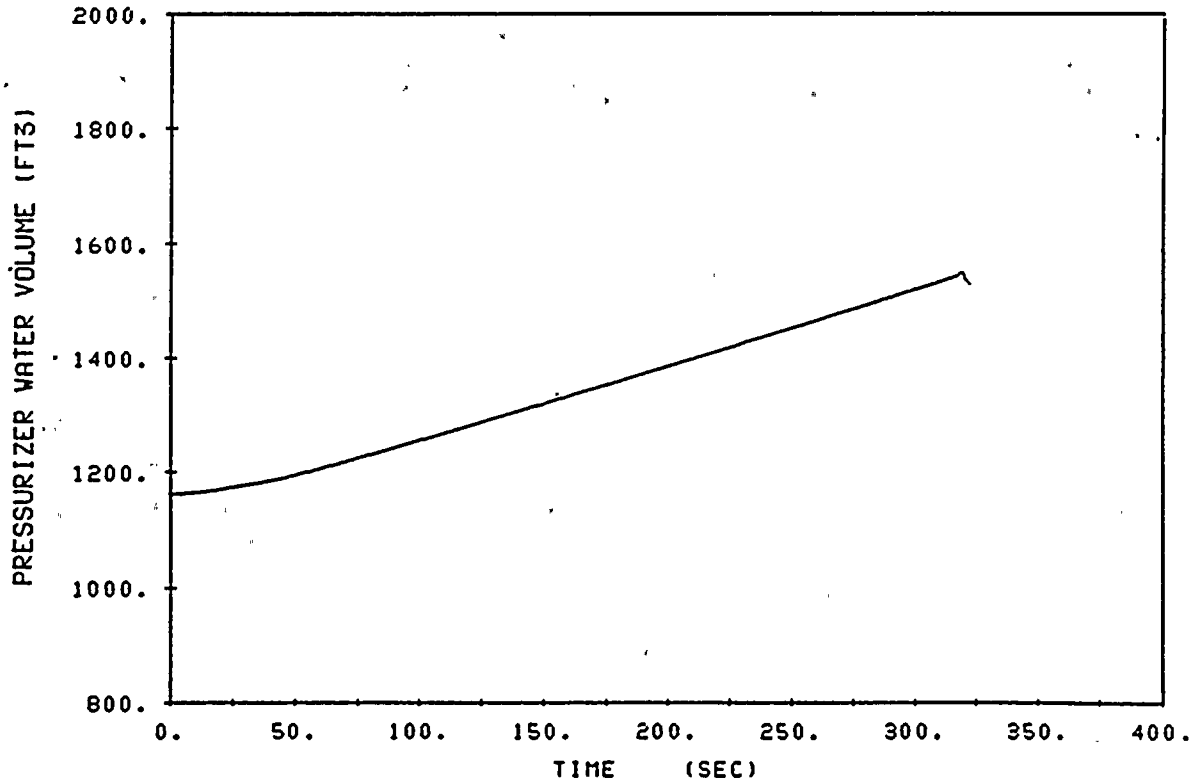


Figure B.3-7B Rod Withdrawal at Power
Pressurizer Pressure and Water Volume Versus Time for Full Power, 4 PCM/Sec Insertion Rate, Maximum Reactivity Feedback

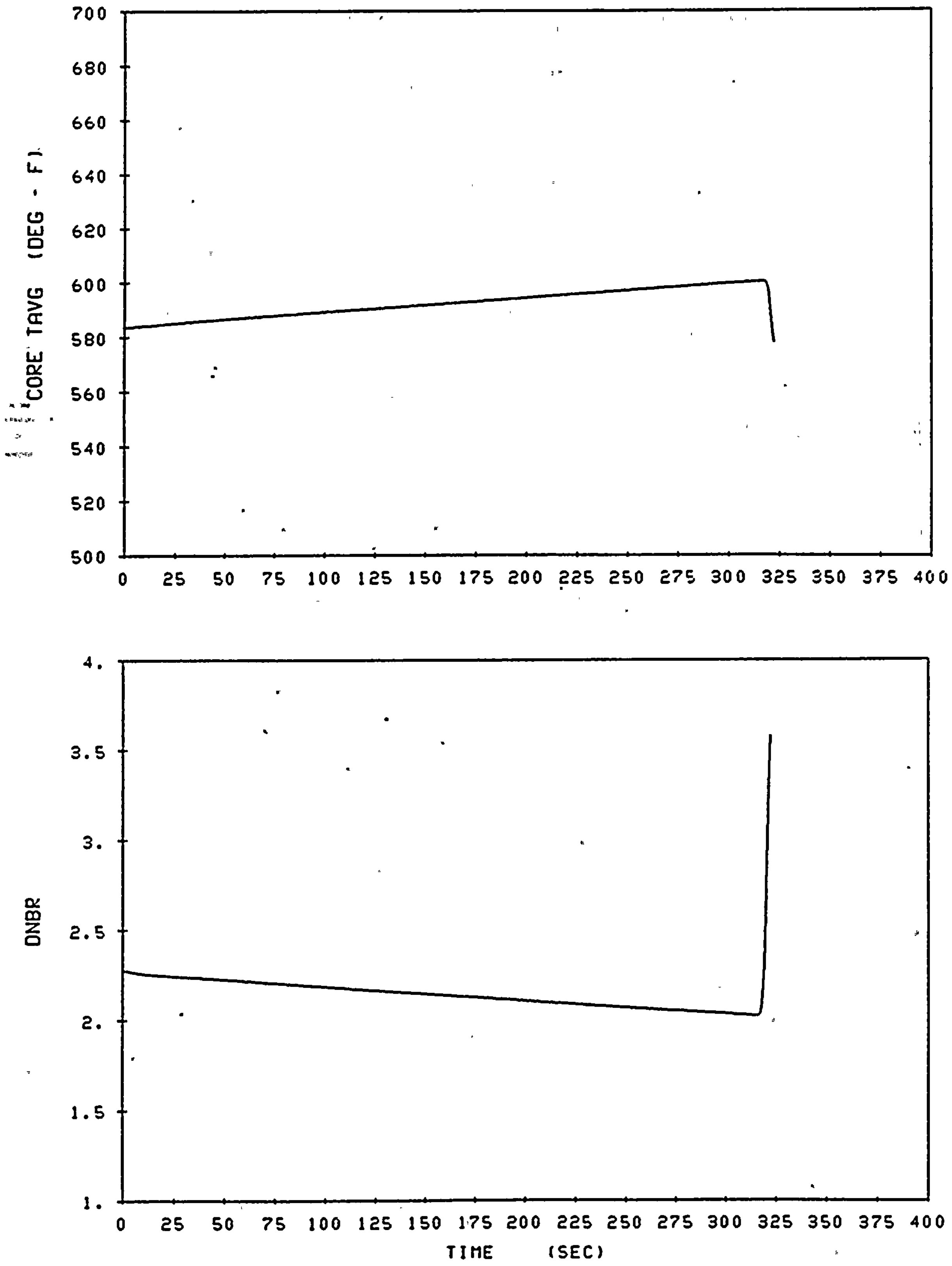


Figure B.3-8B Rod Withdrawal at Power
Core Average Temperature and DNBR Versus Time for Full Power, 4 PCM/Sec Insertion Rate, Maximum Reactivity Feedback

Figure B.3-9B Rod Withdrawal at Power
100% Power, Minimum DNBR Versus Reactivity Insertion Rate

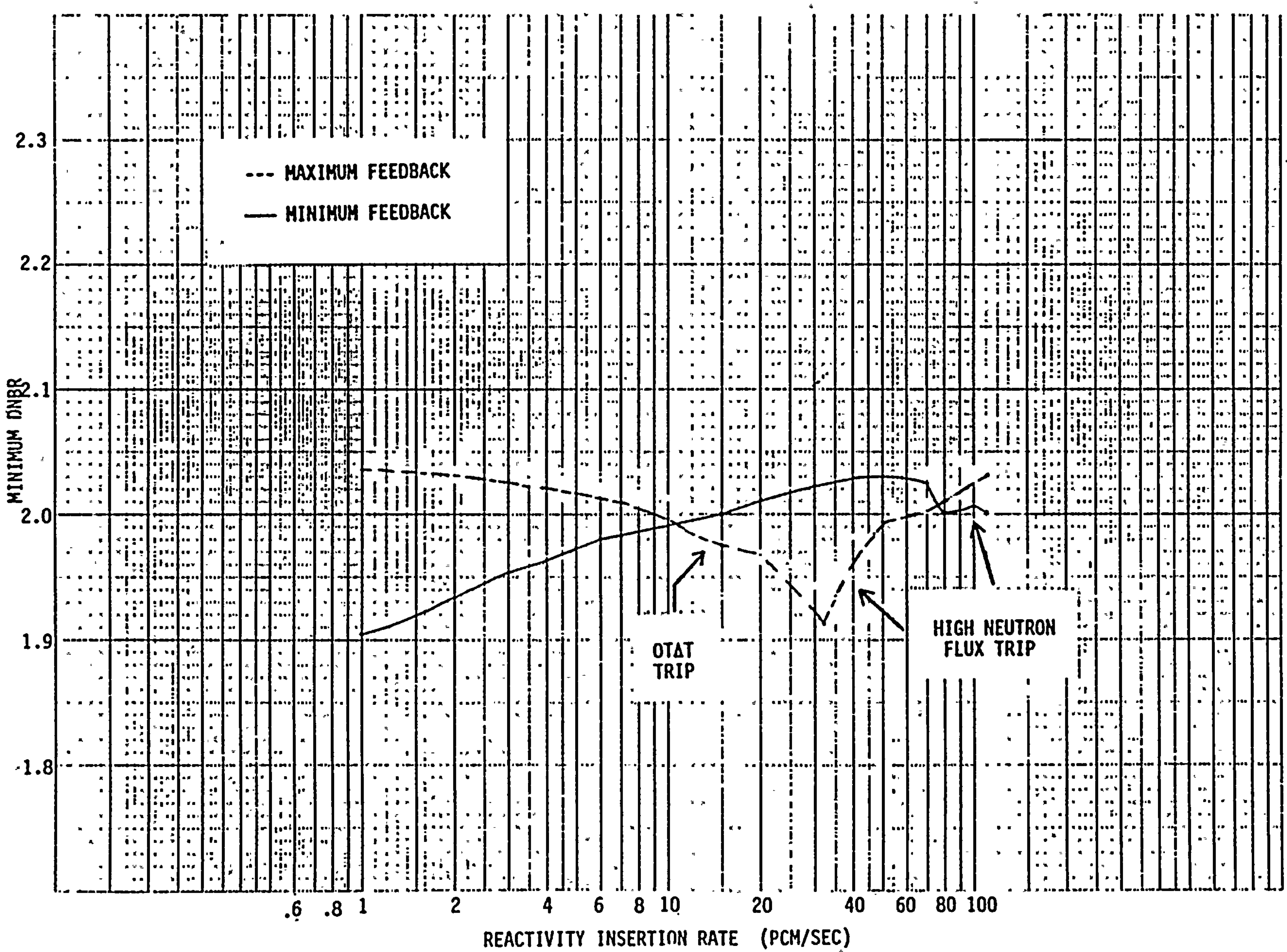


Figure B.3-10B Rod Withdrawal at Power
60% Power, Minimum DNBR Versus Reactivity Insertion Rate

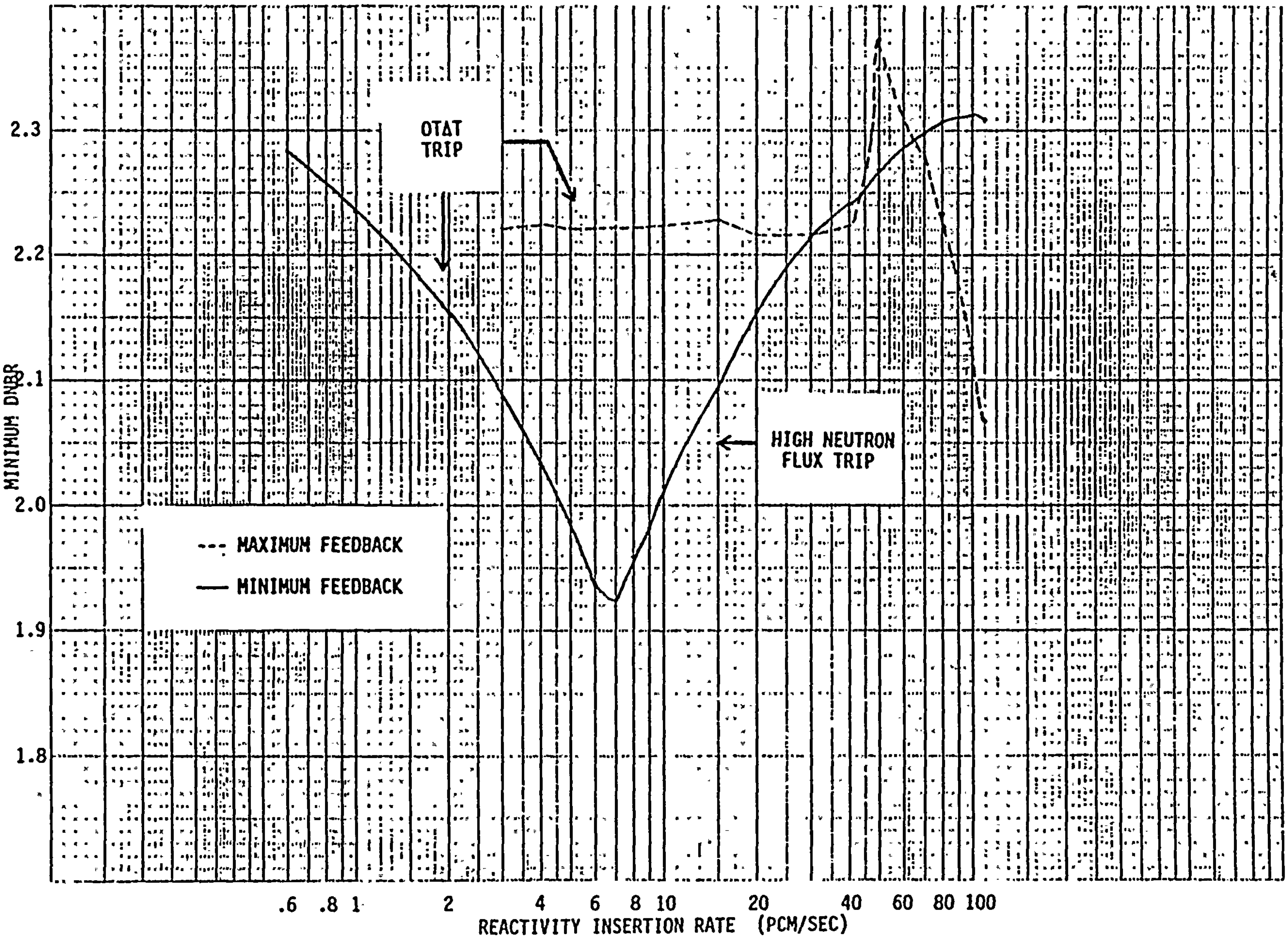
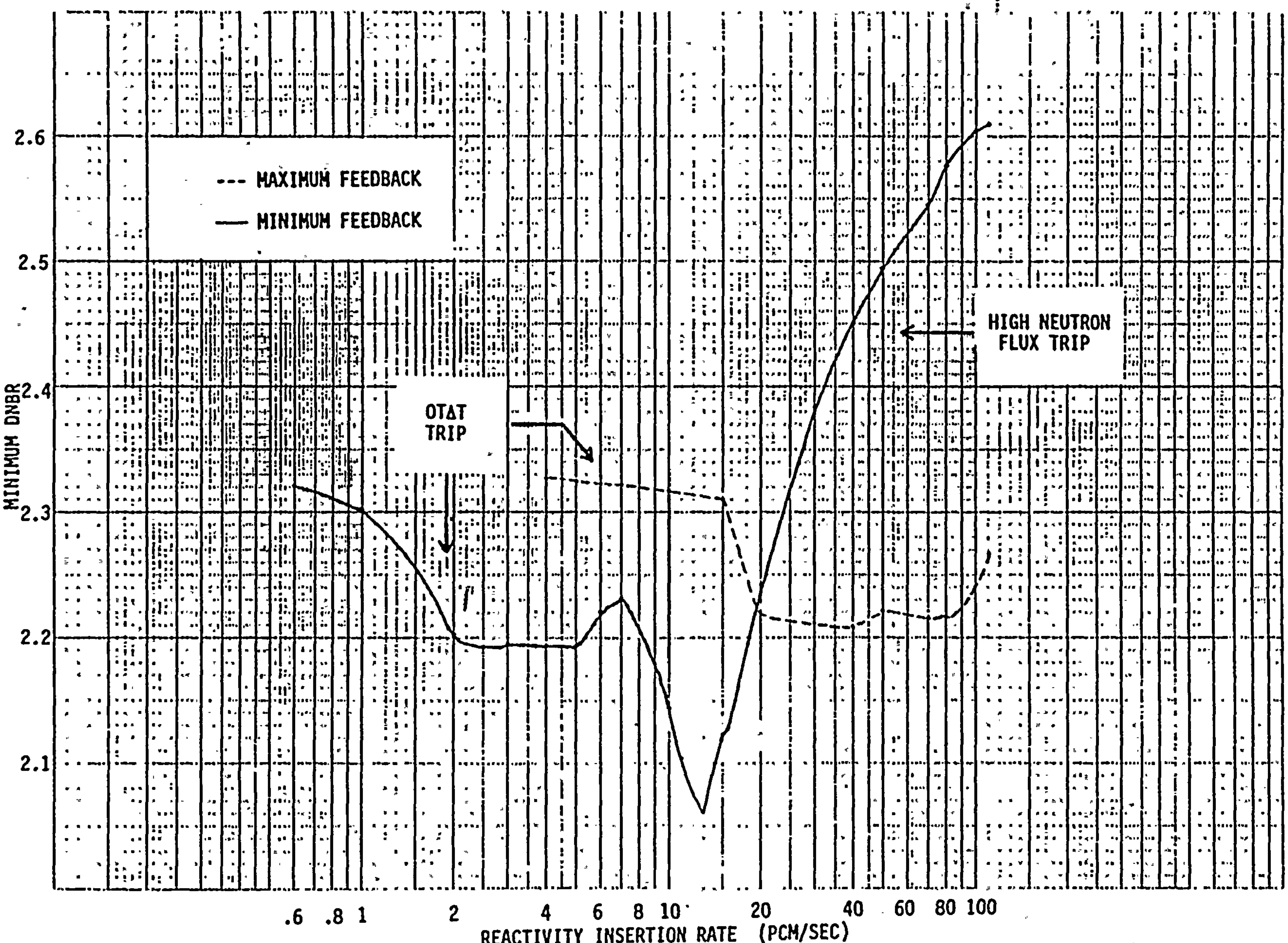


Figure B.3-11B Rod Withdrawal at Power
10% Power, Minimum DNBR Versus Reactivity Insertion Rate



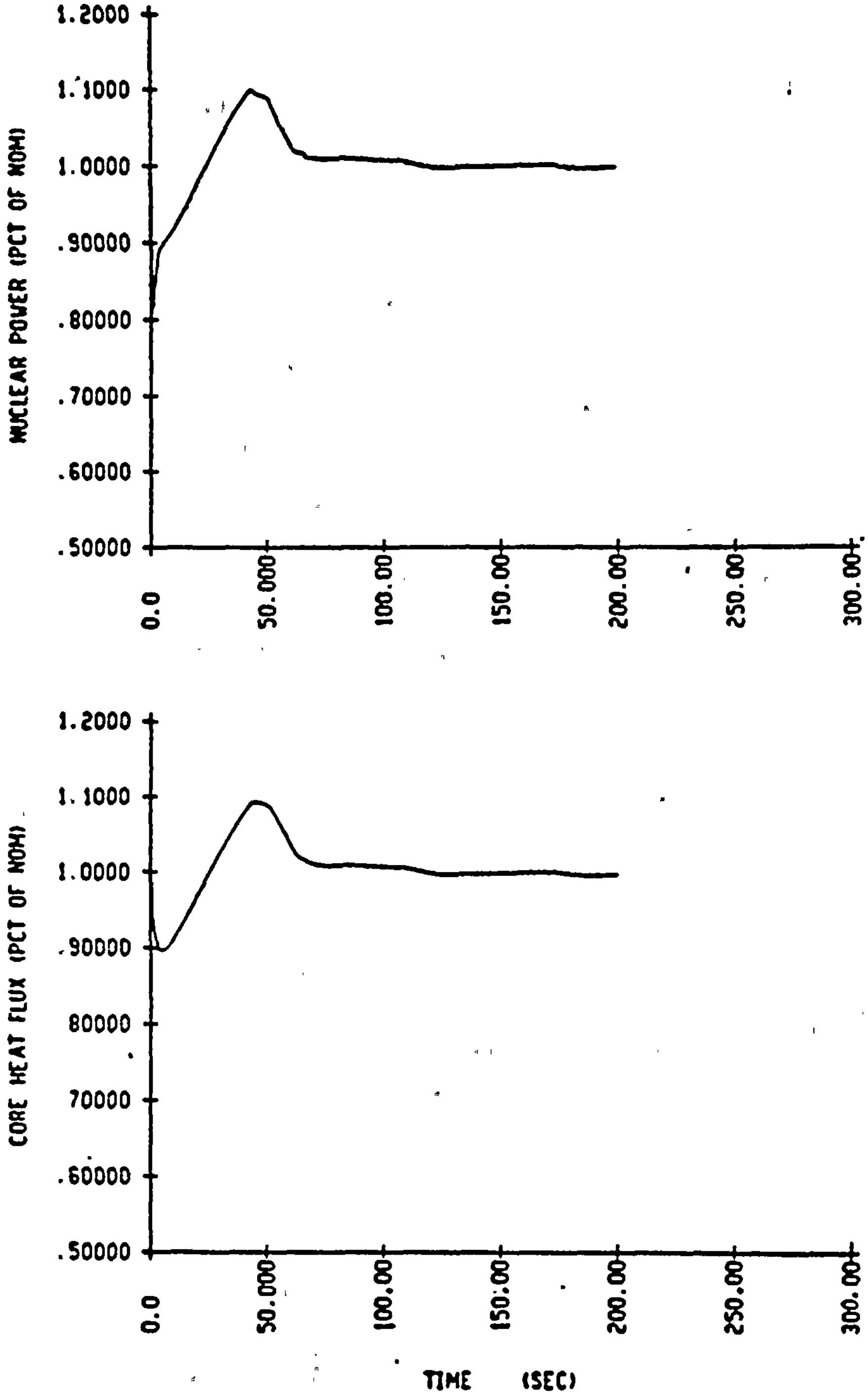


Figure B.3-12 Dropped RCCA(s)
Nuclear Power and Core Heat Flux Versus Time for a Typical Response in Automatic Control

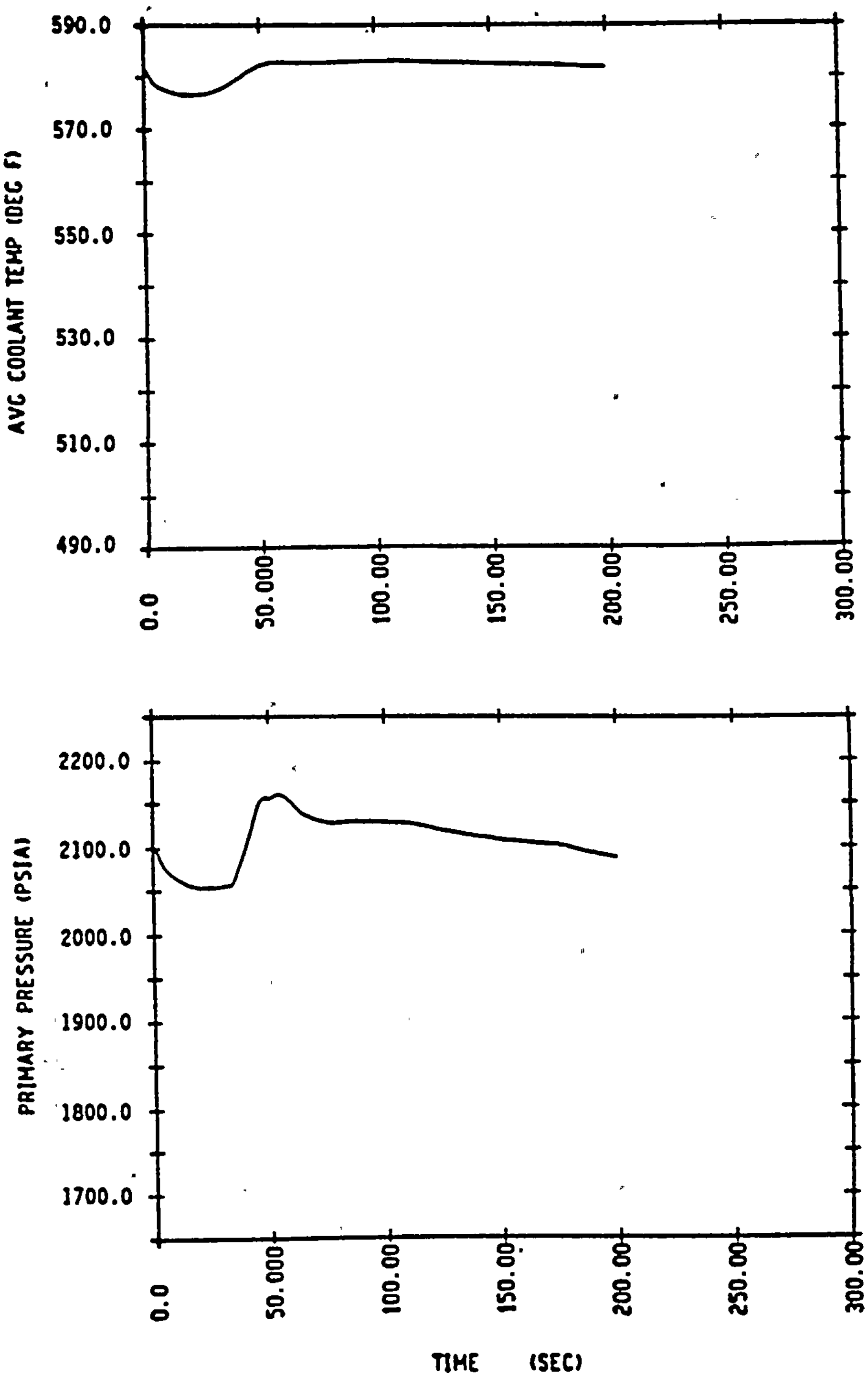


Figure B.3-13 Dropped RCCA(s)
Average Coolant Temperature and Pressurizer Pressure Versus Time for a Typical Response in Automatic Control

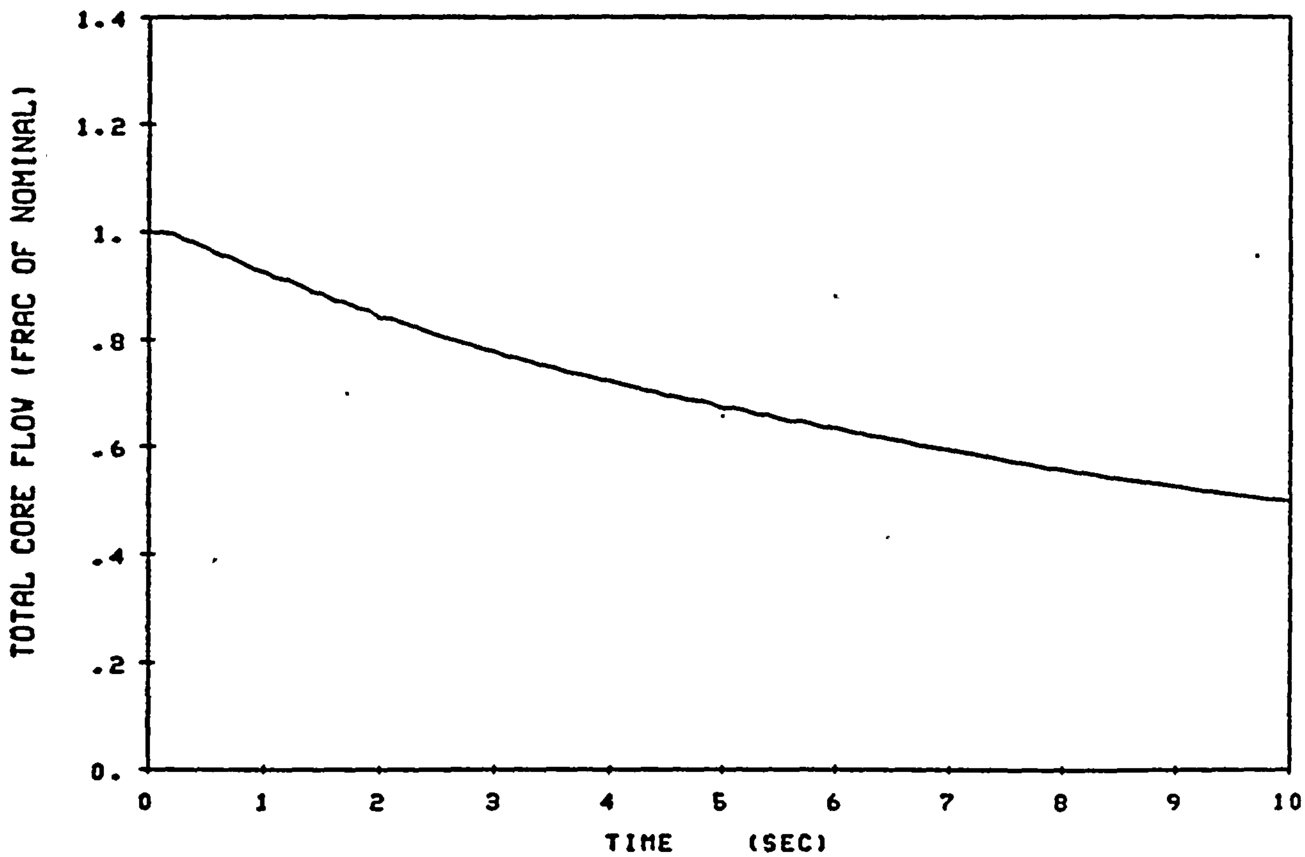


Figure B.3-14 Complete Loss of Flow
Core Flow Coastdown Versus Time

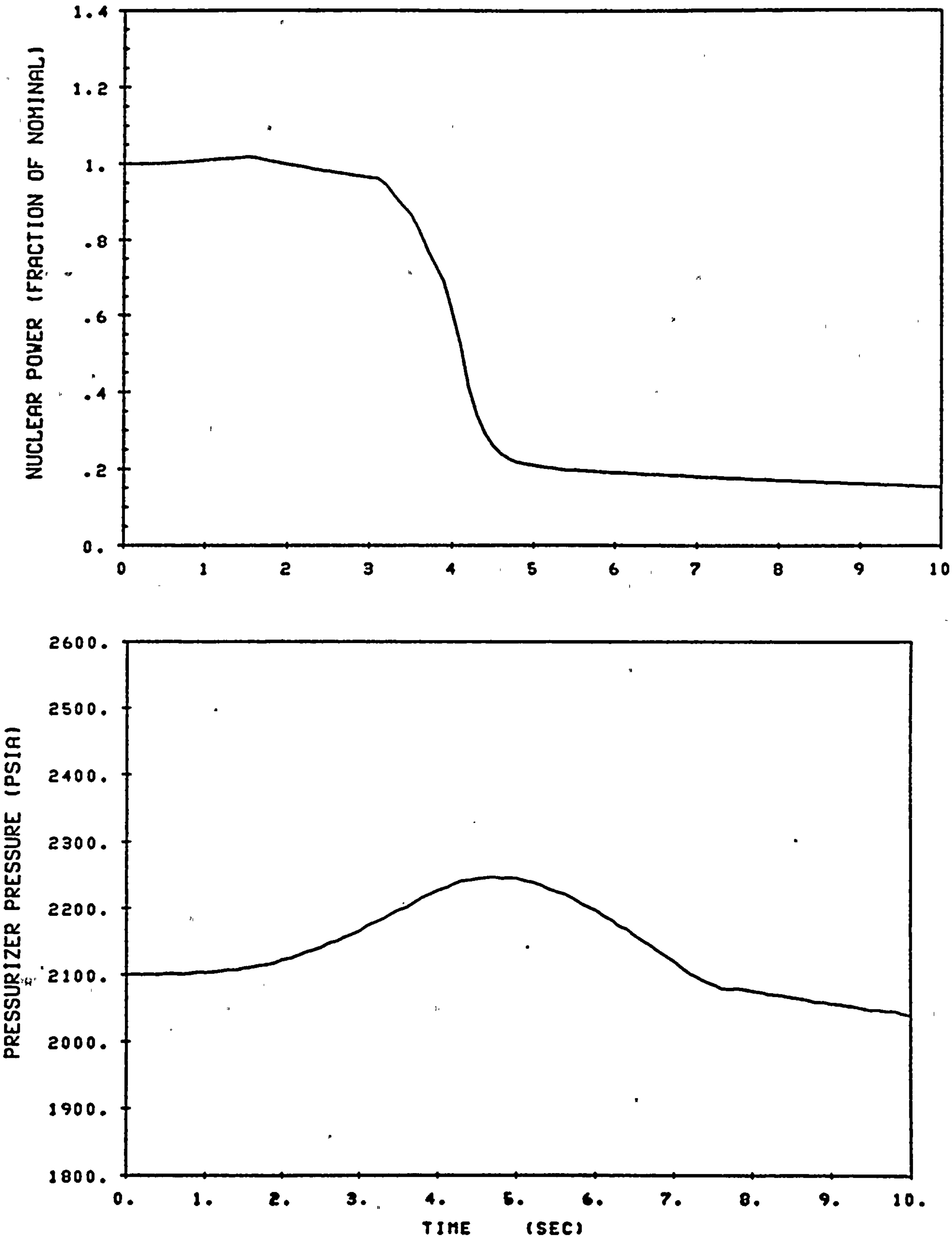


Figure B.3-15 Complete Loss of Flow
Nuclear Power and Pressurizer Pressure Versus Time

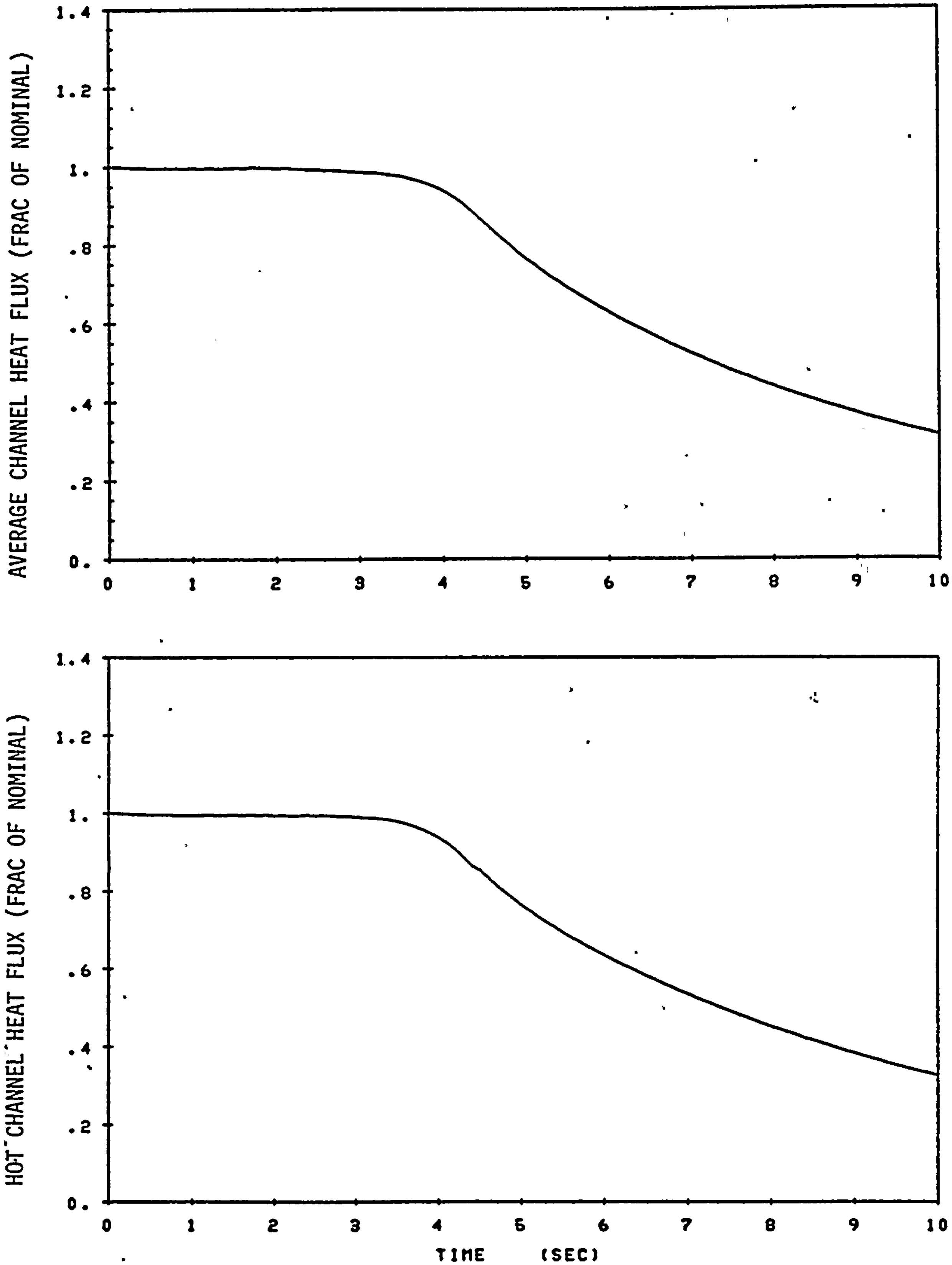


Figure B.3-16 Complete Loss of Flow
Average Channel and Hot Channel Heat Flux Versus Time

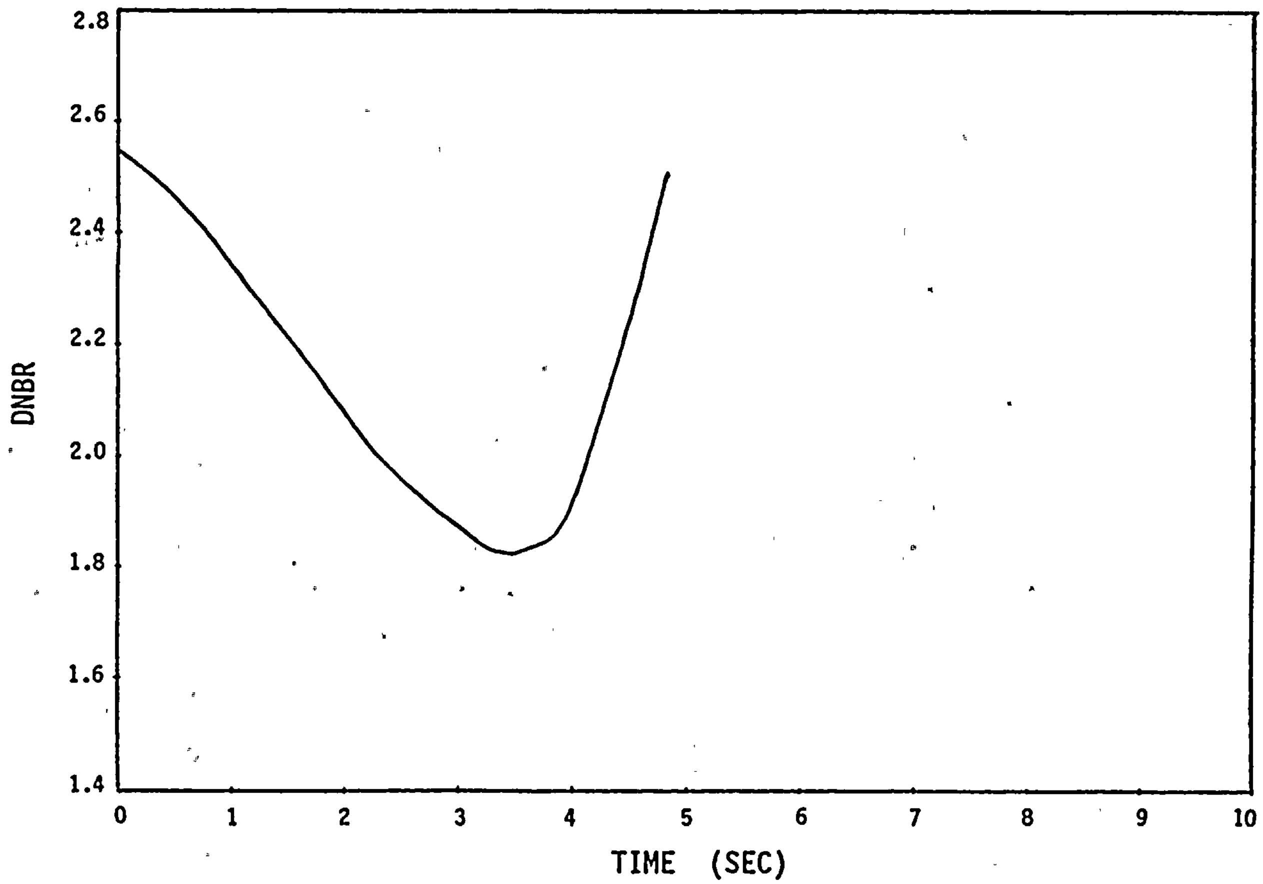


Figure B.3-17 Complete Loss of Flow
DNBR Versus Time

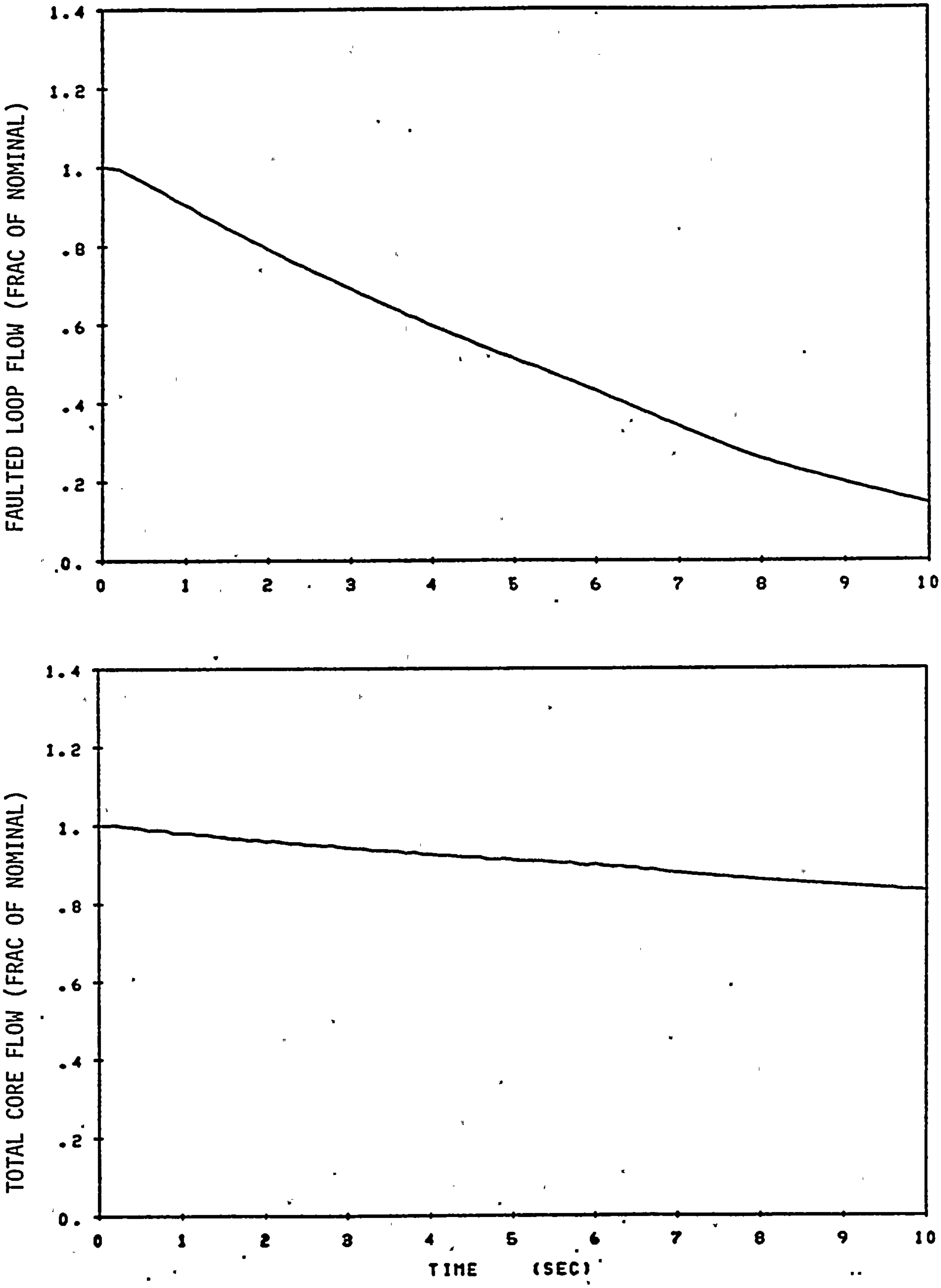


Figure B.3-18 Partial Loss of Flow 1/4
Faulted Loop and Core Flows Versus Time

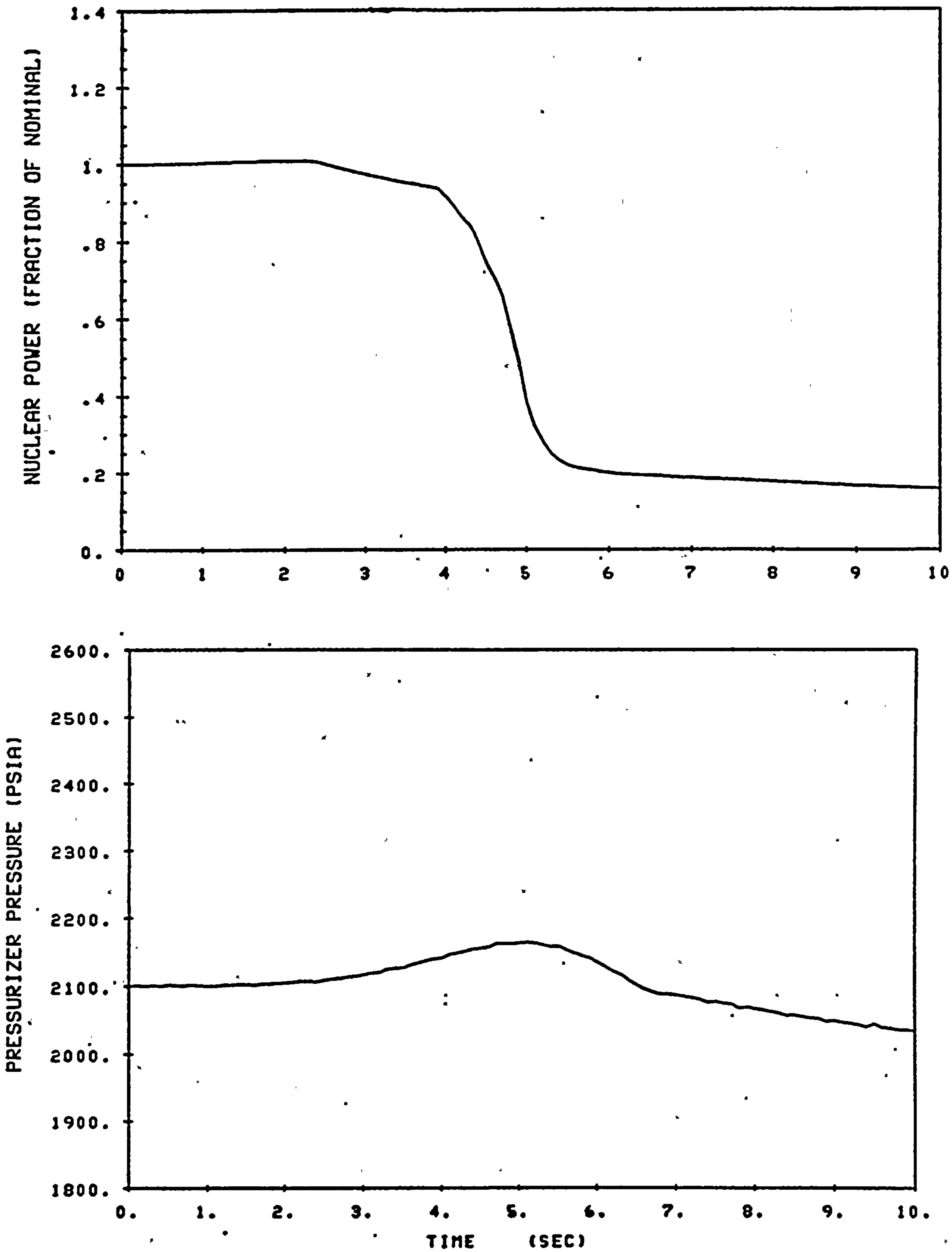


Figure B.3-19 Partial Loss of Flow 1/4
Nuclear Power and Pressurizer Pressure Versus Time

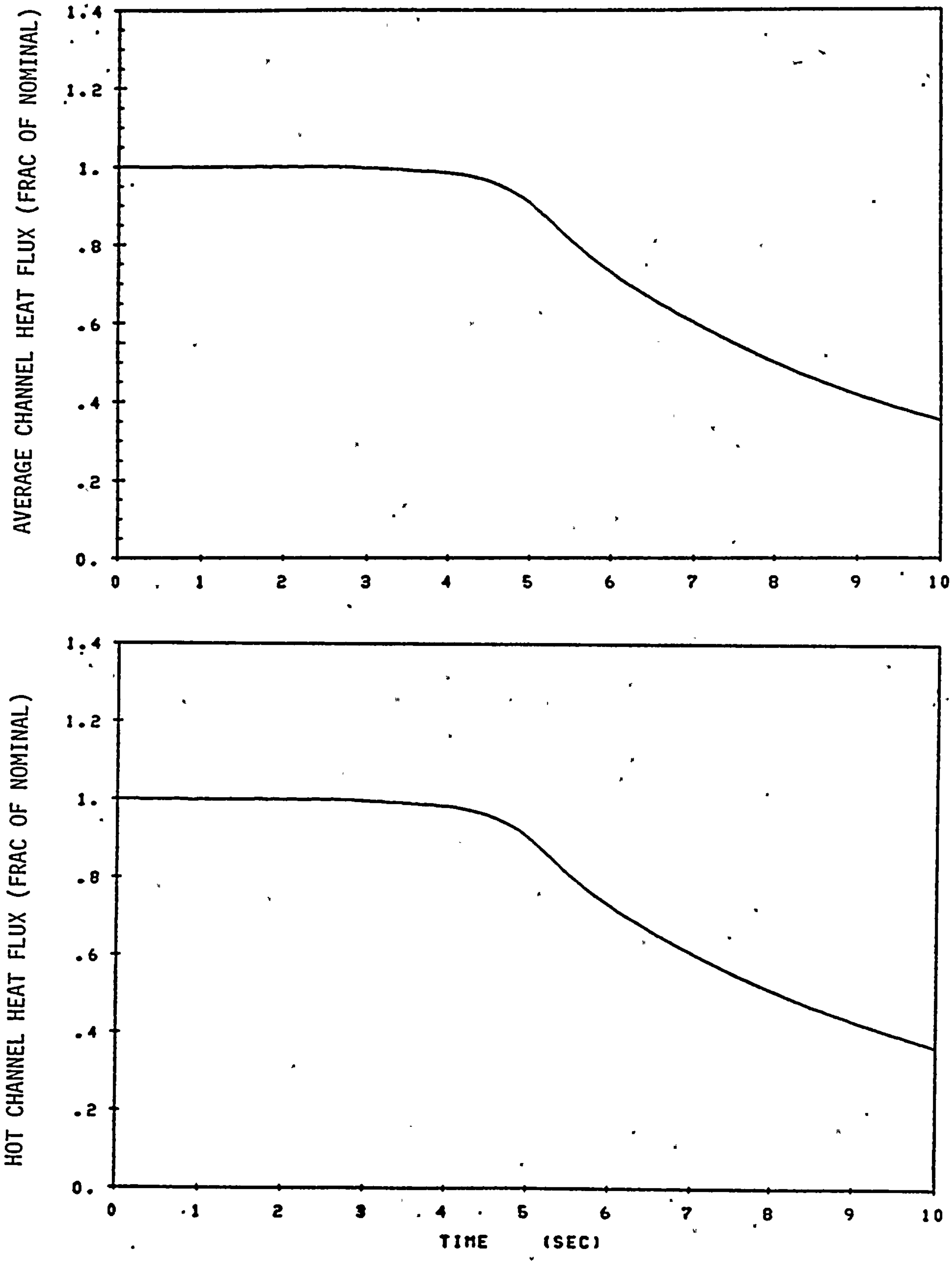


Figure B.3-20 Partial Loss of Flow 1/4
Average Channel and Hot Channel Heat Flux Versus Time

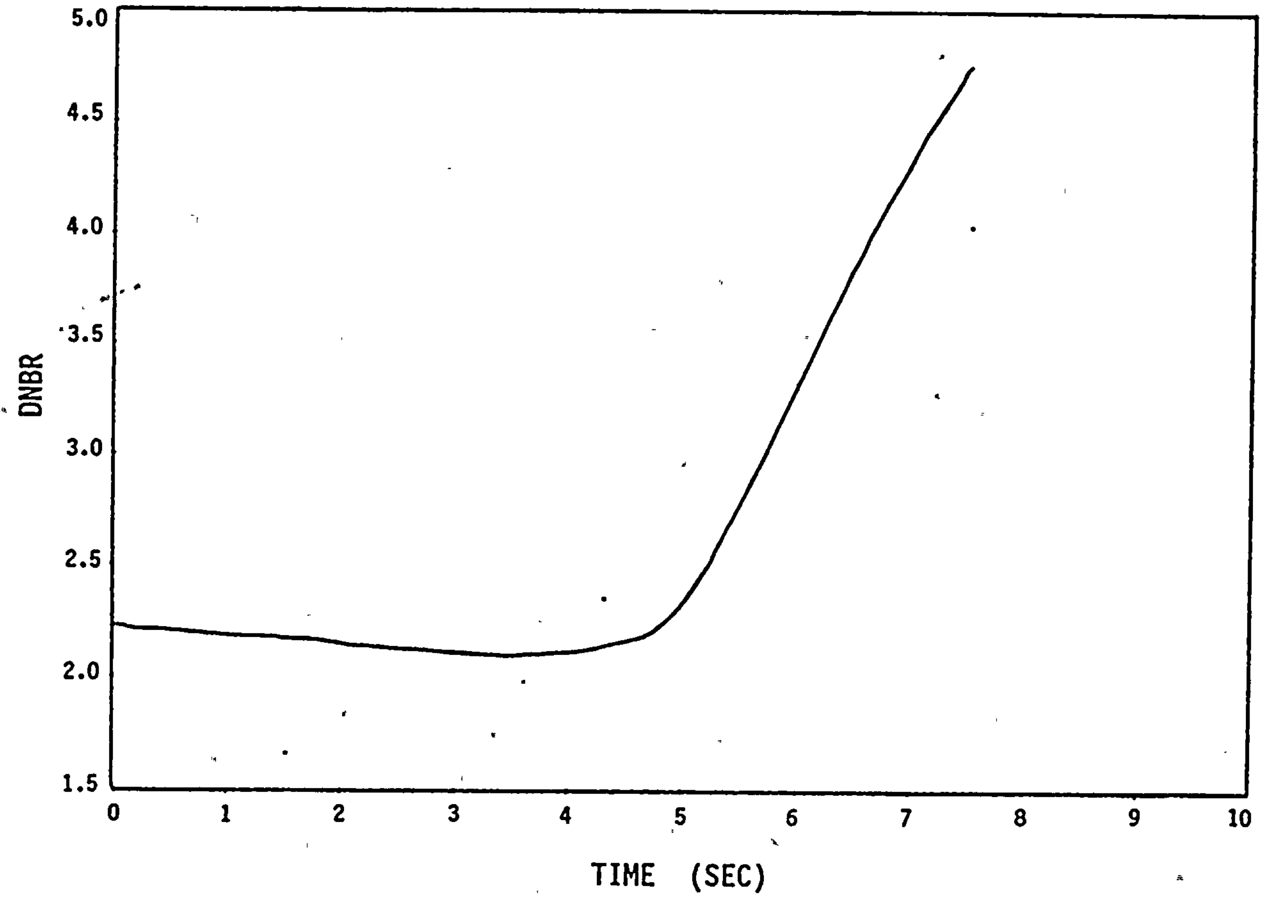


Figure B.3-21 Partial Loss of Flow 1/4
DNBR Versus Time

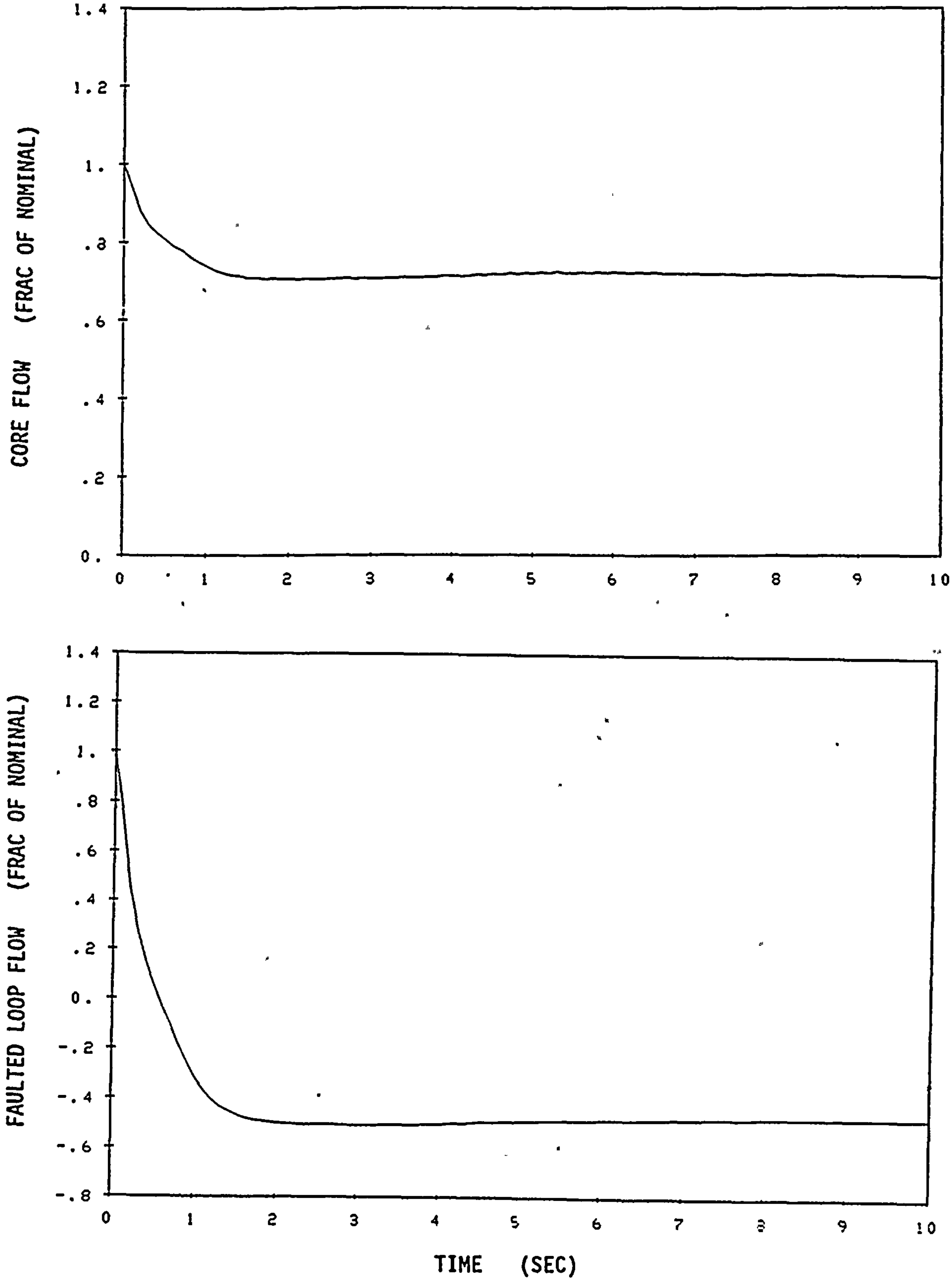


Figure B.3-22 1/4 Locked Rotor
Core and Faulted Loop Flows Versus Time

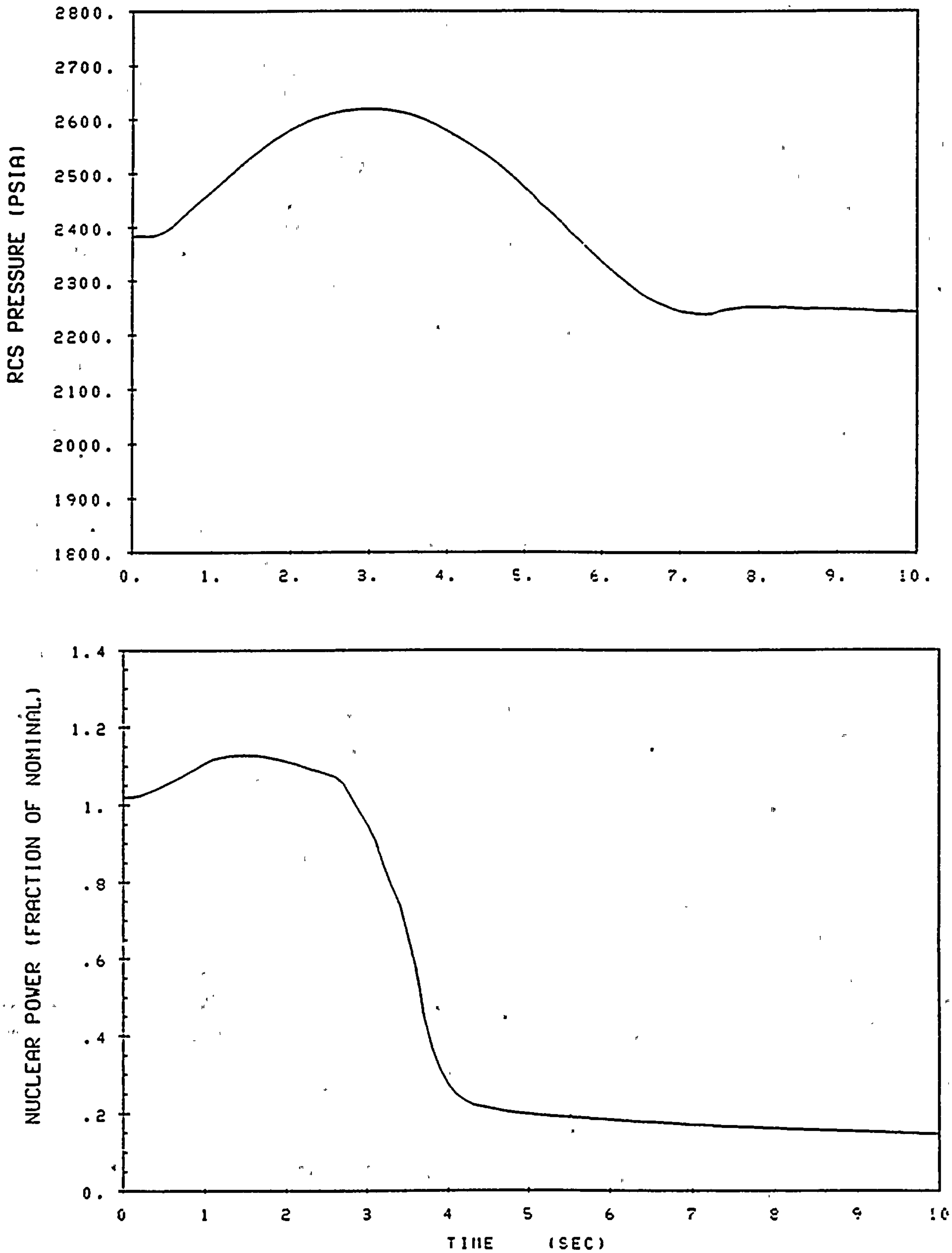


Figure B.3-23 1/4 Locked Rotor
Reactor Pressure and Nuclear Power Versus Time

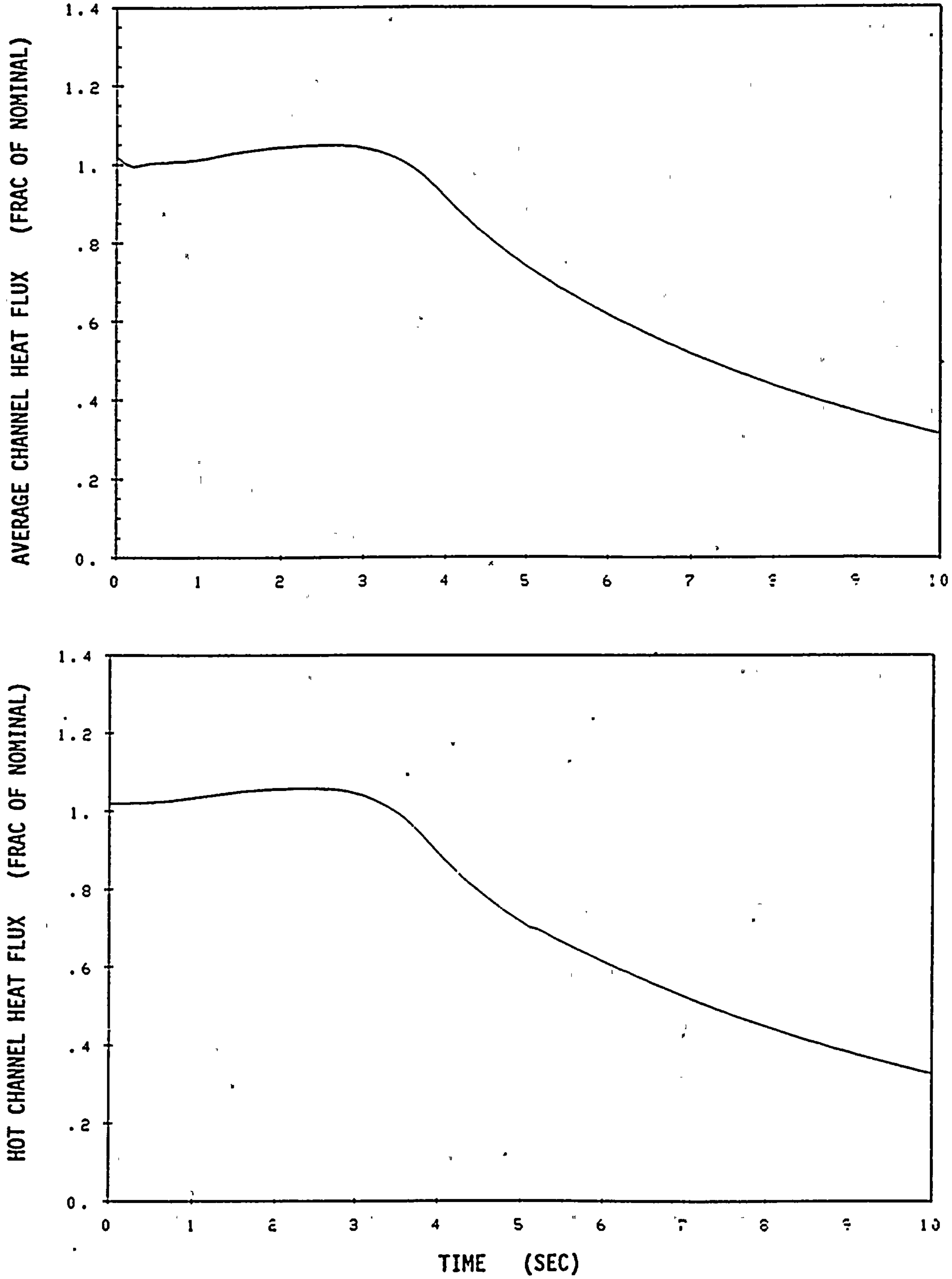


Figure B.3-24 1/4 Locked Rotor
Average Channel and Hot Channel Heat Flux Versus Time

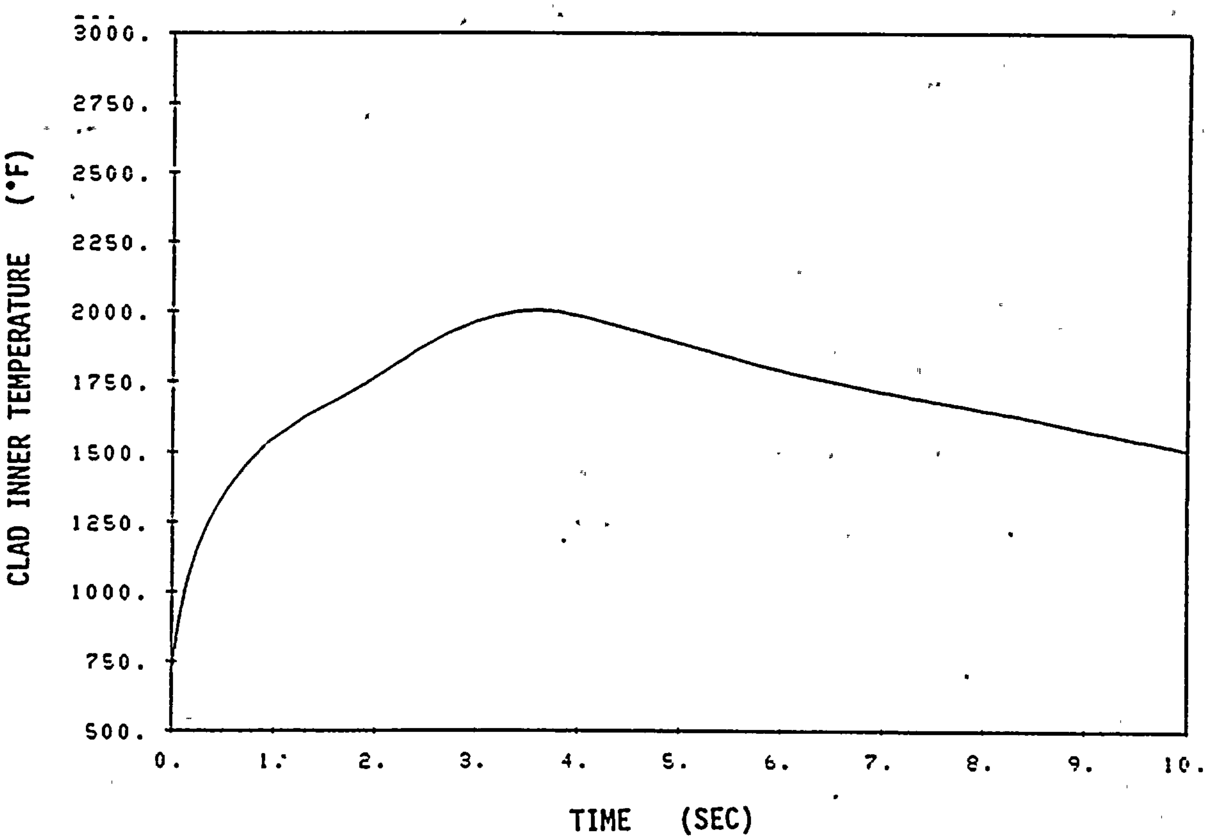
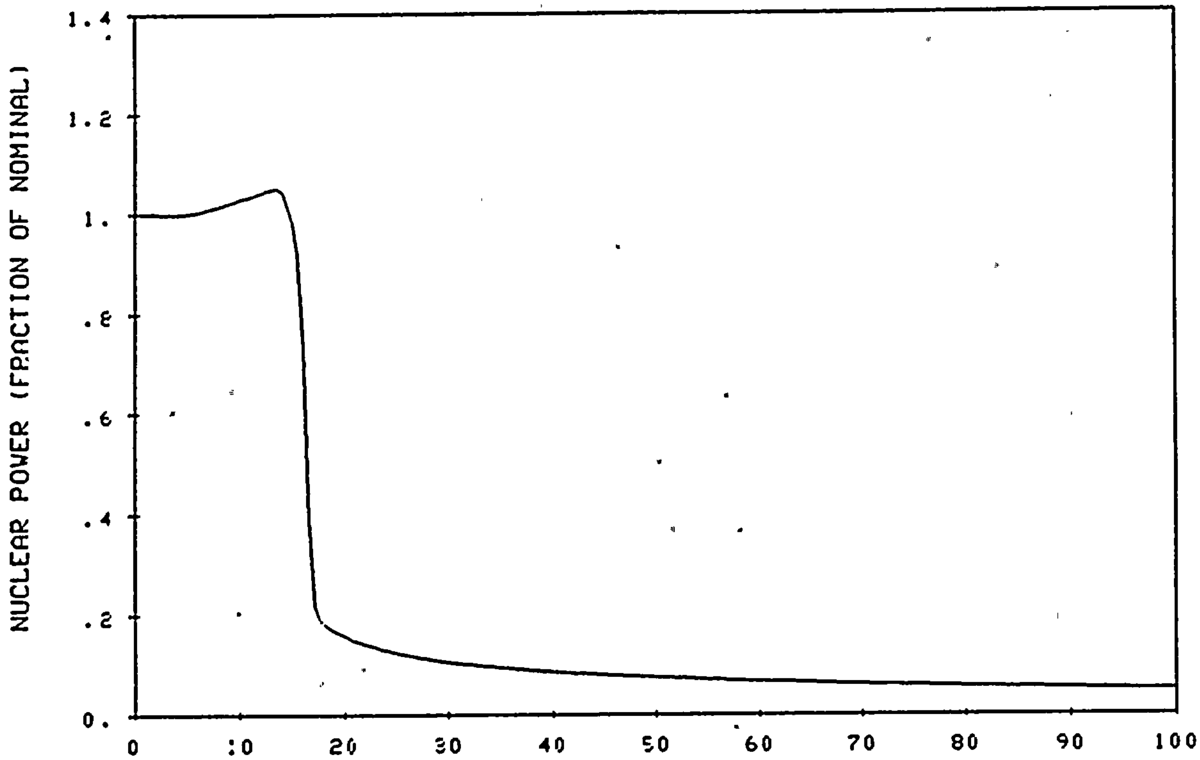


Figure B.3-25 1/4 Locked Rotor
Clad Inner Temperature Versus Time



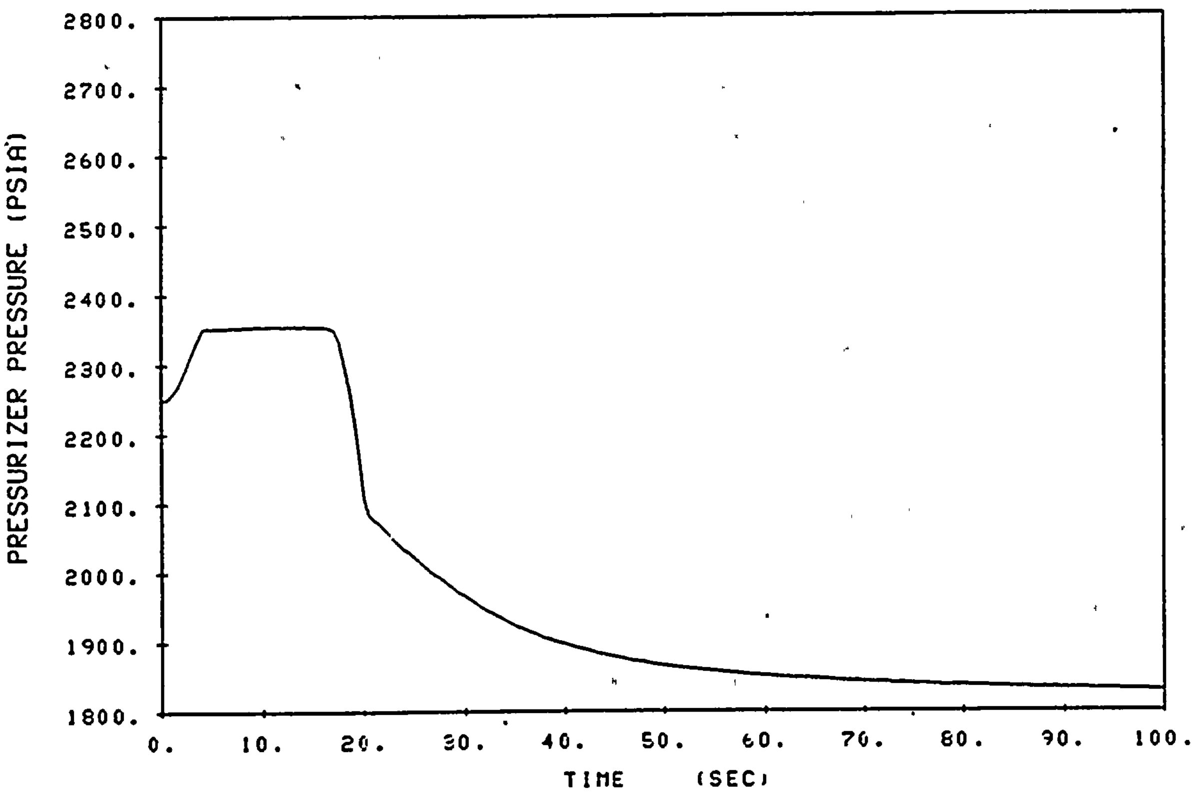
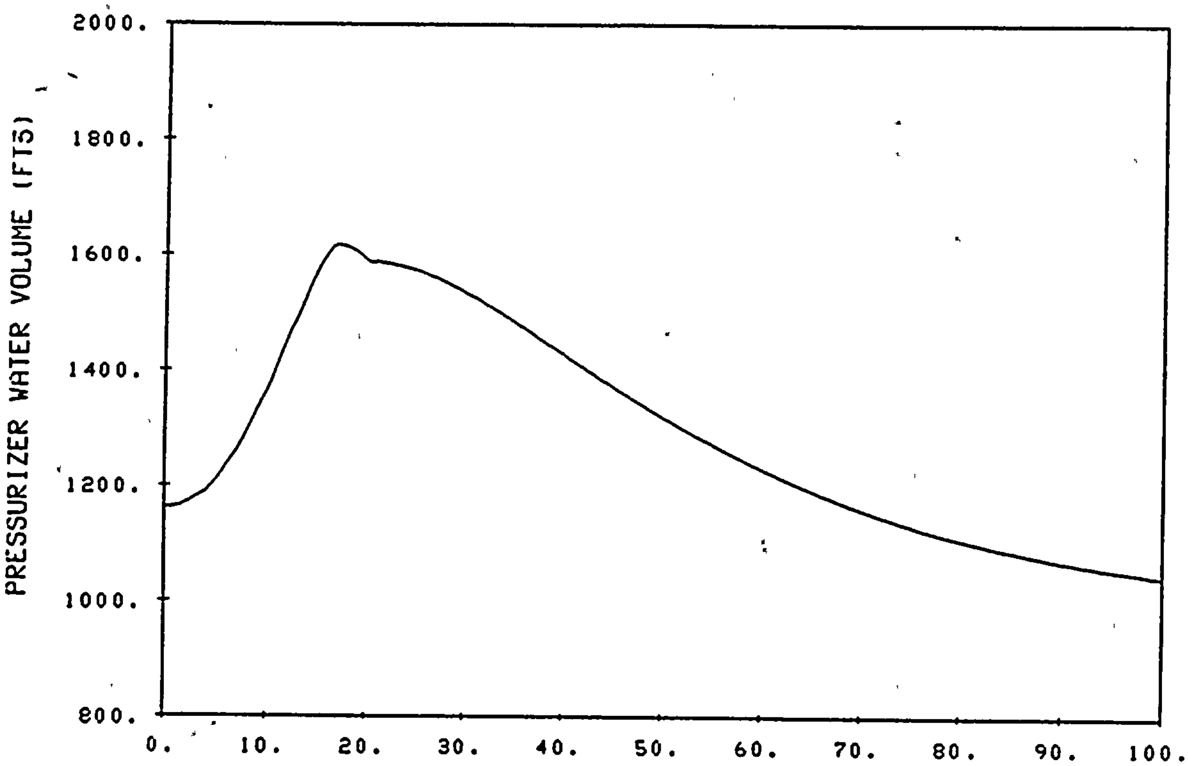


Figure B.3-26A Loss of Load
Nuclear Power and Pressurizer Pressure Versus Time for Minimum Reactivity Feedback with Pressurizer Spray and PORVs



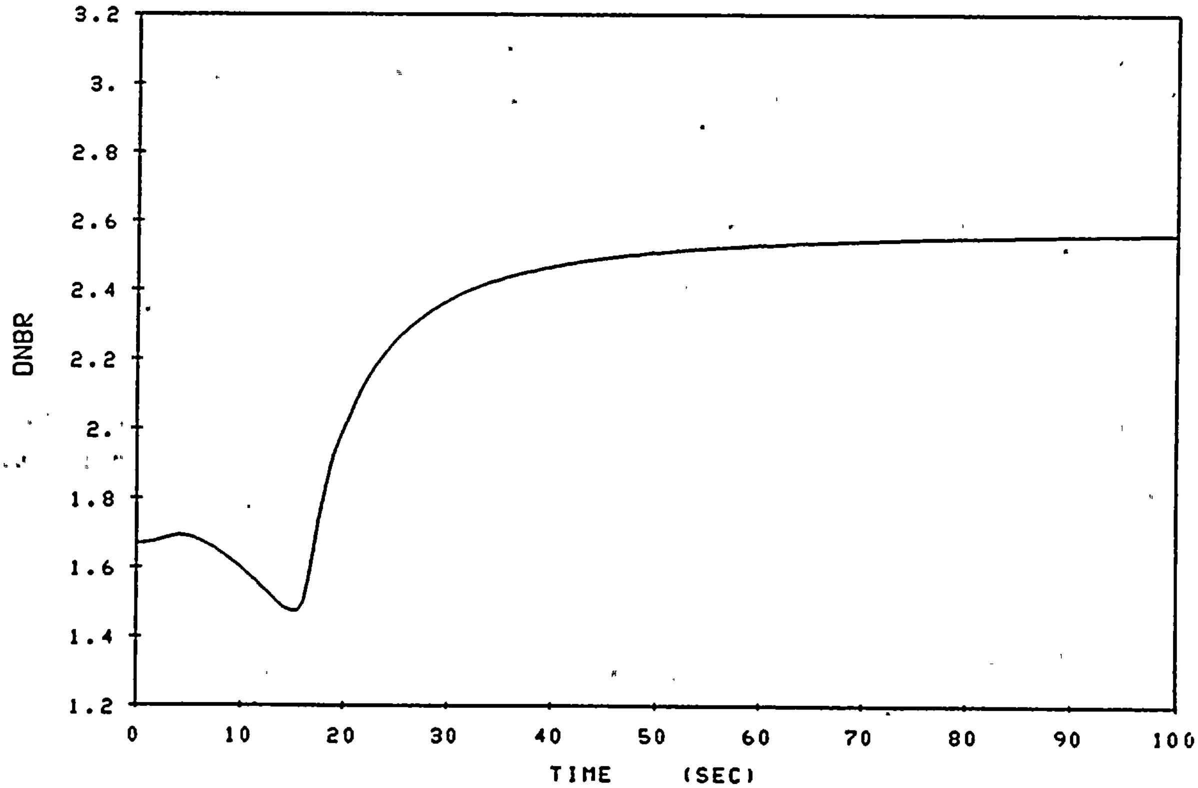


Figure B.3-27A Loss of Load
Pressurizer Water Volume and DNBR Versus Time for Minimum Reactivity with Pressurizer Spray and PORVs

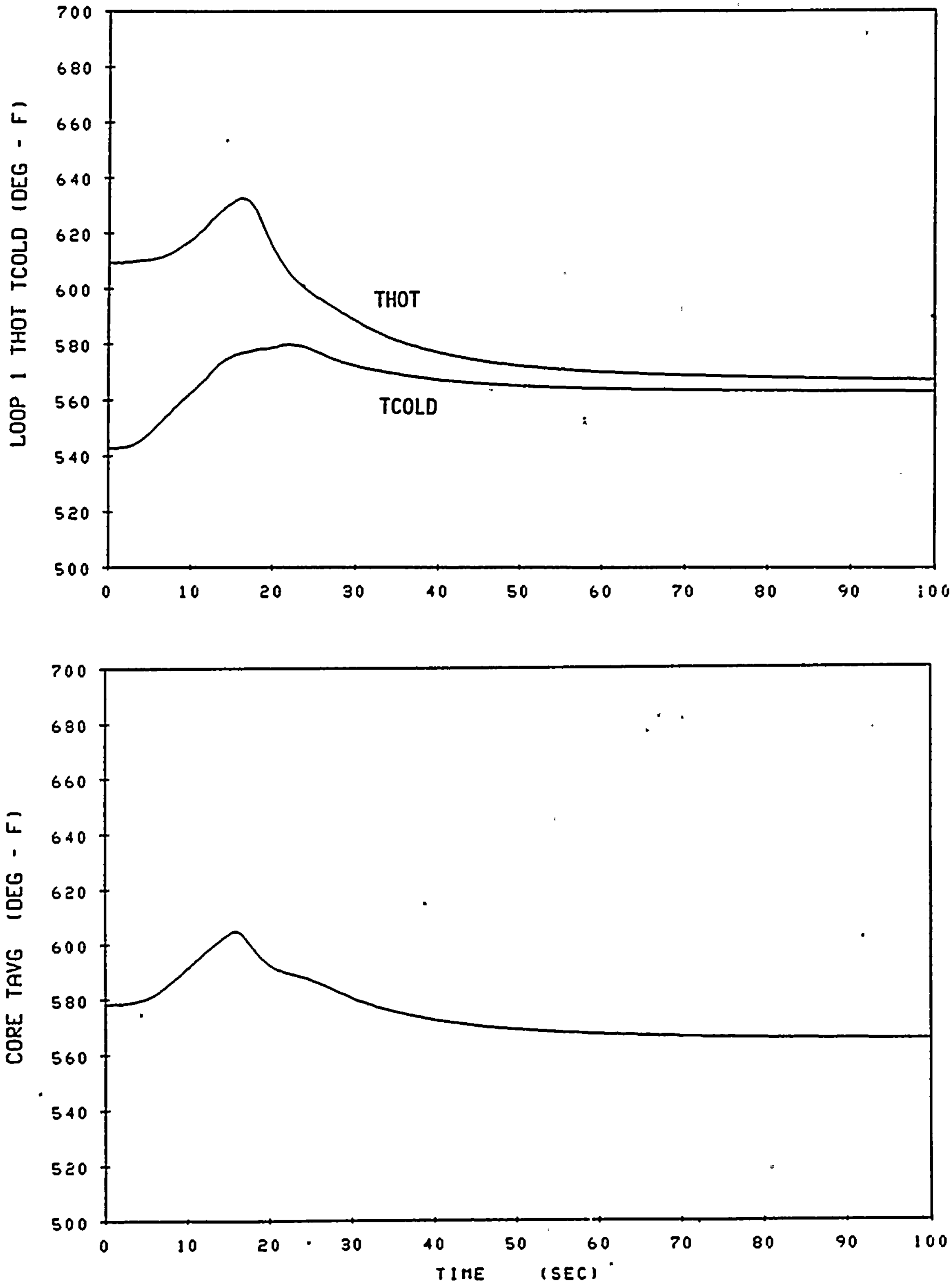


Figure B.3-28A Loss of Load
Loop and Core Average Temperatures Versus Time for Minimum Reactivity with Pressurizer Spray and PORVs

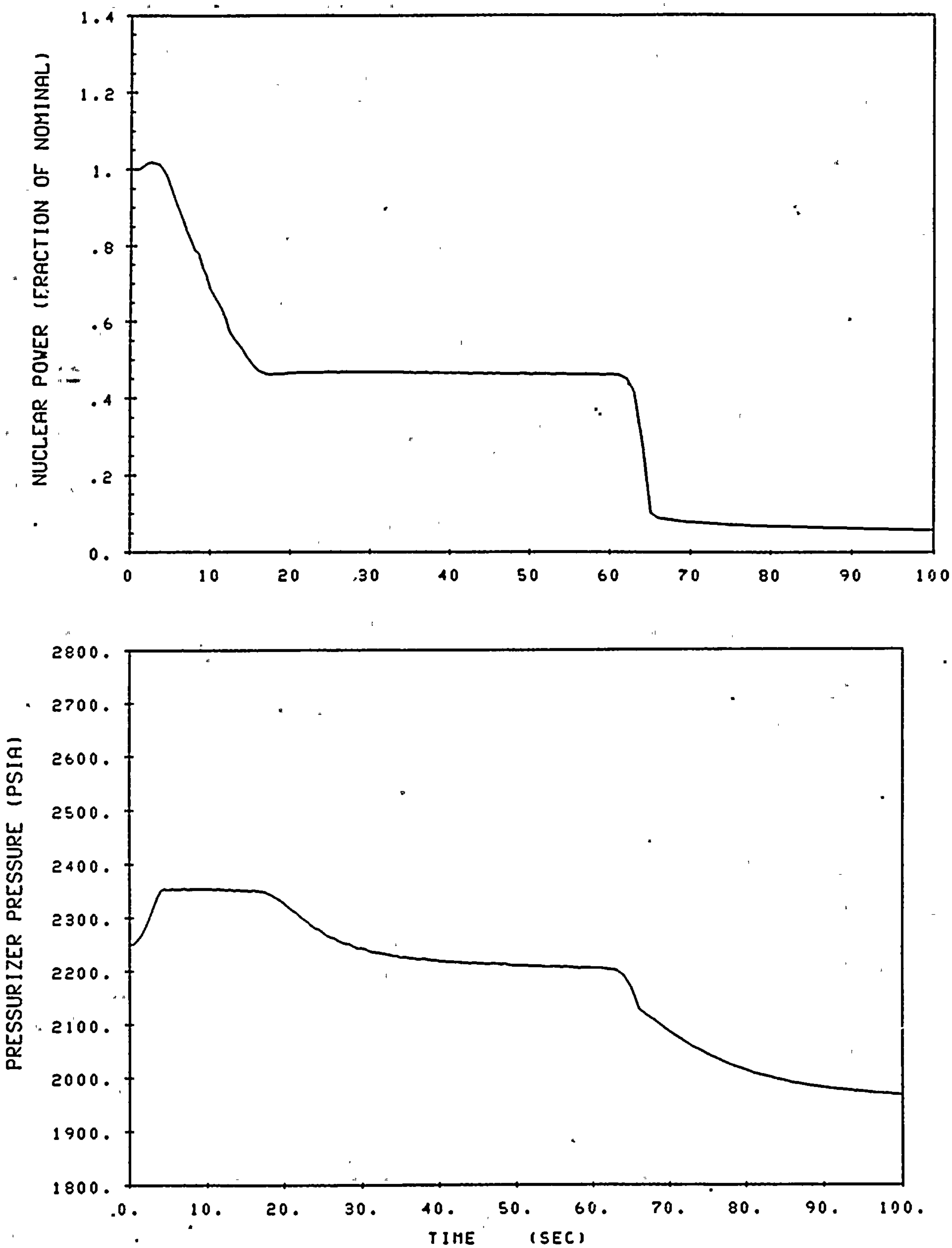


Figure B.3-29A Loss of Load
Nuclear Power and Pressurizer Pressure Versus Time for
Maximum Reactivity Feedback with Pressurizer Spray and PORVs

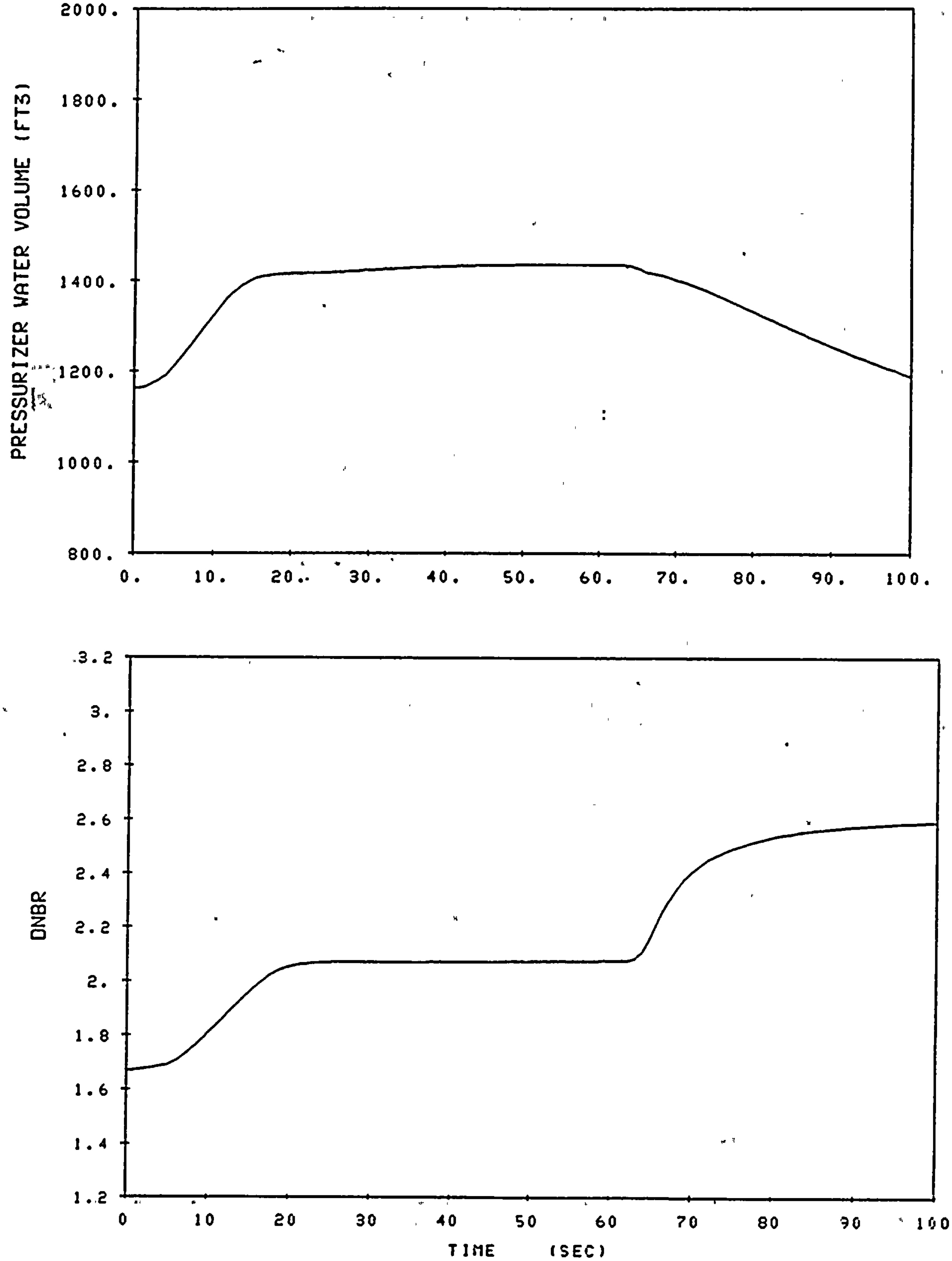


Figure B.3-30A Loss of Load
Pressurizer Water Volume and DNBR Versus Time for Maximum Reactivity Feedback with Pressurizer Spray and PORVs

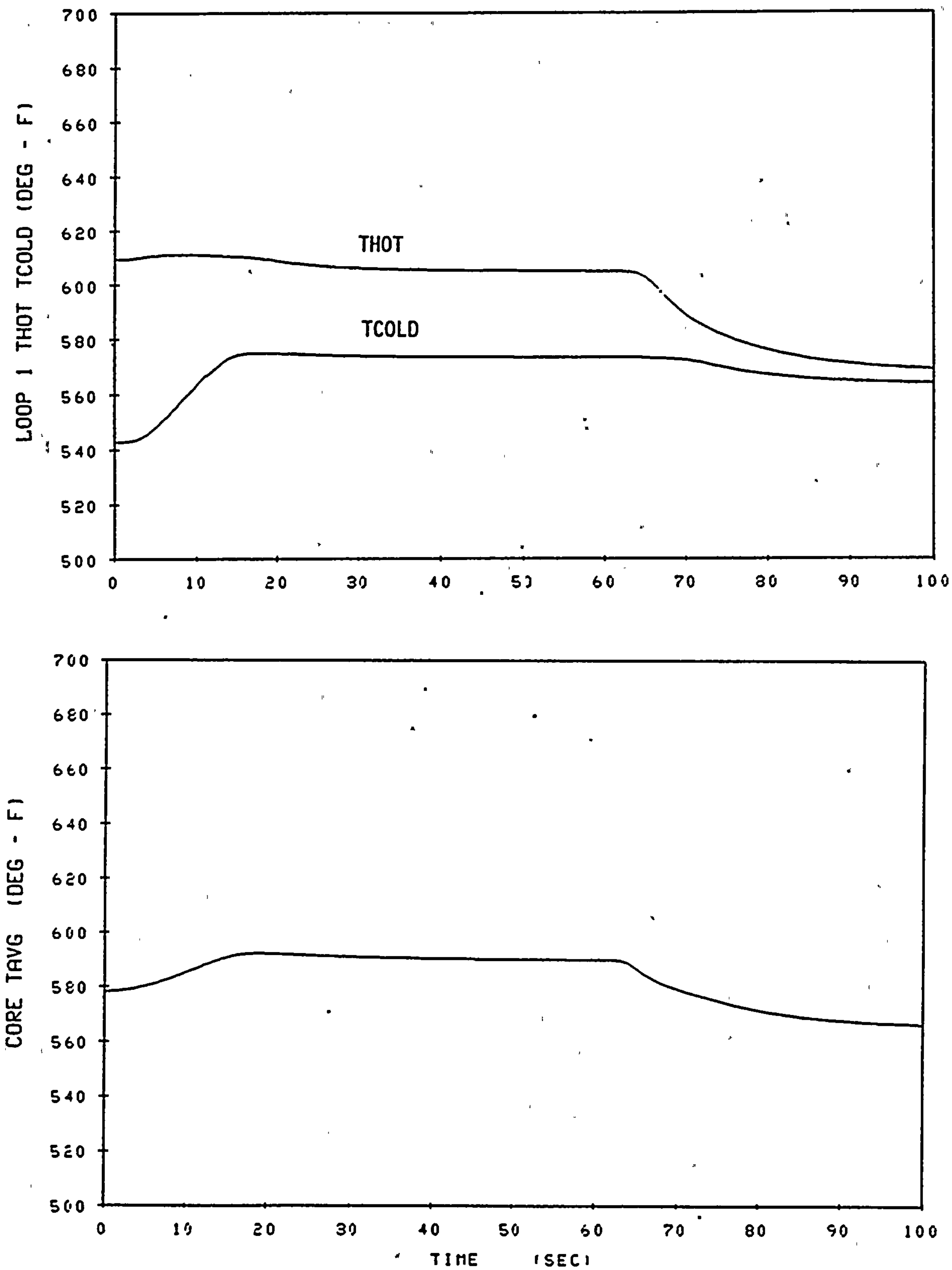
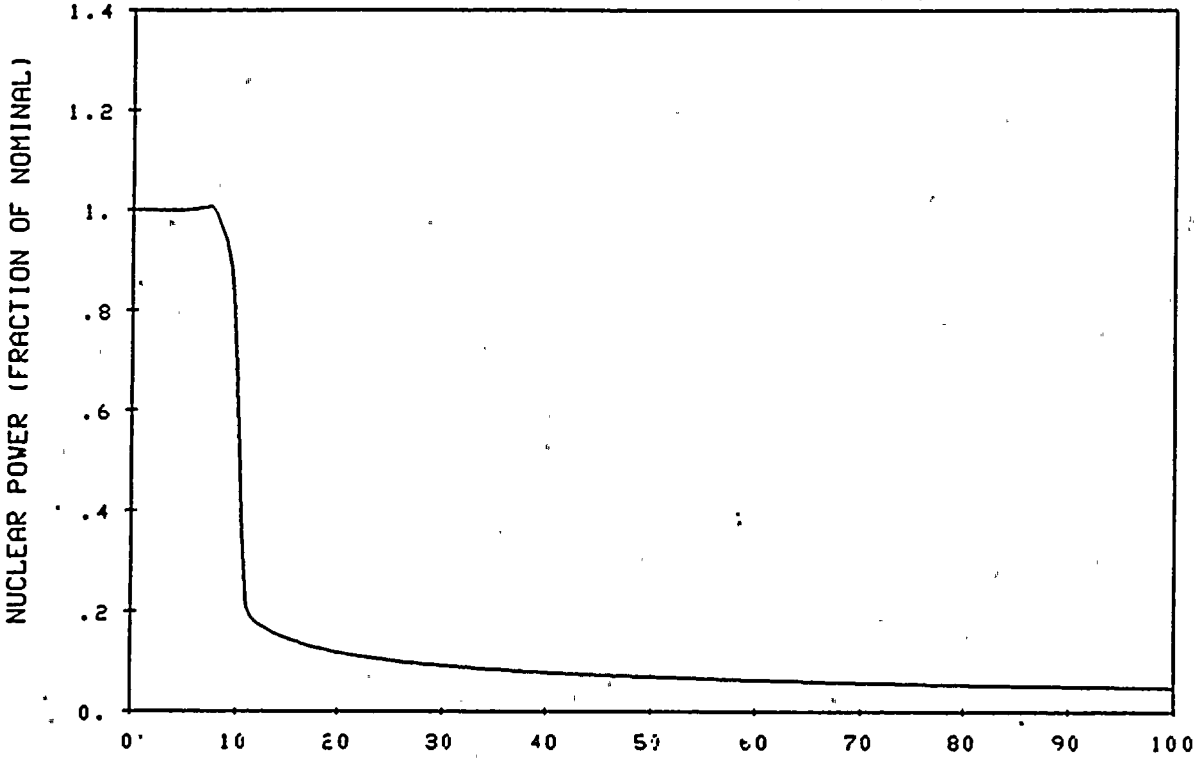


Figure B.3-31A Loss of Load
Loop and Core Average Temperatures Versus Time for Maximum Reactivity Feedback with Pressurizer Spray and PORVs



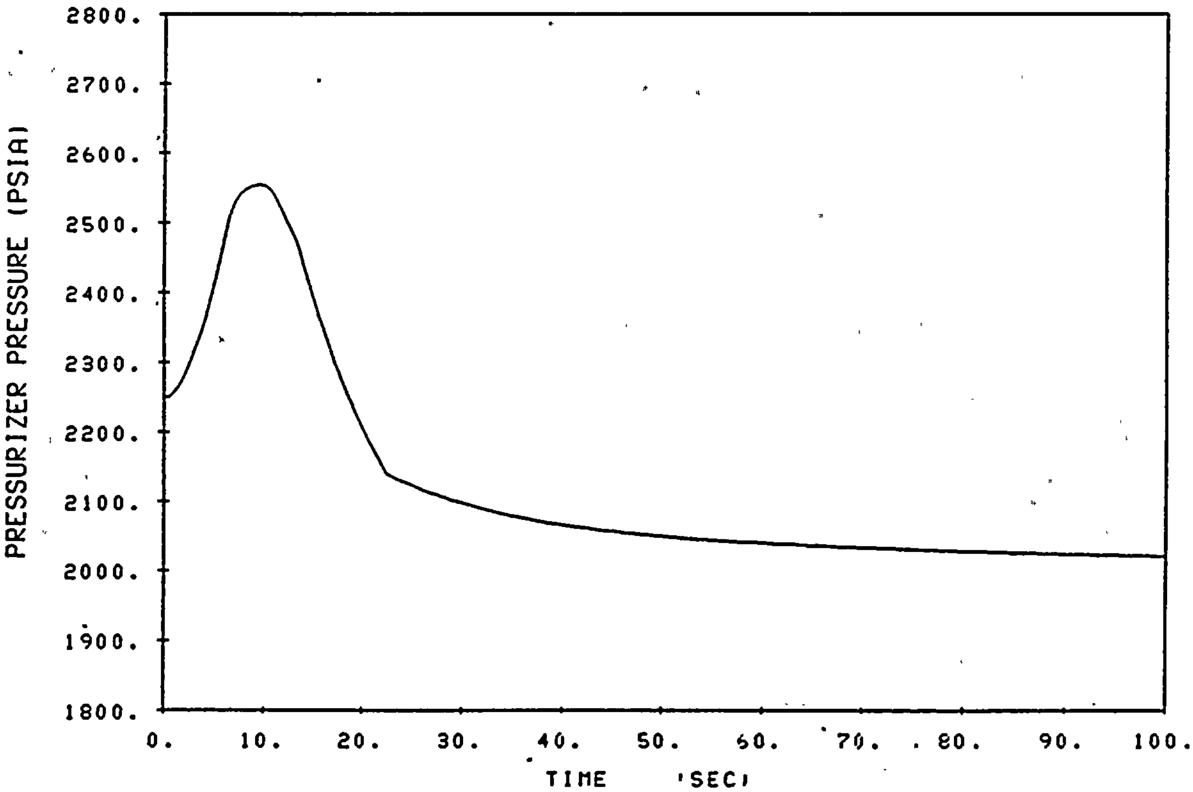


Figure B.3-32A Loss of Load
Nuclear Power and Pressurizer Pressure Versus Time for Minimum Reactivity Feedback Without Pressurizer Spray and PORVs

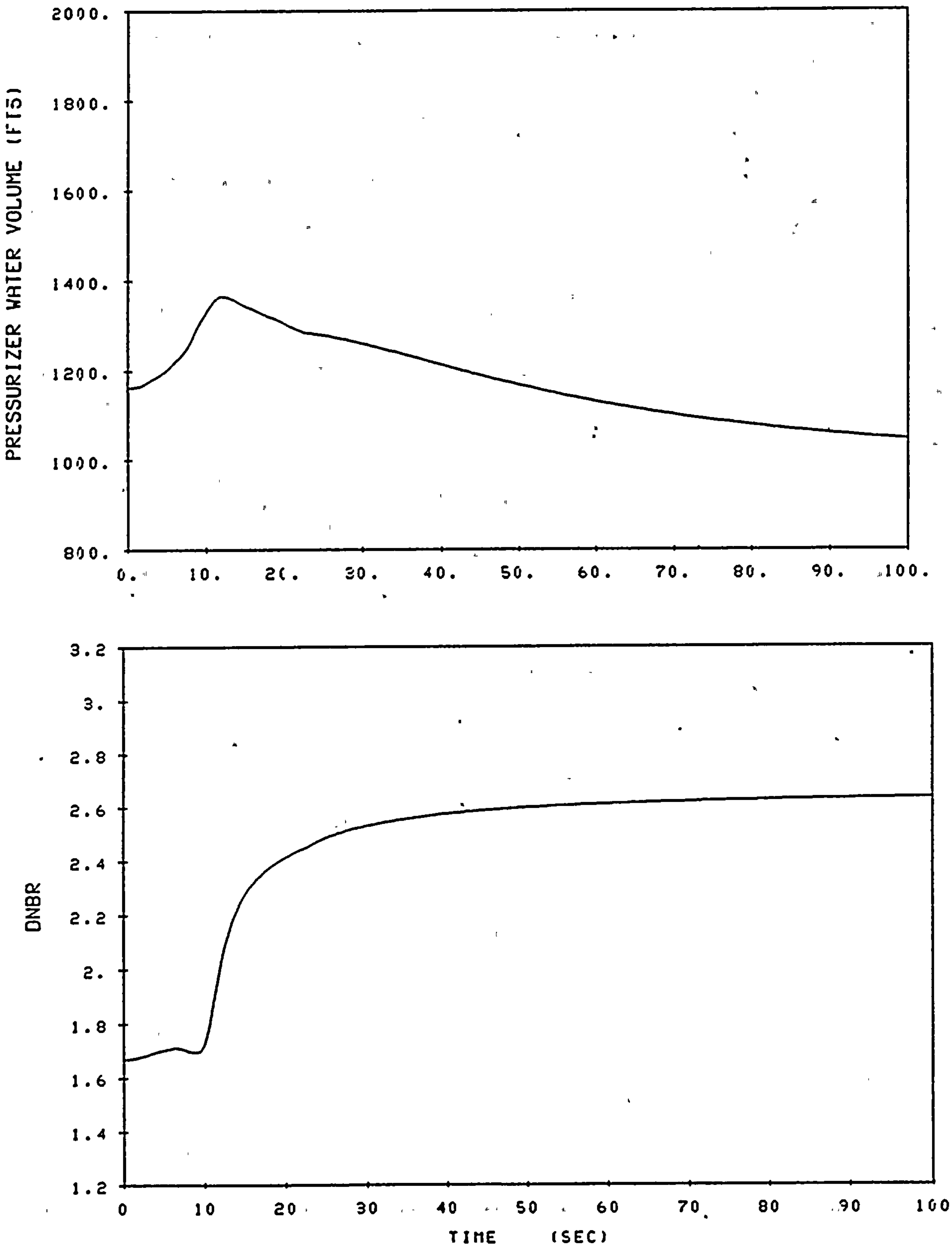


Figure B.3-33A Loss of Load
Pressurizer Water Volume and DNBR Versus Time for Minimum Reactivity Feedback Without Pressurizer Spray and PORVs

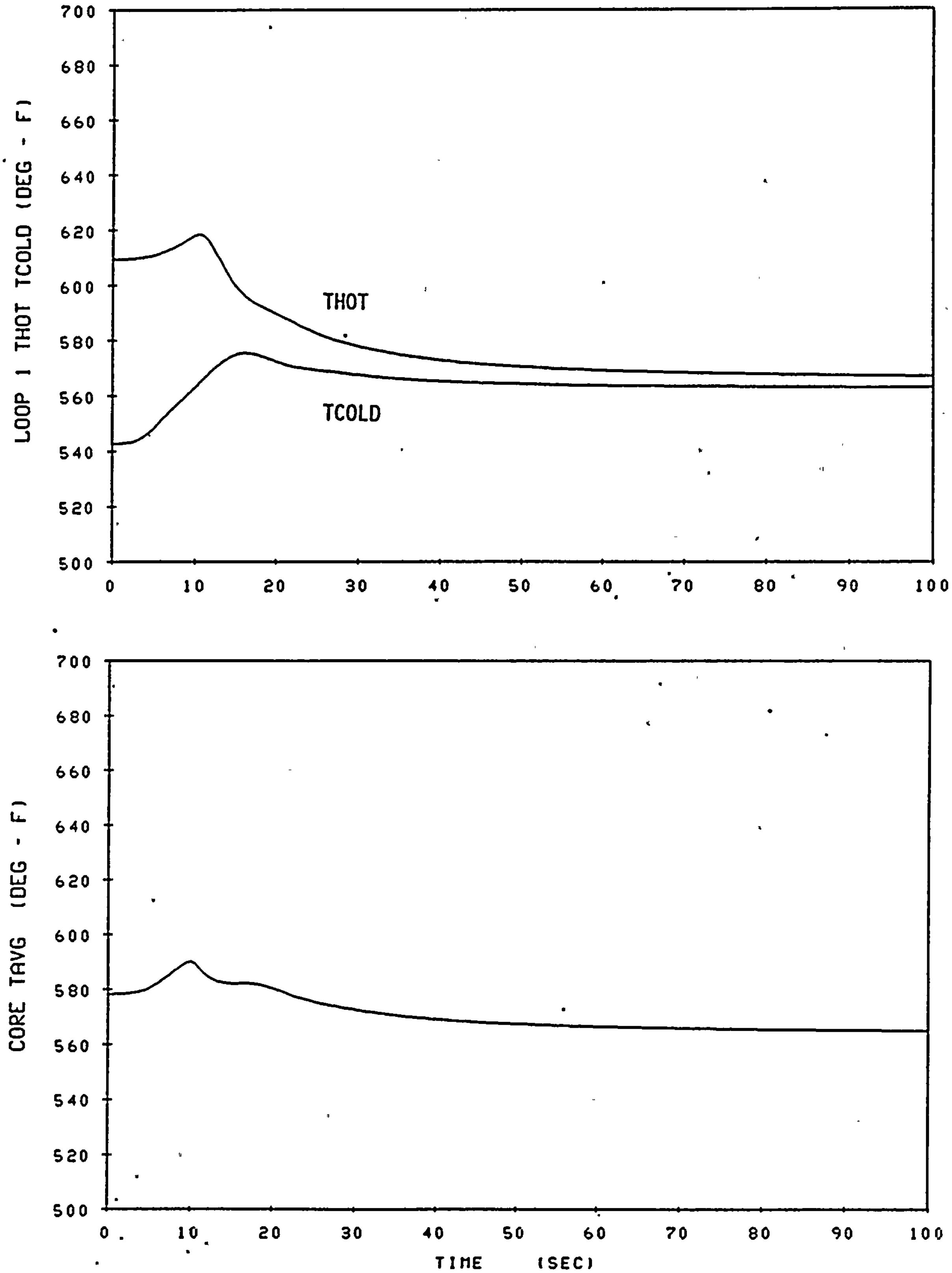


Figure B.3-34A Loss of Load
Loop and Core Average Temperatures Versus Time for Minimum Reactivity Feedback Without Pressurizer Spray and PORVs

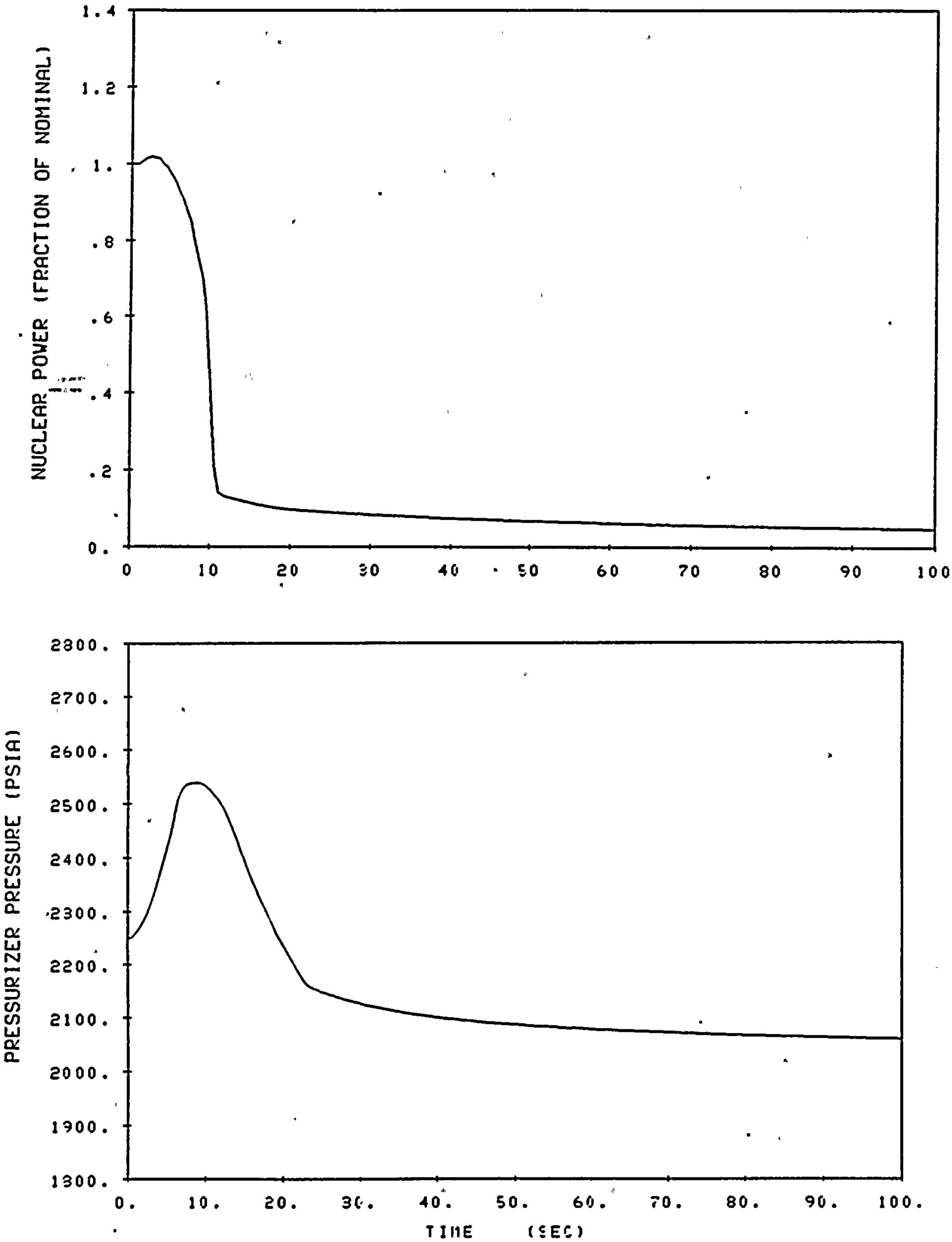


Figure B.3-35A Loss of Load
Nuclear Power and Pressurizer Pressure Versus Time for Maximum Reactivity Feedback without Pressurizer Spray and PORVs

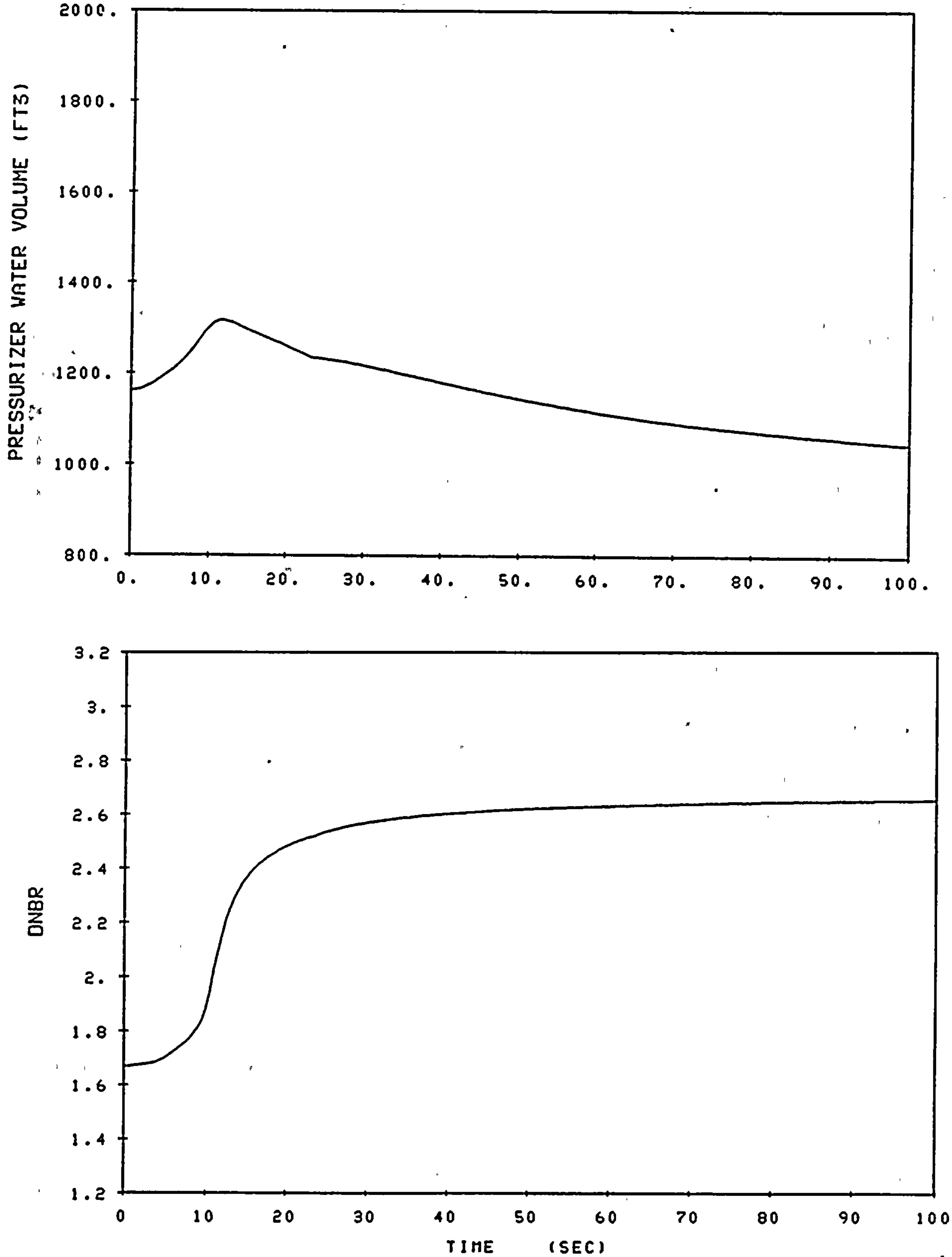
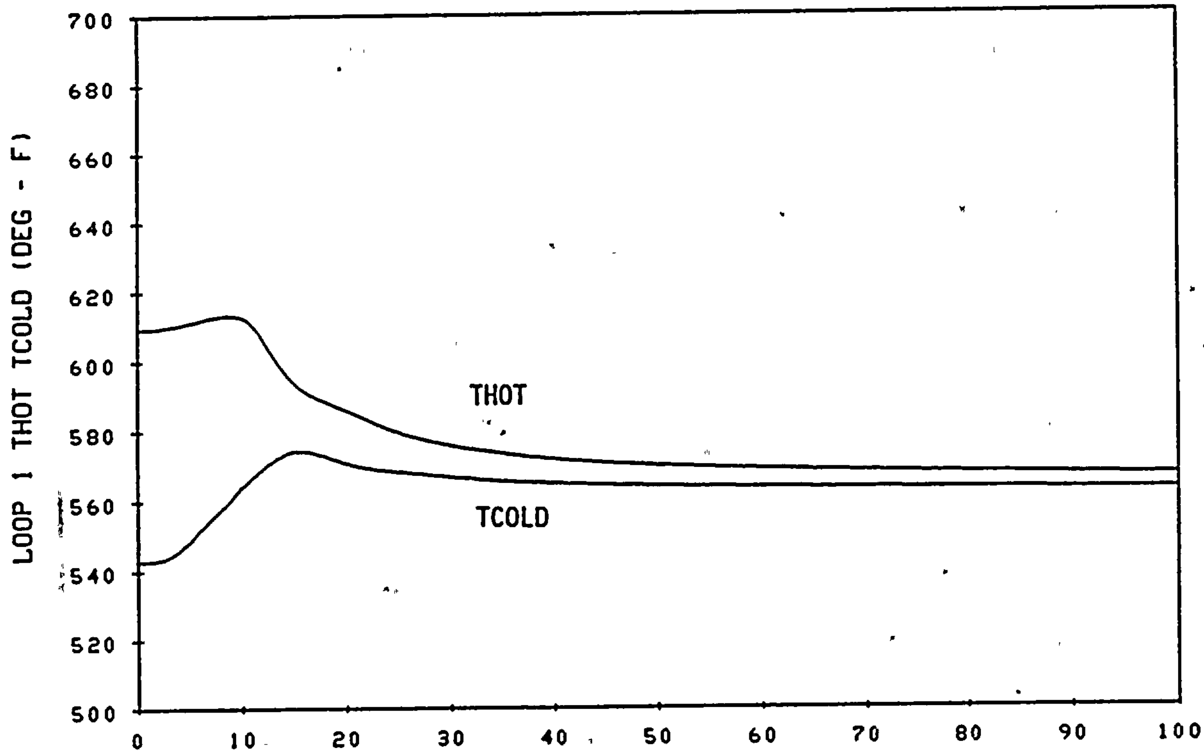


Figure B.3-36A Loss of Load
Pressurizer Water Volume and DNBR Versus Time for Maximum Reactivity Feedback without Pressurizer Spray and PORVs



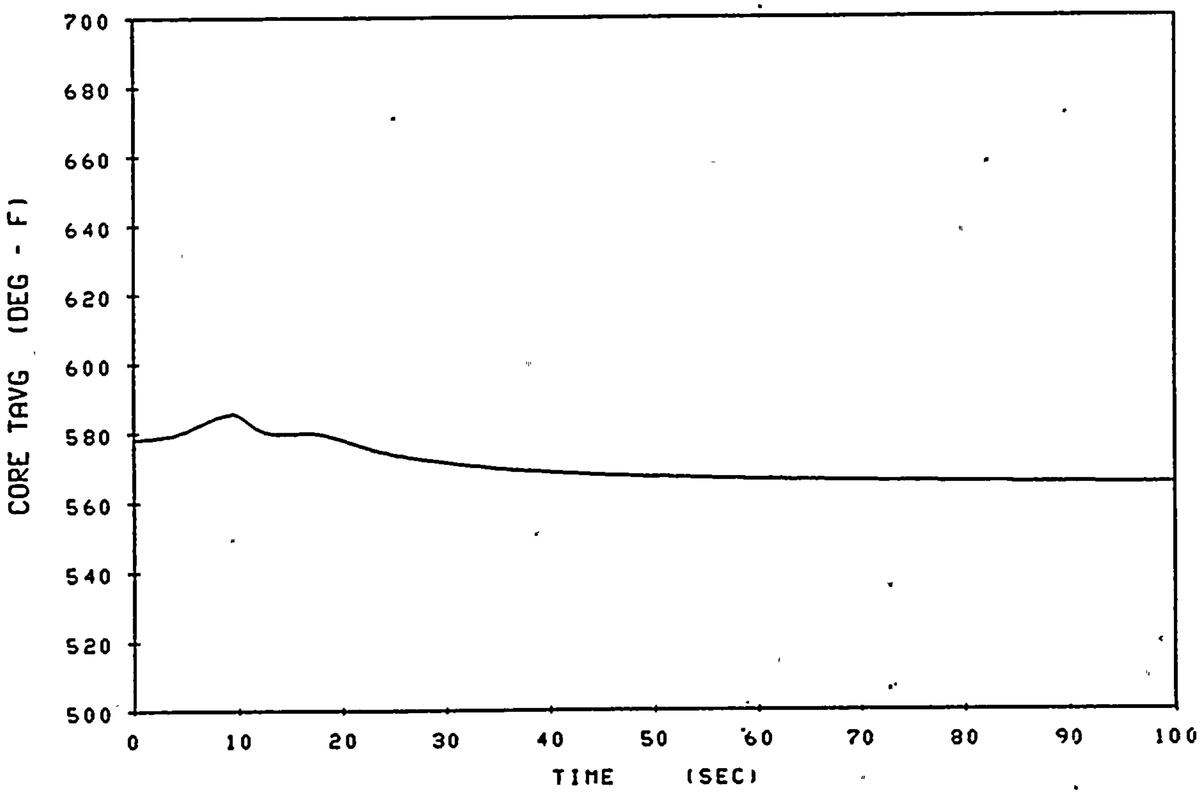


Figure B.3-37A Loss of Load
Loop and Core Average Temperatures Versus Time for Maximum Reactivity Feedwater without Pressurizer Spray and PORVs.

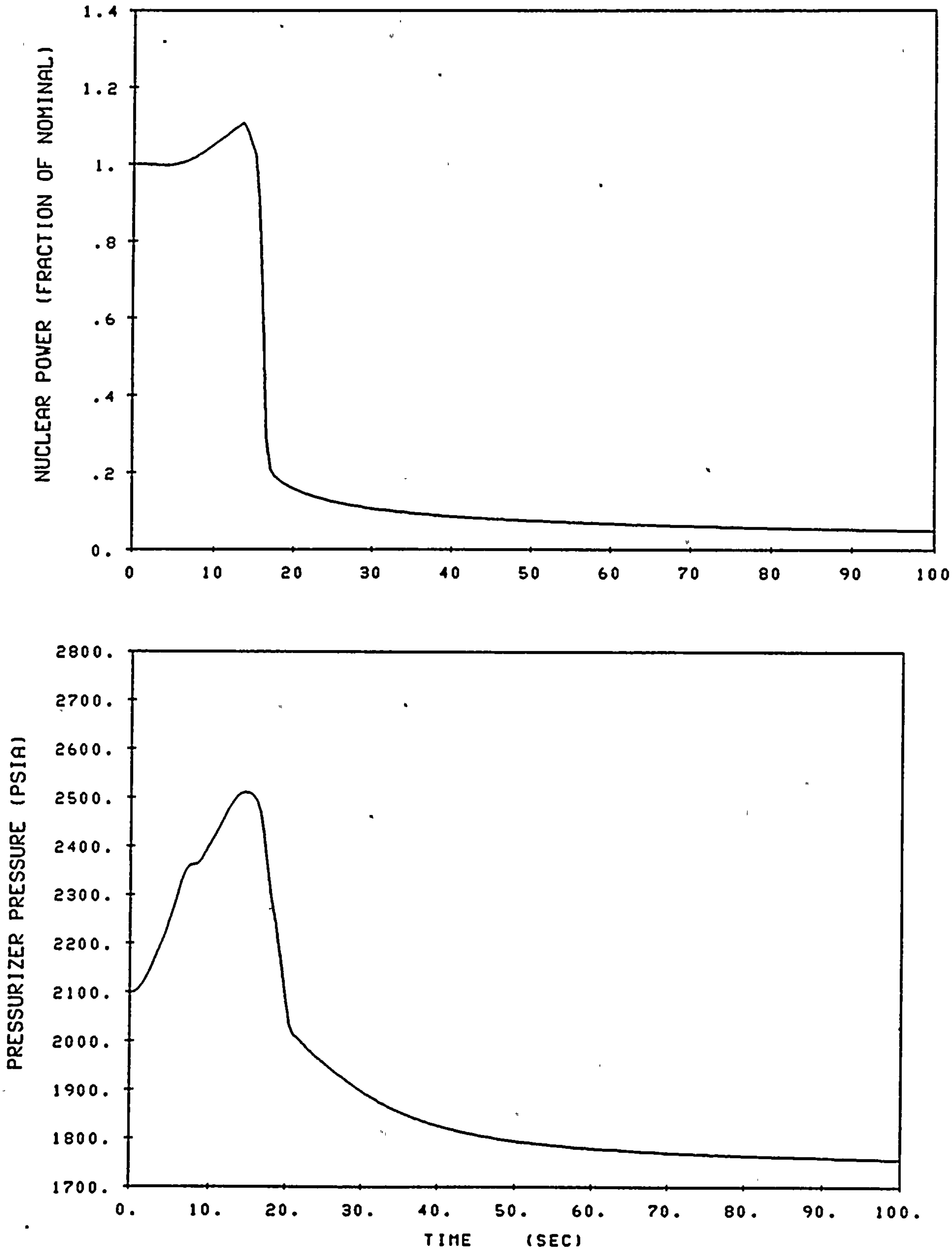


Figure B.3-26B Loss of Load
Nuclear Power and Pressurizer Pressure Versus Time for Minimum Reactivity Feedback with Pressurizer Spray and PORVs

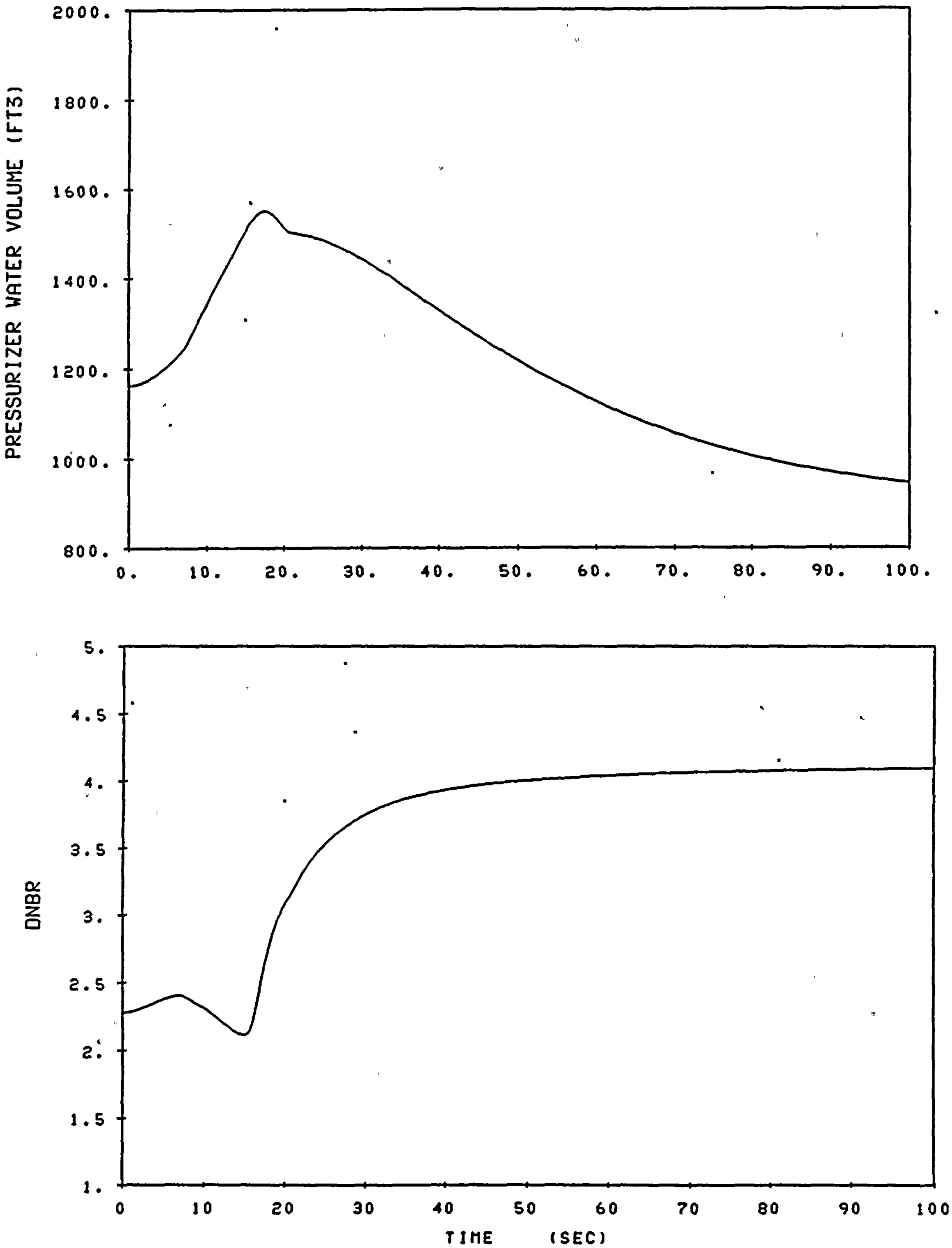


Figure B.3-27B Loss of Load
Pressurizer Water Volume and DNBR Versus Time for Minimum Reactivity with Pressurizer Spray and PORVs

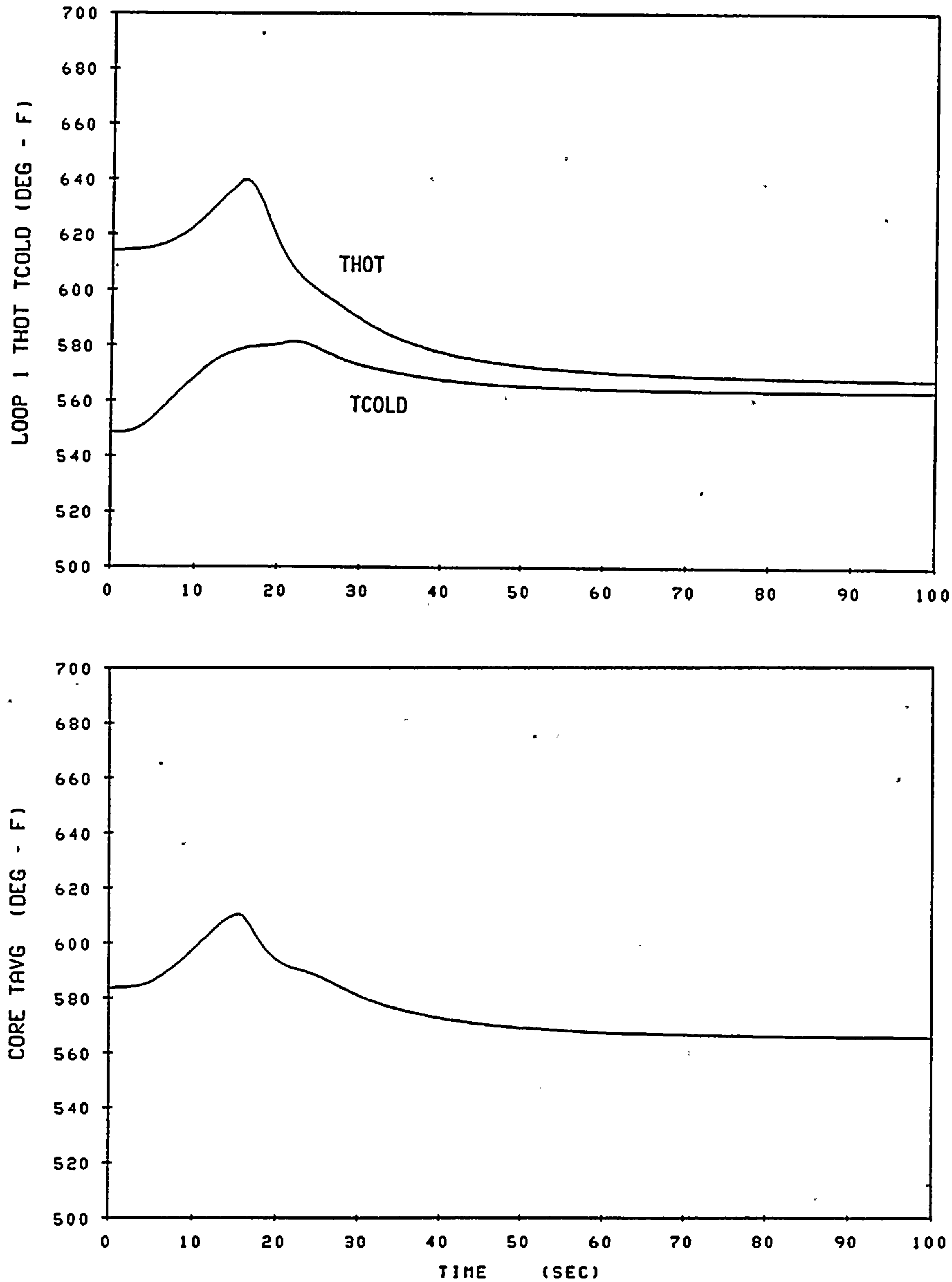


Figure B.3-28B Loss of Load
Loop and Core Average Temperatures Versus Time for Minimum Reactivity with Pressurizer Spray and PORVs

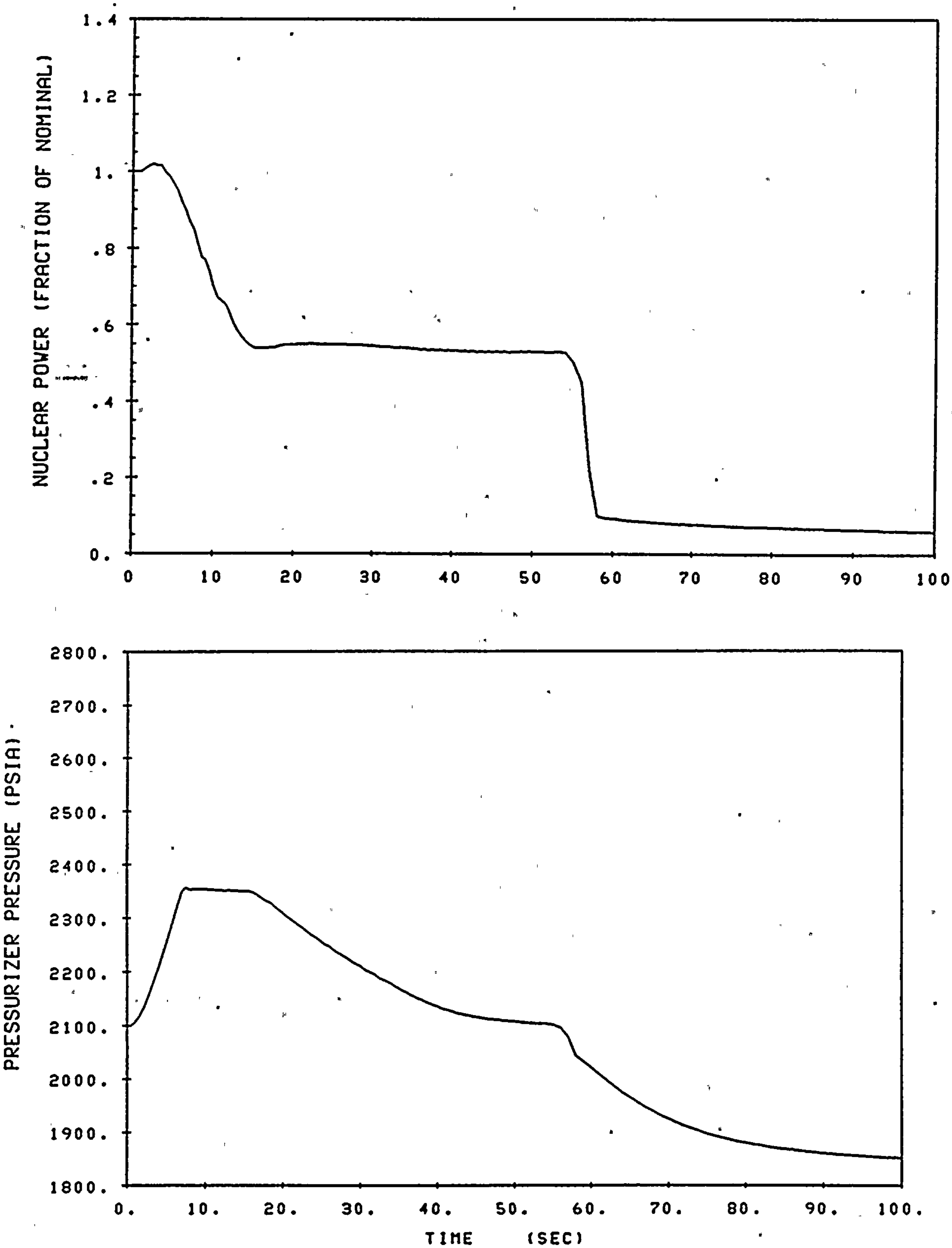


Figure B.3-29B Loss of Load
Nuclear Power and Pressurizer Pressure Versus Time for
Maximum Reactivity Feedback with Pressurizer Spray and PORVs

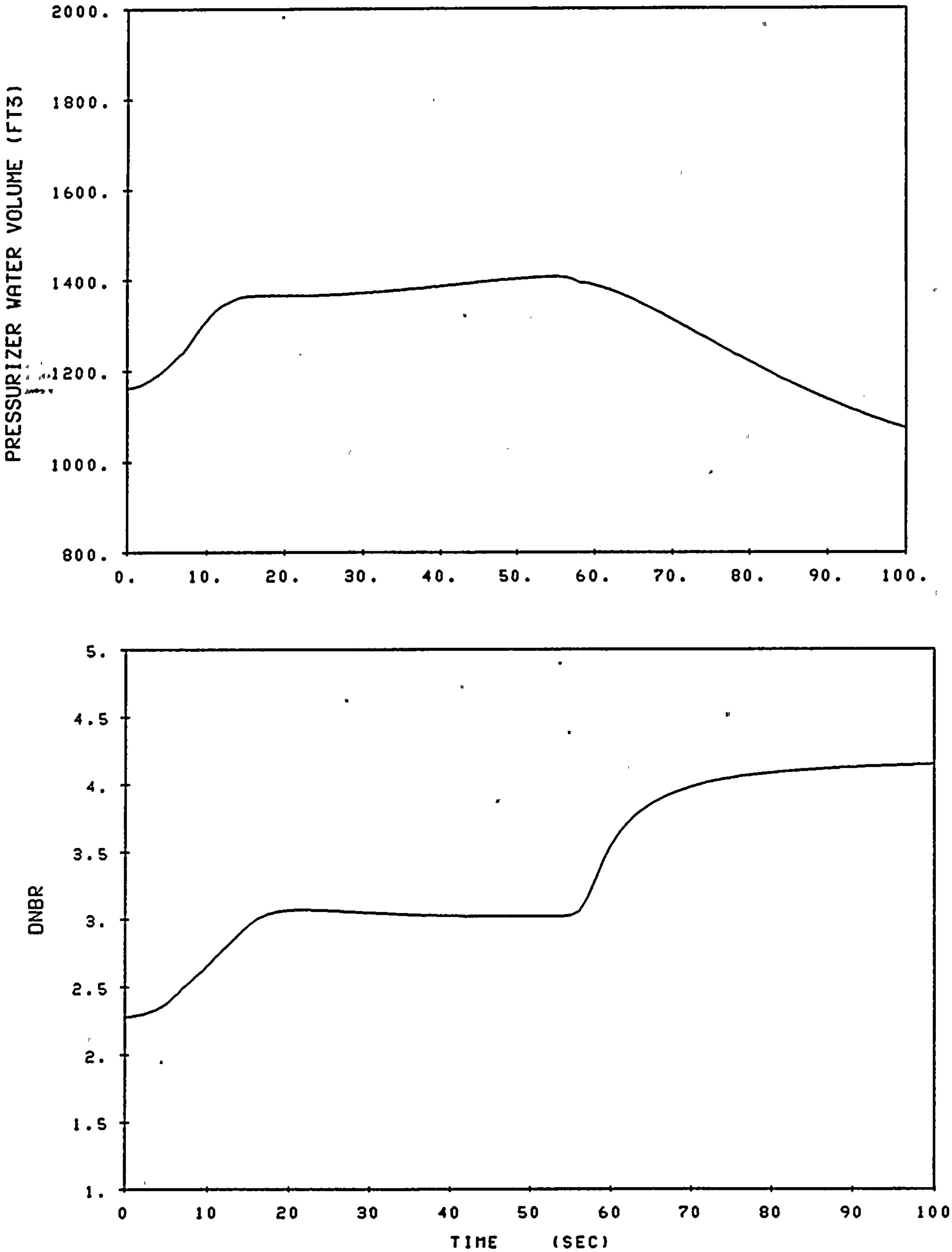


Figure B.3-30B Loss of Load
Pressurizer Water Volume and DNBR Versus Time for Maximum Reactivity Feedback with Pressurizer Spray and PORVs

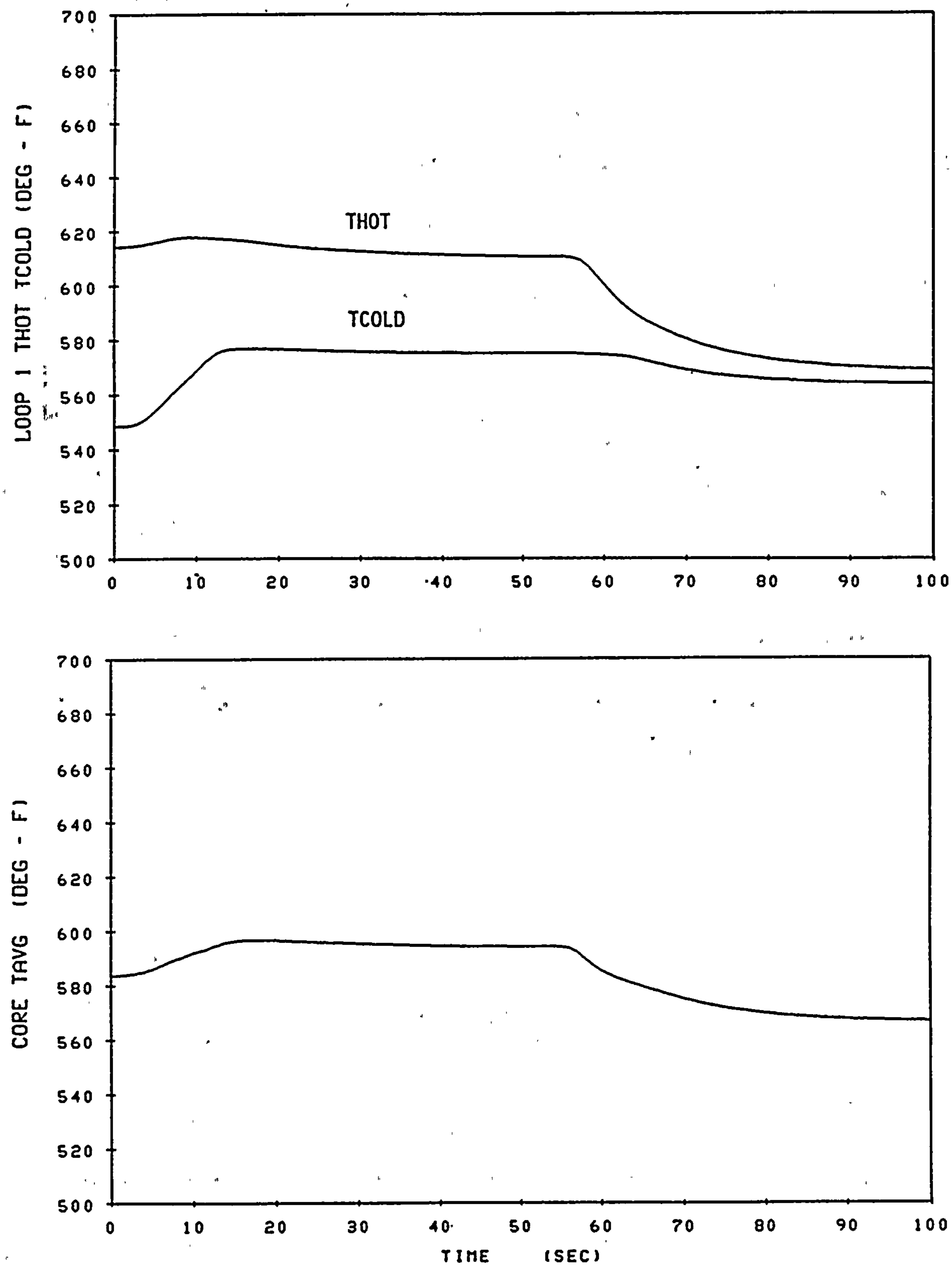
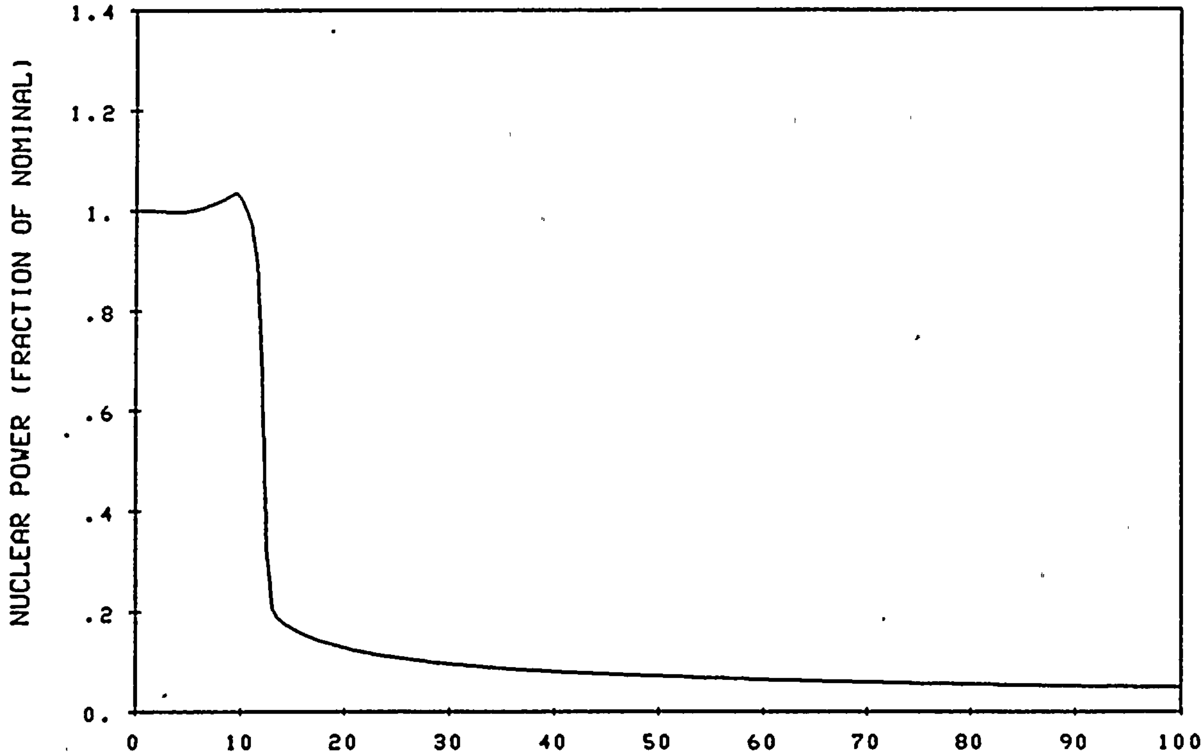


Figure B.3-31B Loss of Load
Loop and Core Average Temperatures Versus Time for Maximum Reactivity Feedback with Pressurizer Spray and PORVs



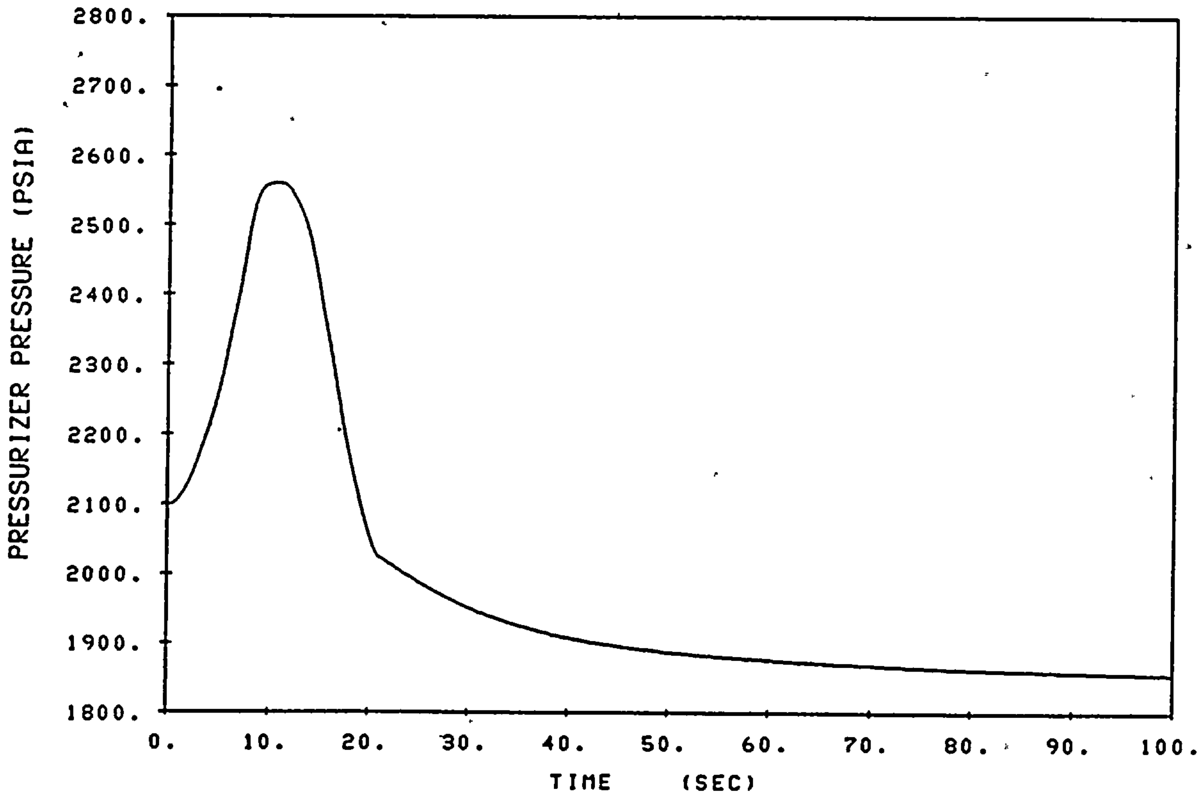


Figure B.3-32B Loss of Load
Nuclear Power and Pressurizer Pressure Versus Time for Minimum Reactivity Feedback Without Pressurizer Spray and PORVs

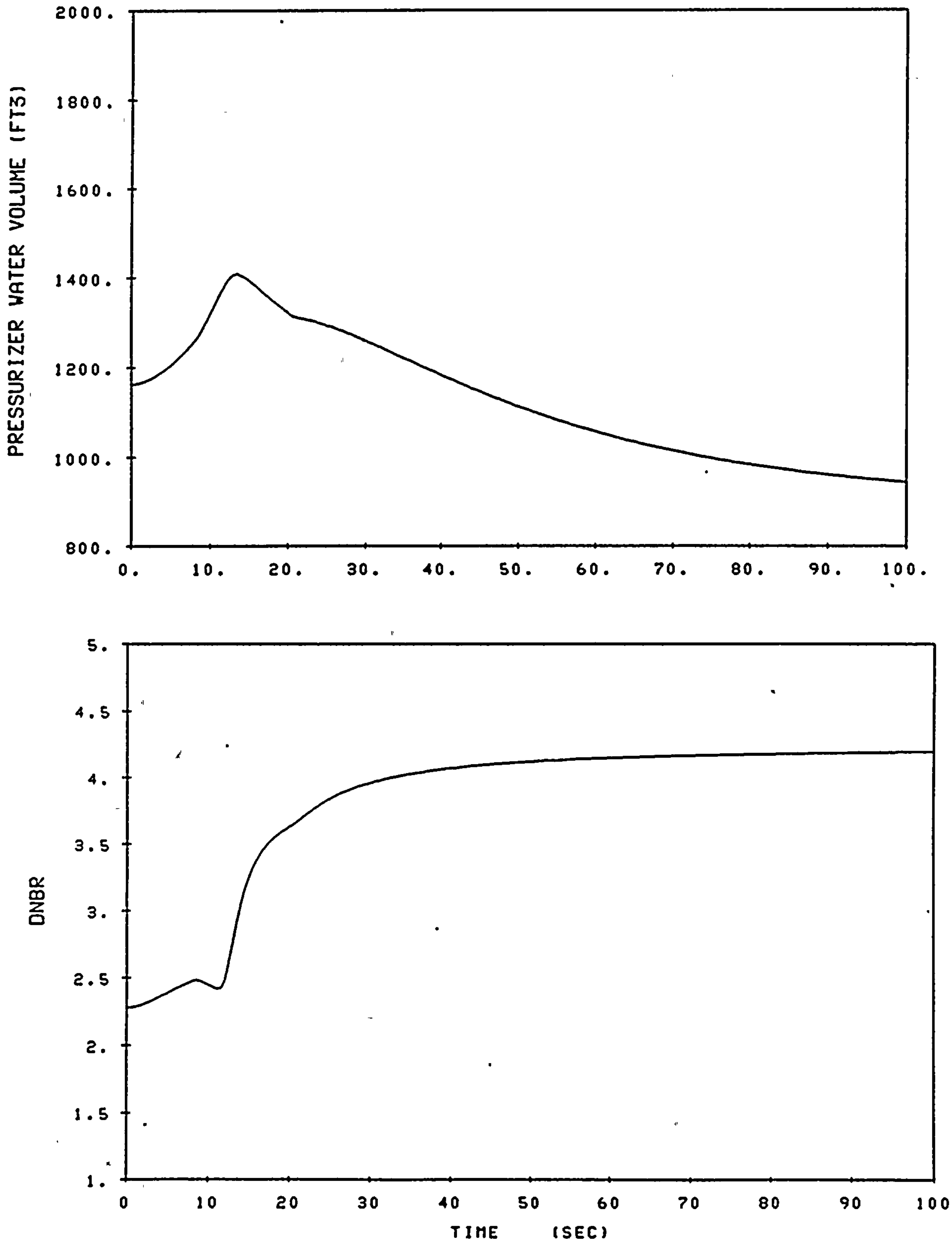


Figure B.3-33B Loss of Load
Pressurizer Water Volume and DNBR Versus Time for Minimum Reactivity Feedback Without Pressurizer Spray and PORVs

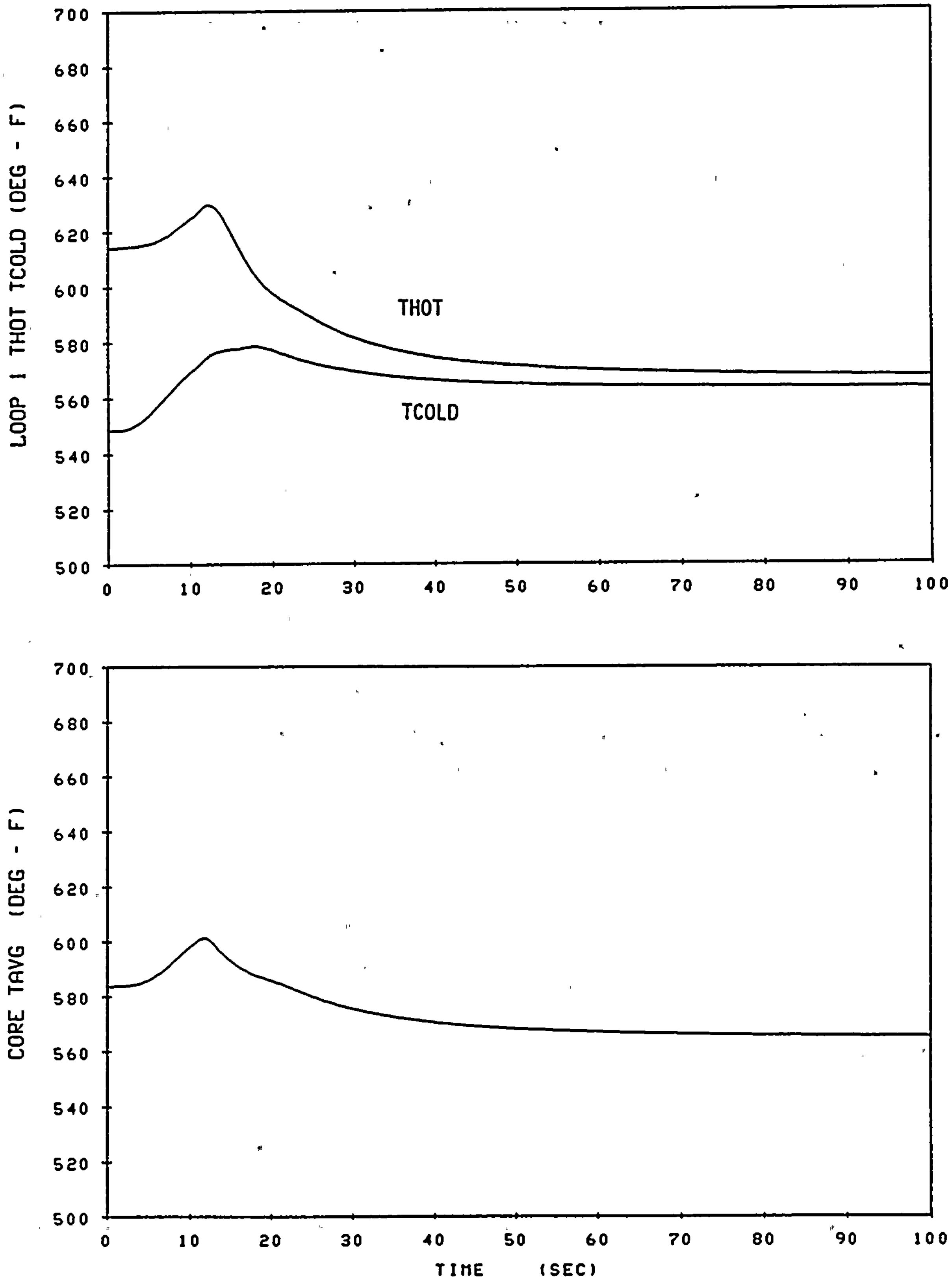


Figure B.3-34B Loss of Load
Loop and Core Average Temperatures Versus Time for Minimum Reactivity Feedback Without Pressurizer Spray and PORVs

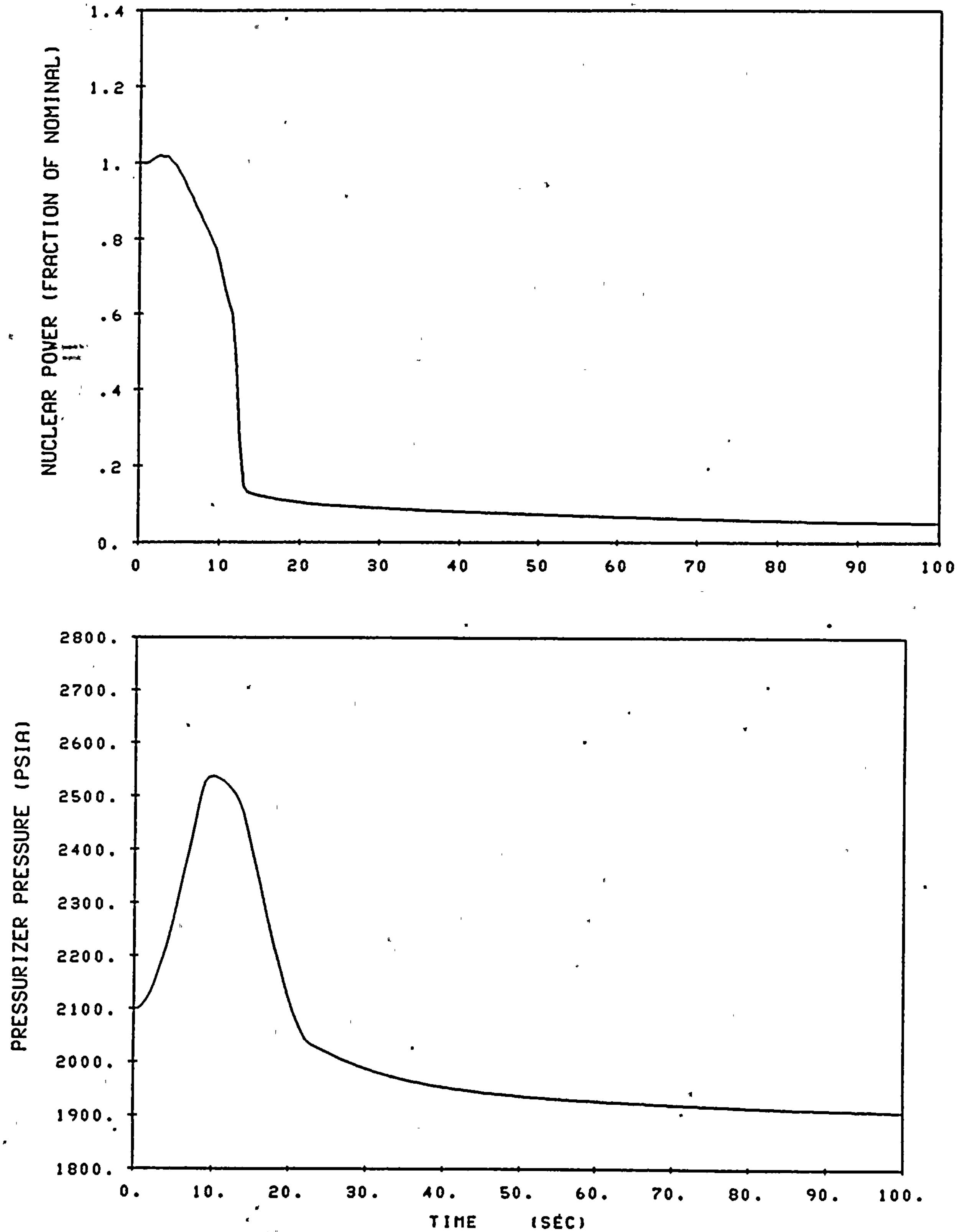


Figure B.3-35B Loss of Load
Nuclear Power and Pressurizer Pressure Versus Time for Maximum Reactivity Feedback without Pressurizer Spray and PORVs

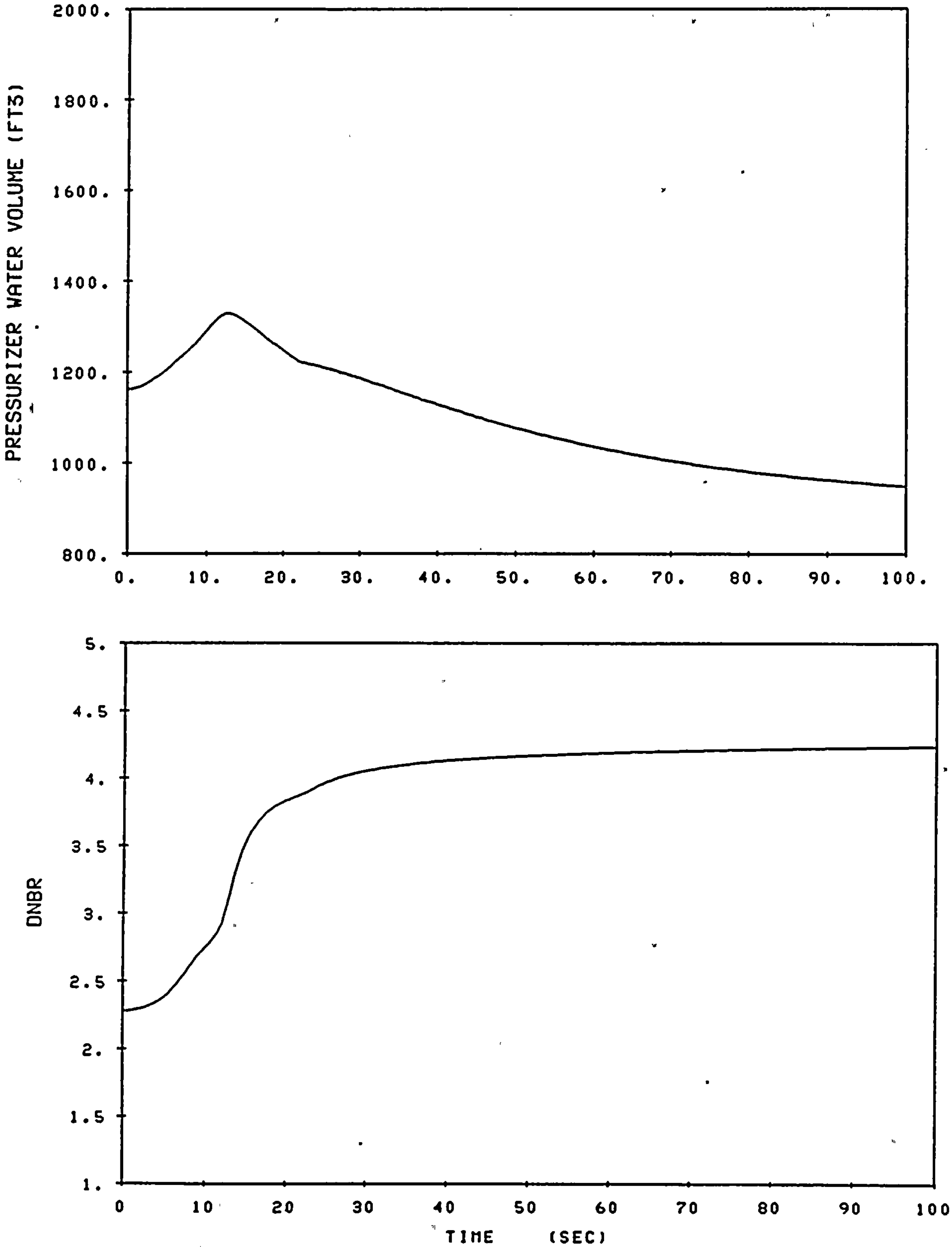


Figure B.3-36B Loss of Load
Pressurizer Water Volume and DNBR Versus Time for Maximum Reactivity Feedback without Pressurizer Spray and PORVs

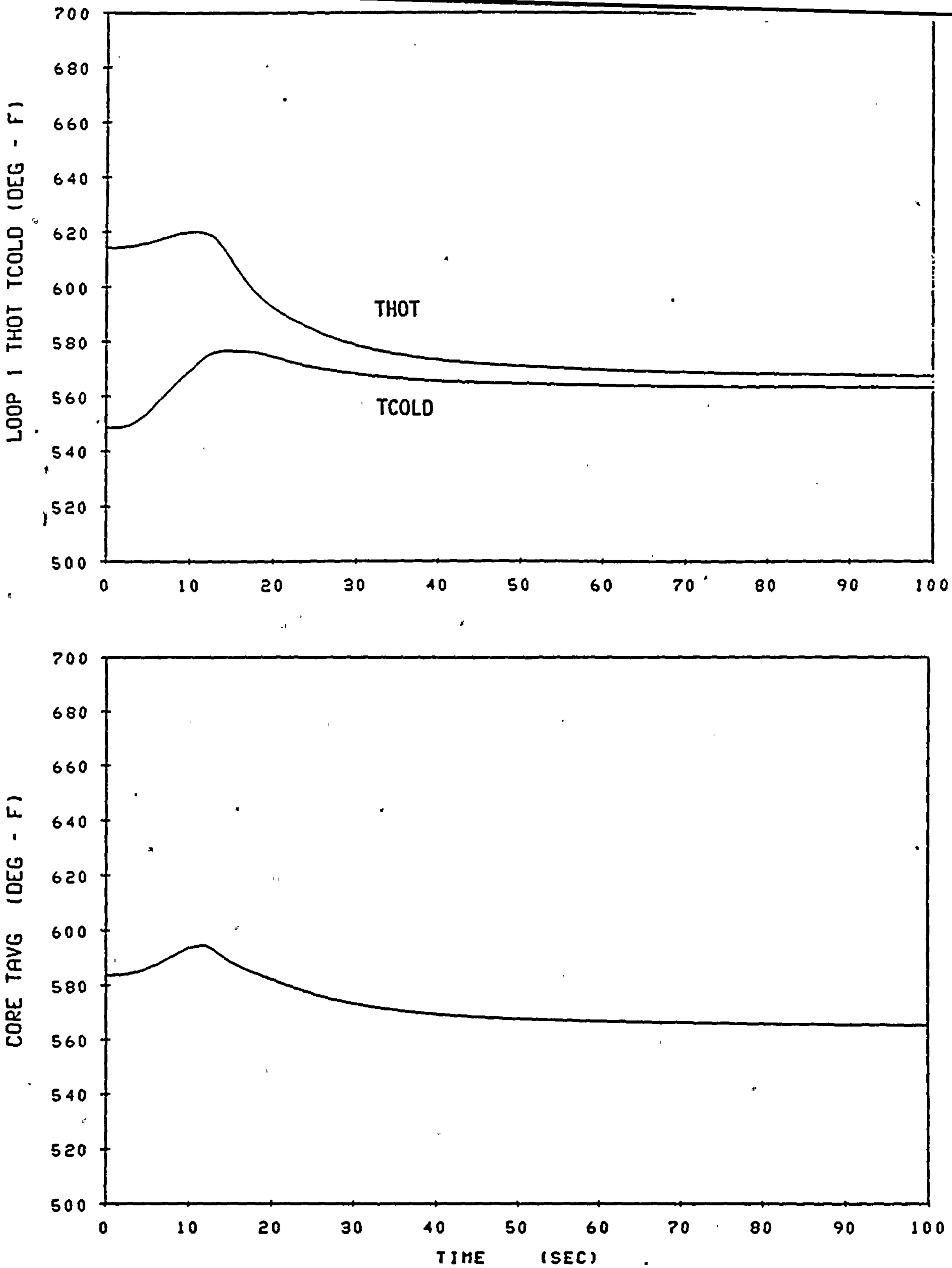


Figure B.3-37B Loss of Load
Loop and Core Average Temperatures Versus Time for Maximum Reactivity Feedwater without Pressurizer Spray and PORVs.

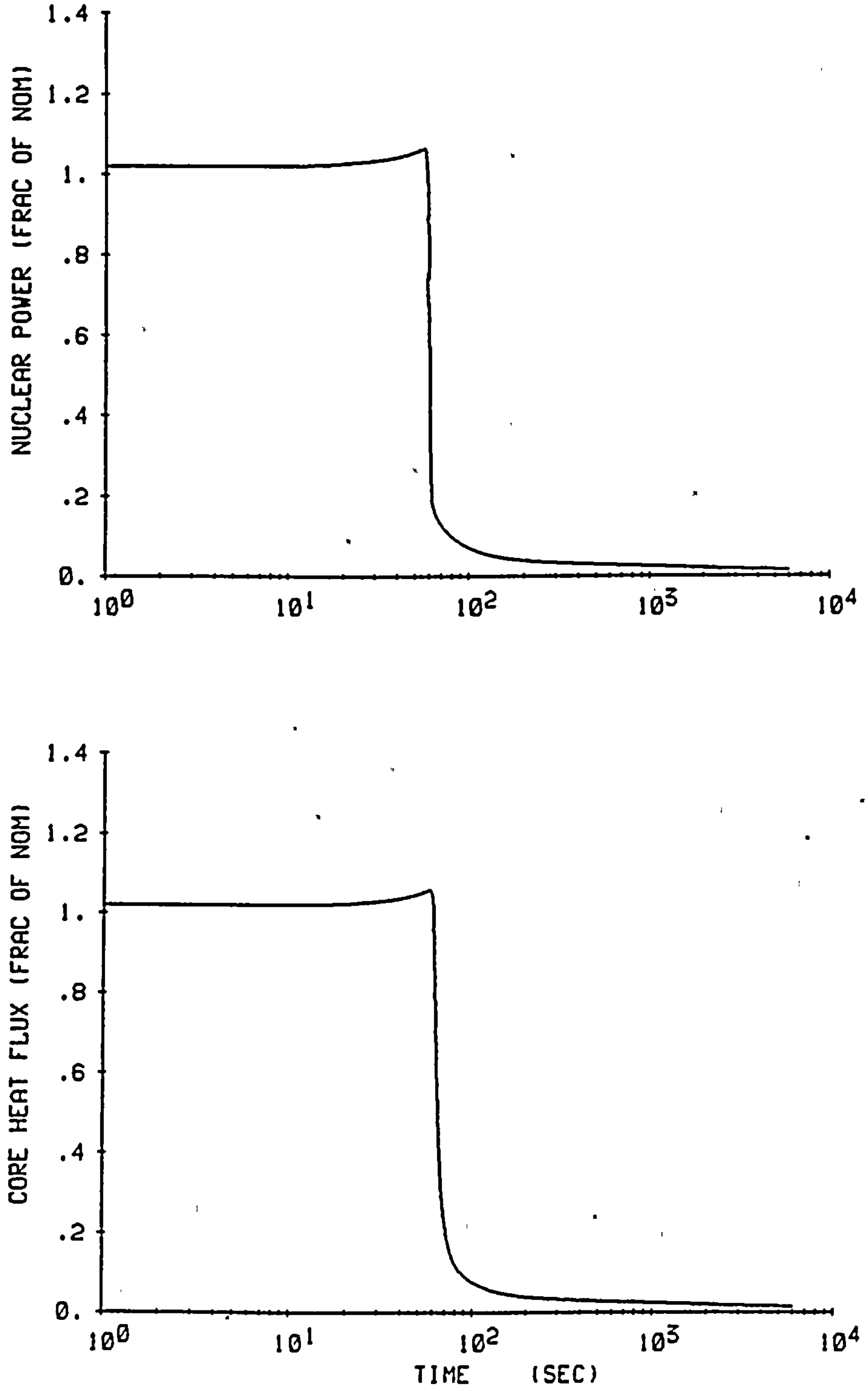


Figure B.3-38 Loss of Normal Feedwater
Nuclear Power and Core Heat Flux Versus Time

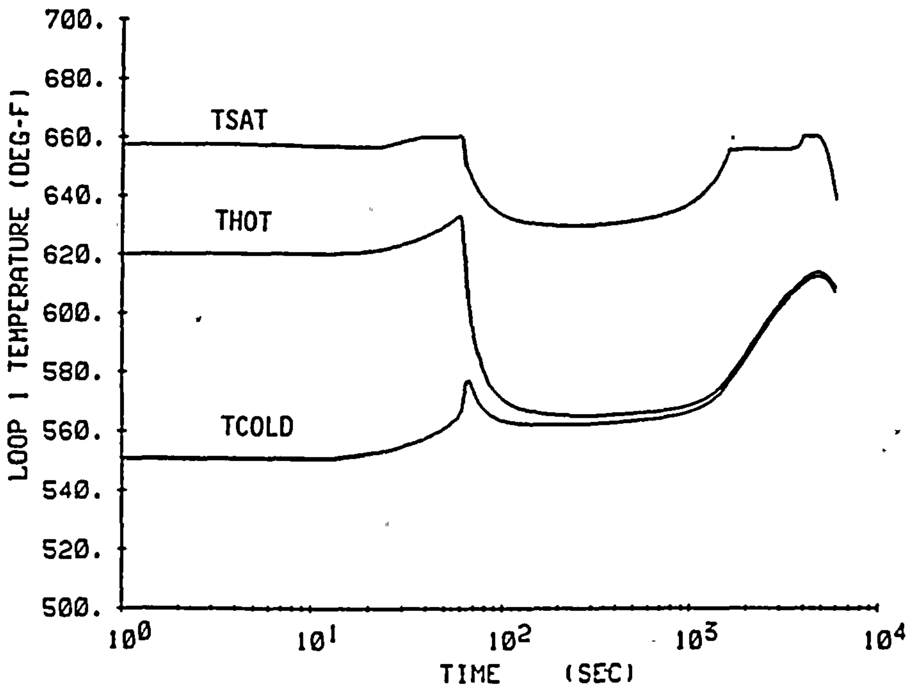


Figure B.3-39 Loss of Normal Feedwater
Loop Temperature Versus Time

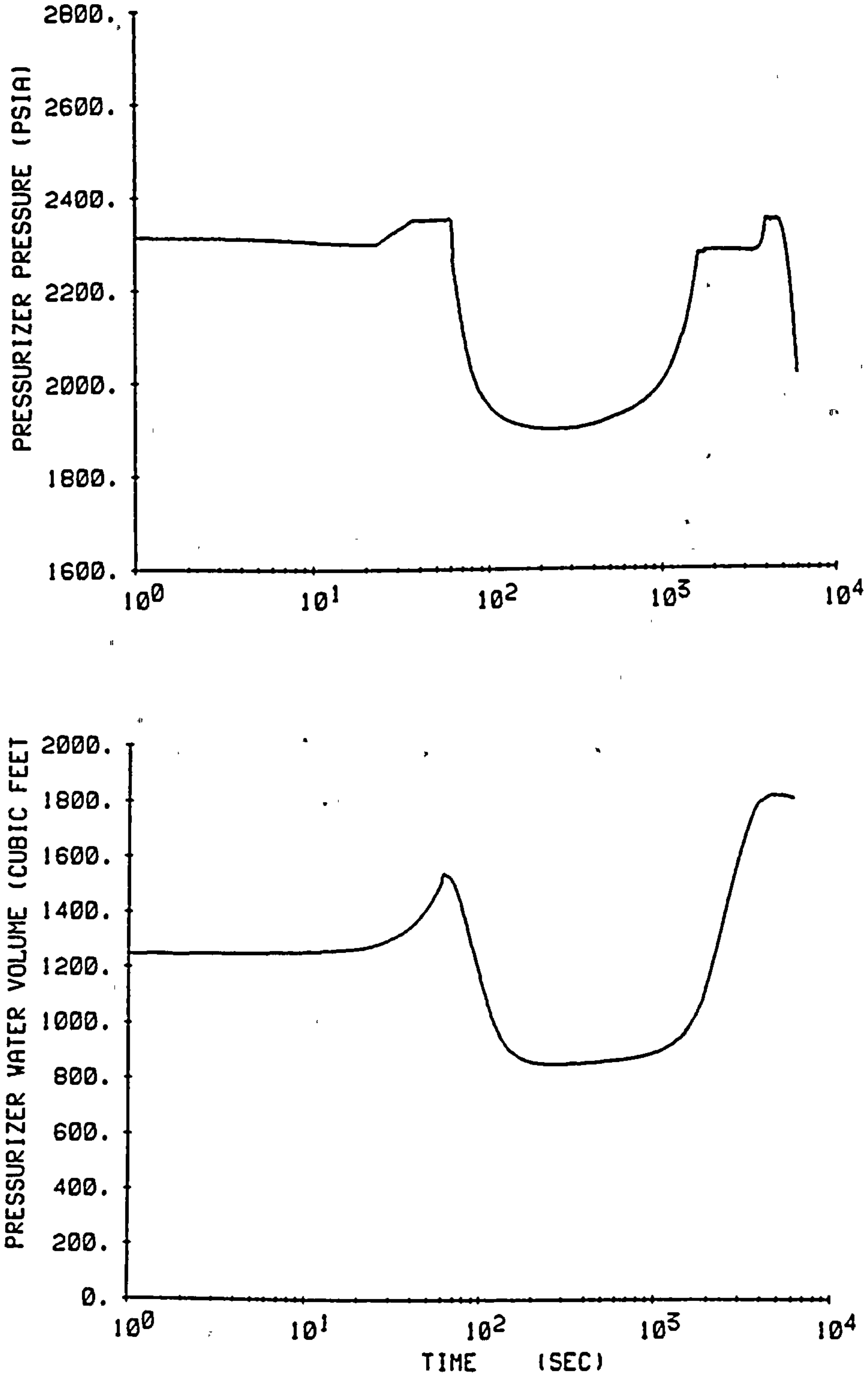


Figure B.3-40 Loss of Normal Feedwater
Pressurizer Pressure and Pressurizer Water Volume Versus Time

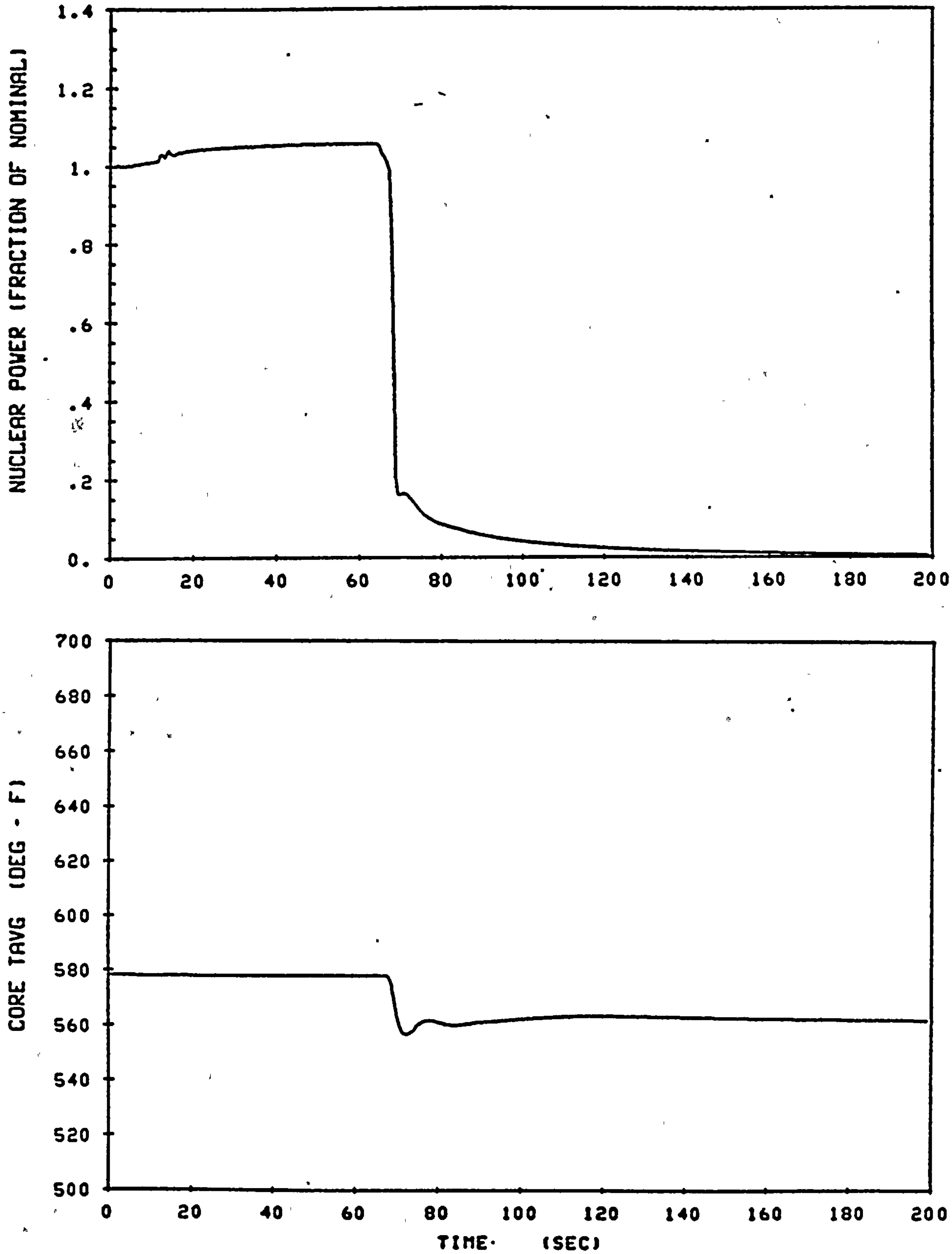


Figure B.3-41A Feedwater Malfunction
Nuclear Power and Core Average Temperature Versus time for Automatic Rod Control

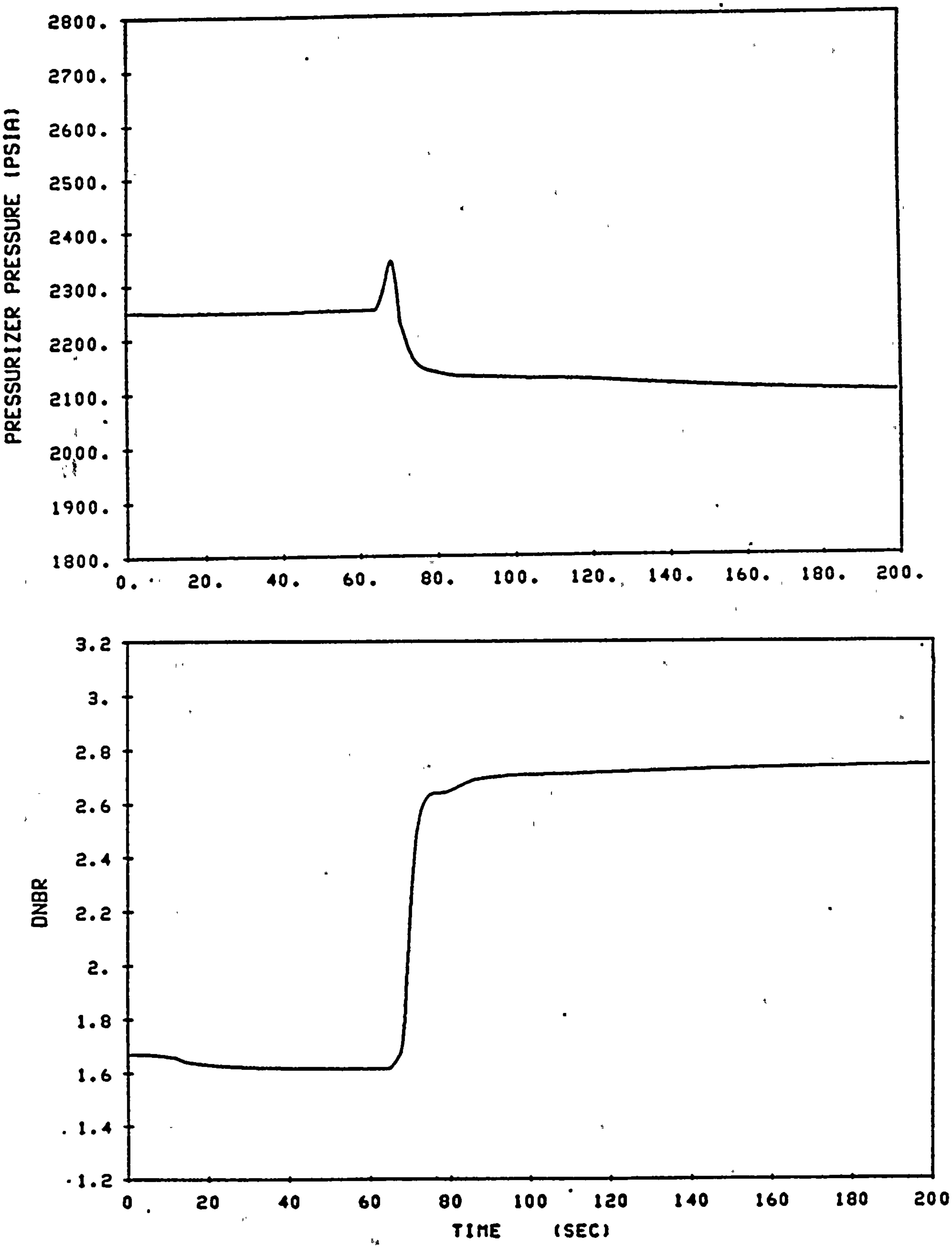


Figure B.3-42A Feedwater Malfunction
Pressurizer Pressure and DNBR Versus Time for Automatic Rod Control

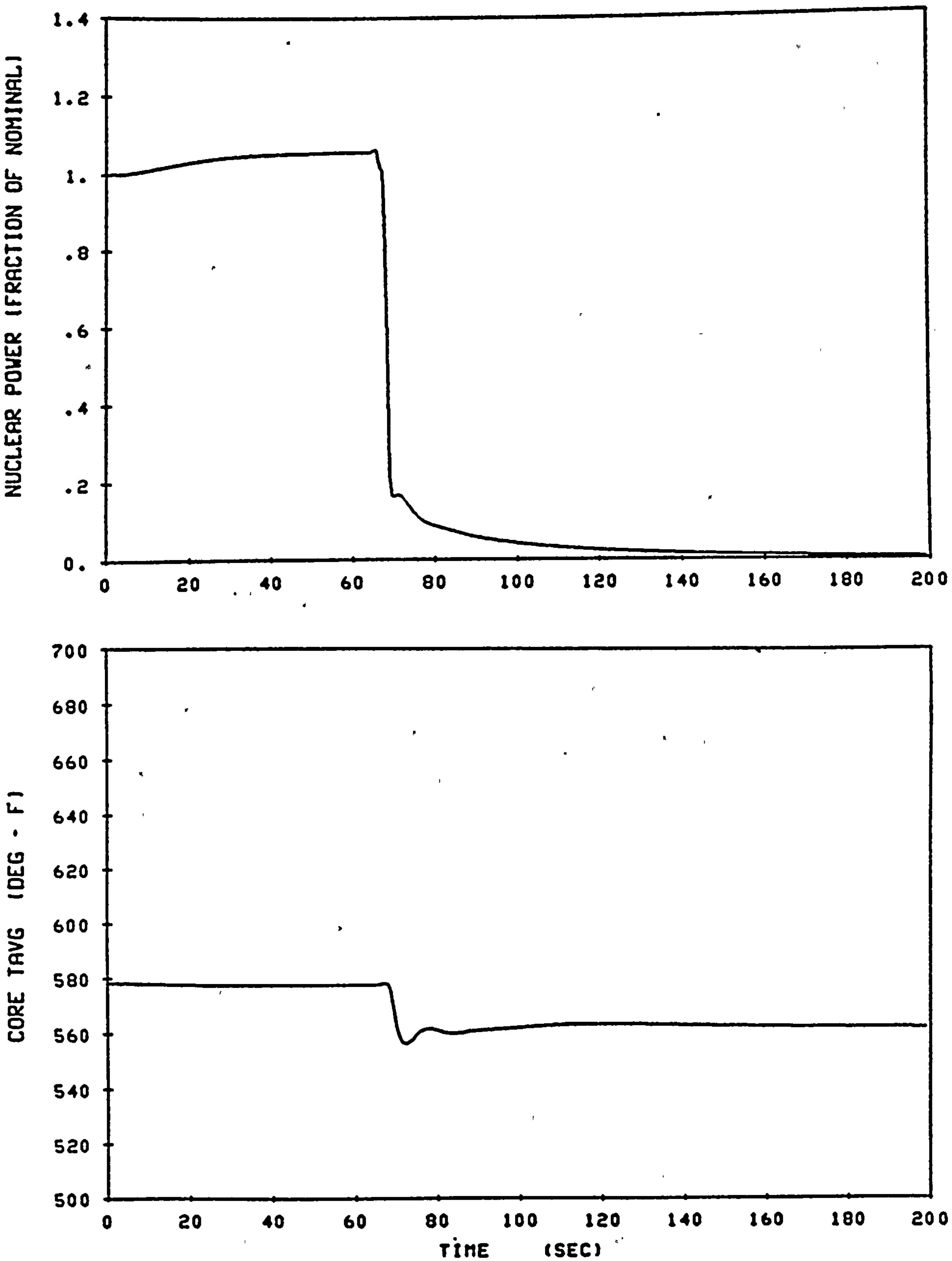


Figure B.3-43A Feedwater Malfunction
Nuclear Power and Core Average Temperature Versus Time for Manual Rod Control

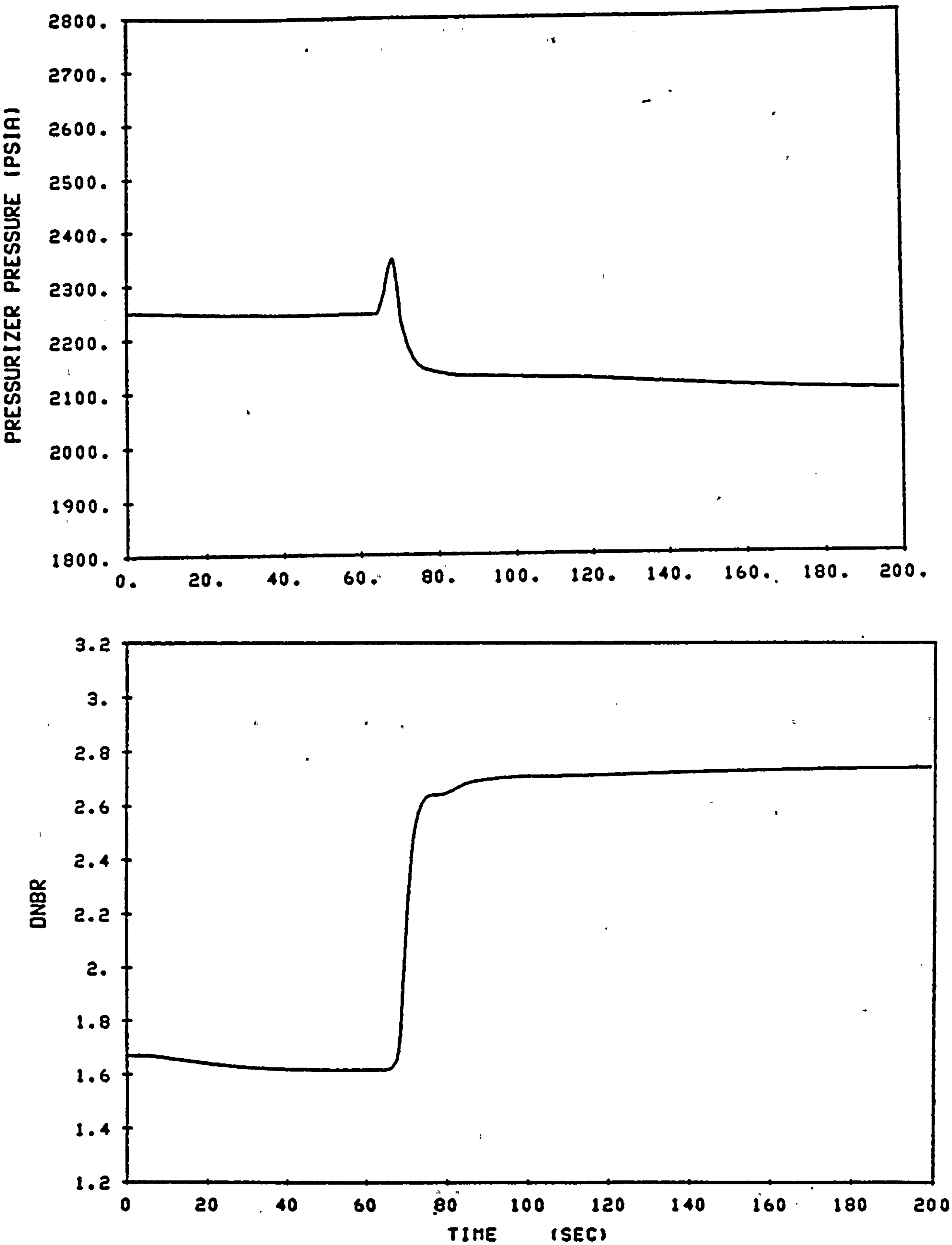


Figure B.3-44A Feedwater Malfunction
Pressurizer Pressure and DNBR Versus Time for Manual Rod Control

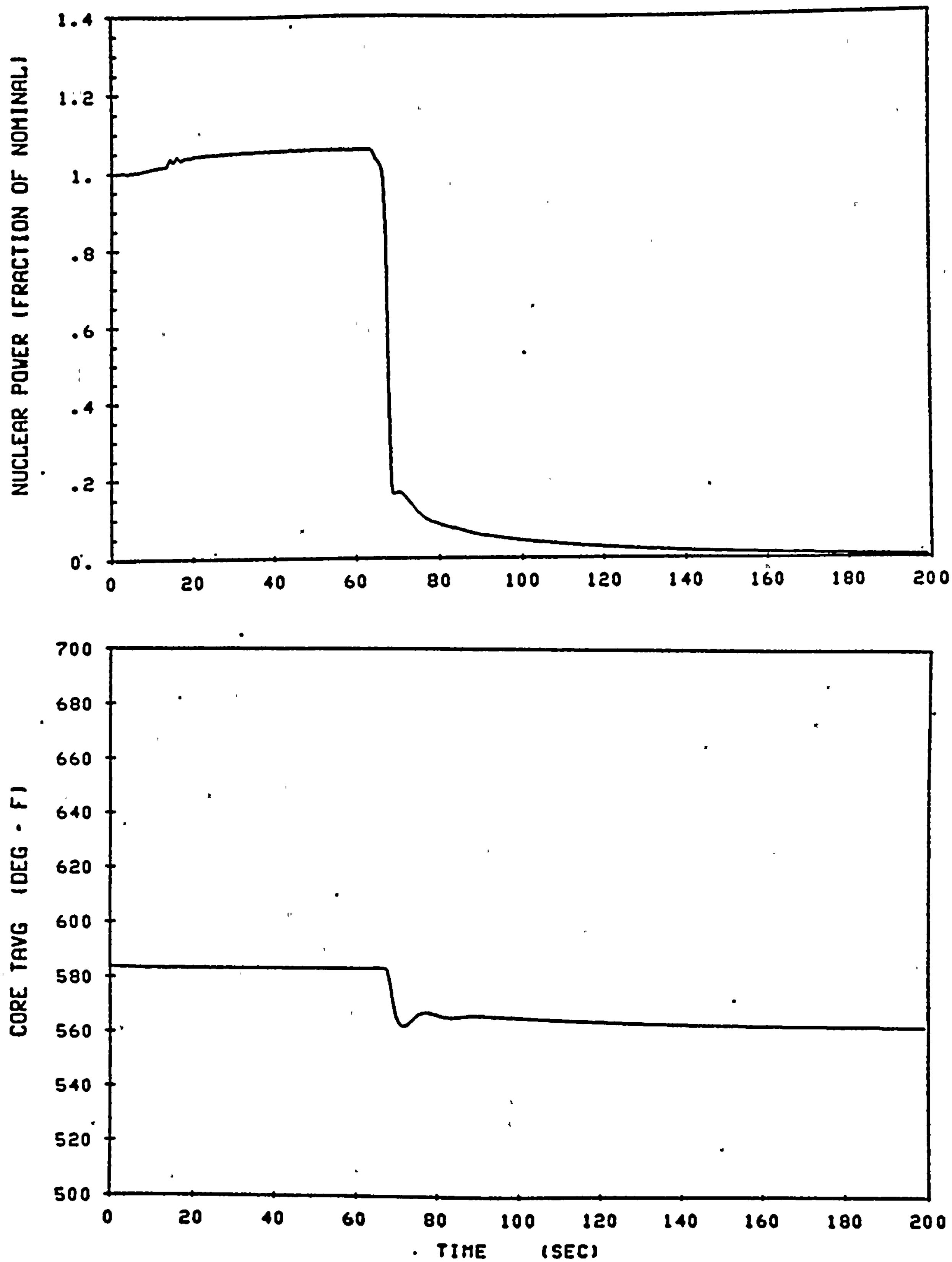


Figure B.3-41B Feedwater Malfunction
Nuclear Power and Core Average Temperature Versus time for Automatic Rod Control

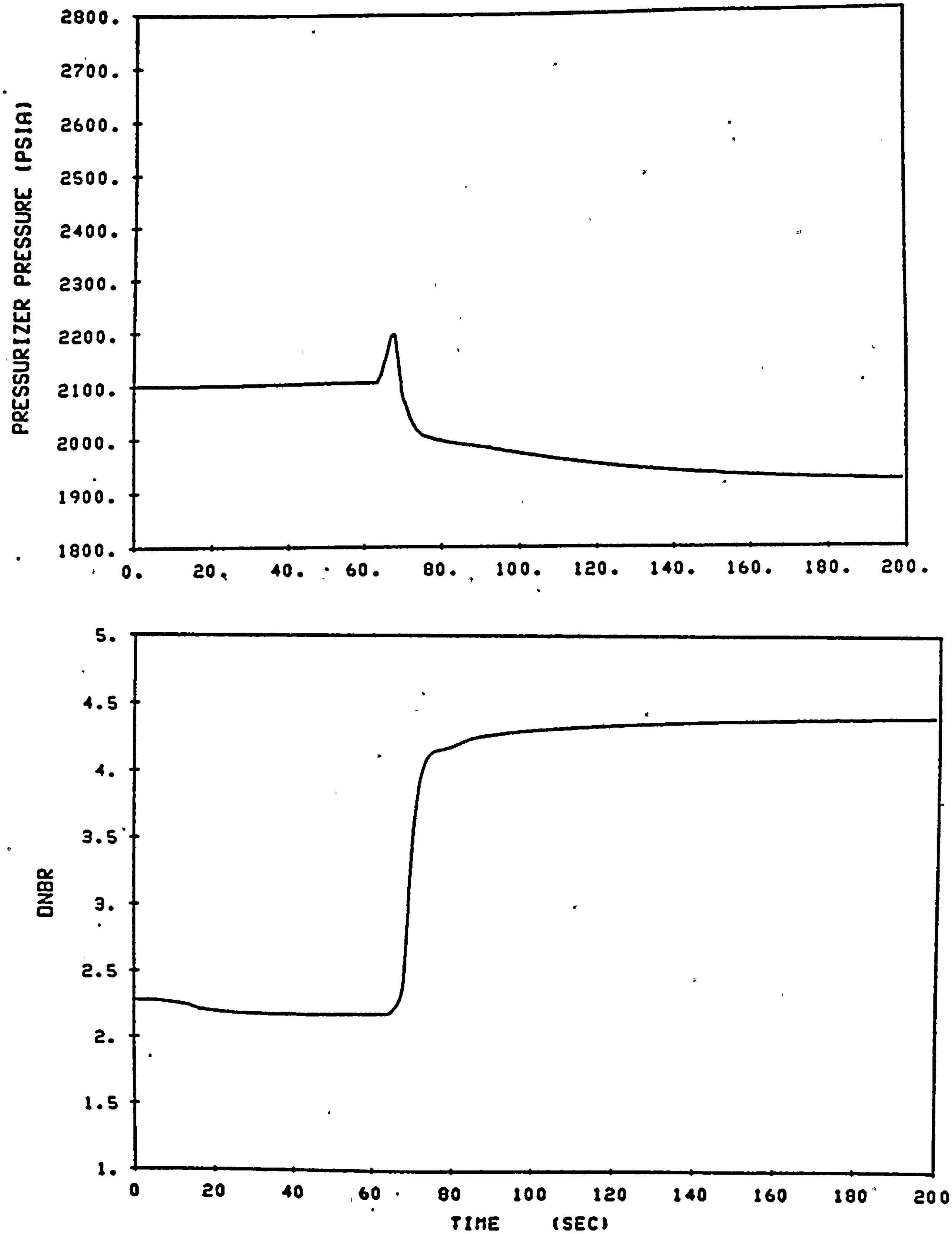


Figure B.3-42B Feedwater Malfunction
Pressurizer Pressure and DNBR Versus Time for Automatic Rod Control

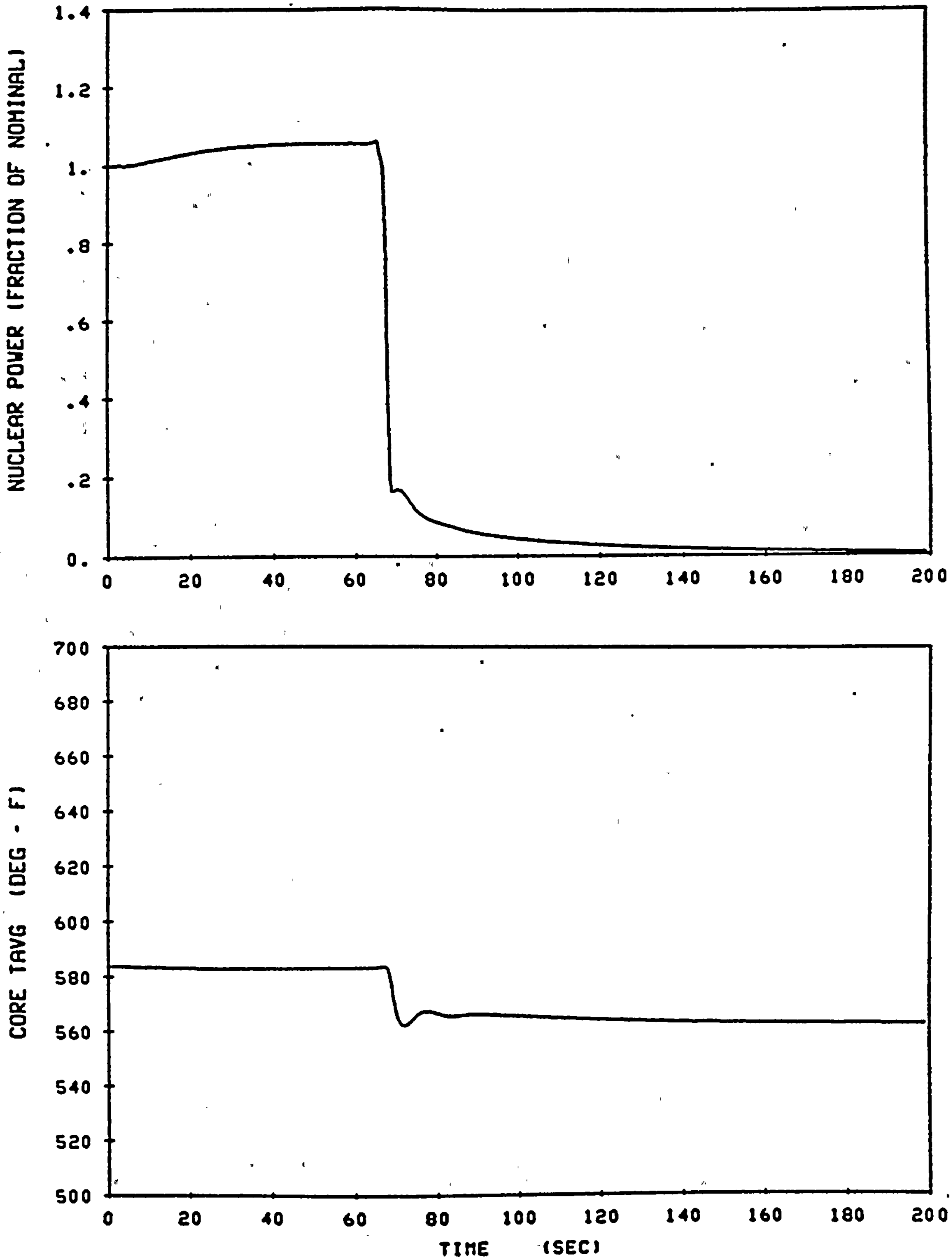


Figure B.3-43B Feedwater Malfunction
Nuclear Power and Core Average Temperature Versus Time for Manual Rod Control

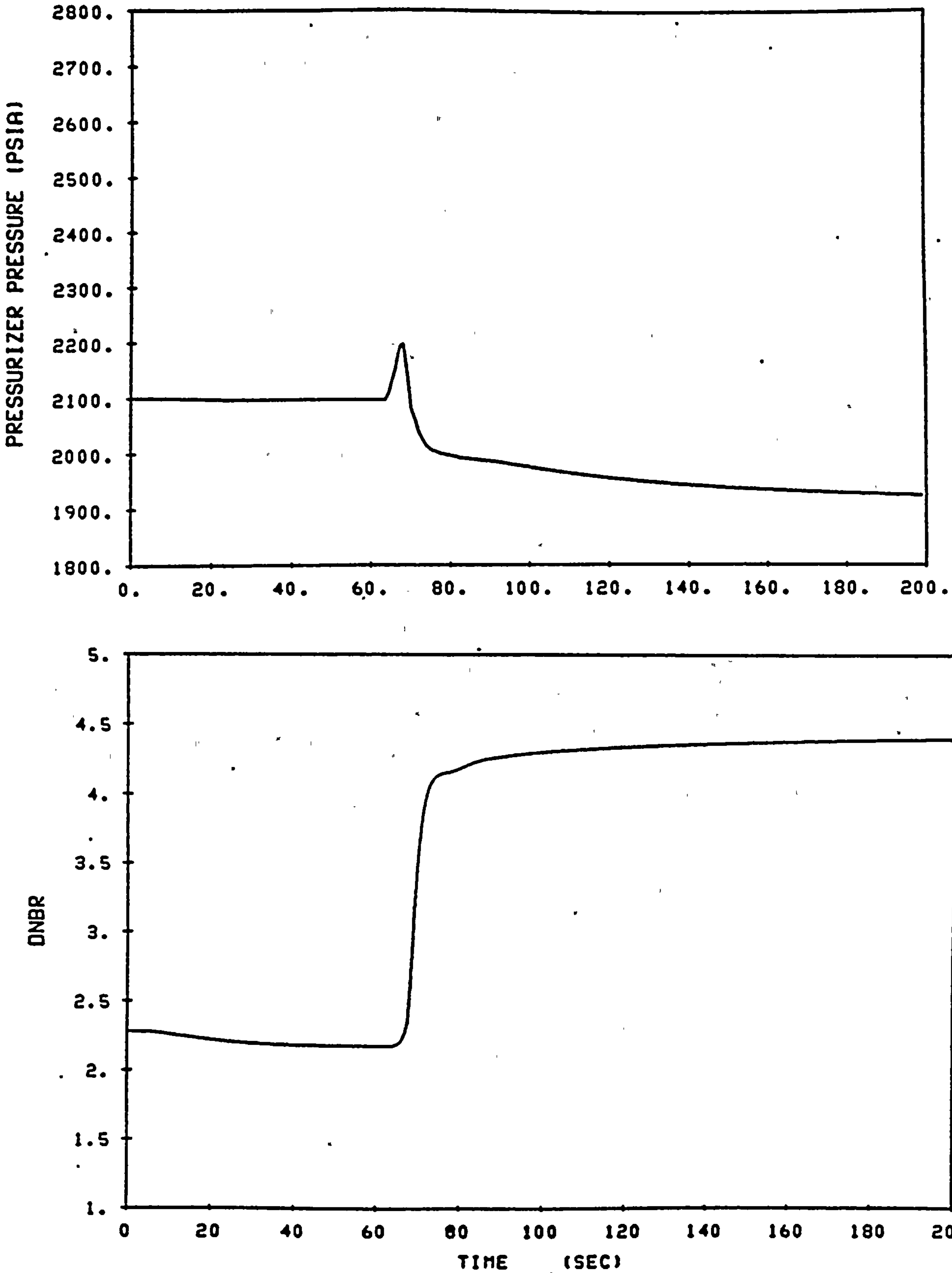


Figure B.3-44B Feedwater Malfunction
Pressurizer Pressure and DNBR Versus Time for Manual Rod Control

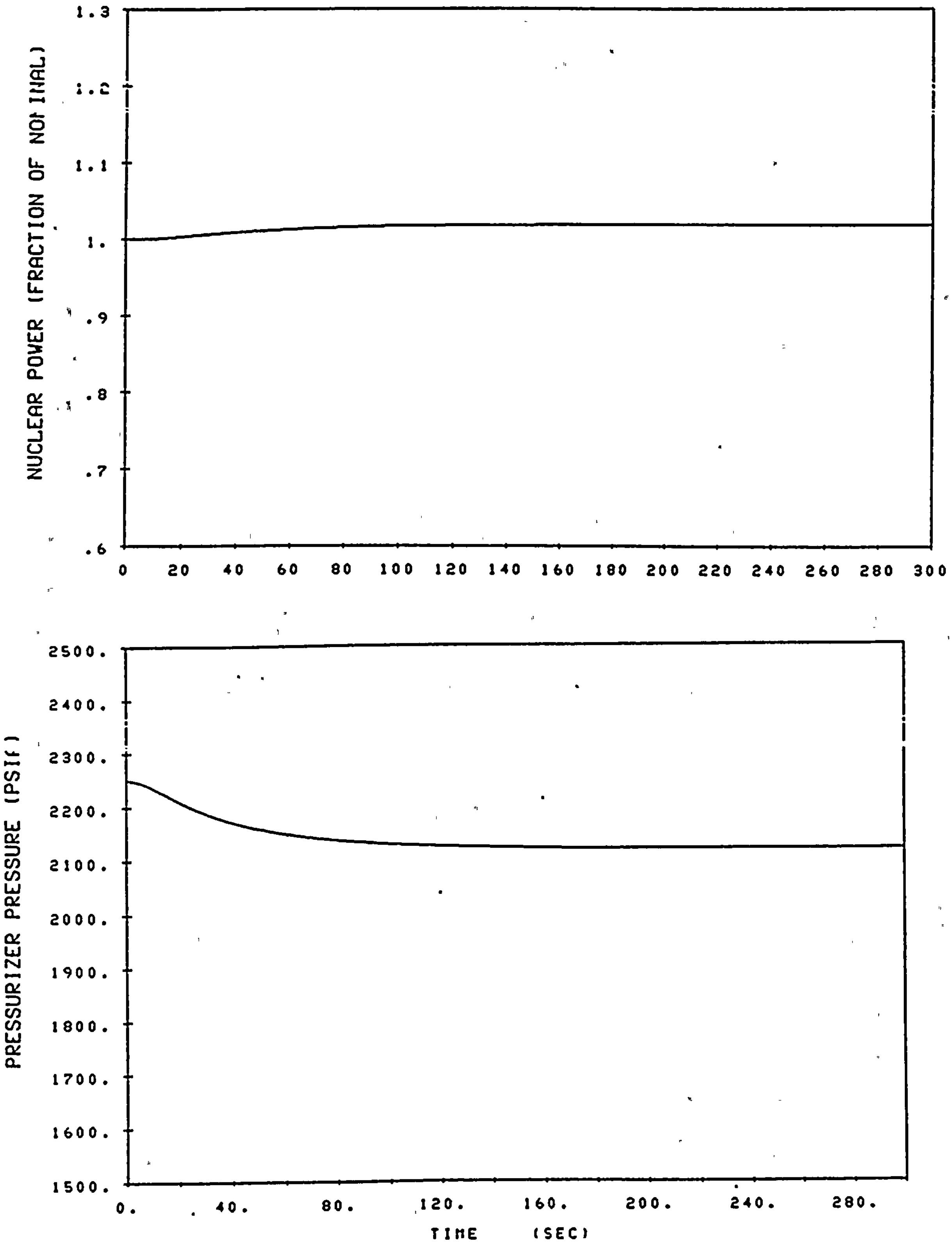


Figure B.3-45A Excessive Load Increase
Nuclear Power and Pressurizer Pressure Versus Time for Minimum Reactivity Feedback with Manual Rod Control

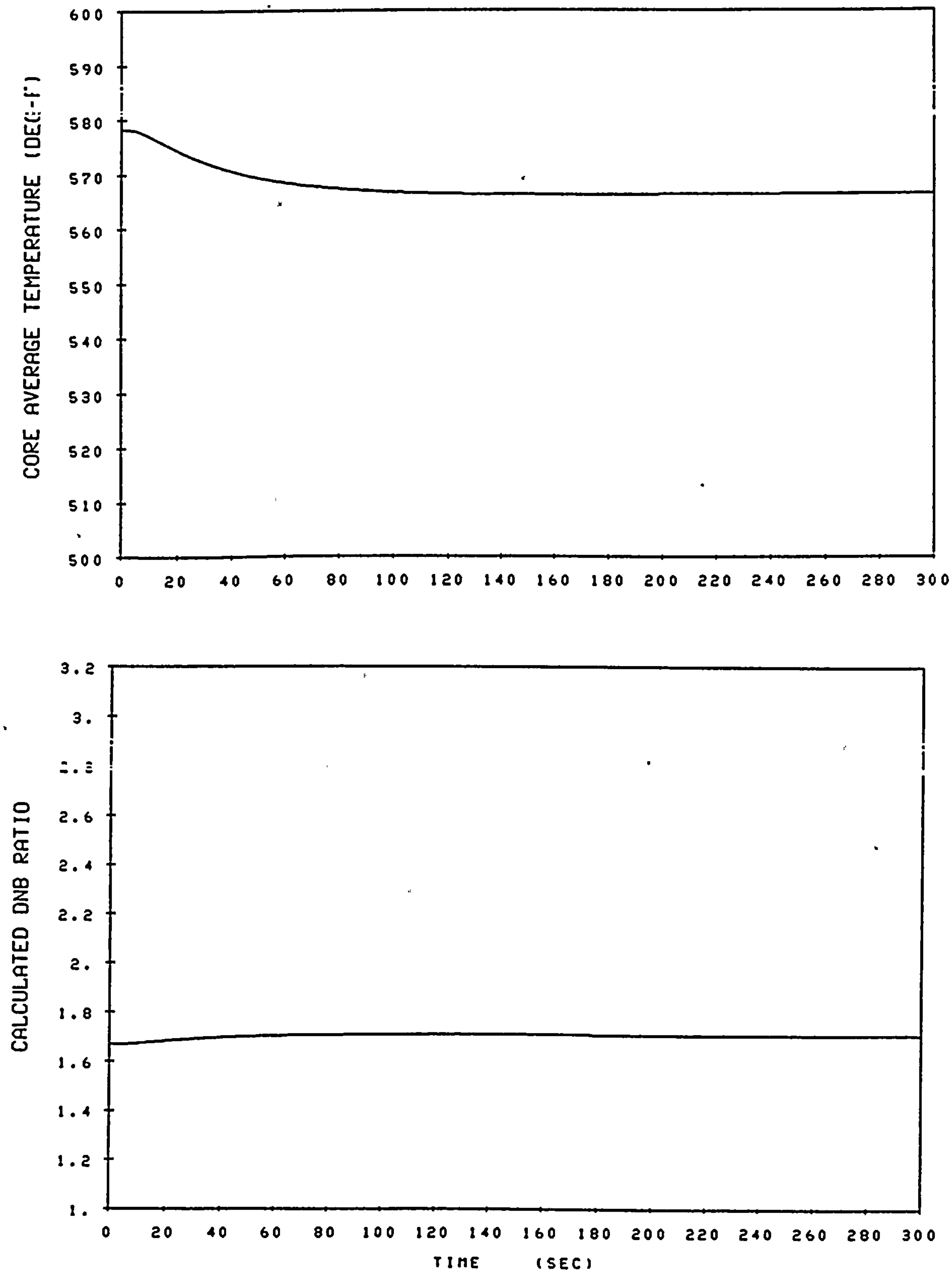


Figure B.3-46A Excessive Load Increase
Core Average Temperature and DNBR Versus Time for Minimum Reactivity Feedback with Manual Rod Control

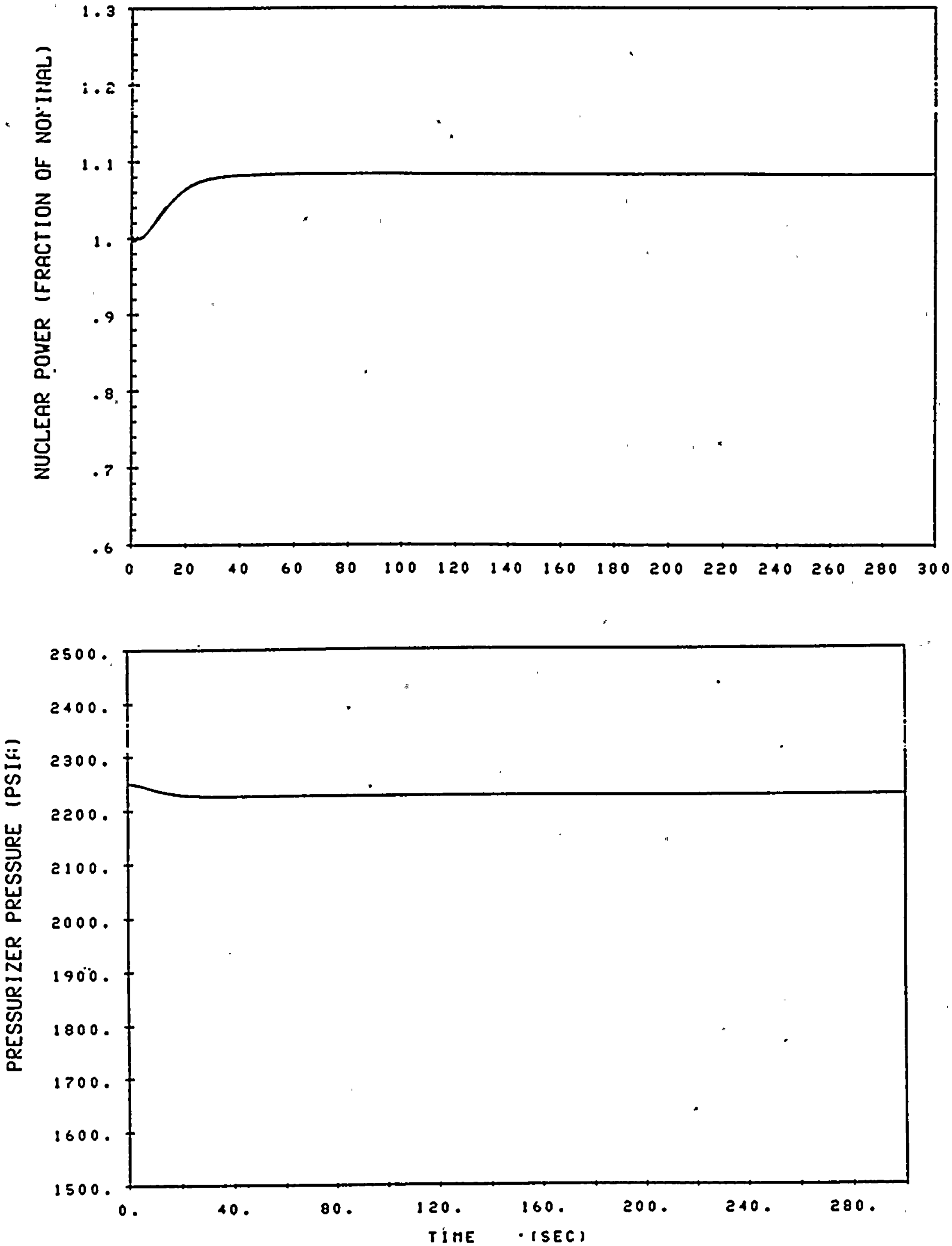


Figure B.3-47A Excessive Load Increase
Nuclear Power and Pressurizer Pressure Versus Time for Maximum Reactivity Feedback with Manual Control

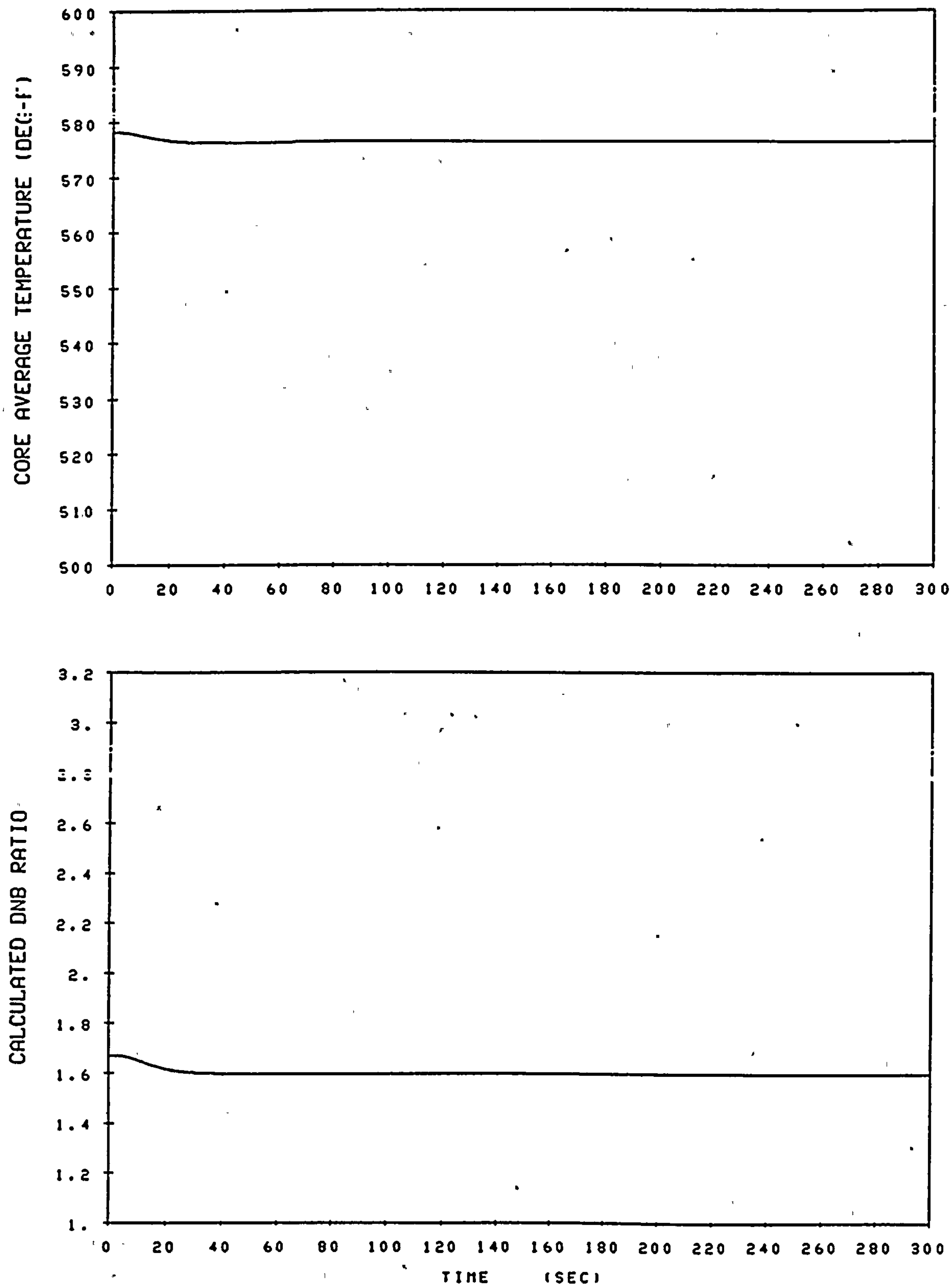


Figure B.3-48A Excessive Load Increase
Core Average Temperature and DNBR Versus Time for Maximum Reactivity Feedback with Manual Control

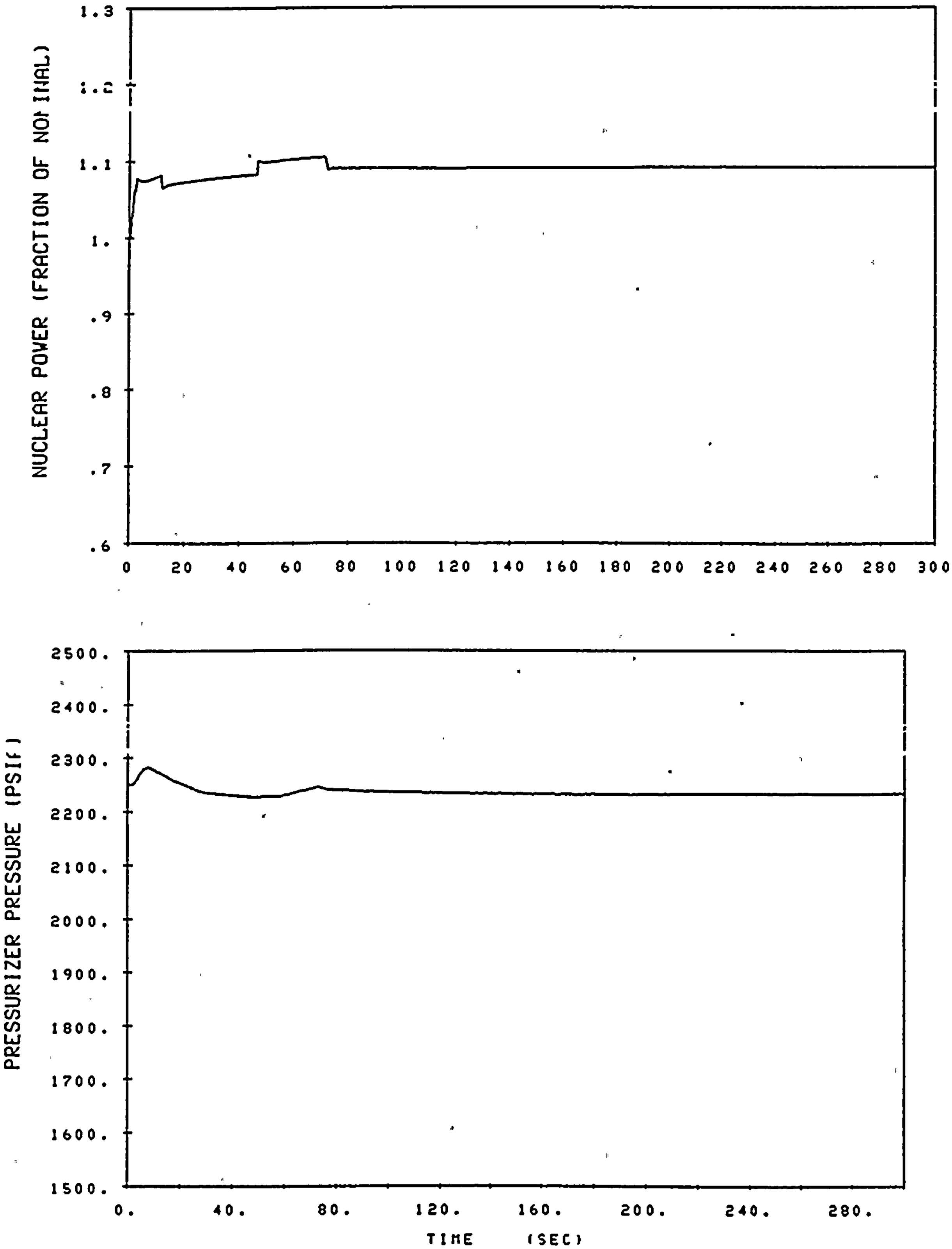


Figure B.3-49A Excessive Load Increase
Nuclear Power and Pressurizer Pressure Versus Time for Minimum Reactivity Feedback with Automatic Rod Control

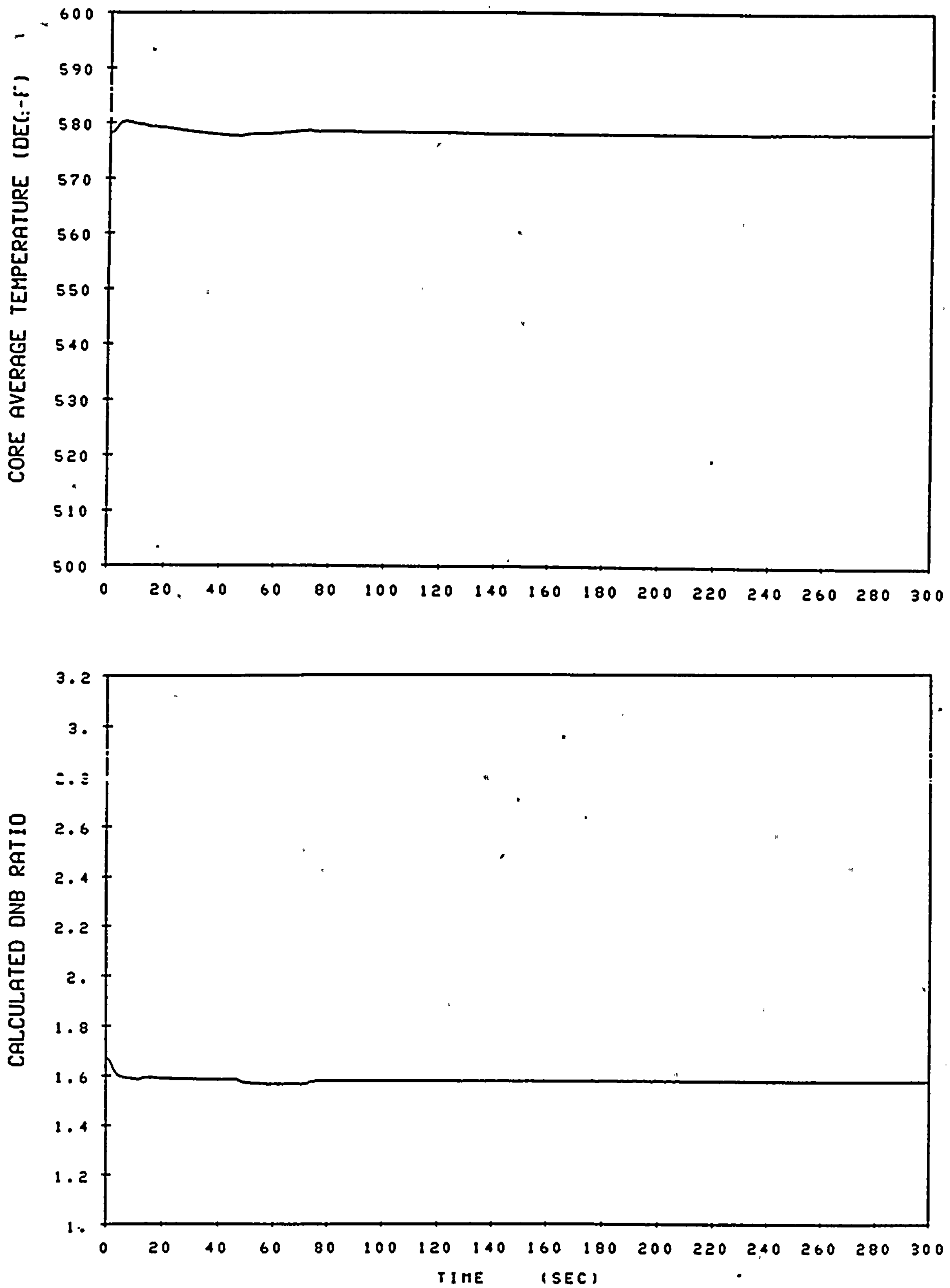


Figure B.3-50A Excessive Load Increase
Core Average Temperature and DNBR Versus Time for Minimum Reactivity Feedback with Automatic Rod Control

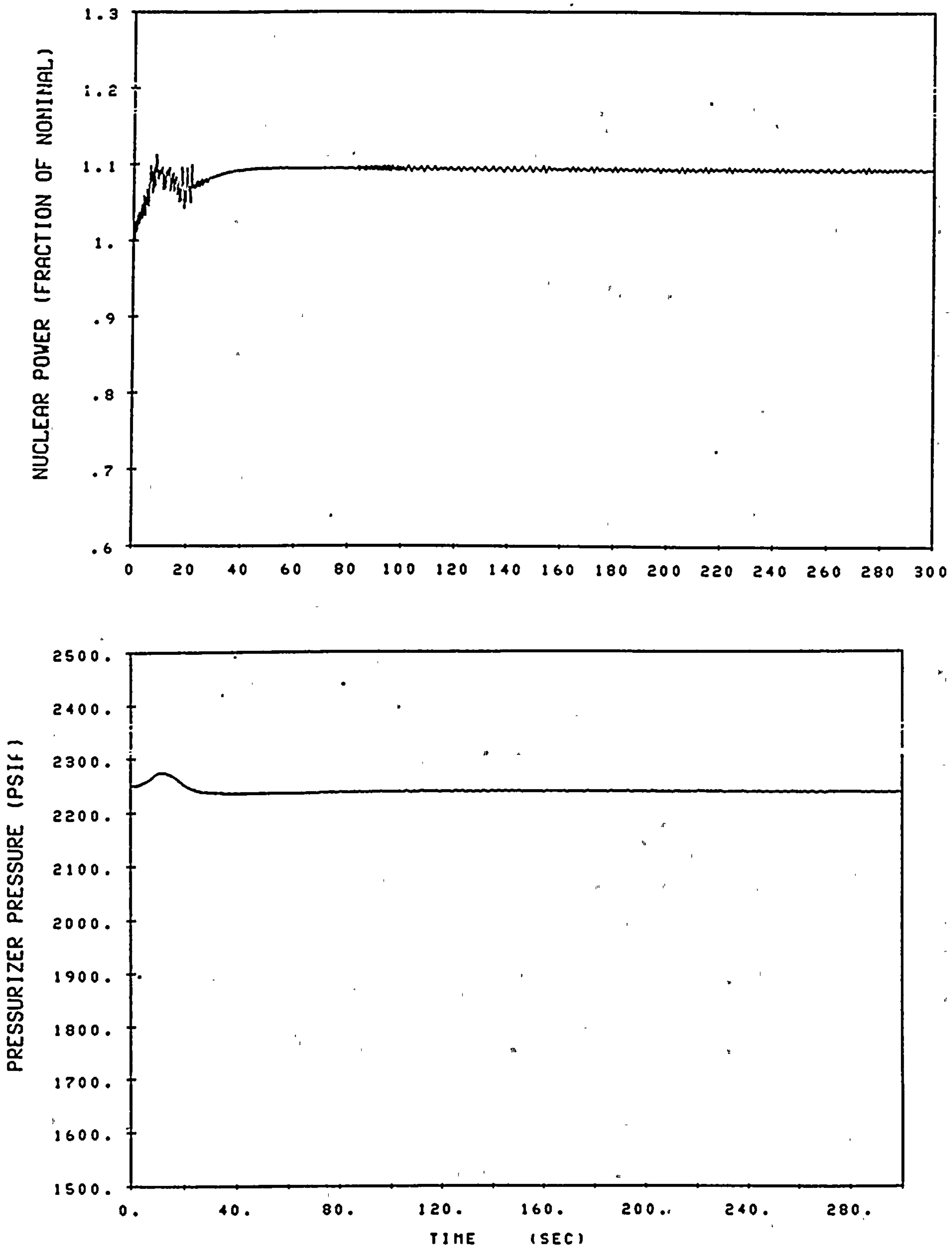
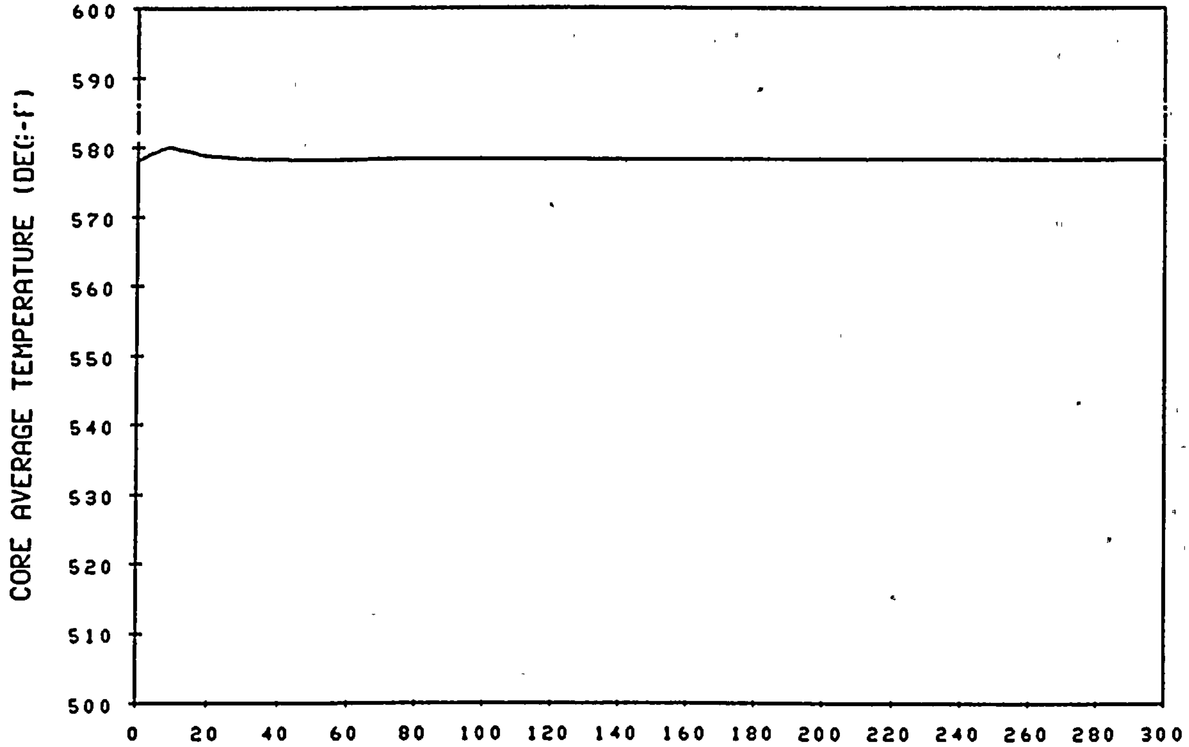


Figure B.3-51A Excessive Load Increase
Nuclear Power and Pressurizer Pressure Versus Time for Maximum Reactivity Feedback with Automatic Rod Control



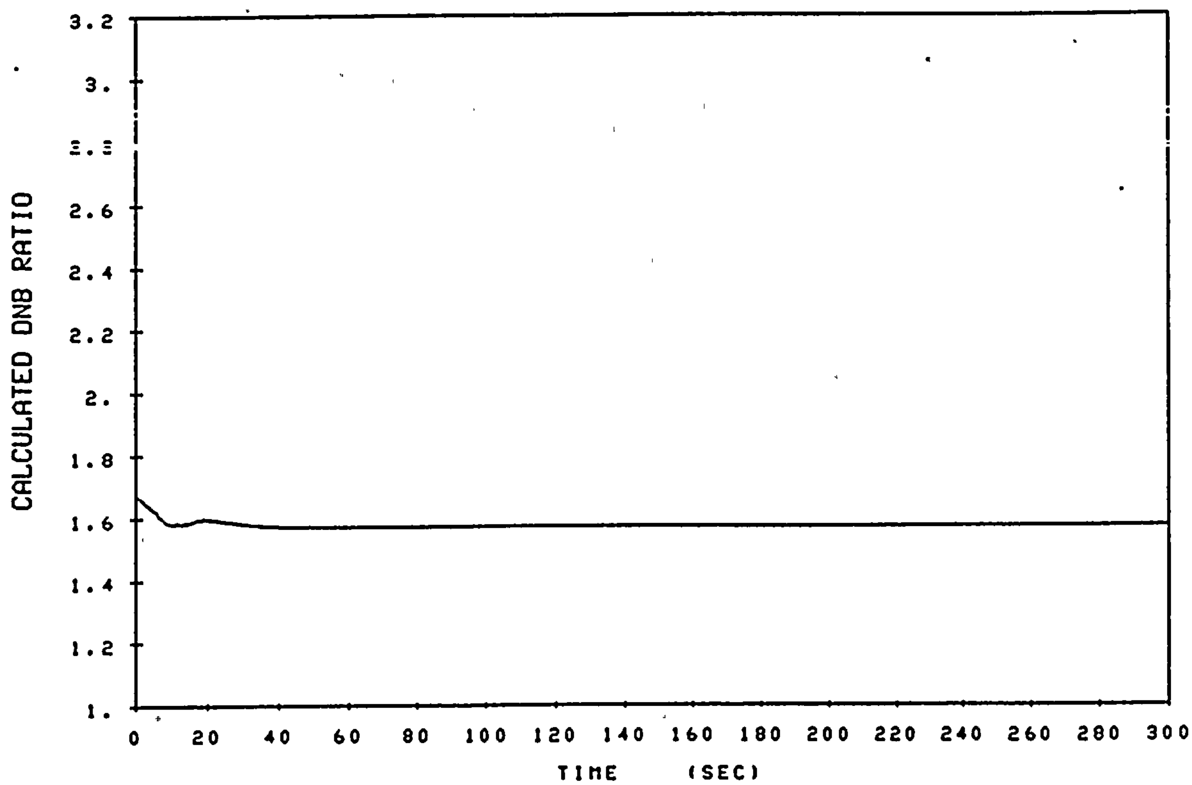


Figure B.3-52A Excessive Load Increase
Core Average Temperature and DNBR Versus Time for Maximum Reactivity Feedback with Automatic Rod Control

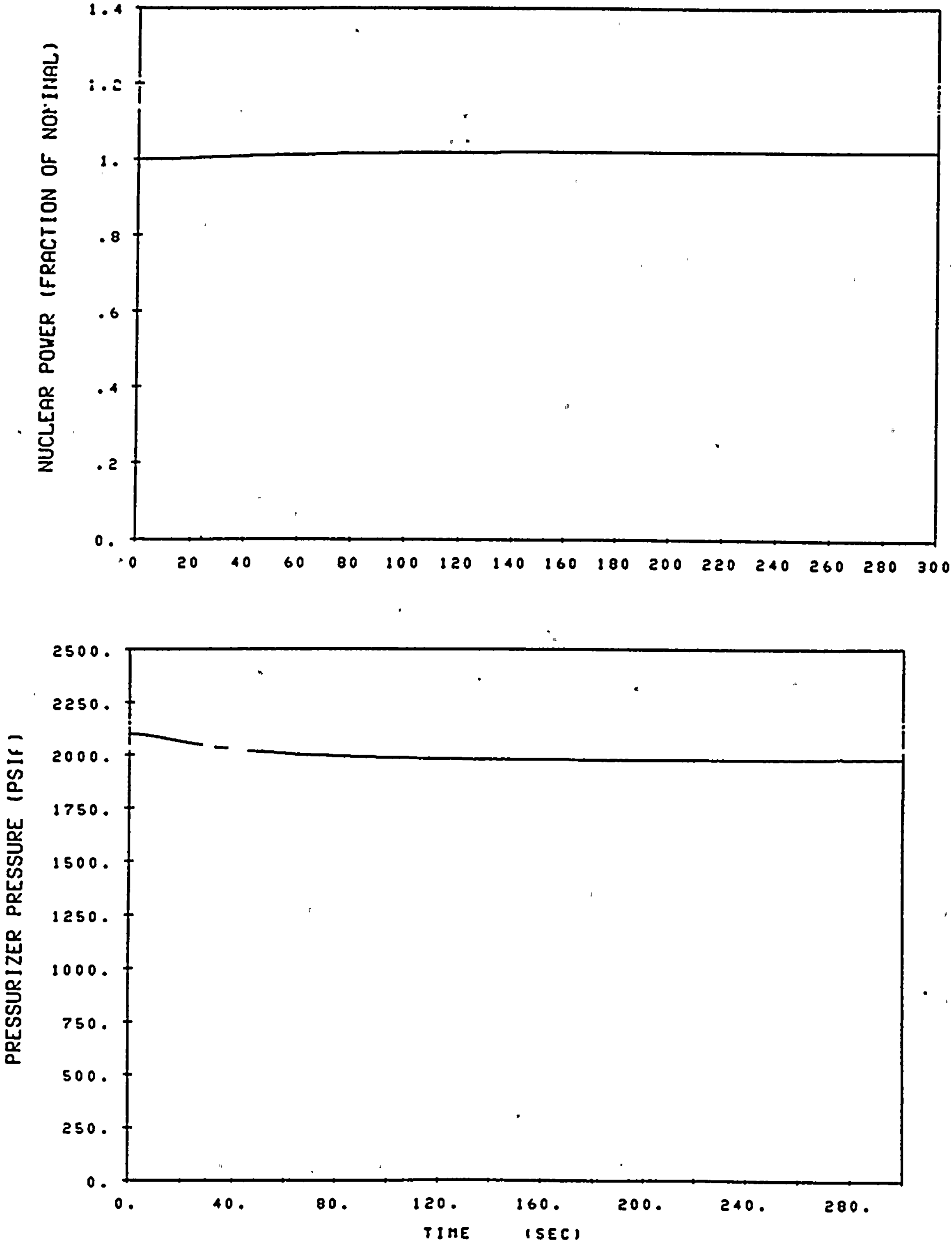


Figure B.3-45B Excessive Load Increase
Nuclear Power and Pressurizer Pressure Versus Time for Minimum Reactivity Feedback with Manual Rod Control

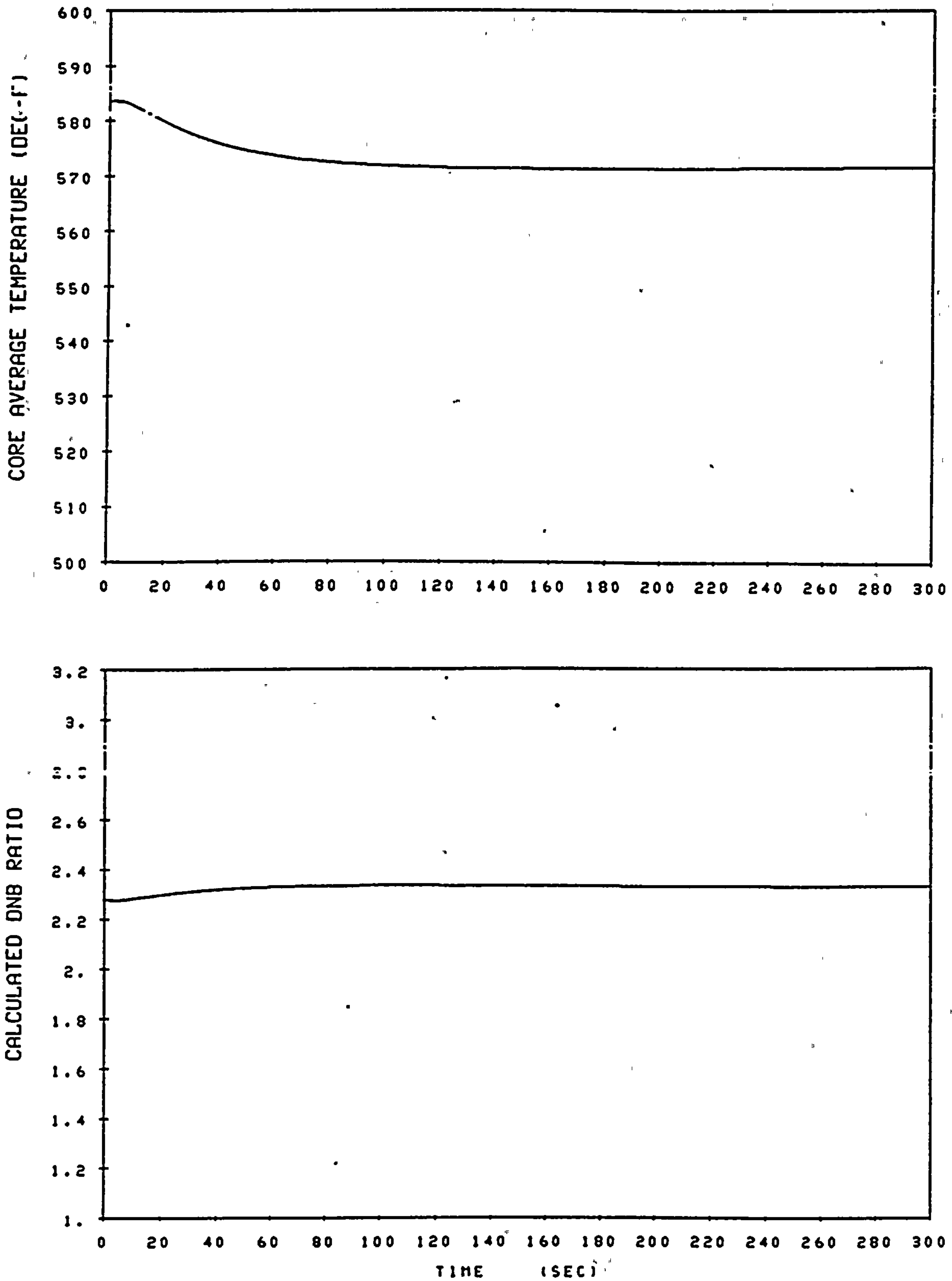


Figure B.3-46B Excessive Load Increase.
Core Average Temperature and DNBR Versus Time for Minimum Reactivity Feedback with Manual Rod Control

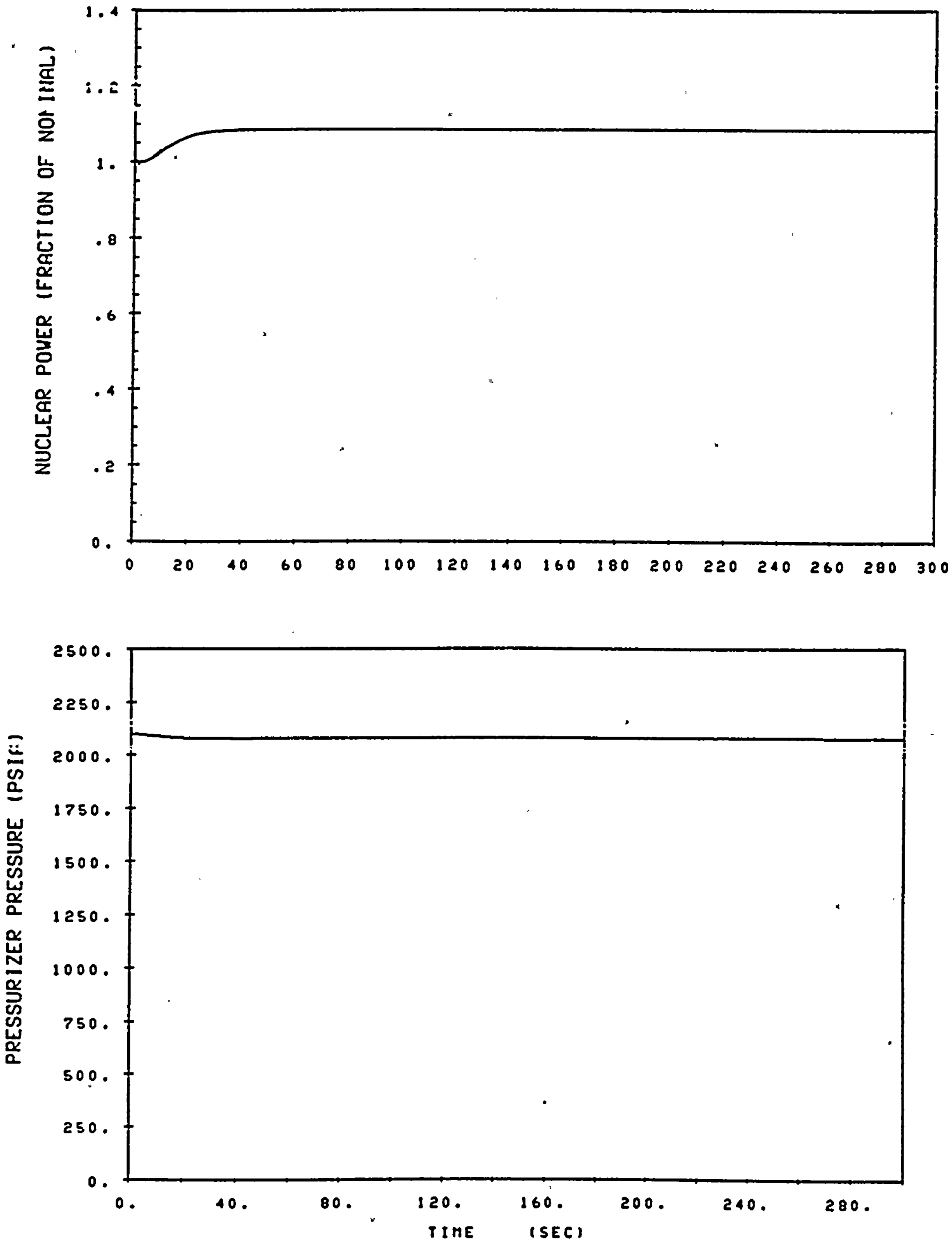


Figure B.3-47B Excessive Load Increase
Nuclear Power and Pressurizer Pressure Versus Time for Maximum Reactivity Feedback with Manual Control

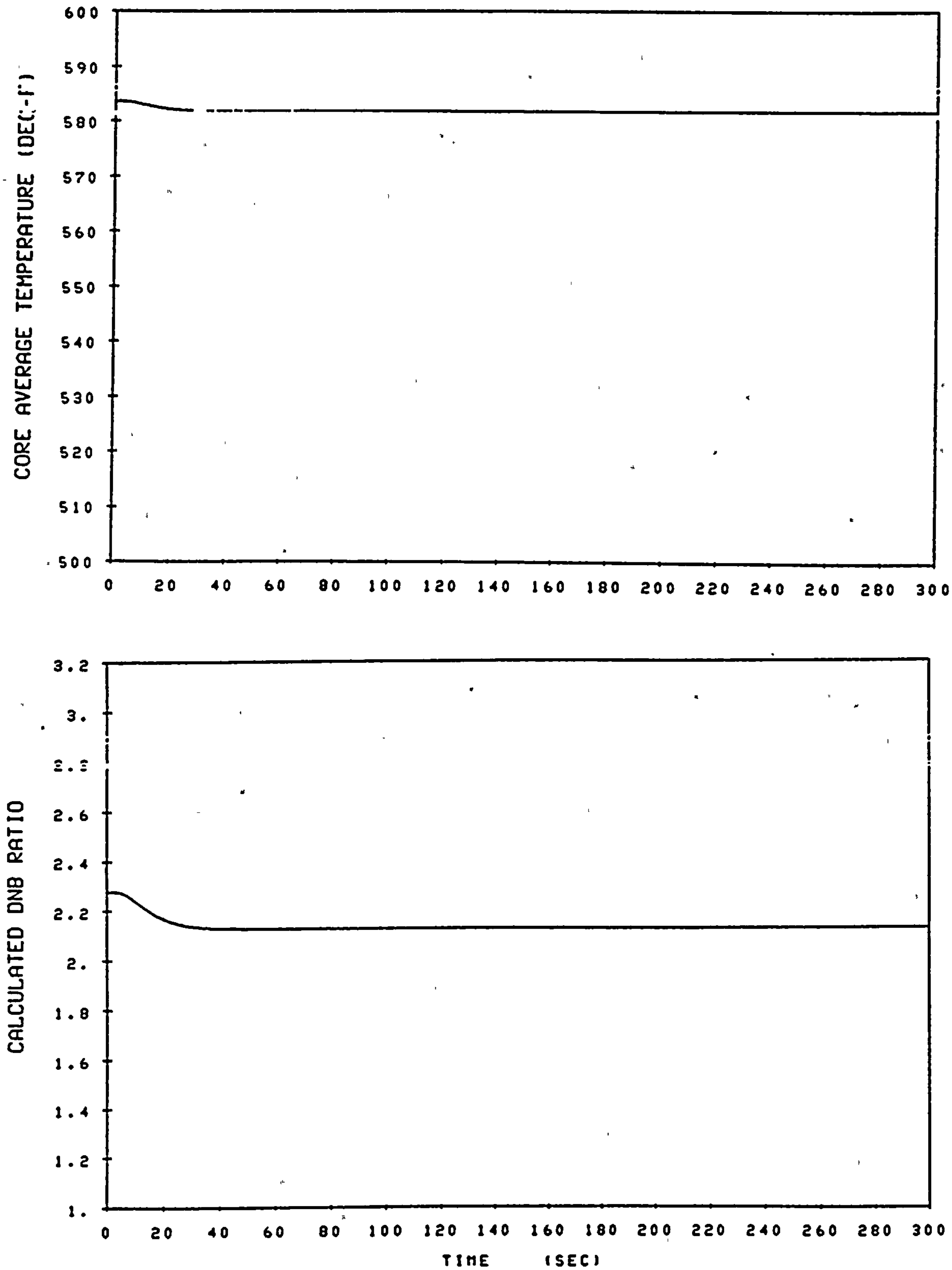
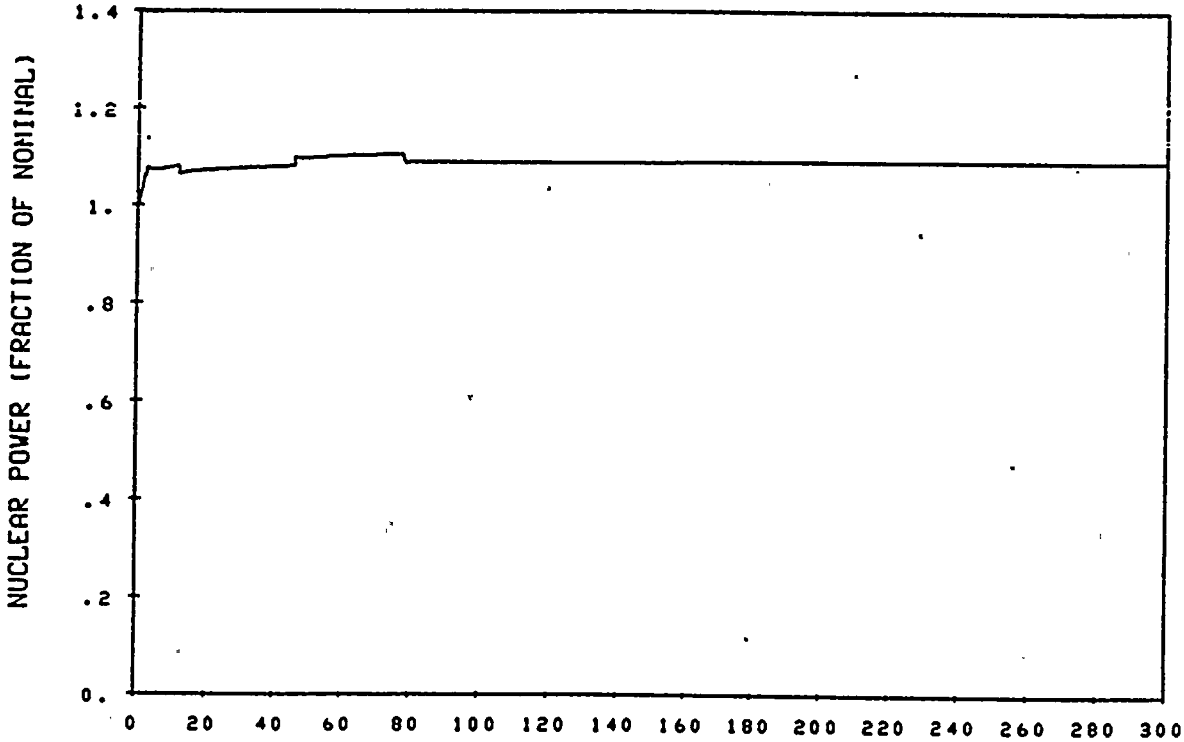


Figure B.3-48B Excessive Load Increase
Core Average Temperature and DNBR Versus Time for Maximum Reactivity Feedback with Manual Control



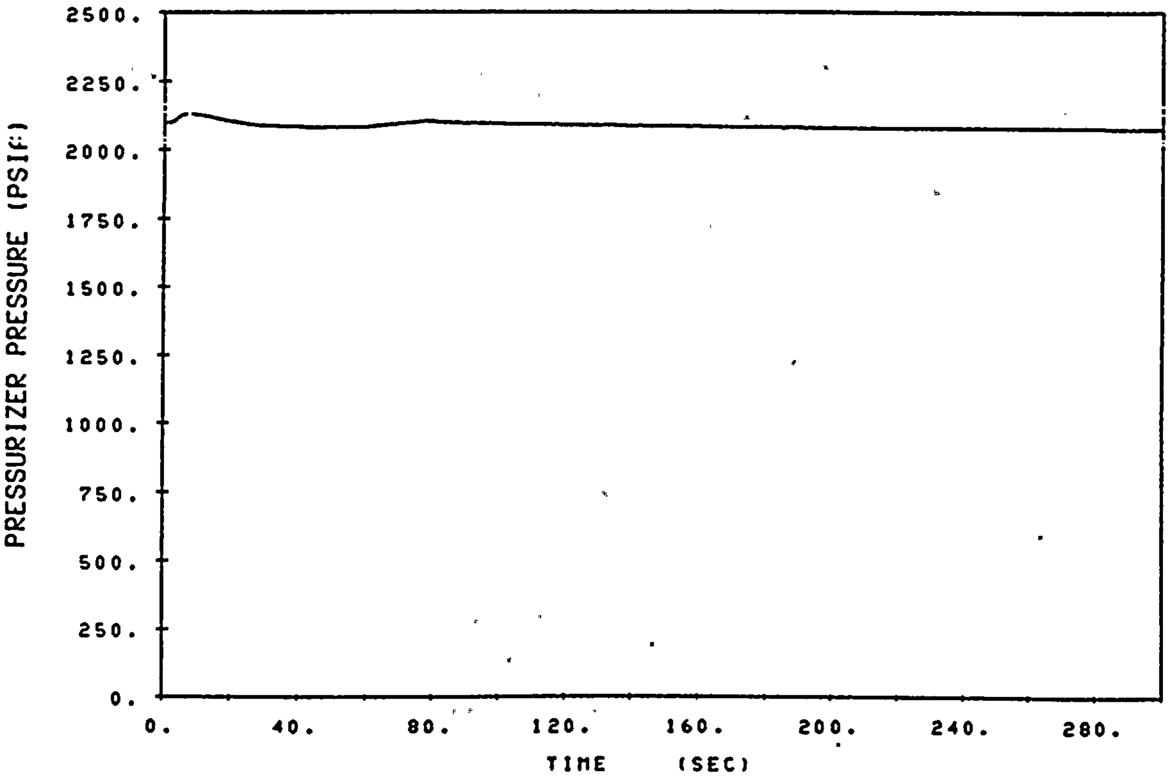


Figure B.3-49B Excessive Load Increase
Nuclear Power and Pressurizer Pressure Versus Time for Minimum Reactivity Feedback with Automatic Rod Control

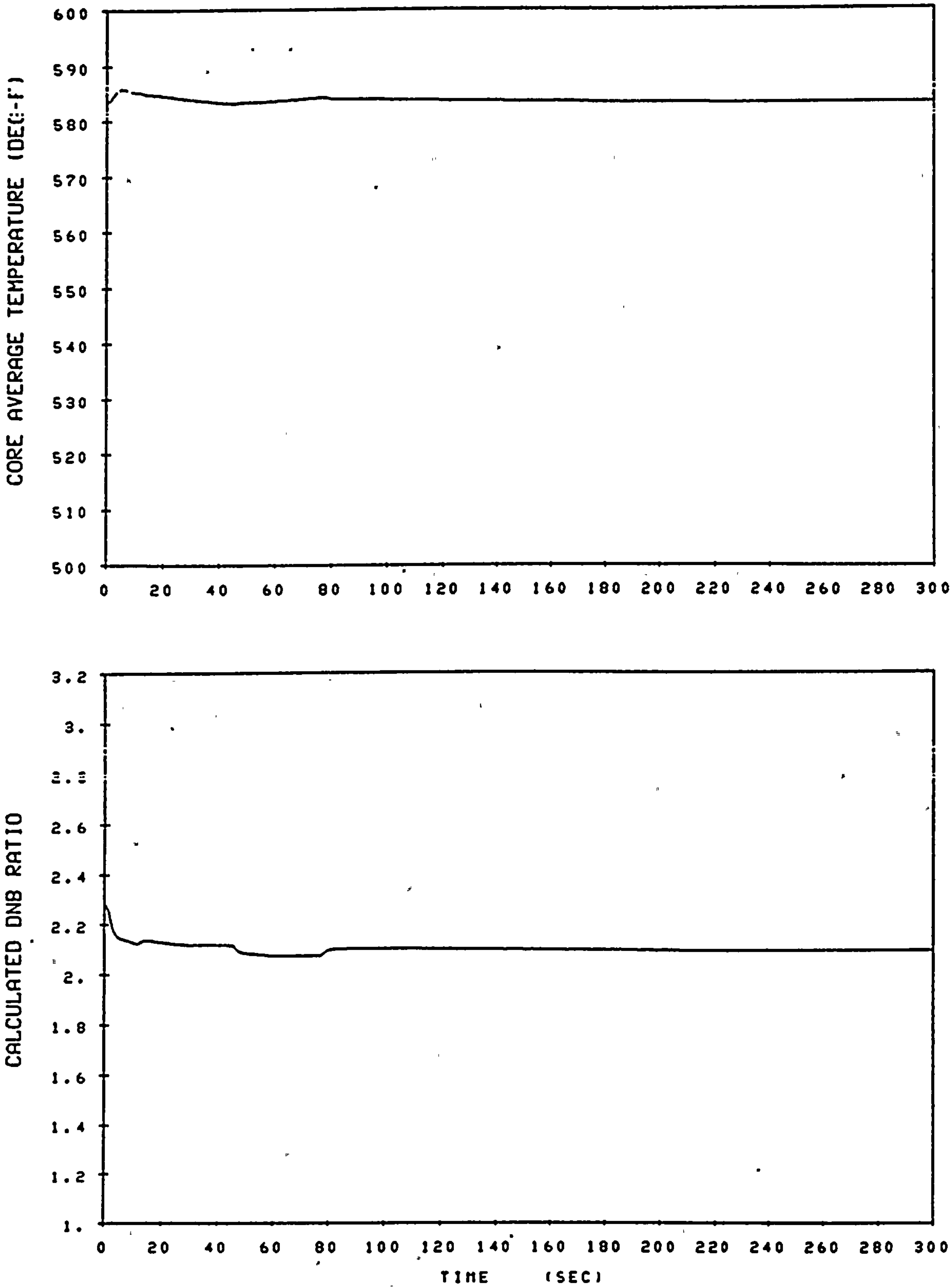


Figure B.3-50B Excessive Load Increase
Core Average Temperature and DNBR Versus Time for Minimum Reactivity Feedback with Automatic Rod Control

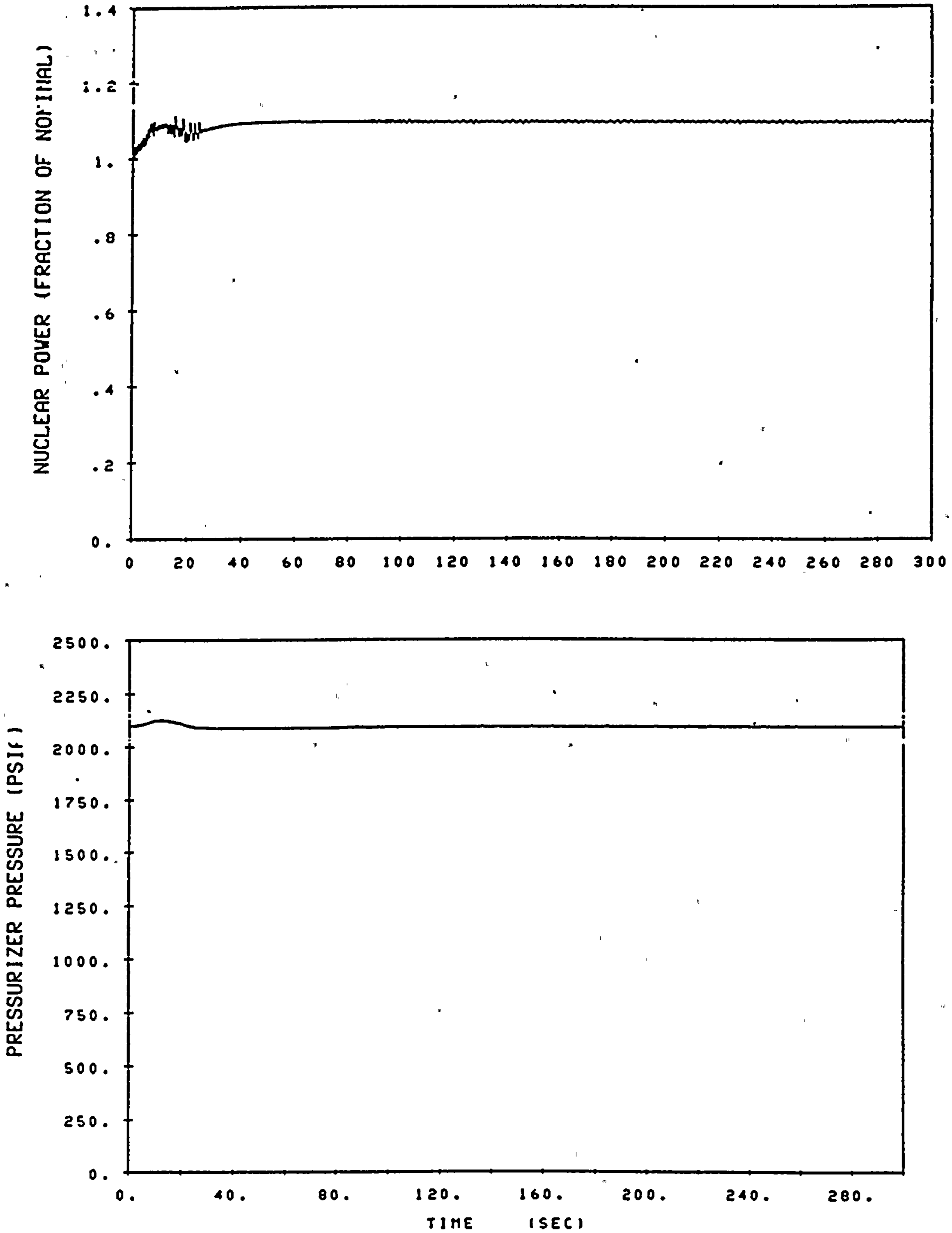


Figure B.3-51B Excessive Load Increase
Nuclear Power and Pressurizer Pressure Versus Time for Maximum Reactivity Feedback with Automatic Rod Control

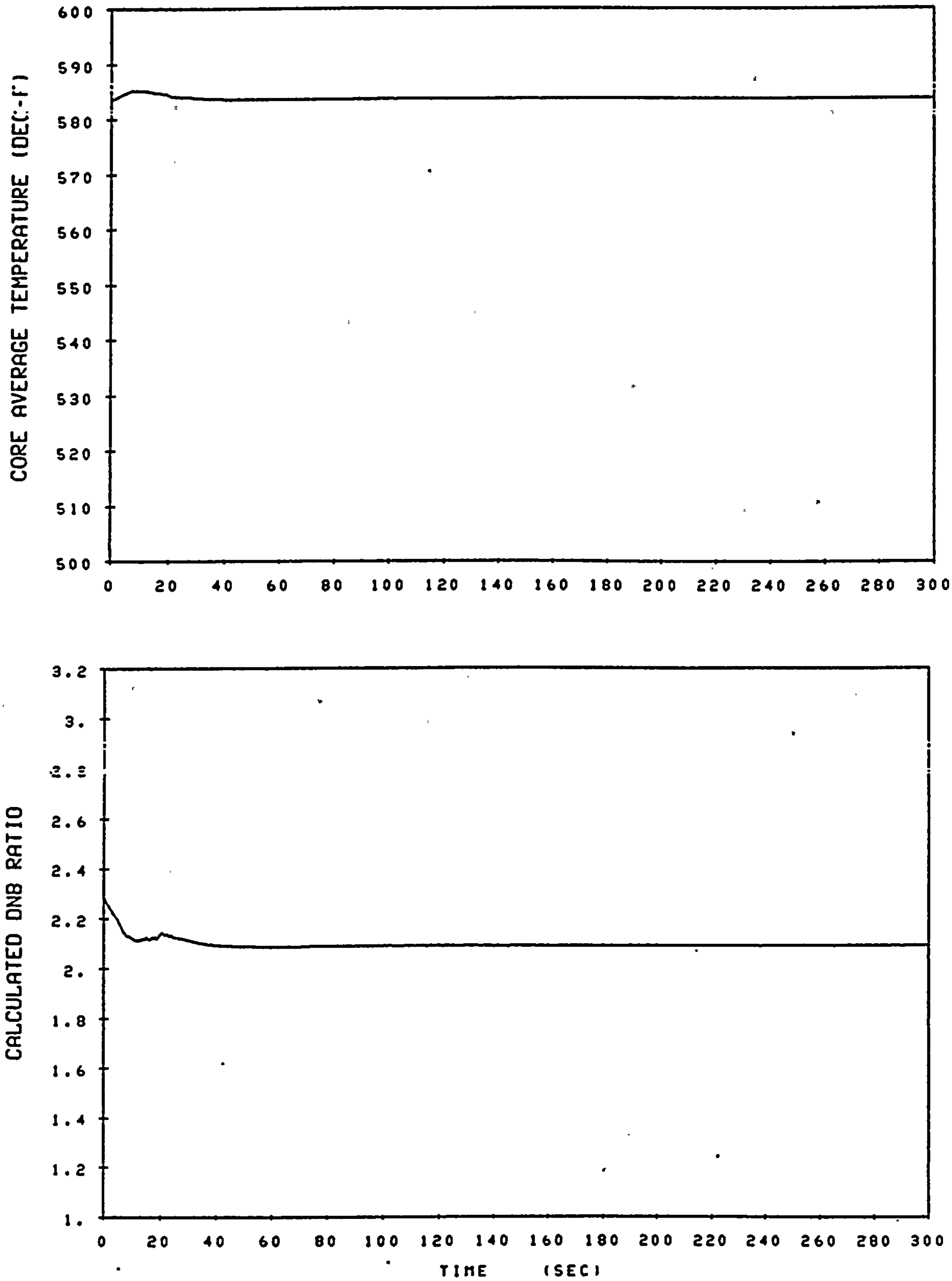


Figure B.3-52B Excessive Load Increase
Core Average Temperature and DNBR Versus Time for Maximum Reactivity Feedback with Automatic Rod Control

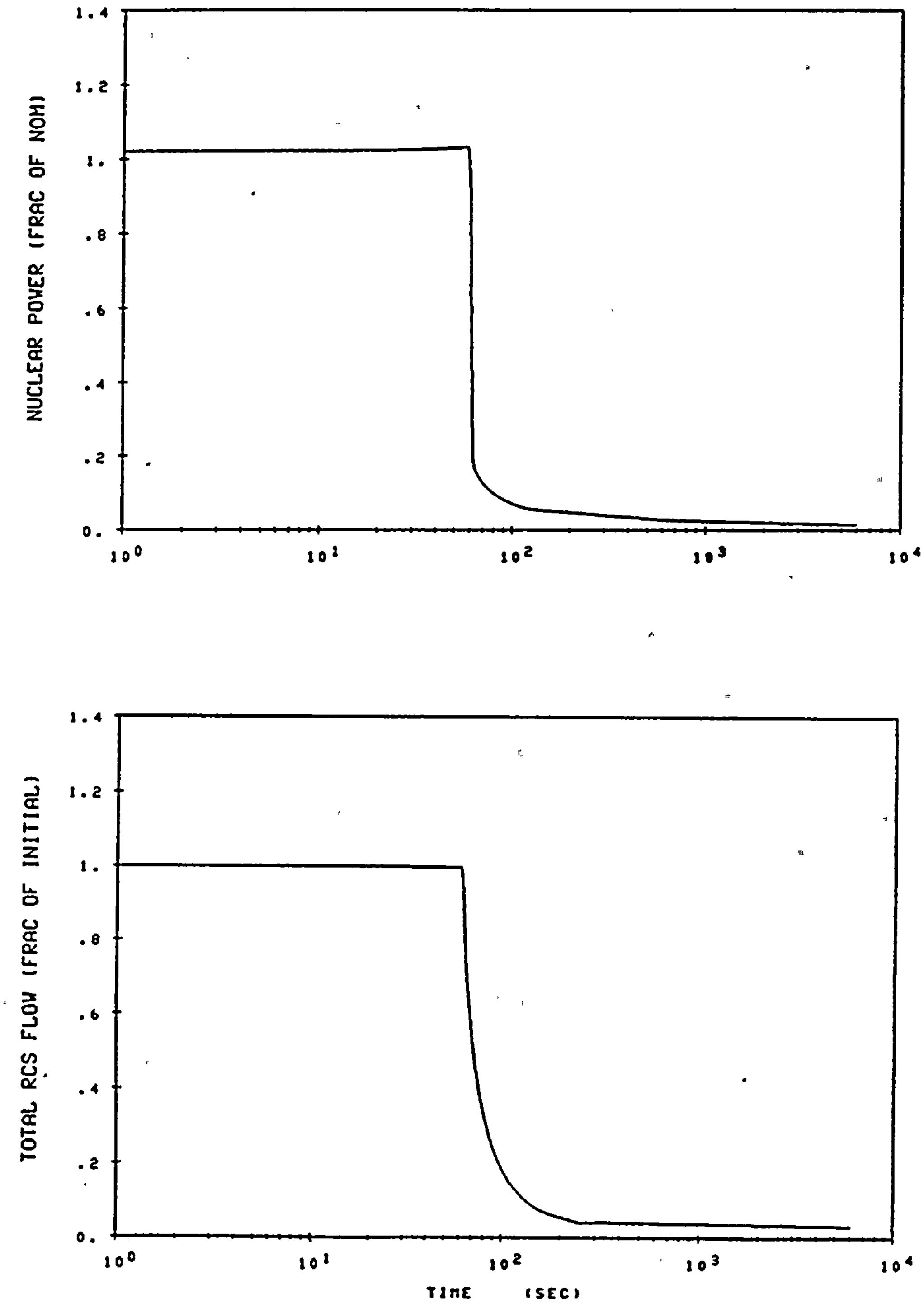


Figure B.3-53 Loss of Offsite Power to the Station Auxiliaries Nuclear Power and Core FLow Versus Time

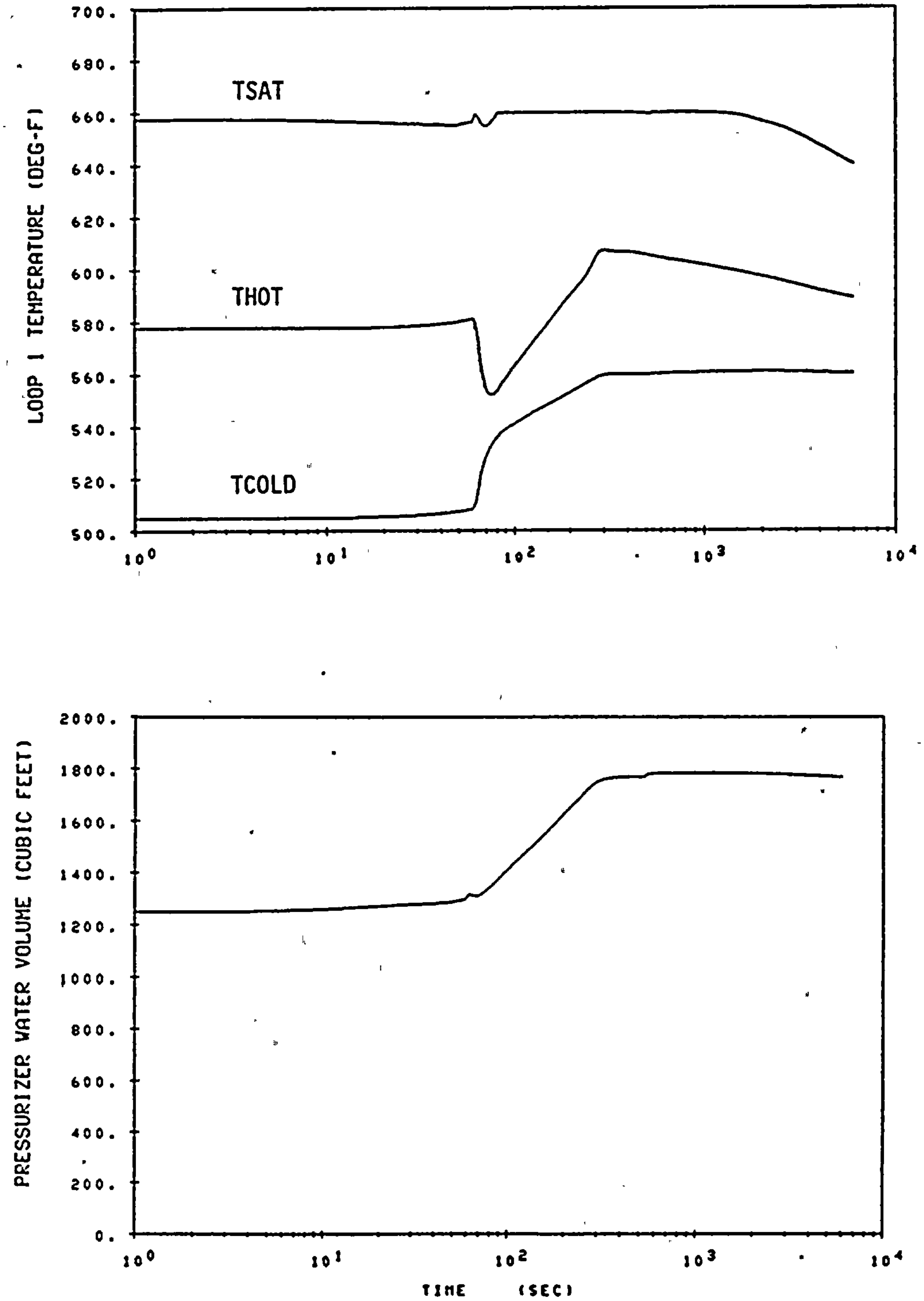


Figure B.3-54 Loss of Offsite Power to the Station Auxiliaries
Loop Temperature and Pressurizer Water Volume Versus Time

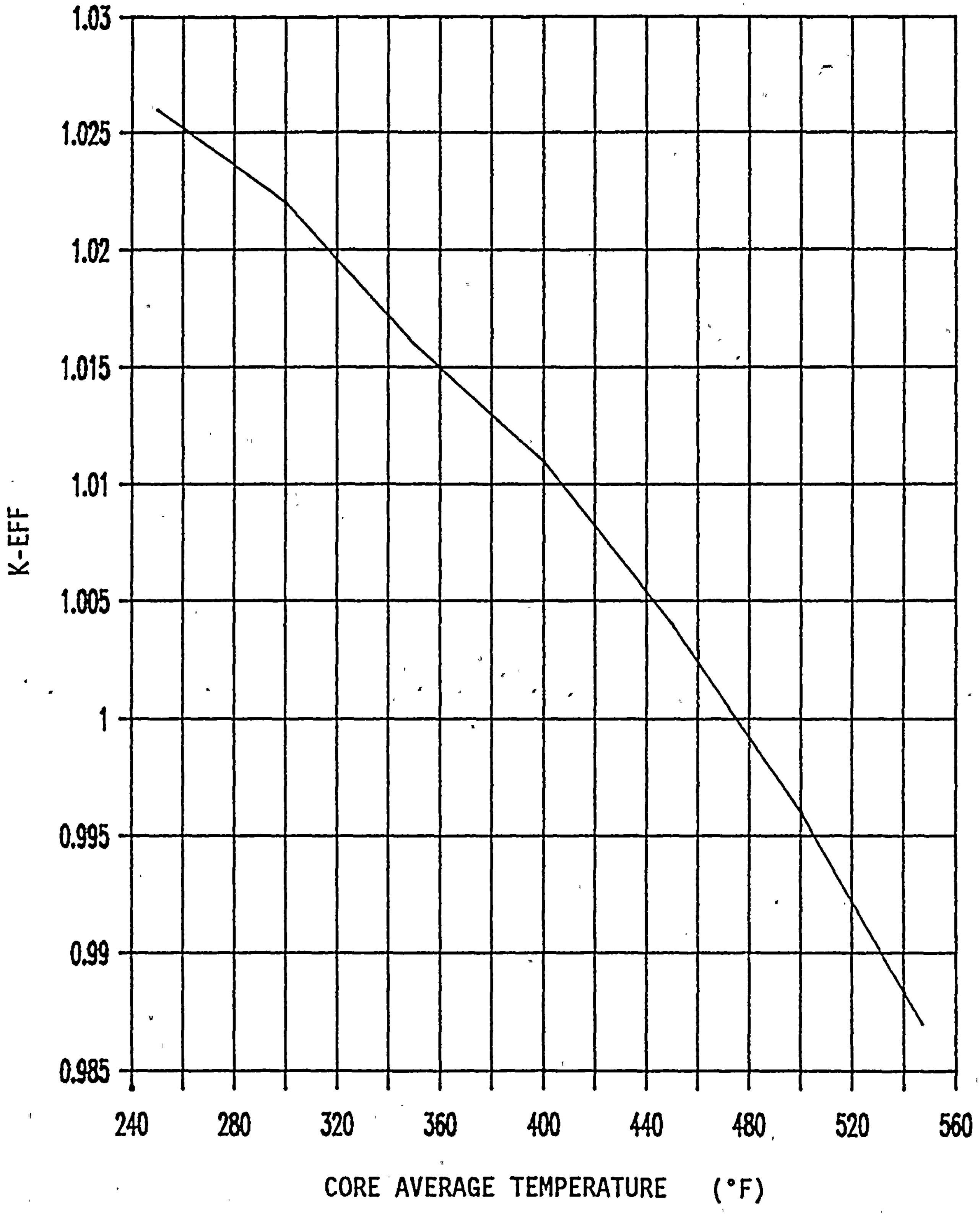


Figure B.3-55 Variation of Reactivity with Core Temperature at 1050 PSIA for the End of Life Rodded Core with One Control Rod Assembly Stuck (Assumes Zero Power)

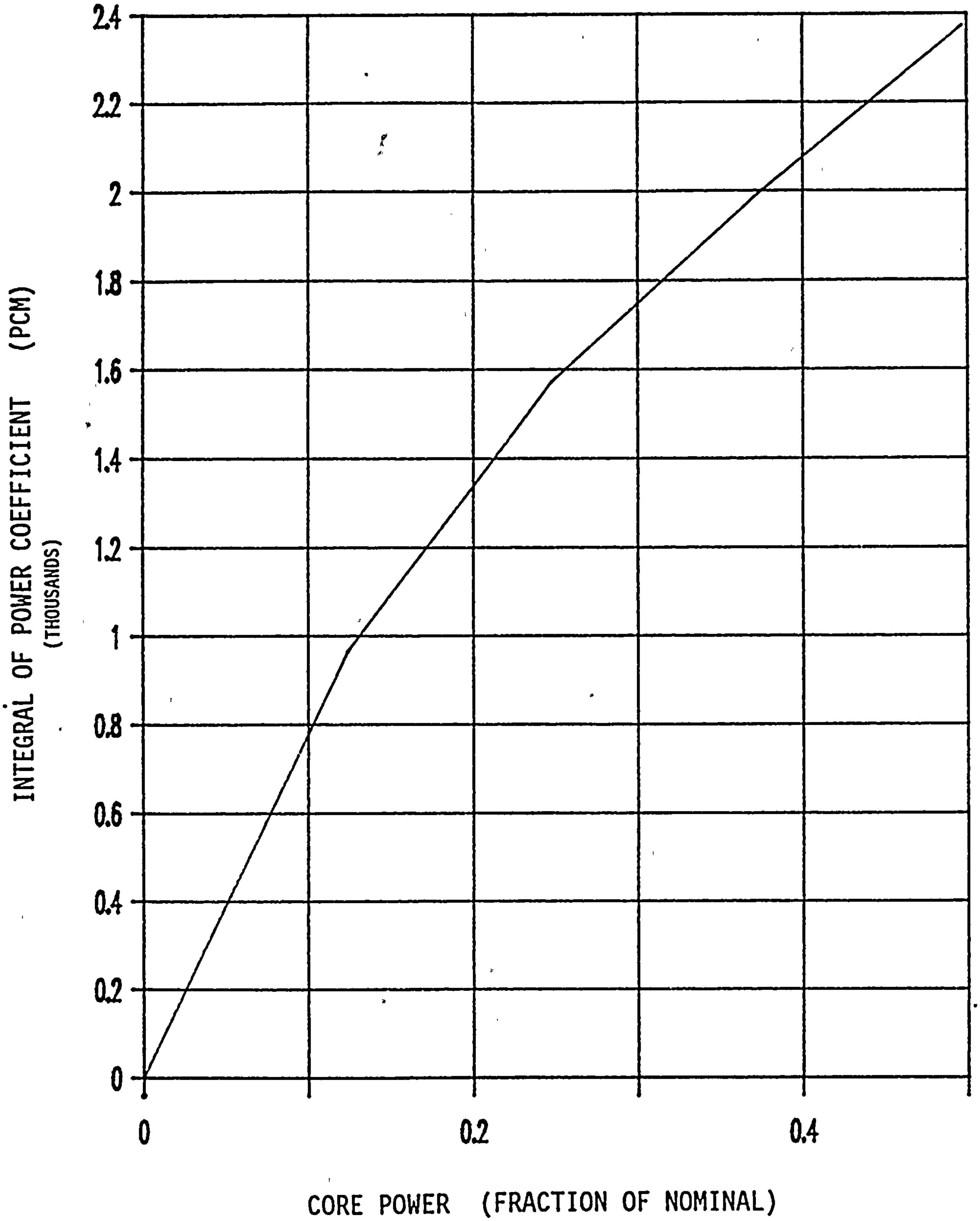


Figure B.3-56 Doppler Power Feedback for Steamline Break

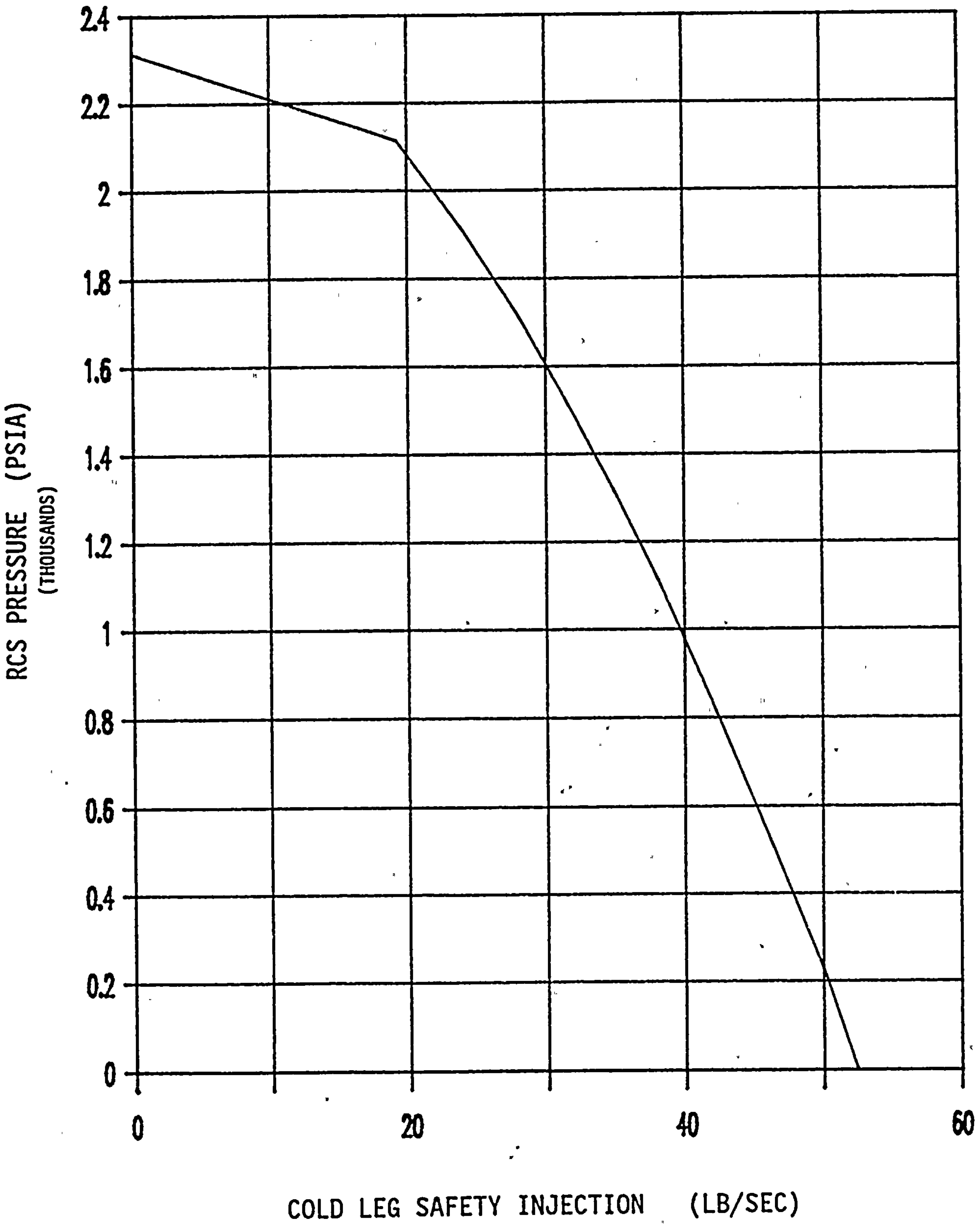


Figure B.3-57 Safety Injection Flow Supplied by One Charging Pump

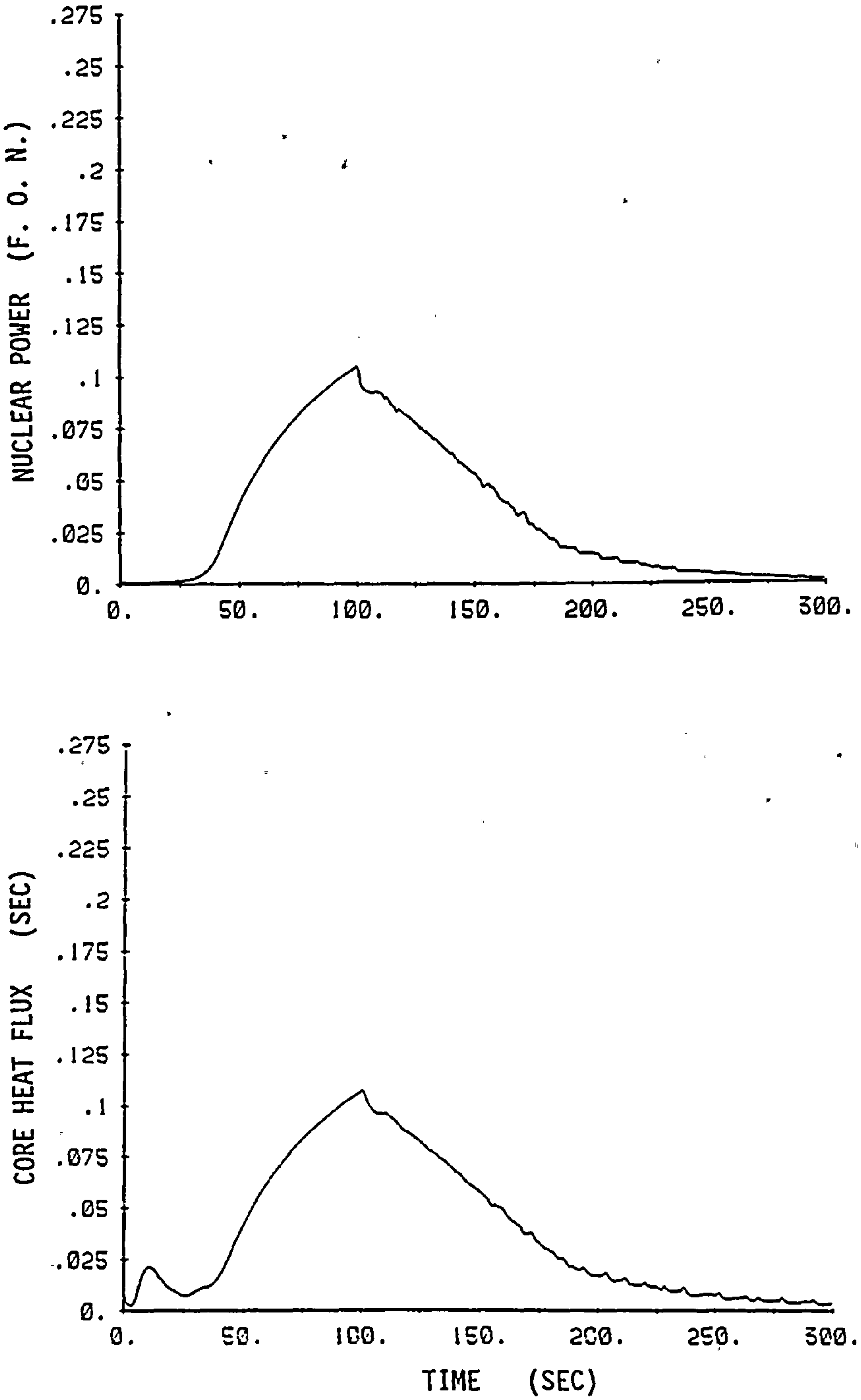


Figure B.3-58 Nuclear Power and Core Heat Flux Versus Time Steamline Break DER Inside Containment with Power

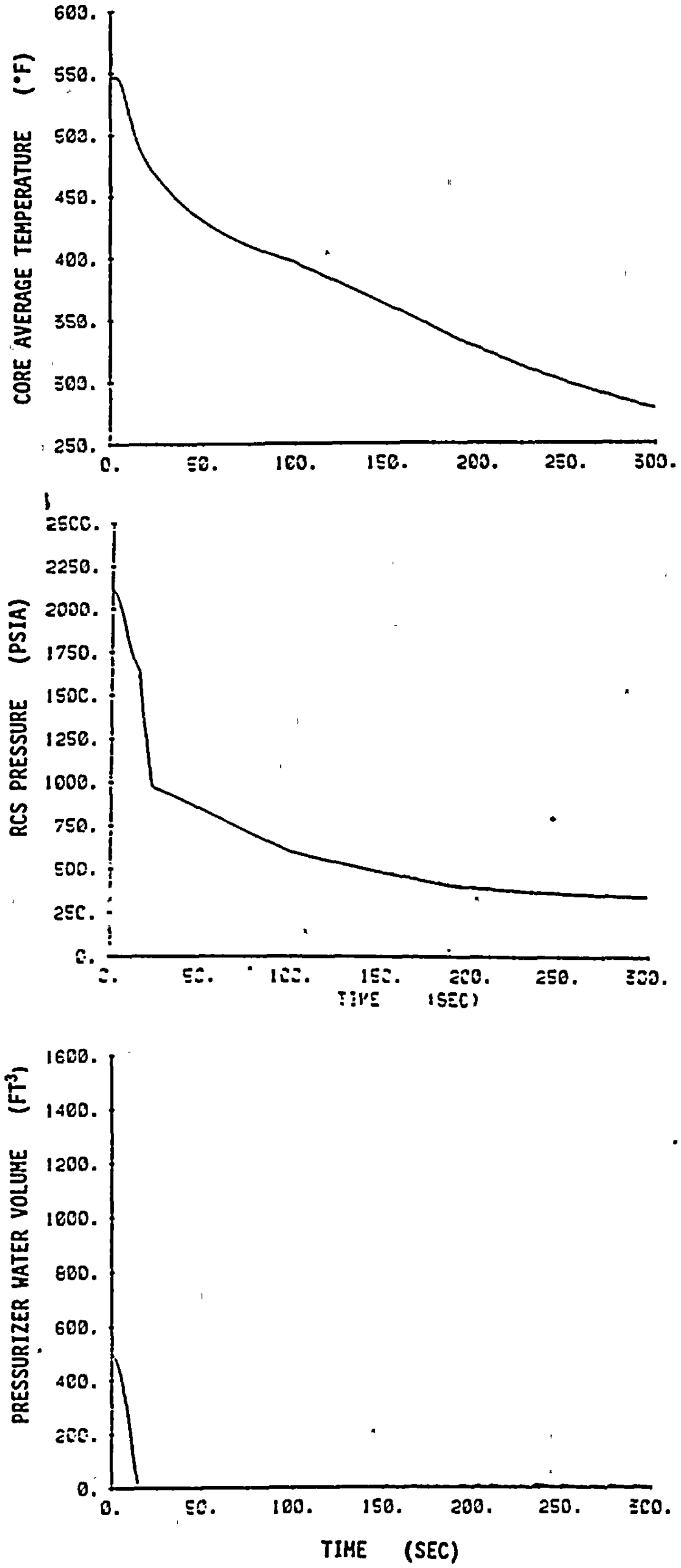


Figure B.3-59 Core Average Temperature, RCS Pressure, and Pressurizer Water Volume Versus Time Steamline Break DER Inside Containment with Power

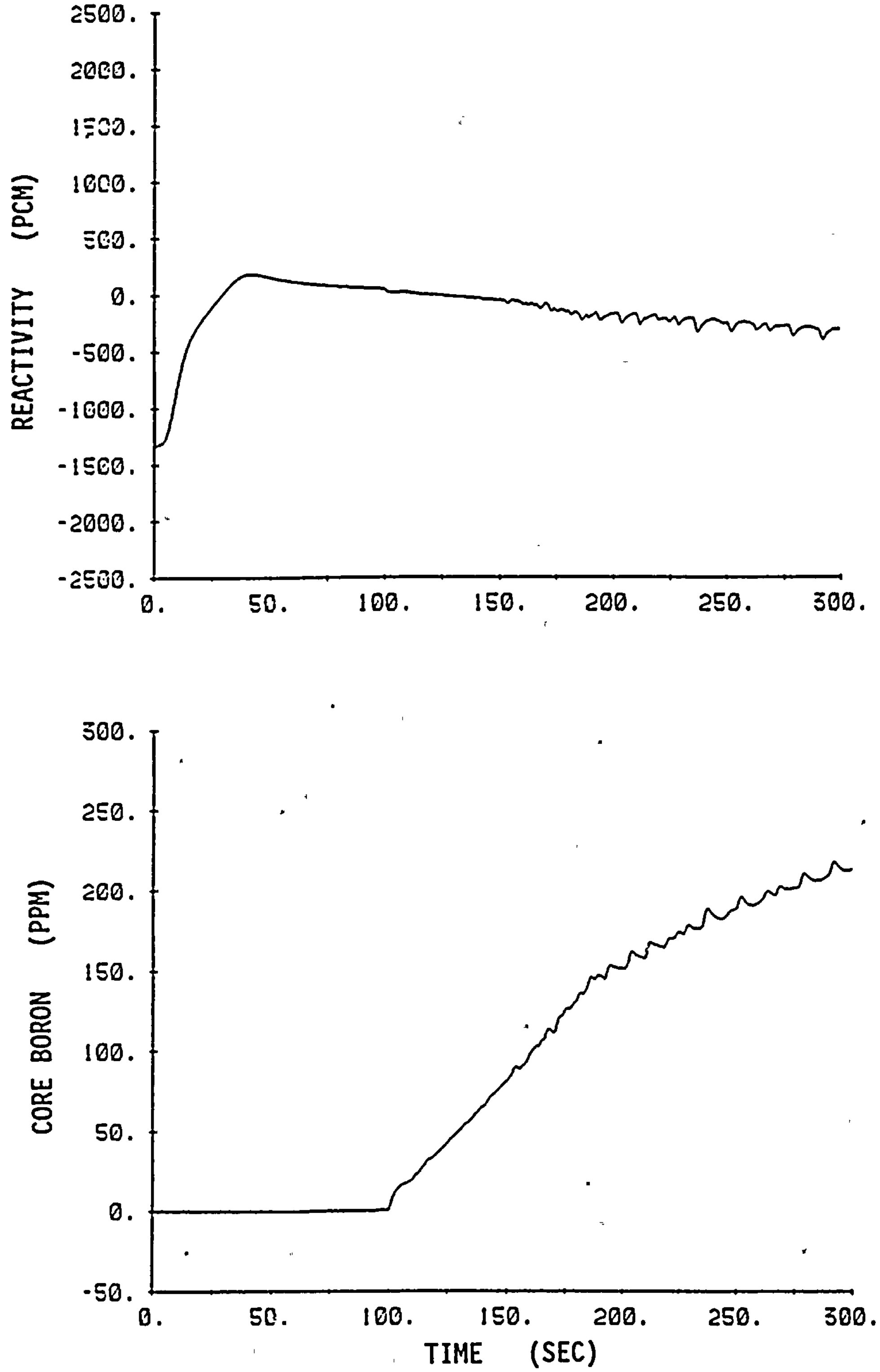


Figure B.3-60 Reactivity and Core Boron Concentration Versus Time
Steamline Break DER Inside Containment with Power

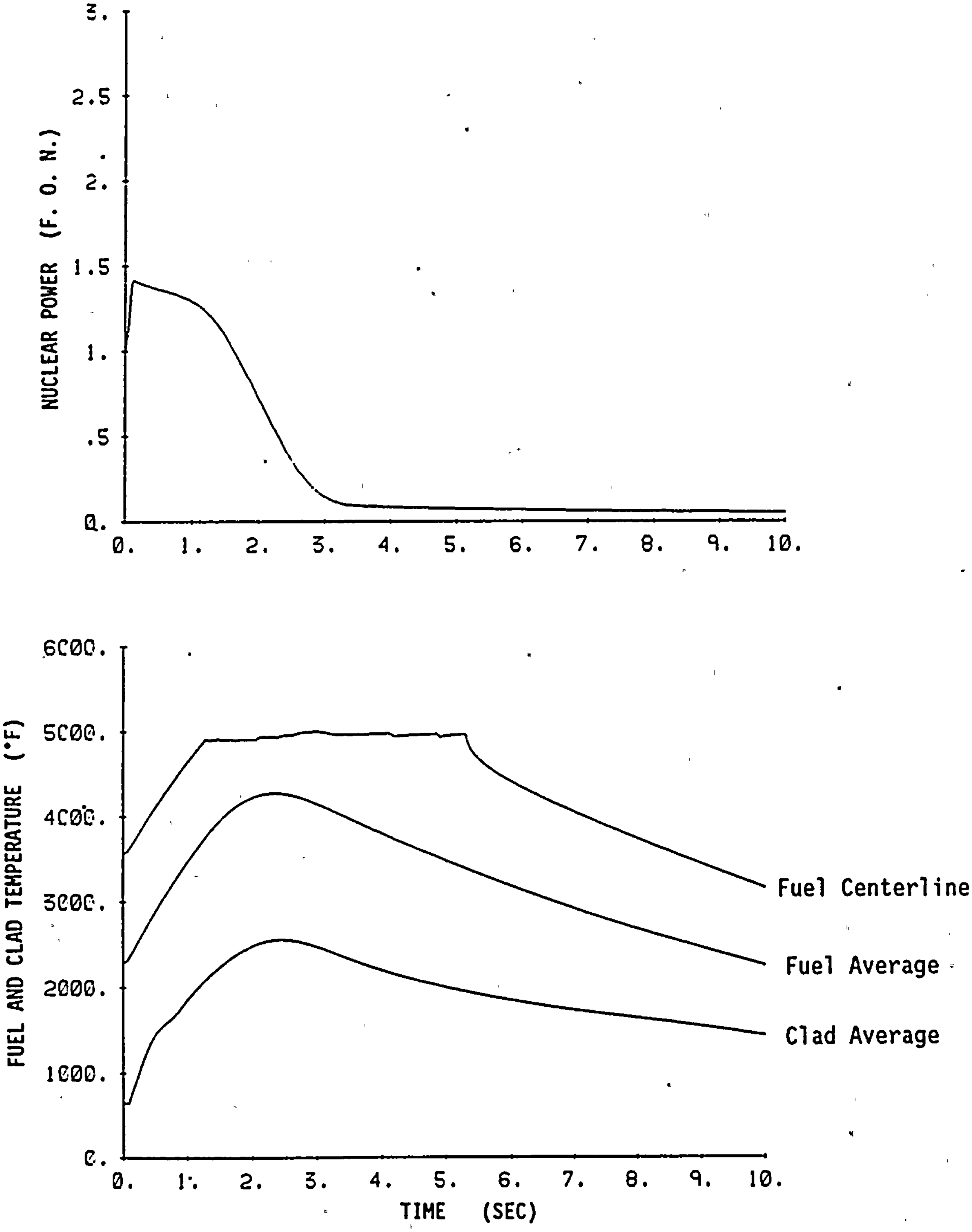


Figure B.3-61 Rod Ejection
Nuclear Power and Fuel Clad Temperature Versus Time for Hot Full Power at Beginning of Life

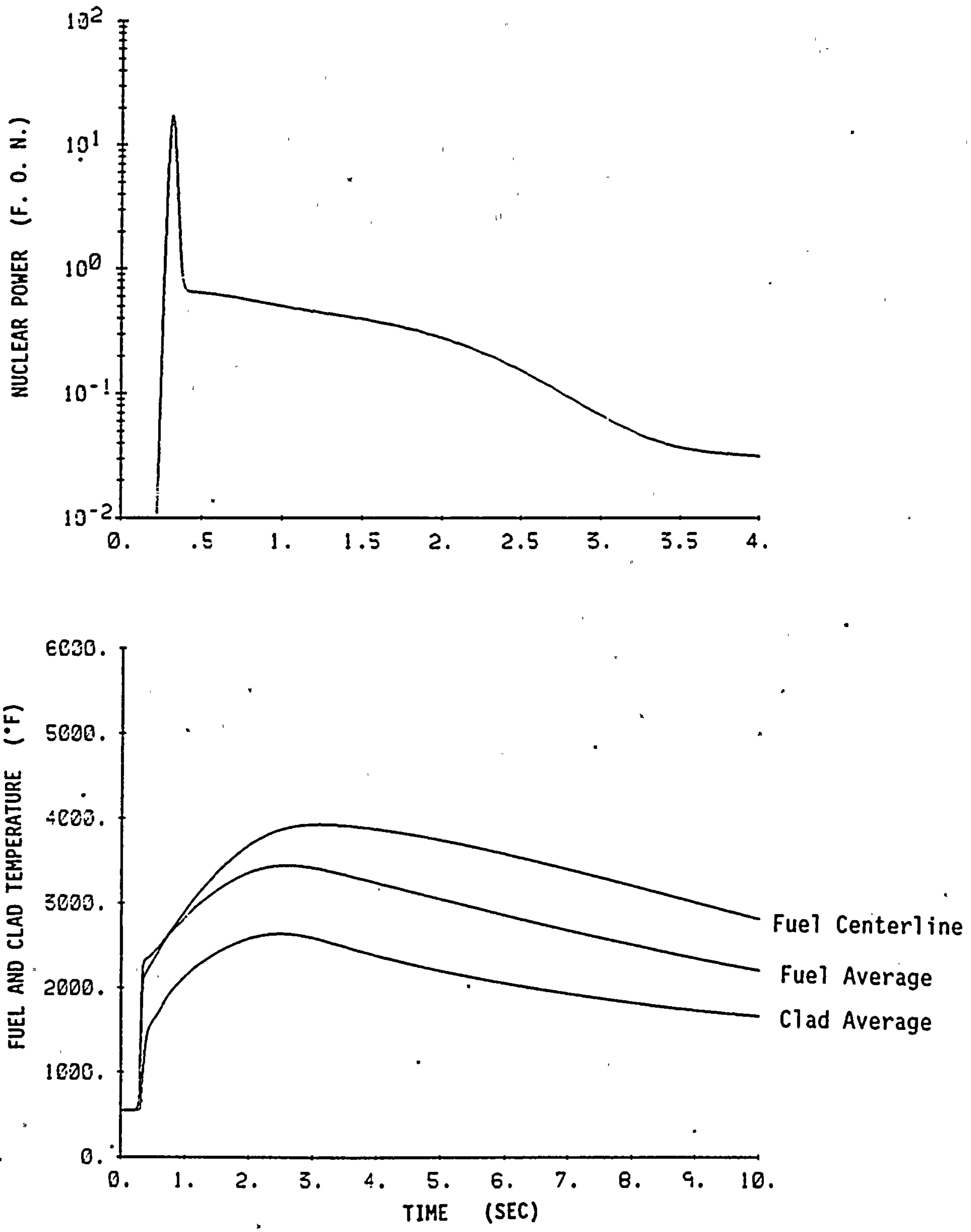


Figure B.3-62 Rod Ejection
Nuclear Power and Fuel and Clad Temperatures Versus Time for
Hot Zero Power at Beginning of Life

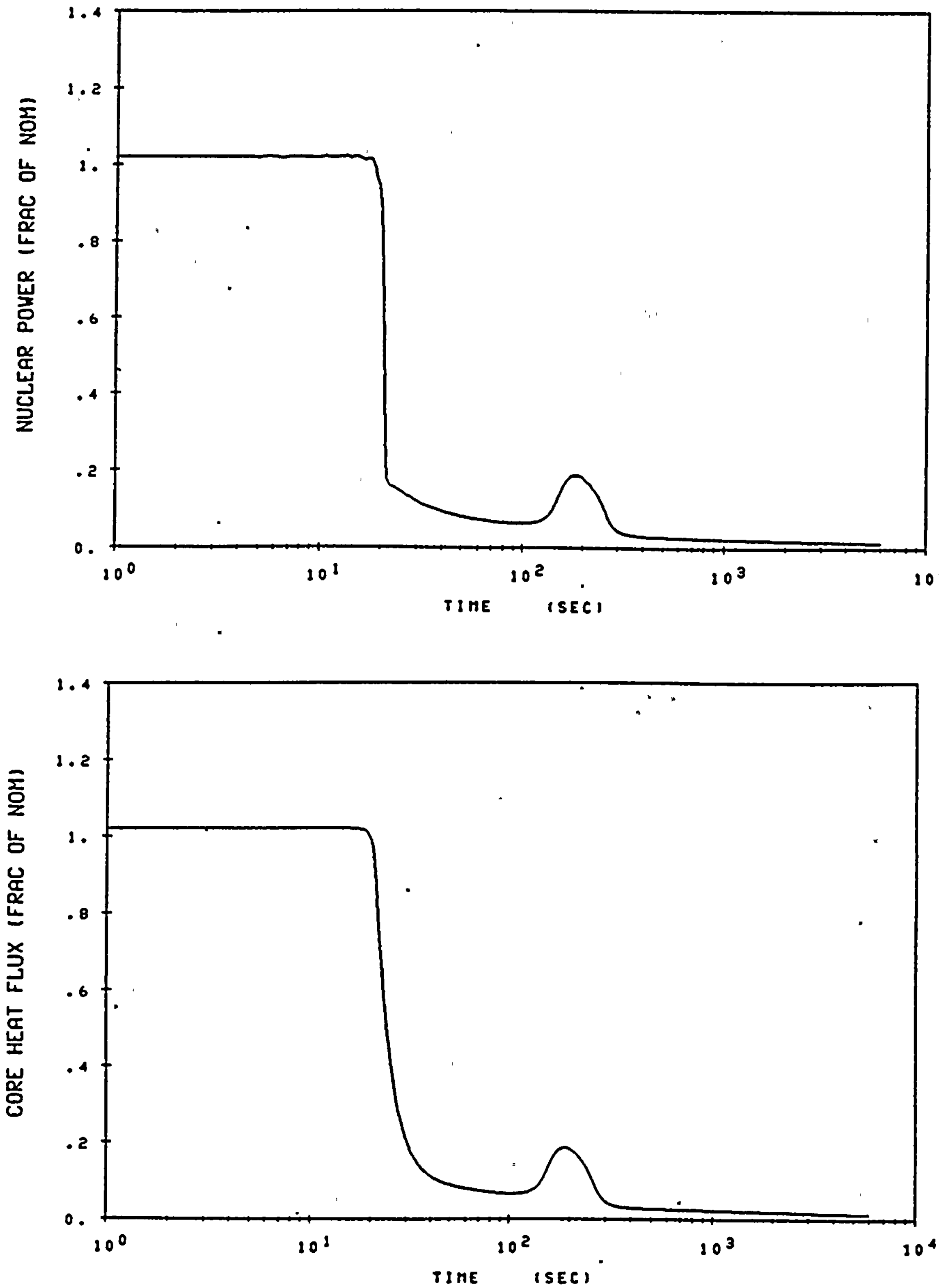


Figure B.3-63 Feedline Break With Power
Nuclear Power and Core Heat Flux Versus Time

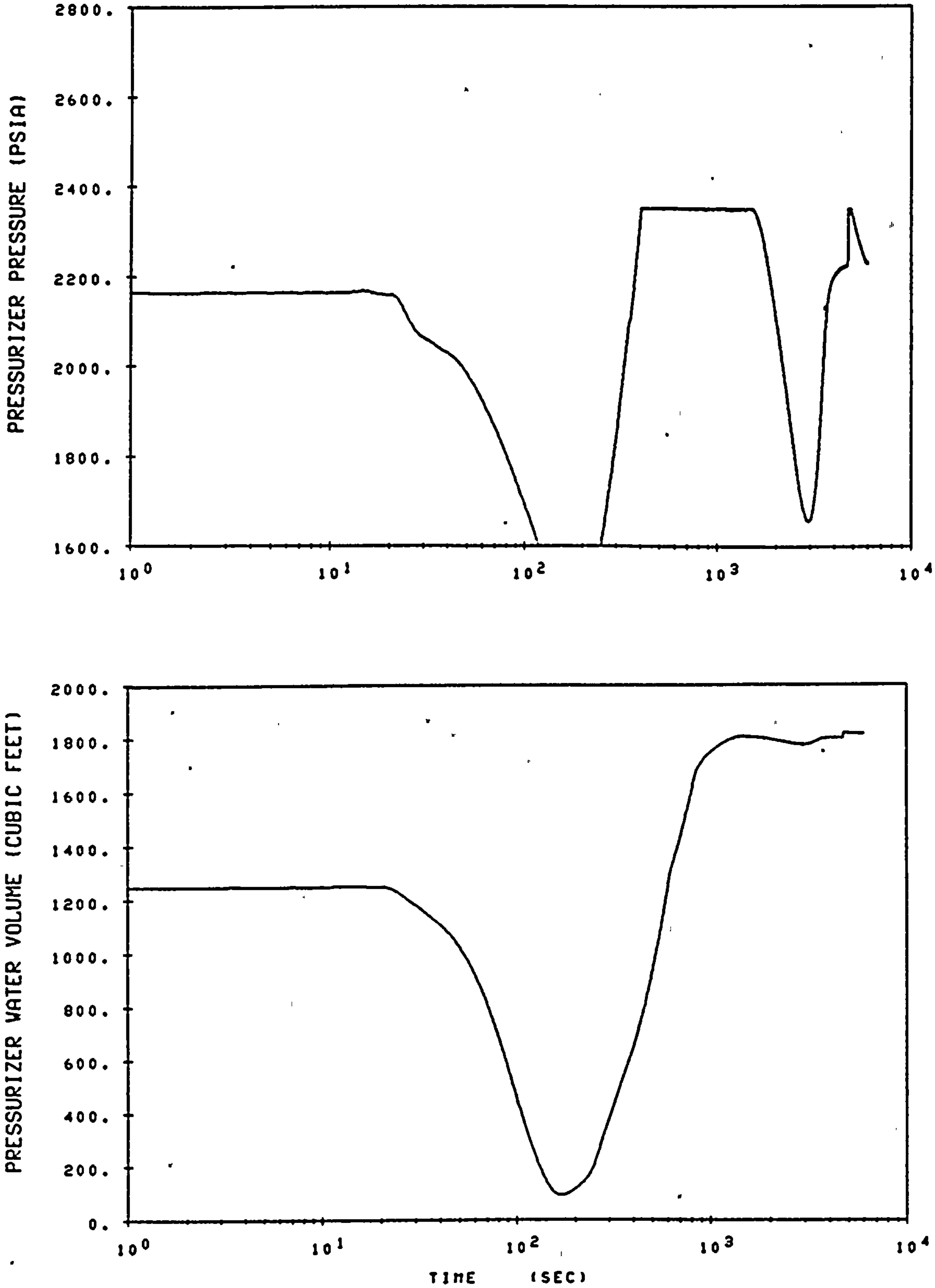


Figure B.3-64 Feedline Break with Power
Pressurizer Pressure and Pressurizer Water Volume Versus Time

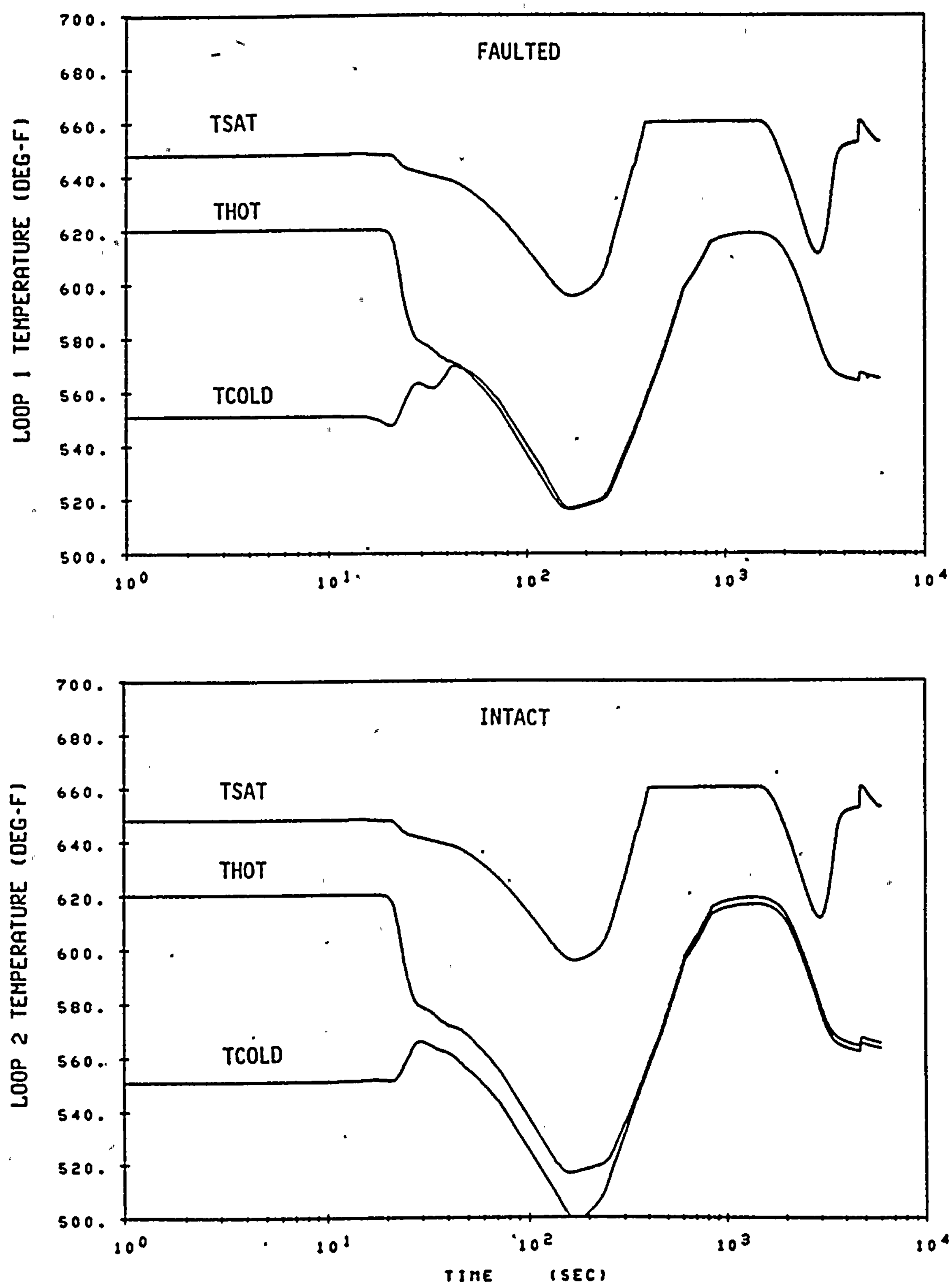


Figure B.3-65 Feedline Break with Power
Faulted and Non-Faulted Loop Temperatures Versus Time

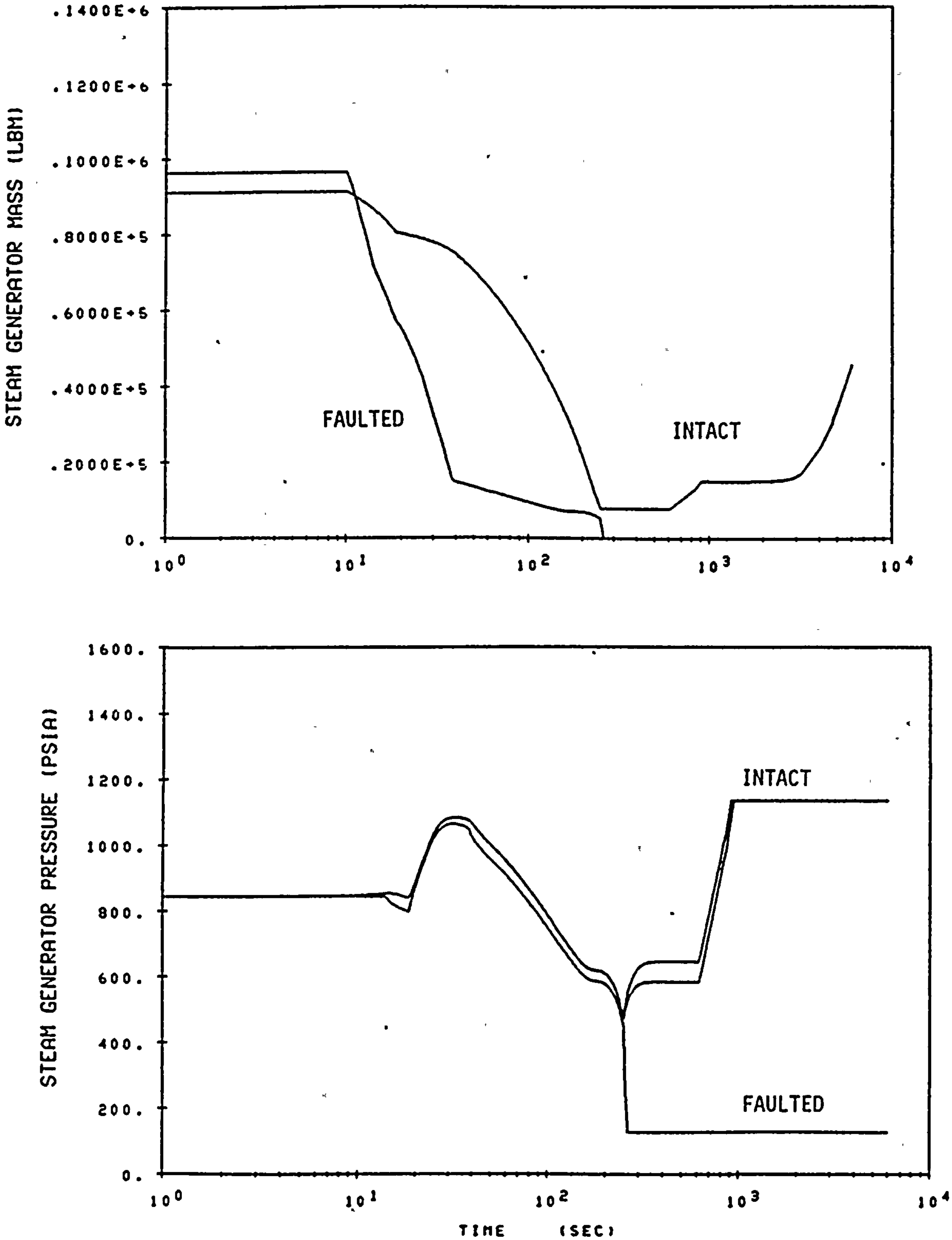


Figure B.3-66 Feedline Break With Power
Steam Generator Mass and Steam Generator Pressure Versus Time

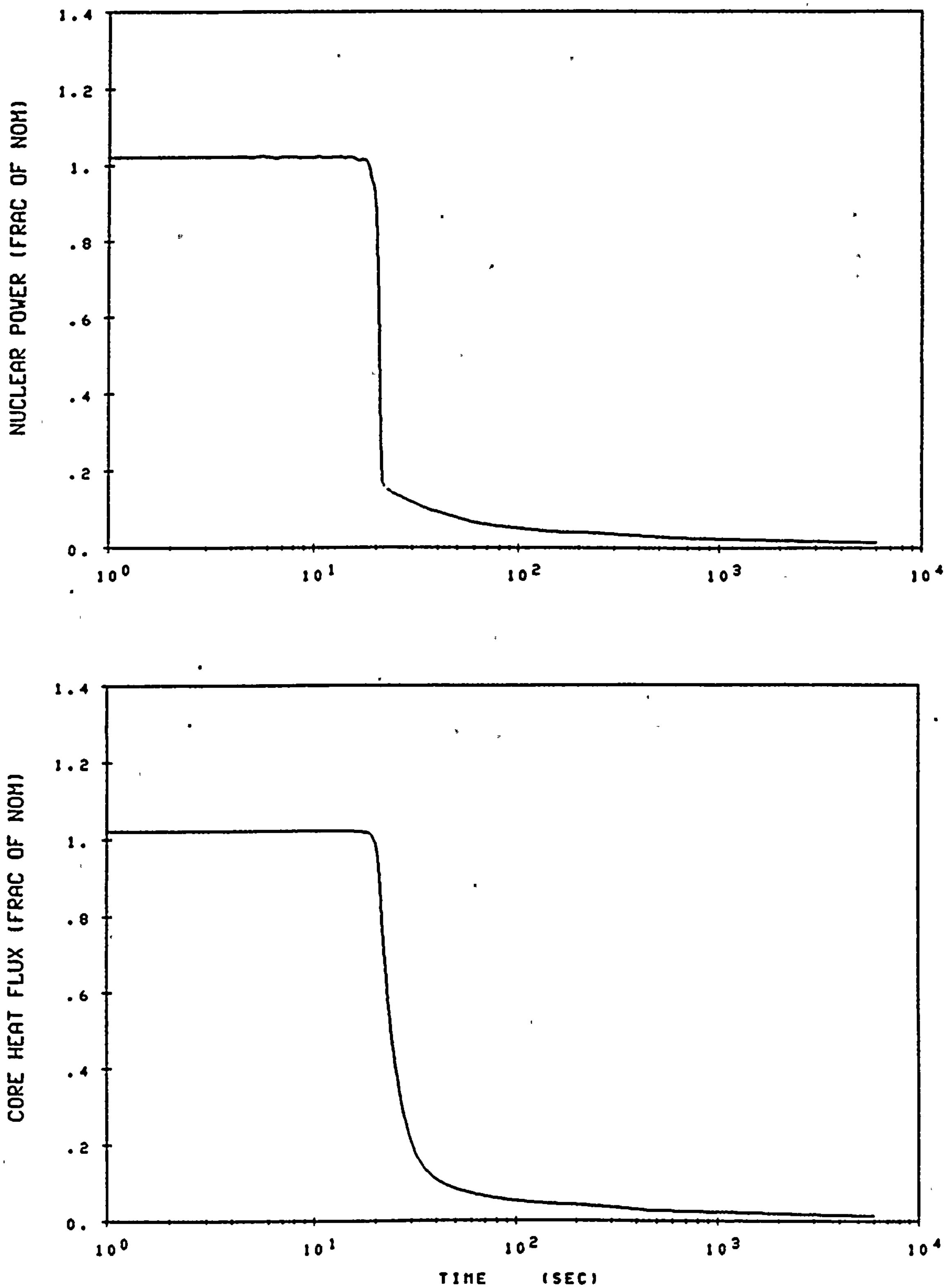


Figure B.3-67 Feedline Break without Power
Nuclear Power and Core Heat Flux Versus Time

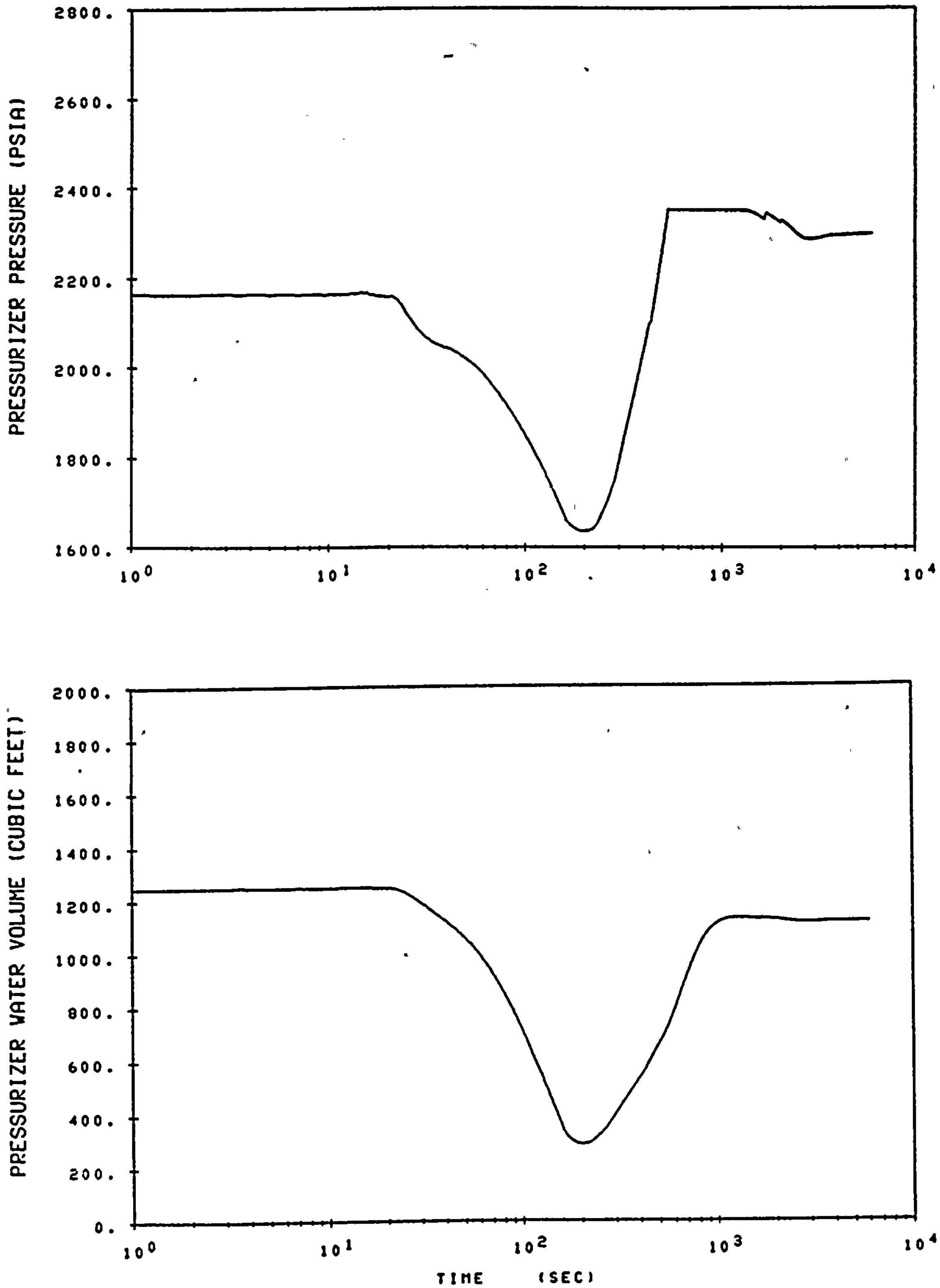


Figure B.3-68 Feedline Break without Power
Pressurizer Pressure and Pressurizer Water Volume Versus Time

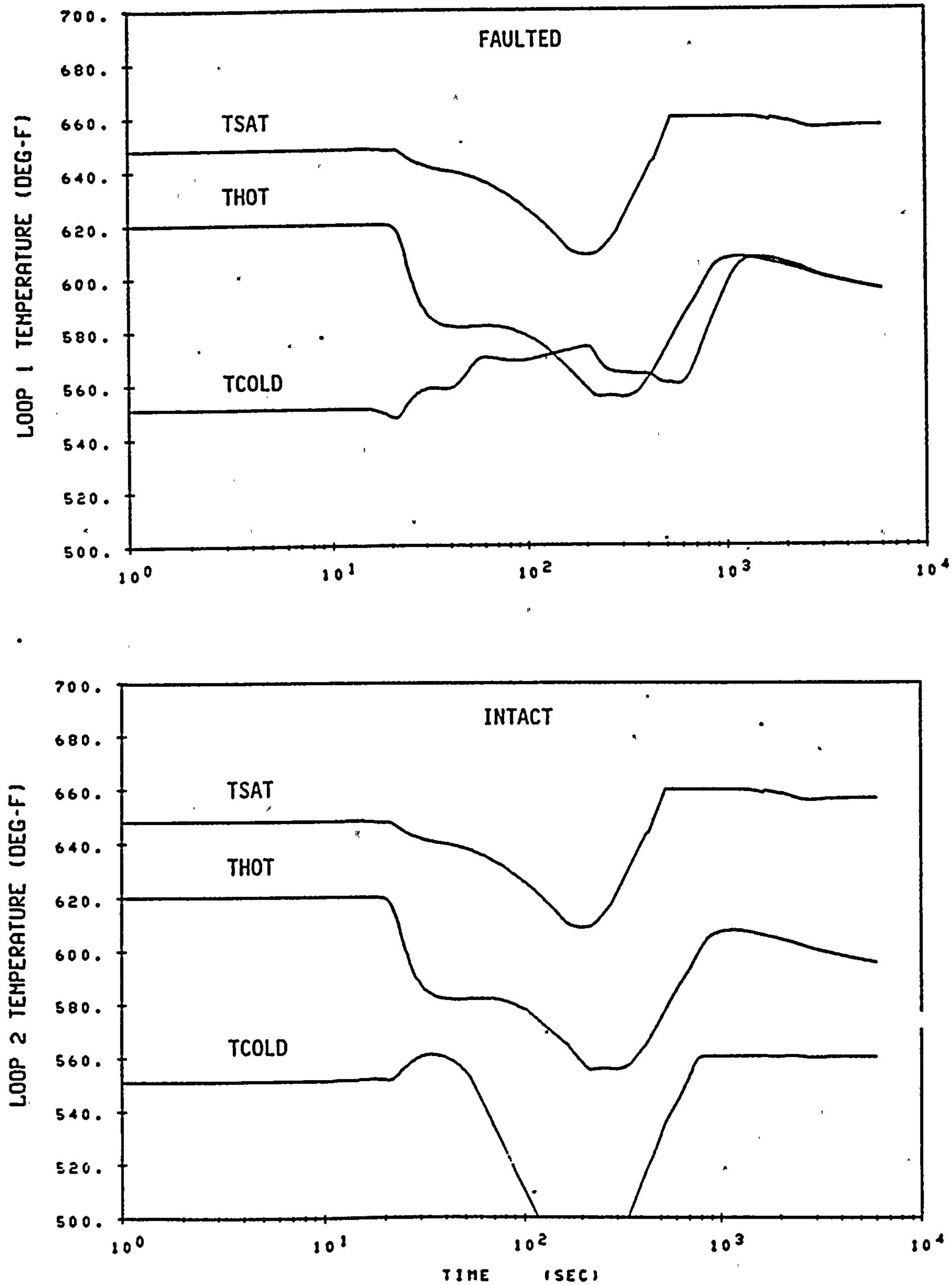
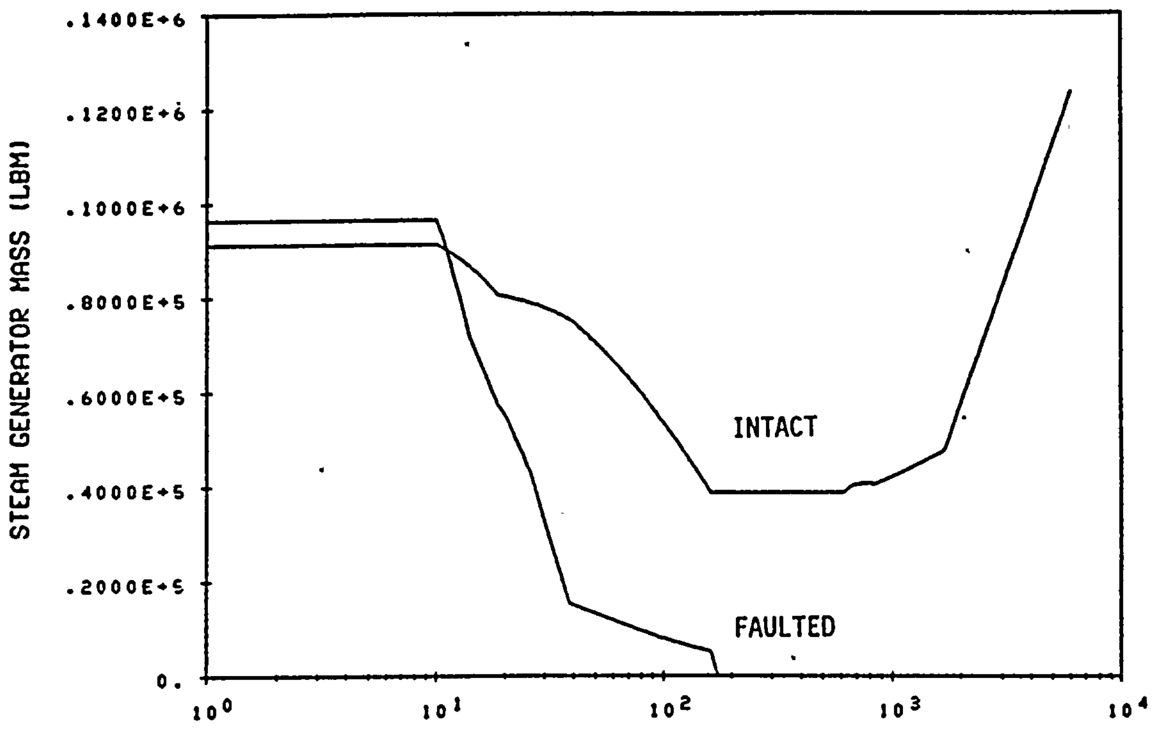


Figure B.3-69 Feedline Break Without Power
Faulted and Non-Faulted Loop Temperatures Versus Time



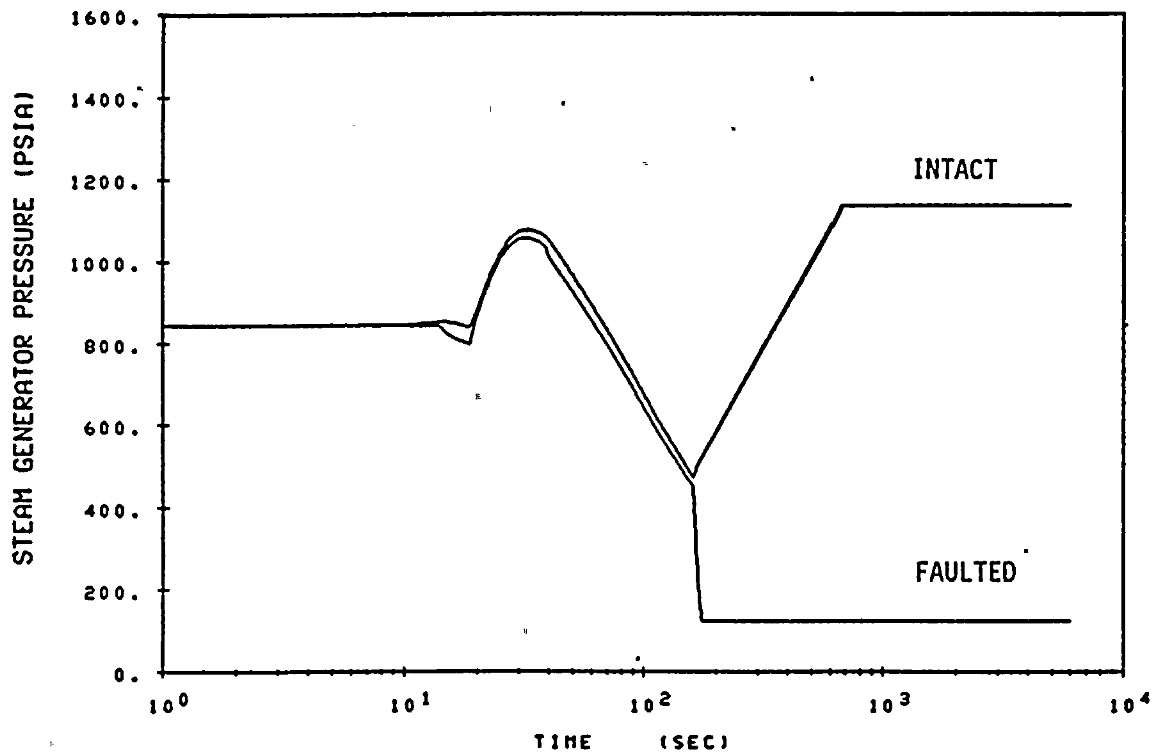


Figure B.3-70 Feedline Break Without Power
Steam Generator Mass and Steam Generator Pressure Versus Time

APPENDIX C

LOCA ANALYSES

FOR THE

DONALD C. COOK NUCLEAR PLANT UNIT 2

TRANSITION TO 17x17 VANTAGE 5 FUEL

C.3.1.2 MAJOR LOCA ANALYSES APPLICABLE TO WESTINGHOUSE FUEL

Identification of Causes and Frequency Classification

A loss-of-coolant accident (LOCA) is the result of a pipe rupture of the RCS pressure boundary. For the analyses reported here, a major pipe break (large break) is defined as a rupture with a total cross-sectional area equal to or greater than 1.0 ft^2. This event is considered an ANS Condition IV event, a limiting fault, in that it is not expected to occur during the lifetime of the Donald C. Cook Nuclear Plant Unit 2, but is postulated as a conservative design basis.

The Acceptance Criteria for the LOCA are described in 10 CFR 50.46 (10 CFR 50.46 and Appendix K of 10 CFR 50 1974)[1] as follows:

1. The calculated peak fuel element clad temperature is below the requirement of 2200°F.

2. The amount of fuel element cladding that reacts chemically with water or steam to generate hydrogen, does not exceed 1 percent of the total amount of Zircaloy in the fuel rod cladding.

3. The clad temperature transient is terminated at a time when the core geometry is still amenable to cooling. The localized cladding oxidation limit of 17 percent is not exceeded during or after quenching.

4. The core remains amenable to cooling during and after the break.

5. The core temperature is reduced and decay heat is removed for an extended period of time, as required by the long-lived radioactivity remaining in the core.

These criteria were established to provide a significant margin in emergency core cooling system (ECCS) performance following a LOCA. WASH-1400 (USNRC 1975)[10] presents a study in regards to the probability of occurrence of RCS pipe ruptures.

Sequence of Events and Systems Operations

Should a major break occur, depressurization of the RCS results in a pressure decrease in the pressurizer. Loss-Of-Offsite Power (LOOP) is assumed coincident with the occurence of the break. The reactor trip signal subsequently occurs when the pressurizer low pressure trip setpoint is reached. A safety injection signal is generated when the appropriate setpoint is reached.

These countermeasures will limit the consequence of the accident in two ways:

1. Reactor trip and borated water injection supplement void formation in causing rapid reduction of power to the residual level corresponding to fission product decay heat. No credit is taken in the LOCA analysis for the boron content of the injection water, however an average RCS/sump mixed boron concentration is calculated to ensure that the core remains subcritical. In addition, the insertion of control rods to shut down the reactor is neglected in the large break analysis.

2. Injection of borated water provides for heat transfer from the core and prevents excessive clad temperatures.

In the present Westinghouse design, the large break single failure is the loss of one RHR (low head) pump. This means that credit could be taken for two high head charging pumps, two safety injection pumps, and one low head pump. The following is a discussion of the modelling procedure for the minimum safeguards and the flow splitting from a break of an ECCS branch injection line (i.e., the spilling line assumptions).

The current procedure for large break analyses assumes that at least one train of ECCS is available for delivery of water to the RCS. Although the single failure is an RHR pump, only one pump in each subsystem is assumed to deliver to the primary loops. However, both Emergency Diesel Generators (EDGs) are assumed to start in the modelling of the containment deck fans and sprays. Modelling full containment heat removal systems operation is required by Branch Technical Position CSB 6-1 and is conservative for the large break LOCA. The high head charging pump starts and delivers flow through the injection lines (one per loop) with one branch injection line spilling to the containment backpressure. To minimize delivery to the reactor, the branch line chosen to spill

is selected as the one with the minimum resistance. When one safety injection pump and one low head residual heat removal pump start, flow is delivered to the reactor coolant system through the accumulator injection lines. Again, one line, with the minimum resistance, is assumed to spill to containment backpressure. In addition, all safety injection pump performance curves were degraded by 10% and a 25 gpm flow imbalance was assumed for the high head charging pumps.

Therefore, in the large break ECCS analysis performed by Westinghouse, single failure is conservatively accounted for via the loss of an ECCS train, and the spilling of the minimum resistance injection line despite full containment active heat removal system operation (i.e., two EDGs).

The time sequence of events following a large break LOCA is presented in Table C.3.1-5. The safety injection performance, as modelled for the large break LOCA, is presented in Figures C.3.1.1 and C.3.1.2.

Before the break occurs, the unit is in an equilibrium condition; that is, the heat generated in the core is being removed via the secondary system. During blowdown, heat from fission product decay, hot internals and the vessel, continues to be transferred to the reactor coolant. At the beginning of the blowdown phase, the entire RCS contains subcooled liquid which transfers heat from the core by forced convection with some fully developed nucleate boiling. After the break develops, the time to departure from nucleate boiling is calculated, consistent with Appendix K of 10 CFR 50[1]. Thereafter, the core heat transfer is unstable, with both nucleate boiling and film boiling occurring. As the core becomes uncovered, both turbulent and laminar forced convection and radiation are considered as core heat transfer mechanisms.

The heat transfer between the RCS and the secondary system may be in either direction, depending on the relative temperatures. In the case of continued heat addition to the secondary system, the secondary system pressure increases and the main steam safety valves may actuate to limit the pressure. Makeup water to the secondary side is automatically provided by the auxiliary feedwater system. The safety injection signal actuates a feedwater isolation signal which isolates main feedwater flow by closing the main feedwater isolation valves, and also initiates auxiliary feedwater flow by starting the auxiliary feedwater pumps. The secondary flow aids in the reduction of RCS pressure.

When the RCS depressurizes to 600 psia, the accumulators begin to inject borated water into the reactor coolant loops. The conservative assumption is made that accumulator water injected bypasses the core and goes out through the break until the termination of bypass. This conservatism is again consistent with Appendix K of 10 CFR 50. Since loss of offsite power (LOOP) is assumed, the RCPs are assumed to trip at the inception of the accident. The effects of pump coastdown are included in the blowdown analysis.

The blowdown phase of the transient ends when the RCS pressure (initial values with uncertainty assumed to range from 2037 to 2313 psia) falls to a value approaching that of the containment atmosphere. Prior to or at the end of the blowdown, the mechanisms that are responsible for the emergency core cooling water bypassing the core, are calculated not to be effective. At this time (called end-of-bypass) refill of the reactor vessel lower plenum begins. Refill is completed when emergency core cooling water has filled the lower plenum of the reactor vessel, which is bounded by the bottom of the fuel rods (called bottom of core recovery time).

The reflood phase of the transient is defined as the time period lasting from the bottom of core recovery until the reactor vessel has been filled with water to the extend that the core temperature rise has been terminated. From the latter stage of blowdown and then the beginning-of-reflood, the safety injection accumulator tanks rapidly discharge borated cooling water into the RCS, contributing to the filling of the reactor vessel downcomer. The downcomer water elevation heat provides the driving force required for the reflooding of the reactor core. The RHR (low head), safety injection and high head charging pumps aid in the filling of the downcomer and, subsequently, supply water to maintain a full downcomer and complete the reflooding process.

Continued operation of the ECCS pumps supplies water during long-term cooling. Core temperatures have been reduced to long-term steady state levels associated with the dissipation of residual heat generation. After the water level of the residual water storage tank (RWST) reaches a minimum allowable value, coolant for long-term cooling of the core is obtained by switching to the cold leg recirculation phase of operation in which spilled borated water is drawn from the engineered safety features (ESF) containment sumps by the residual heat removal (low head) safety injection pumps and returned to the RCS cold legs. The containment spray system continues to operate to further reduce containment pressure.

Approximately 12 hours after the initiation of the LOCA, the ECCS is realigned to inject water to the RCS hot legs in order to control the boric acid concentration in the reactor vessel. Long-term cooling includes long-term criticality control. Criticality control is achieved by determining the RWST and accumulator concentrations necessary to maintain subcriticality without credit for RCCA insertion. The necessary RWST and accumulator concentrations are a function of each core design and are checked each cycle. The current Technical Specifications value are 2400 to 2600 ppm boron for the RWST and 2400 to 2600 ppm for the accumulators. The accumulators are conservatively modelled at 2300 ppm for the post-LOCA subcriticality requirement.

<u>Core and System Performance</u>

Mathematical Model:

The requirements of an acceptable ECCS evaluation model are presented in Appendix K of 10 CFR 50[1].

Large Break LOCA Evaluation Model

The analysis of a large break LOCA transient is divided into three phases: (1) blowdown, (2) refill, and (3) reflood. There are three distinct transients analyzed in each phase, including the thermal-hydraulic transient in the RCS, the pressure and temperature transient within the containment, and the fuel and clad temperature transient of the hottest fuel rod in the core. Based on these considerations, a system of interrelated computer codes has been developed for the analysis of the LOCA.

A description of the various aspects of the LOCA analysis methodology is given by Bordelon, Massie, and Zordan (1974)[6]. This document describes the major phenomena modeled, the interfaces among the computer codes, and the features of the codes which ensure compliance with the Acceptance Criteria. The SATAN-VI, WREFLOOD, BASH and LOCBART codes, which are used in the LOCA analysis, are described in detail by Bordelon et al. (1974)[5]; Kelly et al. (1974)[9]; Young et al. (1987)[4]; and Bordelon et al. (1974)[6]. Code modifications are specified in References 2, 7, 13, and 17. These codes assess the core heat transfer geometry and determine if the core remains amenable to cooling through and subsequent to the blowdown, refill, and reflood phases of the LOCA. The SATAN-VI computer code analyzes the thermal-hydraulic

transient in the RCS during blowdown and the WREFLOOD computer code calculates this transient during the refill phase of the accident.

The BASH code is used to determine the RCS response during the reflood phase of the transient. The LOTIC computer code, described by Hsieh and Raymund in WCAP-8355 (1975) and WCAP-8345 (1974)(3), calculates the containment backpressure transient. The containment backpressure transient is input to BASH for the purpose of calculating the reflood transient. The LOCBART computer code calculates the thermal transient of the hottest fuel rod in the three phases. The improved fuel performance model, described in Reference 15, generates the initial fuel rod conditions input to LOCBART.

SATAN-VI calculates the RCS pressure, enthalpy, density, and the mass and energy flow rates in the RCS, as well as steam generator energy transfer between the primary and secondary systems as a function of time during the blowdown phase of the LOCA. SATAN-VI also calculates the accumulator water mass and internal pressure and the break mass and energy flow rates that are assumed to be vented to the containment during blowdown.

At the end of the blowdown, information on the state of the system is transferred to the WREFLOOD code which performs the calculation of the refill period to bottom of core (BOC) recovery time. Once the vessel has refilled to the bottom of the core, the reflood portion of the transient begins. The BASH code is used to calculate the thermal-hydraulic simulation of the RCS for the reflood phase.

Information concerning the core boundary conditions is taken from all of the above codes and input to the LOCBART code for the purpose of calculating the core fuel rod thermal response for the entire transient. From the boundary conditions, LOCBART computes the fluid conditions and heat transfer coefficient for the full length of the fuel rod by employing mechanistic models appropriate to the actual flow and heat transfer regimes. Conservative assumptions ensure that the fuel rods modeled in the calculation represent the hottest rods in the entire core.

The large break analysis was performed with the December 1981 version of the Evaluation Model modified to incorporate the BASH(4) computer code.

Input Parameters and Initial Conditions:

The analysis presented in this section was performed with a reactor vessel upper head temperature equal to the RCS hot leg temperature.

A range of reactor operating temperatures was analyzed in order to justify plant operation at a reactor power level of 3588 Mwt between 582.2 °F to 615.2 °F in the hot legs and 511.7 °F to 547.6 °F in the cold legs. In addition to the temperature range analyzed, initial RCS pressurizer pressure was also varied to justify plant operation between 2037 and 2313 psia. A full spectrum break analysis was done at the high pressure/high temperature RCS conditions (initial RCS pressurizer pressure, with uncertainty, of 2313 psia and initial hot leg temperature of 615.2 °F) from which the limiting break size was determined. The limiting break was then reanalyzed for low temperature and high RCS pressure. The limiting break was also reanalyzed for the high temperature and low initial RCS pressure of 2037 psia. The analysis also considered plant operation at reduced power level with the RHR cross tie valve closed. The reduction in power level was considered necessary to offset the reduction in safety injection flow due to the closure of the RHR cross tie valve. This case assumed a reduced power level of 3413 MWt and minimum safeguards with the RHR cross tie valve closed at the limiting RCS conditions. All cases conservatively assumed 15% steam generator tube plugging in all four steam generators. Table C.3.1-1 describes the cases analyzed. Tables C.3.1-2 and C.3.1-3 summarize the key input parameters and setpoints modelled in the Cook Nuclear Plant Unit 2 large break LOCA analysis.

The bases used to select the numerical values that are input parameters to the analysis have been conservatively determined from extensive sensitivity studies (Westinghouse 1974[12]; Salvatori 1974[11]; Johnson, Massie, and Thompson 1975[8]). In addition, the requirements of Appendix K to 10 CFR 50[1] regarding specific model features were met by selecting models which provide a significant overall conservatism in the analysis. The assumptions which were made pertain to the conditions of the reactor and associated safety system equipment at the time that the LOCA occurs, and include such items as the core peaking factors, the containment pressure, and the performance of the ECCS. Decay heat generated throughout the transient is also conservatively calculated as per the requirements of Appendix K to 10 CFR 50[1].

Another input parameter that affects LOCA analysis results is the assumed axial power shape at the beginning of the accident. Power shape sensitivity studies performed with Westinghouse ECCS evaluation models have always demonstrated the chopped cosine shape with the peak at the core midplane to be limiting. Westinghouse has performed "spot check" analyses using the BASH reflood evaluation model for power shapes skewed to the top of the core. Results of these analyses have demonstrated the chopped cosine peaked at the core midplane remains the limiting power shape(18).

A meeting was held at the Westinghouse Licensing Office in Bethesda on December 17, 1981, between members of the U. S. Nuclear Regulatory Commission and members of the Westinghouse Nuclear Safety Department to discuss the impact of maximum safety injection on the large break ECCS analysis on a generic basis. Further discussion of this issue is provided in a letter from E. P. Rahe, Manager of Westinghouse Nuclear Safety Department, to Robert L. Tedesco of the U. S. Nuclear Regulatory Commission(14). A brief description of this issue is given below.

Westinghouse ECCS analyses currently assume minimum safeguards for the safety injection flow, which minimizes the amount of flow to the RCS by assuming maximum injection line resistances, degraded ECCS pump performance, and the loss of one residual heat removal (RHR) pump as the most limiting single failure. This is the limiting single failure assumption when offsite power is unavailable for most Westinghouse plants. However, for some Westinghouse plants, including Cook Nuclear Plant Unit 2, the current nature of the Appendix K ECCS evaluation models is such that it may be more limiting to assume the maximum possible ECCS flow delivery. In that case, maximum safeguards which assume minimum injection line resistances, enhanced ECCS pump performance, and no single failure, result in the highest amount of flow delivered to the RCS.

Therefore, the worst break for Cook Nuclear Plant Unit 2 (C_D=0.6) was reanalyzed, assuming maximum safeguards (Case A vs. Case F of Table C.3.1-1). Examination of the LOCA analysis results in Table C.3.1-6 demonstrates that minimum safeguards assumptions result in the highest peak clad temperature for Cook Nuclear Plant Unit 2.

Transition Core Effects

When assessing the effect of transition cores on the large break LOCA analysis, it must be determined whether the transition core can have a greater calculated peak cladding temperature (PCT) than either a complete core of the 17x17 ANF assembly design or a complete core of the Westinghouse 17x17 VANTAGE 5 design. For a given peaking factor, the only mechanism available to cause a transition core to have a greater calculated PCT than a full core of either fuel is the possibility of flow redistribution due to fuel assembly hydraulic resistance mismatch. Hydraulic resistance mismatch will exist only for a transition core and is the only unique difference between a complete core of either fuel type and the transition core.

The 17x17 ANF fuel assembly is nearly identical to the Westinghouse 17x17 OFA assembly in terms of hydraulic and geometric characteristics. Therefore, the analyses reported in Reference 19 which demonstrate that the 17x17 VANTAGE 5 fuel features result in a fuel assembly that is more limiting than a Westinghouse 17x17 OFA fuel assembly, with respect to large break LOCA ECCS performance, remain valid as applied at Cook Nuclear Plant Unit 2. The same large break LOCA transition core penalty reported in Section 5.2.3 of Reference 19 will be applied to the transition from 17x17 ANF fuel assemblies to Westinghouse 17x17 VANTAGE 5 fuel assemblies.

Westinghouse transition core designs, including specific 17X17 OFA to 17x17 VANTAGE 5 transition core cases, were analyzed. The increase in hydraulic resistance for the VANTAGE 5 assembly was shown to produce a reduction in reflood steam flow rate for the VANTAGE 5 fuel at mixing vane grid elevations for transition core configurations. The various fuel assembly specific transition core analyses performed resulted in peak cladding temperature increases of up to 50 °F for core axial elevations that bound the location of the PCT. Therefore, the maximum PCT penalty possible for VANTAGE 5 fuel residing in a transition core is 50 °F, Reference 19. As stated earlier, this transition core penalty continues to apply to the transition from 17x17 ANF fuel assemblies to Westinghouse 17x17 VANTAGE 5 fuel assemblies due to the near identical design of 17x17 ANF and Westinghouse 17x17 OFA fuel assemblies. Once a full core of VANTAGE 5 fuel is achieved the large break LOCA analysis will apply without the transition core penalty.

Results:

Based on the results of the LOCA sensitivity studies (Westinghouse 1974(12); Salvatori 1974(11); Johnson, Massie, and Thompson 1975(8)), the limiting large break was found to be the double-ended cold leg guillotine (DECLG). Therefore, only the DECLG break is considered in the large break ECCS performance analysis. Calculations were performed for a range of Moody break discharge coefficients. The results of these calculations are summarized in Tables C.3.1-5 and C.3.1-6.

The containment data used to generate the LOTIC backpressure transient are shown in Table C.3.1-4. The mass and energy release data for the minimum and maximum safeguards cases (Case A and F) are shown in Tables C.3.1-7 and C.3.1-8 respectively. In addition, mass and energy release data for Case G (3413 Mwt, RHR cross tie valve closed) are shown in Table C.3.1-9. The mass releases for the remaining cases are not presented, since they do not vary significantly from the data shown in Table C.3.1-7. Nitrogen release rates to the containment are given in Table C.3.1-10.

Figures C.3.1-3a through C.3.1-30 present the results of the cases analyzed for the large break LOCA. The alpha designation in the figure number corresponds to the cases as described in Table C.3.1-1.

Figures C.3.1-3a-g	The system pressure shown is the calculated core pressure.
Figures C.3.1-4a-g	The flow rate from the break is plotted as the sum of both ends of the guillotine break.
Figures C.3.1-5a-g	The core pressure drop shown is from the lower plenum, near the core, to the upper plenum at the core outlet.
Figures C.3.1-6a-g	The core flow rate is shown during the blowdown phase of the transient.
Figures C.3.1-7a-g	The accumulator flow rate during blowdown is plotted as the sum of that injected into the intact cold legs.

Figures C.3.1-8a-g	The core and downcomer collapsed liquid water levels are plotted during the reflood phase of the transient.
Figures C.3.1-9a-g	The core inlet flow rate is shown as it is calculated during the reflood phase.
Figures C.3.1-10a-g	The total pumped ECCS flow rate injecting into the intact cold legs is shown.
Figures C.3.1-11a-g	The integral of the core inlet flow rate as calculated with BASH is plotted.
Figures C.3.1-12a-g	The mass flux is plotted at the hot spot (the node which produced the peak clad temperature) on the hot rod.
Figures C.3.1-13a-g	The heat transfer coefficient is plotted at the hot spot on the hot rod.
Figures C.3.1-14a-g	The fluid temperature at the hot spot on the hot rod is plotted.
Figures C.3.1-15a-g	The clad temperature at the hot spot is shown for the hot rod.
Figures C.3.1-16-18	The containment backpressure transient used in the analysis is provided for Cases A, F and G (the minimum and maximum SI flow cases, and the 3413 Mwt cross tie valve closed case).
Figures C.3.1-19-27	These figures show the heat removal rates of the heat sinks found in the lower and upper compartment and the heat removal by the sump and lower compartment spray for Cases A, F and G.
Figures C.3.1-28-30	These figures show the temperature transients in both the lower and upper compartments of containment and flow from the upper to lower compartments for Cases A, F and G.

The peak clad temperature calculated for a large break is 2140 °F, which is less than the acceptance criterion limit of 2200 °F. The maximum local metal-water reaction is 6.80 percent, which is well below the embrittlement limit of 17 percent as required by 10 CFR 50.46. The total

metal-water reaction is less than 0.3 percent for all breaks, corresponding to less than 0.3 percent hydrogen generation, as compared with the 1 percent criterion of 10 CFR 50.46. The clad temperature transient is terminated at a time when the core geometry is still amenable to cooling. As a result, the core temperature will continue to drop and the ability to remove decay heat generated in the fuel for an extended period of time will be provided.

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TABLE C.3.1-1

LARGE BREAK LOCA - CASES ANALYZED

CASE A - C_D=0.6, 3588 Mwt Core Power, High Temperature (T_{HOT}=615.2 °F), High Pressure (P_{RCS}=2313 psia), F_Q=2.220, $F^N_{\Delta H}$ =1.620, Minimum SI with cross-tie valves open. Limiting break case, i.e., this case had highest PCT for all cases analyzed.

CASE B - C_D=0.4, 3588 Mwt Core Power, High Temperature (T_{HOT}=615.2 °F), High Pressure (P_{RCS}=2313 psia), F_Q=2.240, $F^N_{\Delta H}$=1.620, Minimum SI with cross-tie valves open.

CASE C - C_D=0.8, 3588 Mwt Core Power, High Temperature (T_{HOT}=615.2 °F), High Pressure (P_{RCS}=2313 psia), F_Q=2.240, °$F^N_{\Delta H}$=1.620, Minimum SI with cross-tie valves open.

CASE D - C_D=0.6, 3588 Mwt Core Power, Low Temperature (T_{HOT}=582.3 °F), High Pressure (P_{RCS}=2313 psia), F_Q=2.220, $F^N_{\Delta H}$=1.620, Minimum SI with cross-tie valves open.

CASE E - C_D=0.6, 3588 Mwt Core Power, High Temperature (T_{HOT}=615.0 °F), Low Pressure (P_{RCS}=2037 psia), F_Q=2.220, $F^N_{\Delta H}$=1.620, Minimum SI with cross-tie valves open.

CASE F - C_D=0.6, 3588 Mwt Core Power, High Temperature (T_{HOT}=615.2 °F), High Pressure (P_{RCS}=2313 psia), F_Q=2.220, $F^N_{\Delta H}$=1.620, Maximum SI with cross-tie valves open.

CASE G - C_D=0.6, 3413 Mwt Core Power, High Temperature (T_{HOT}=611.2 °F), High Pressure (P_{RCS}=2313 psia), F_Q=2.335, $F^N_{\Delta H}$=1.644, Minimum SI with RHR crosstie valves closed.

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TABLE C.3.1-2
INPUT PARAMETERS USED IN THE LARGE BREAK LOCA ECCS ANALYSIS

	Cross Ties Open	RHR Cross Ties Closed
License Core Power[a], (MWt)	3588	3413
Peak Linear Power[a], (kw/ft)	12.714	12.721
Total Peaking Factor, $F_Q{}^T$	2.220	2.335
Axial Peaking Factor, F_Z	1.370	1.420
Hot Channel Enthalpy Rise Factor, $F^N{}_{\Delta H}$	1.620	1.644
Power Shape:	Chopped Cosine	
Fuel Assembly Array	17 X 17 VANTAGE 5	
Accumulator Water Volume, Nominal (ft^3/accumulator)	946	946
Allowance	±25	±25
Accumulator Tank Volume, Nominal (ft^3/accumulator)	1350	1350
Accumulator Gas Pressure, Minimum (psia)	600	600
Safety Injection Pumped Flow Rate (All pumps degraded 10%, Charging pump flow rate imbalance = 25 gpm)	See Figures C.3.1.1 and C.3.1.2	
Containment Parameters	See Table C.3.1-4	
Initial Loop Flow (GPM)	88,500	88,500
Vessel Inlet Temperature (°F)	511.7 to 547.6	513.3 to 546.4
Vessel Outlet Temperature (°F)	582.2 to 615.2	580.6 to 611.2
Average Reactor Coolant Pressure (psia)	2037.4 to 2312.6	2037.4 to 2312.6
Steam Pressure (psia)	587 to 820	603 to 820
Steam Generator Tube Plugging Level (%)	15	15
Refueling Water Storage Tank Temperature (°F)	70[b]	70[b]

(a) Two percent is added to this power to account for calorimetric error.

(b) The BASH computer code models average RWST temperature during core reflooding (85 °F). Other computer codes in the model use 70 °F.

TABLE C.3.1-3
LARGE BREAK LOCA ECCS ANALYSIS SYSTEMS MODELLING

Pressurizer Low Pressure Reactor Trip (psia)	1860.0
Pressurizer Low Pressure Safety Injection (psia)[a]	1715.0
Containment HI Pressure for Safety Injection (psia)	15.8
Safety Injection Delay (includes signal processing, EDGs start-up, sequencer and pumps to full speed, sec)	27.0
Feedwater Isolation Delay after Reactor Trip (sec)[b]	0.0
Steamline Isolation Delay after Reactor Trip (sec)[b]	0.0

(a) This setpoint causes actuation of the safety injection at the times shown in Table C.3.1-5, for all seven cases.

(b) Conservative modelling for Large Break LOCA

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TABLE C.3.1-4
LARGE BREAK LOCA CONTAINMENT DATA
(ICE CONDENSER CONTAINMENT)

Net Free Volume

(Includes distribution between Upper, Lower,	UC - 746,829 ft(3)
Dead-Ended and Ice Compartments)	LC - 249,446 ft(3)
	DE - 116,168 ft(3)
	IC - 122,350 ft(3)

Initial Conditions

Pressure	14.7 psia
Temperature for the Upper, Lower and Dead-Ended Compartments	UC - 100.0°F LC - 120.0°F DE - 120.0°F
RWST Temperature	70.0°F
Service Water Temperature	40.0°F
Temperature Outside Containment	-22.0°F
Initial Spray Temperature	70.0°F

Spray System

Runout Flow for a Spray Pump	3,700 gpm
Number of Spray Pumps Operating	2
Post-Accident Initiation of Spray System	36 sec
Distribution of the Spray Flow to the Lower and Upper Compartments	LC - 2,914 gpm UC - 4,486 gpm

Deck Fans

Post-Accident Initiation of Deck Fans	480 sec
Number of Deck Fans Operating	2
Flow Rate per Deck Fan	43,890 cfm

Assumed Spray Efficiency of Water from Ice Condenser Drains	100%

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TABLE C.3.1-4 (continued)
LARGE BREAK LOCA CONTAINMENT DATA
(ICE CONDENSER CONTAINMENT)

Structural Heat Sinks

Compartments	Area (ft^2)	Thickness (ft)	Material
1. DE	12,105	0.0469/2.0	Steel/Concrete
2. LC/DE	11,700	2.00	Concrete
3. LC/DE	65,980	1.35	Concrete
4. LC	5,481	0.0833	Steel
5. LC	4,735	0.01147	Steel
6. LC	289	0.250	Lead
7. LC	14,690	0.0079	Steel
8. LC	3,439	0.1561	Steel
9. LC	5,775	0.009	Steel
10. LC	49,665	0.0096	Steel
11. LC	7,013	0.037	Steel
12. LC	2,457	0.0334	Stainless Steel
13. UC	378	0.0365/0.1667	Steel/Concrete
14. UC	29,772	0.0092	Steel
15. UC	8,033	0.0209	Steel
16. UC	420	0.0052	Steel
17. UC	29,330	1.47	Concrete
18. UC	34,125	0.0469/2.0	Steel/Concrete
19. UC	420	0.0052	Steel

KEY:

UC: Upper Compartment
LC: Lower Compartment
DE: Dead-Ended Compartment
IC: Ice Condenser Compartment

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TABLE C3.1-5
LARGE BREAK LOCA ANALYSIS TIME SEQUENCE OF EVENTS

	Case A	Case B	Case C	Case D	Case E	Case F	Case G
	C_D=0.6	C_D=0.4	C_D=0.8	C_D=0.6	C_D=0.6	C_D=0.6	C_D=0.6
	Min SI	Min SI	Min SI	Min SI	Min SI	Max SI	RHR X-Tie
	3588 Mwt	3588 Mwt	3588 Mwt	3588 Mwt	3588 Mwt	3588 Mwt	3413Mwt
T_{HOT} =	615.2 °F	615.2 °F	615.2 °F	582.3 °F	615.0 °F	615.2 °F	611.2 °F
P_{RCS} =	2313 psia	2313 psia	2313 psia	2313 psia	2037 psia	2313 psia	2313 psia
Start (sec)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Reactor Trip Signal (sec)	0.669	0.681	0.661	0.527	0.515	0.669	0.642
Safety Injection Signal (sec)	4.70	4.99	4.54	4.14	3.93	4.70	4.62
Accumulator Injection Begins (sec)	14.6	20.4	12.0	13.0	14.8	14.6	14.6
End-of-Bypass (sec)	31.69	40.51	26.94	33.48	31.70	31.69	32.02
End-of-Blowdown (sec)	31.69	41.13	26.94	33.48	31.70	31.69	32.02
Pump Injection Begins (sec)	31.70	31.99	31.54	31.14	30.93	31.70	31.62
Bottom of Core Recovery (sec)	45.99	56.00	40.87	48.88	45.95	45.39	46.79
Accumulator Empty (sec)	59.40	66.64	55.66	60.00	59.40	59.57	59.40

DONALD C. COOK NUCLEAR PLANT UNIT 2
TABLE C.3.1-6
LARGE BREAK LOCA RESULTS FUEL CLADDING DATA

	Case A	Case B	Case C	Case D	Case E	Case F	Case G
	C_D=0.6	C_D=0.4	C_D=0.8	C_D=0.6	C_D=0.6	C_D=0.6	C_D=0.6
	Min SI	Min SI	Min SI	Min SI	Min SI	Max SI	RHR X-Tie
	3588 Mwt	3588 Mwt	3588 Mwt	3588 Mwt	3588 Mwt	3588 Mwt	3413 Mwt
T_{HOT} =	615.2 °F	615.2 °F	615.2 °F	582.3 °F	615.0 °F	615.2 °F	611.2 °F
P_{RCS} =	2313 psia	2313 psia	2313 psia	2313 psia	2037 psia	2313 psia	2313 psia
Peak Clad Temperature (°F)	2140.0	1848.2	1766.0	1878.4	2074.7	2102.7	2090.0
Peak Clad Temperature Location (ft)	9.75	8.75	6.25	9.75	9.75	9.75	9.75
Peak Clad Temperature Time (sec)	258.9	250.1	57.9	239.9	255.4	253.1	244.4
Local Zr/H_2O Reaction Maximum (%)	6.80	3.56	2.97	3.30	5.71	6.18	6.08
Local Zr/H_2O Reaction Location (ft)	9.75	6.25	5.25	9.75	9.75	9.75	9.75
Total Zr/H_2O Reaction (%)	<0.3	<0.3	<0.3	<0.3	<0.3	<0.3	<0.3
Hot Rod Burst Time (sec)	45.79	60.93	50.66	50.11	46.05	46.04	46.10
Hot Rod Burst Location (ft)	6.00	6.25	5.25	6.00	6.00	6.00	6.00

CALCULATION ASSUMPTIONS

Peak Linear Power (Kw/ft), 102% of	12.714 (12.721 for Case G)
Peaking Factor (at License Rating)	2.220 (2.335 for Case G)
Accumulator Water Volume (ft^3) per accumulator	946
Cycle Analyzed	All

DONALD C. COOK NUCLEAR PLANT UNIT 2

TABLE C.3.1-7
CASE A - LARGE BREAK LOCA C_D=0.6 MINIMUM SAFEGUARDS
MASS AND ENERGY RELEASE RATES

Time (sec)	Mass Flow Rate (lbm/sec)	Energy Flow Rate (BTU/sec)
0.0	70562.0	37960066.0
1.0	66324.0	34809386.0
2.0	58446.0	30872684.0
3.0	47776.0	25444113.0
4.0	40310.0	21684814.0
5.0	32388.0	17815357.0
6.0	30679.0	17103044.0
7.0	29057.0	16373321.0
8.0	27299.0	15517895.0
9.0	25547.0	14706648.0
10.0	22446.0	13347482.0
11.0	19737.0	11937678.0
12.0	17626.0	10722934.0
12.4	16806.0	10271911.0
13.0	15567.0	9618894.0
14.0	13863.0	8692759.0
15.0	12346.0	7910304.0
16.0	10803.0	7134722.0
17.0	9785.0	6598154.0
18.0	8687.0	5904895.0
19.0	7013.0	5001042.0
20.0	4975.0	3600314.0
21.0	5361.0	3099603.0
22.0	7165.0	3249819.0
23.0	7503.0	2958259.0
24.0	7368.0	2506588.0
25.0	6741.0	1964716.0
26.0	5803.0	1452731.0
27.0	5513.0	1313192.0
28.0	4940.0	1064918.0
29.0	4386.0	833363.0
30.0	3459.0	548032.0
31.0	2581.0	354346.0
32.0	1419.0	80449.0
33.0	1406.0	79650.0
34.0	1393.0	78887.0
35.8	1381.0	78166.0
40.0	193.2	7361.0
46.0	193.2	7361.0
46.6	193.2	7408.0
66.0	608.1	208262.0
86.5	623.2	208283.0
109.9	631.6	204153.0
135.2	637.8	199042.0
171.5	676.6	204636.0
257.9	691.8	200029.0

DONALD C. COOK NUCLEAR PLANT UNIT 2

TABLE C.3.1-8
CASE F_D- LARGE BREAK LOCA C =0.6 MAXIMUM SAFEGUARDS
MASS AND ENERGY RELEASE RATES

Time (sec)	Mass Flow Rate (lbm/sec)	Energy Flow Rate (BTU/sec)
0.0	70562.0	37960066.0
1.0	66324.0	34809386.0
2.0	58446.0	30872684.0
3.0	47776.0	25444113.0
4.0	40310.0	21684814.0
5.0	32388.0	17815357.0
6.0	30679.0	17103044.0
7.0	29057.0	16373321.0
8.0	27299.0	15517895.0
9.0	25547.0	14706648.0
10.0	22446.0	13347482.0
11.0	19737.0	11937678.0
12.0	17626.0	10722934.0
12.4	6806.0	0271911.0
13.0	15567.0	9618894.0
14.0	13863.0	8692759.0
15.0	12346.0	7910304.0
16.0	10803.0	7134722.0
17.0	9785.0	6598154.0
18.0	8687.0	5904895.0
19.0	7013.0	5001042.0
20.0	4975.0	3600314.0
21.0	5361.0	3099603.0
22.0	7165.0	3249819.0
23.0	7503.0	2958259.0
24.0	7368.0	2506588.0
25.0	6741.0	964716.0
26.0	5803.0	1452731.0
27.0	5513.0	1313192.0
28.0	4940.0	1064918.0
29.0	4386.0	833363.0
30.0	3459.0	548032.0
31.0	2581.0	354346.0
32.0	1507.0	83787.0
33.0	1493.0	82988.0
34.0	1481.0	82225.0
35.8	1468.0	81504.0
40.0	280.8	10699.0
45.4	280.8	10699.0
46.6	280.8	10744.0
65.0	1074.4	206990.0
89.1	1089.1	205157.0
116.7	1168.5	215651.0
146.5	318.7	59930.6
196.6	894.2	163447.0
292.5	1133.7	202696.0

DONALD C. COOK NUCLEAR PLANT UNIT 2

TABLE C.3.1-9
CASE G - LARGE BREAK LOCA C_D=0.6 CROSS TIE CLOSED - 3413 MWT
MASS AND ENERGY RELEASE RATES

Time (sec)	Mass Flow Rate (lbm/sec)	Energy Flow Rate (BTU/sec)
0.0	69955.0	37511781.0
1.0	65675.0	34325858.0
2.0	58553.0	30781406.0
3.0	47675.0	25263840.0
4.0	37824.0	20253019.0
5.0	33291.0	18234589.0
6.0	30576.0	16975965.0
7.0	29017.0	16257874.0
8.0	27467.0	15514324.0
9.0	25627.0	14673972.0
10.0	22582.0	13346458.0
11.0	19985.0	11974533.0
12.0	17999.0	10830851.0
12.4	17215.0	10400634.0
13.0	15991.0	9759812.0
14.0	14187.0	8807926.0
15.0	12631.0	8004972.0
16.0	11039.0	7204344.0
17.0	10018.0	6689233.0
18.0	8915.0	6018811.0
19.0	7349.0	5141732.0
20.0	5303.0	3863526.0
21.0	5118.0	3077866.0
22.0	7198.0	3310544.0
23.0	7560.0	3029284.0
24.0	7473.0	2587535.0
25.0	6881.0	2056578.0
26.0	5935.0	1523714.0
27.0	5688.0	1381335.0
28.0	5096.0	1125072.0
29.0	4465.0	871308.0
30.0	4110.0	695178.0
31.0	3587.0	558339.0
32.0	1322.0	79532.0
33.0	1448.0	81246.0
34.0	1435.0	80483.0
35.8	1423.0	79762.0
40.0	235.1	8957.0
46.8	235.1	8957.0
48.1	235.1	9005.0
67.0	416.3	197413.0
88.0	430.4	198512.0
111.7	438.1	195756.0
137.2	443.5	191962.0
168.5	473.5	196699.0
241.2	492.0	196263.0

TABLE C.3.1-10
NITROGEN MASS RELEASE RATES

Time (sec)	Mass Flow Rate [lbm/sec)
35.76	83.80
36.76	76.83
39.76	59.68
42.76	46.83
45.76	36.82
48.76	28.89
51.76	22.48
55.76	15.76
60.77	230.44
65.77	152.14
70.77	101.88
75.77	67.57
80.77	43.29
85.77	26.68
90.77	16.85
95.77	11.85
100.77	8.92
110.77	5.21
120.77	5.21
140.77	1.05
160.77	0.33
180.77	0.23

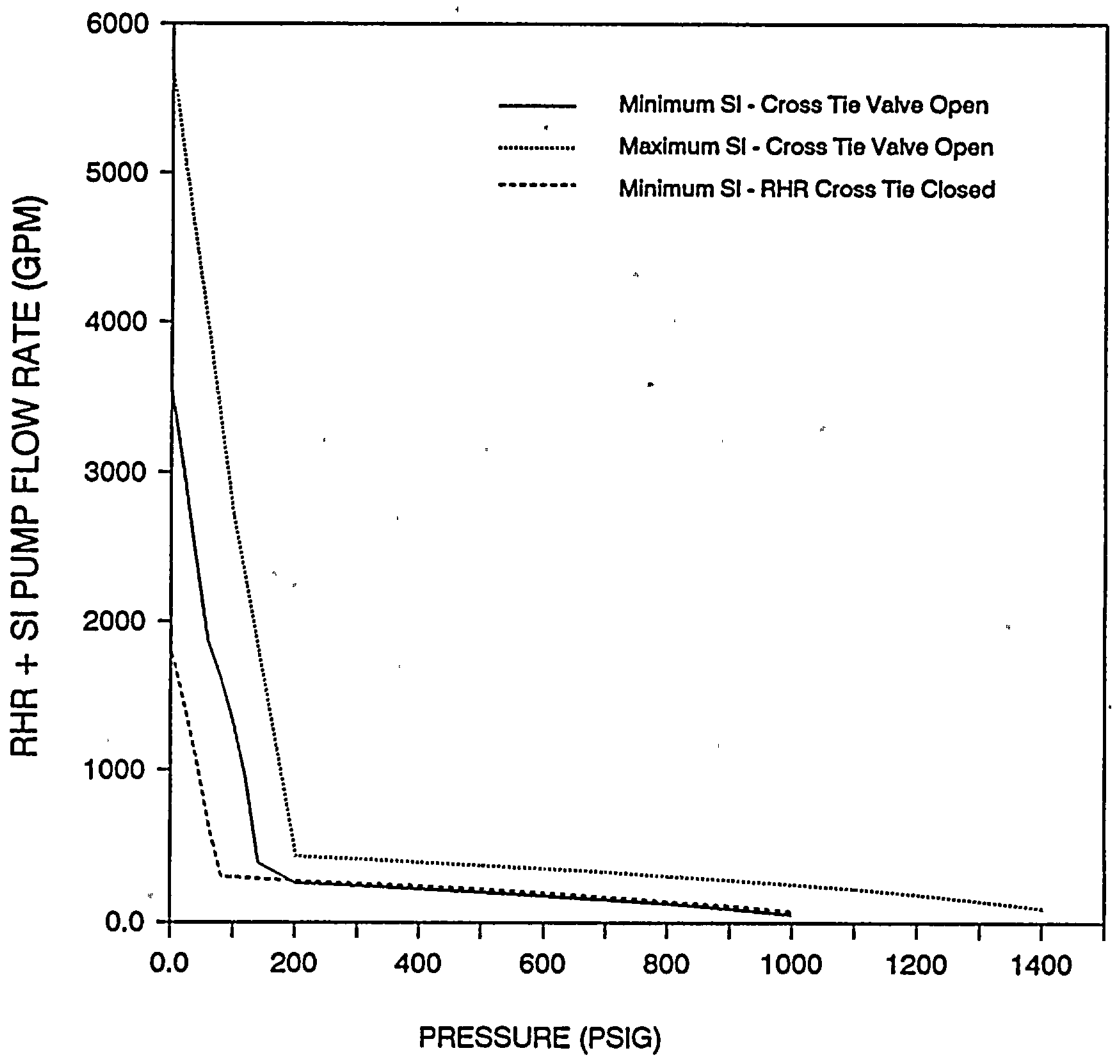

FIGURE C.3.1-1
RHR AND SAFETY INJECTION PUMP
FLOW RATE VS RCS PRESSURE
Donald C. Cook Unit 2

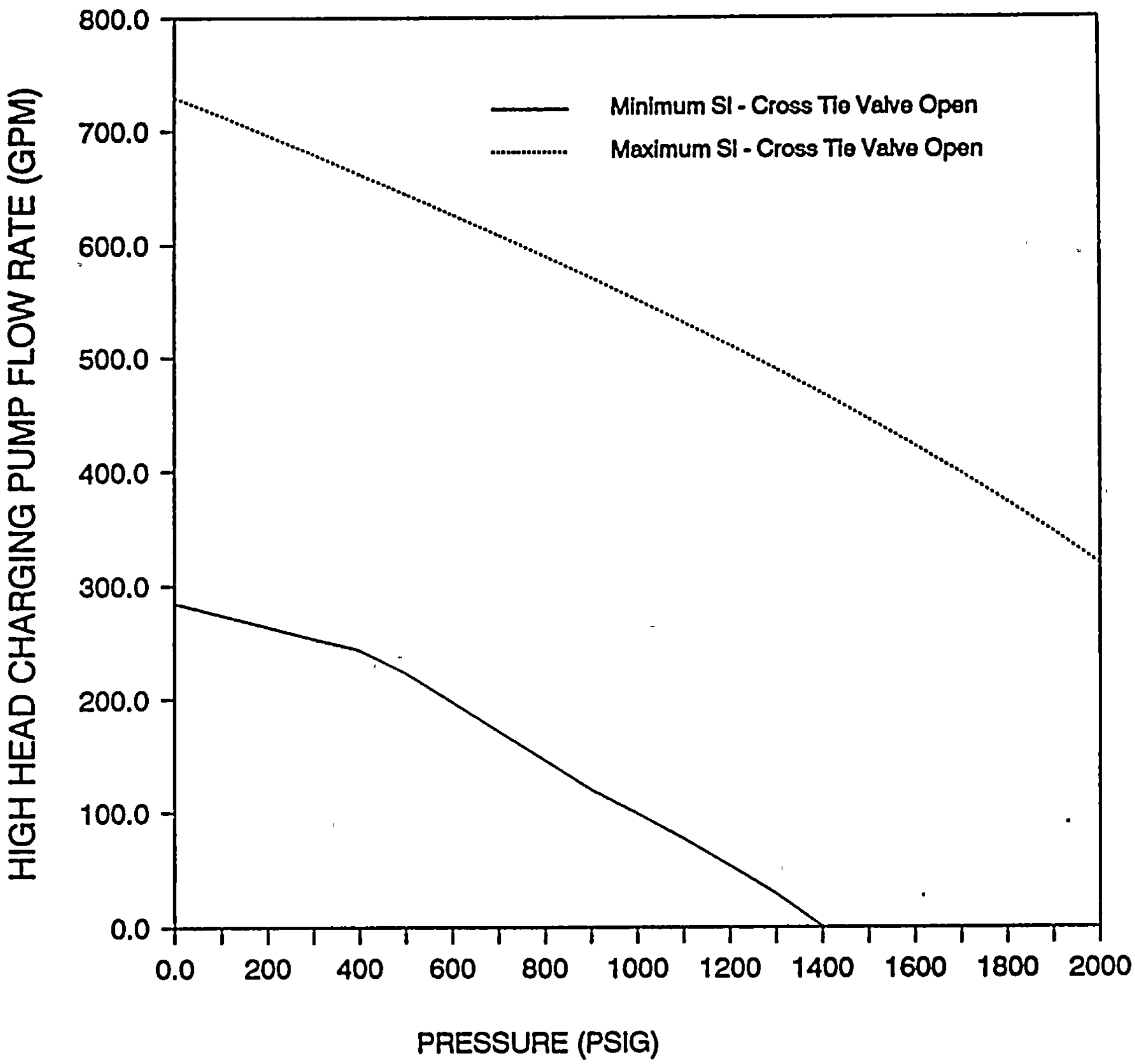

FIGURE C.3.1-2
HIGH HEAD CHARGING PUMP FLOW RATE VS RCS PRESSURE
Donald C. Cook Unit 2

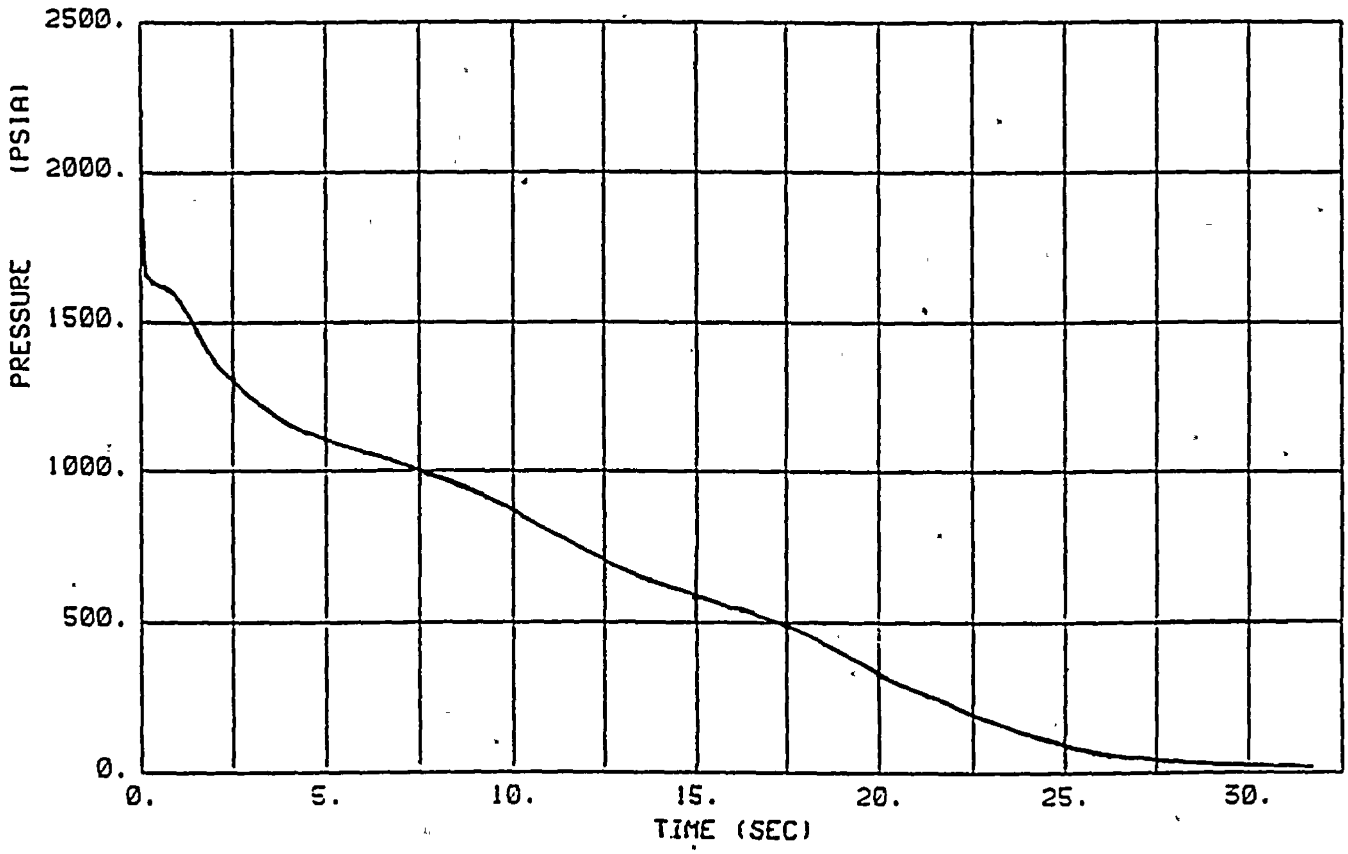

FIGURE C.3.1-3a
REACTOR COOLANT SYSTEM PRESSURE
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

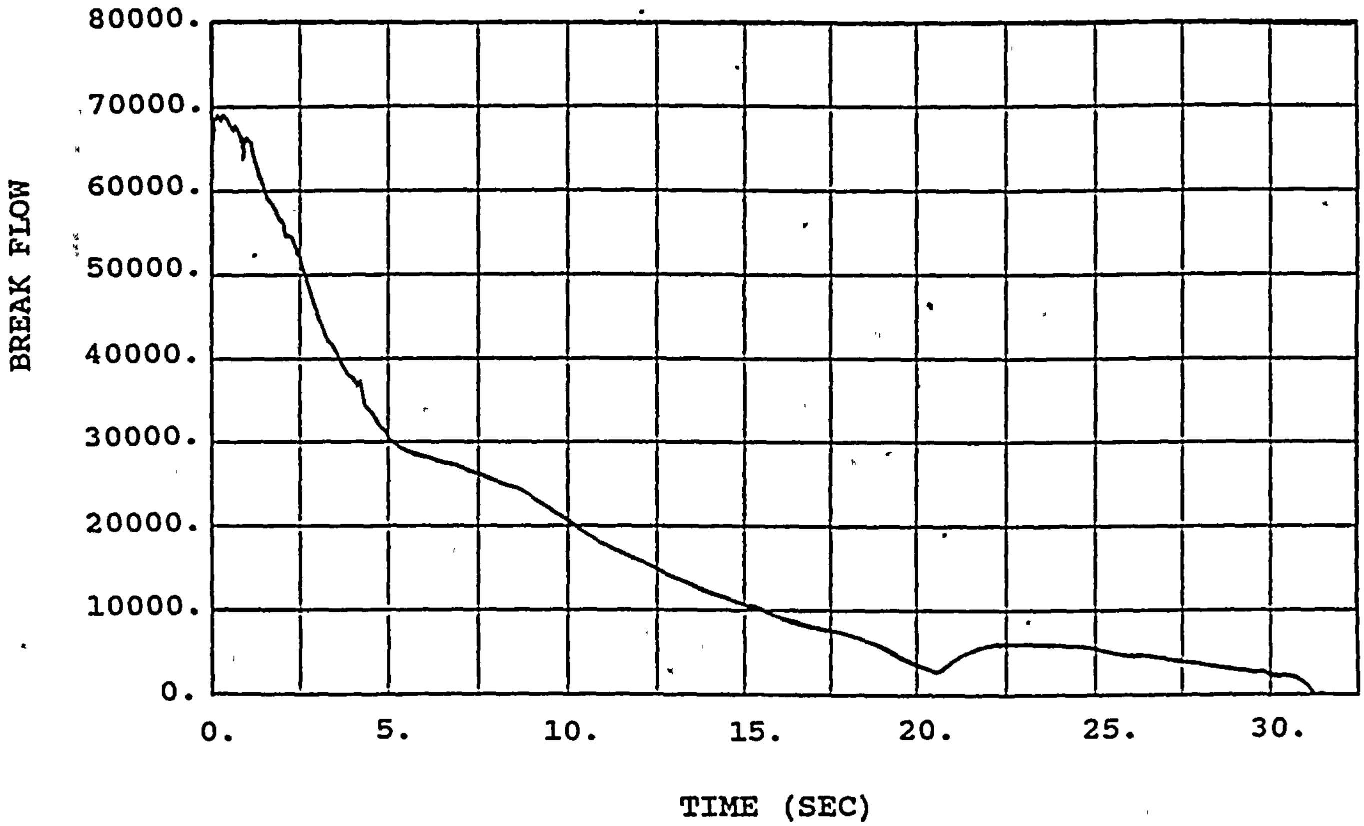

FIGURE C.3.1-4a
BREAK FLOW DURING BLOWDOWN
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

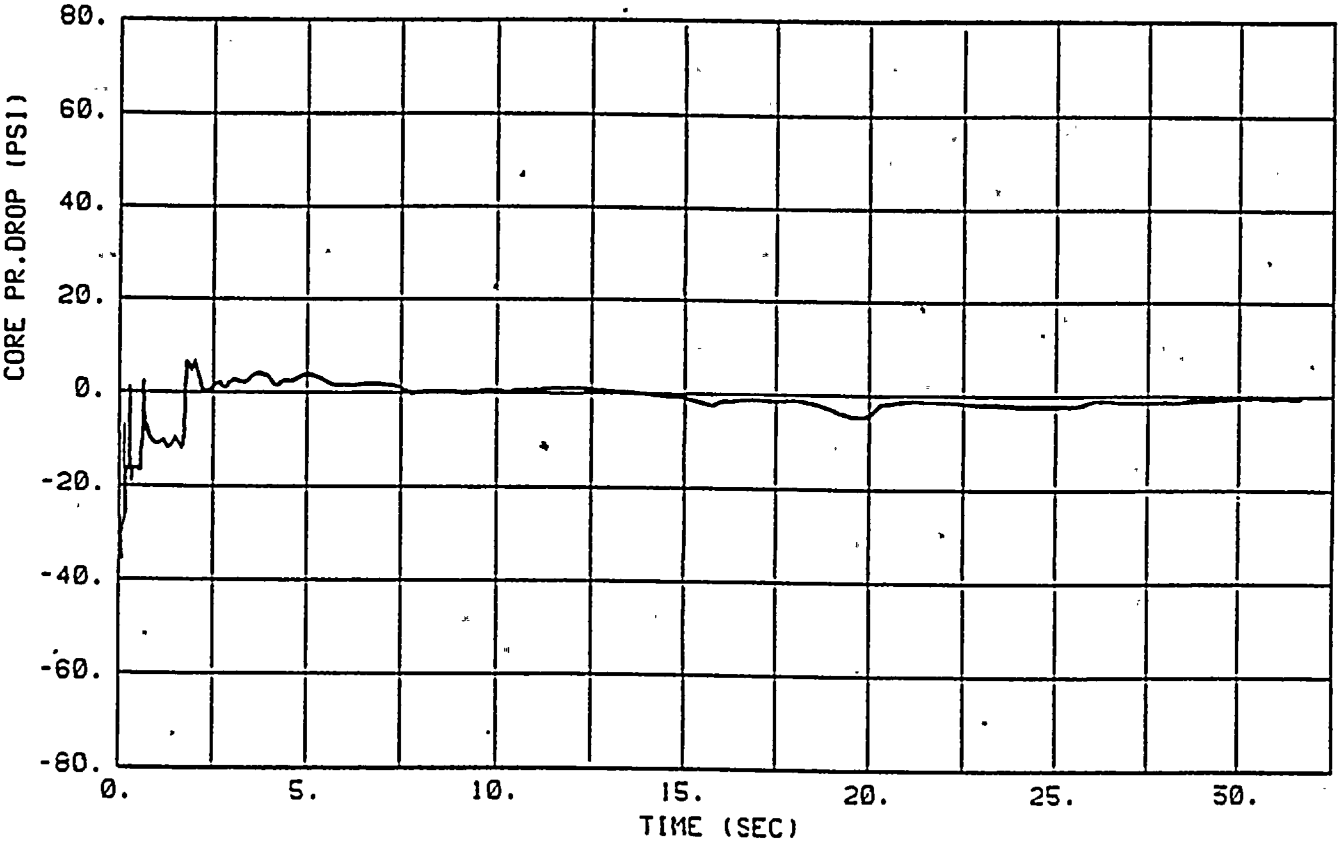

FIGURE C.3.1-5a
CORE PRESSURE DROP
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

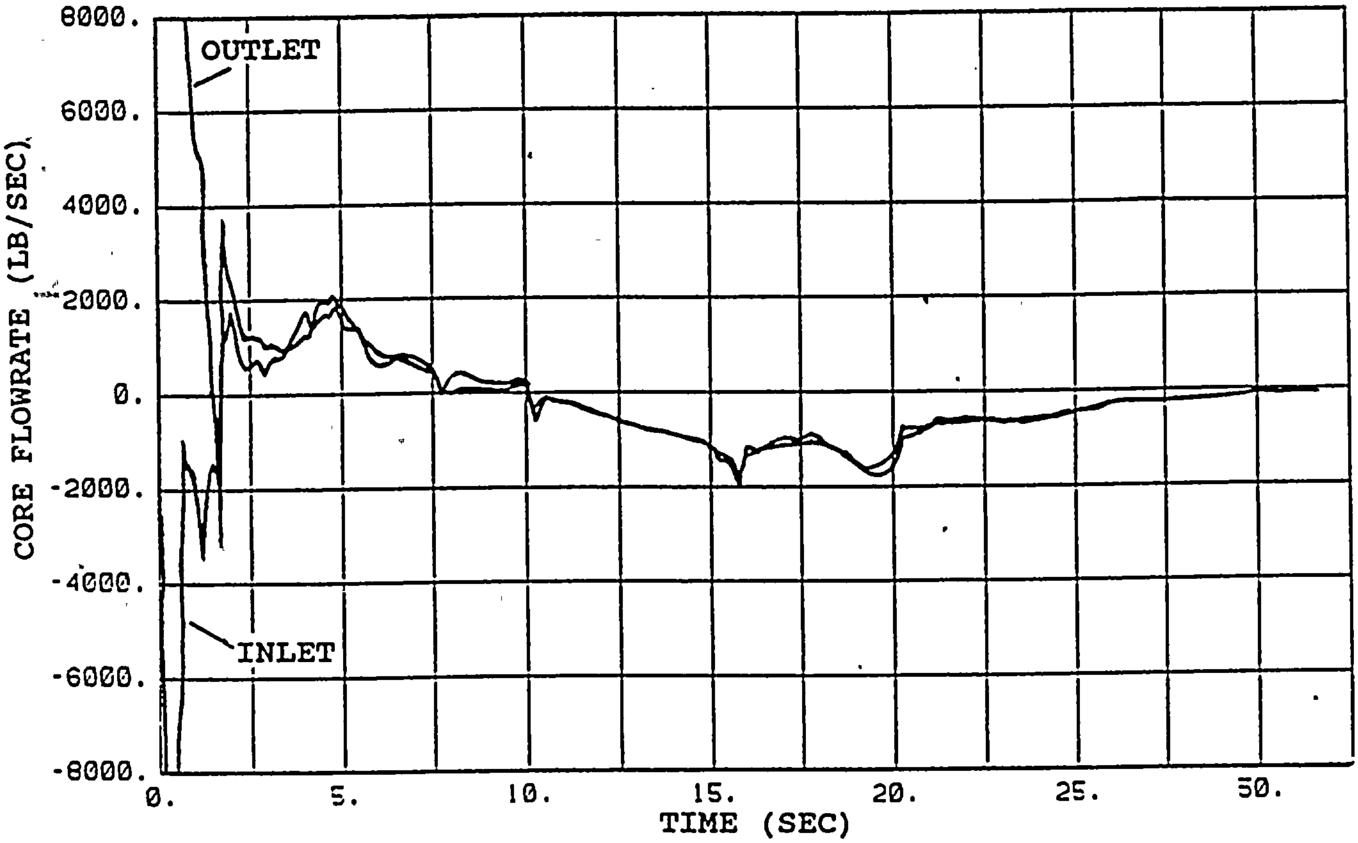

FIGURE C.3.1-6a
CORE FLOWRATE
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

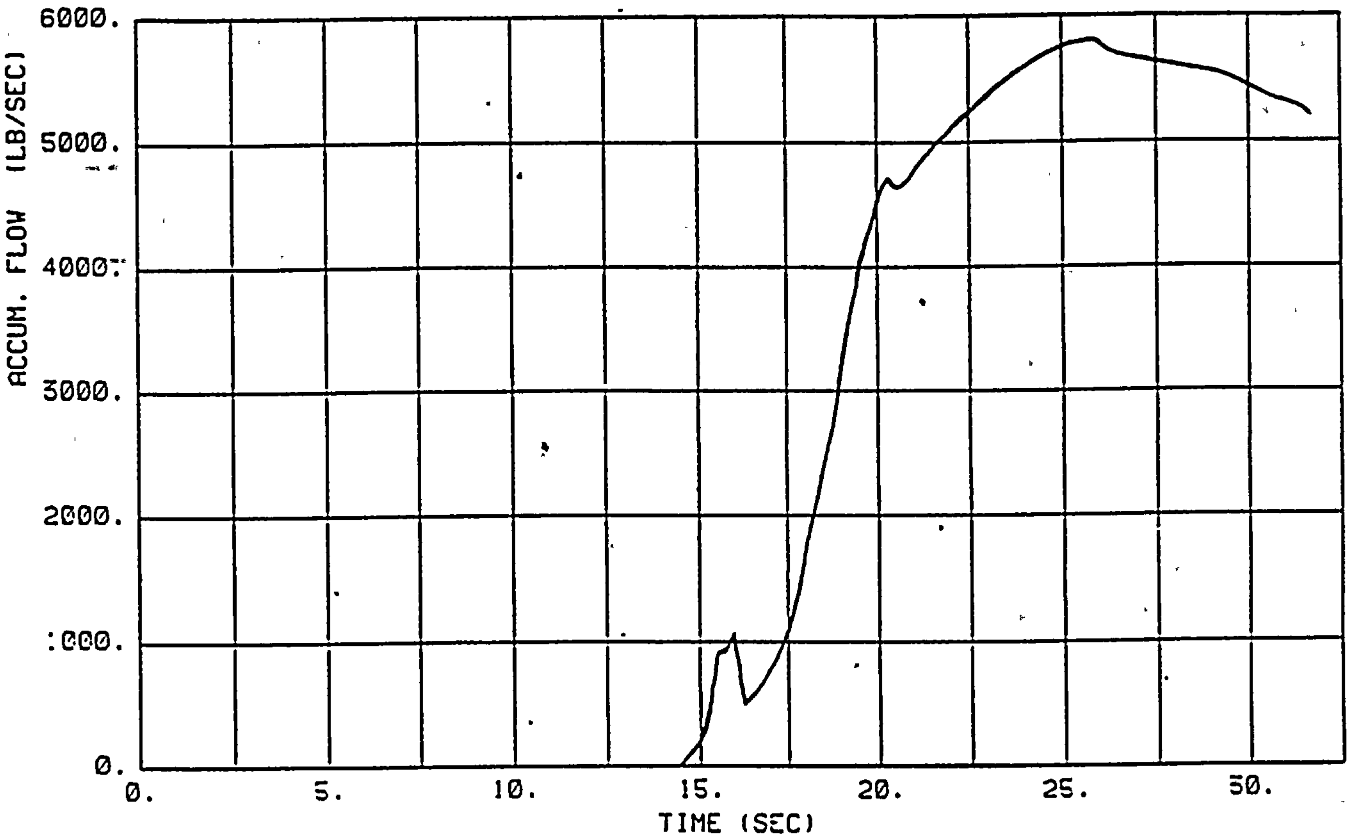

FIGURE C.3.1-7a
ACCUMULATOR FLOW DURING BLOWDOWN
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

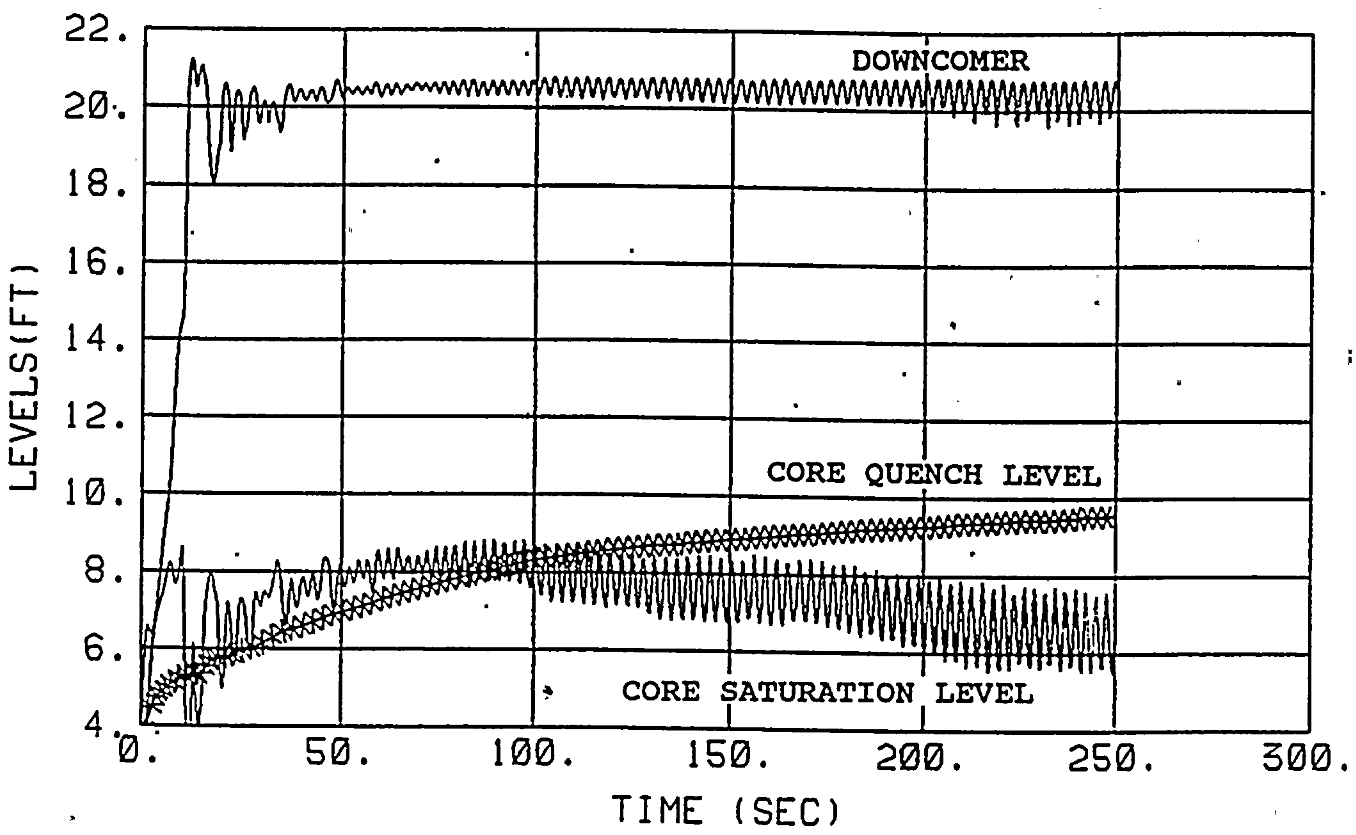

FIGURE C.3.1-8a
CORE AND DOWNCOMER LIQUID LEVELS
DURING REFLOOD
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

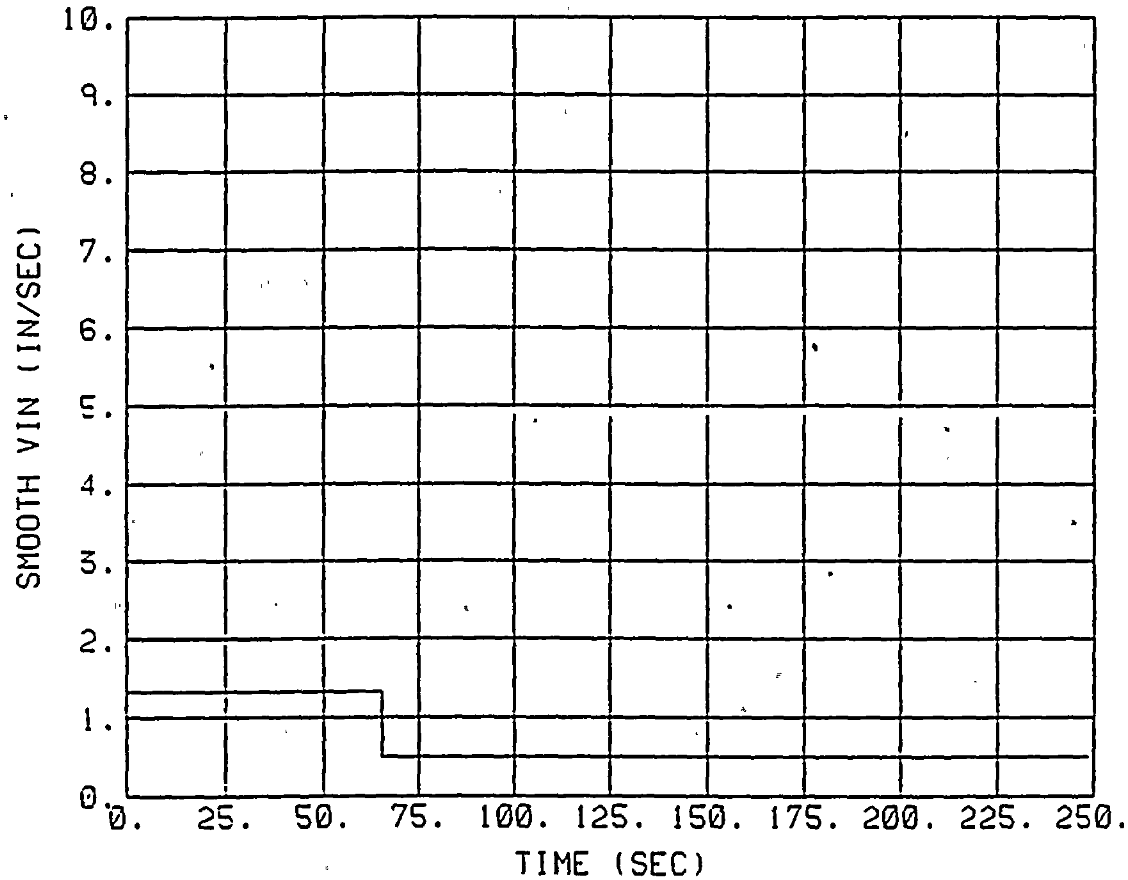

FIGURE C.3.1-9a
CORE INLET FLOW DURING REFLOOD
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

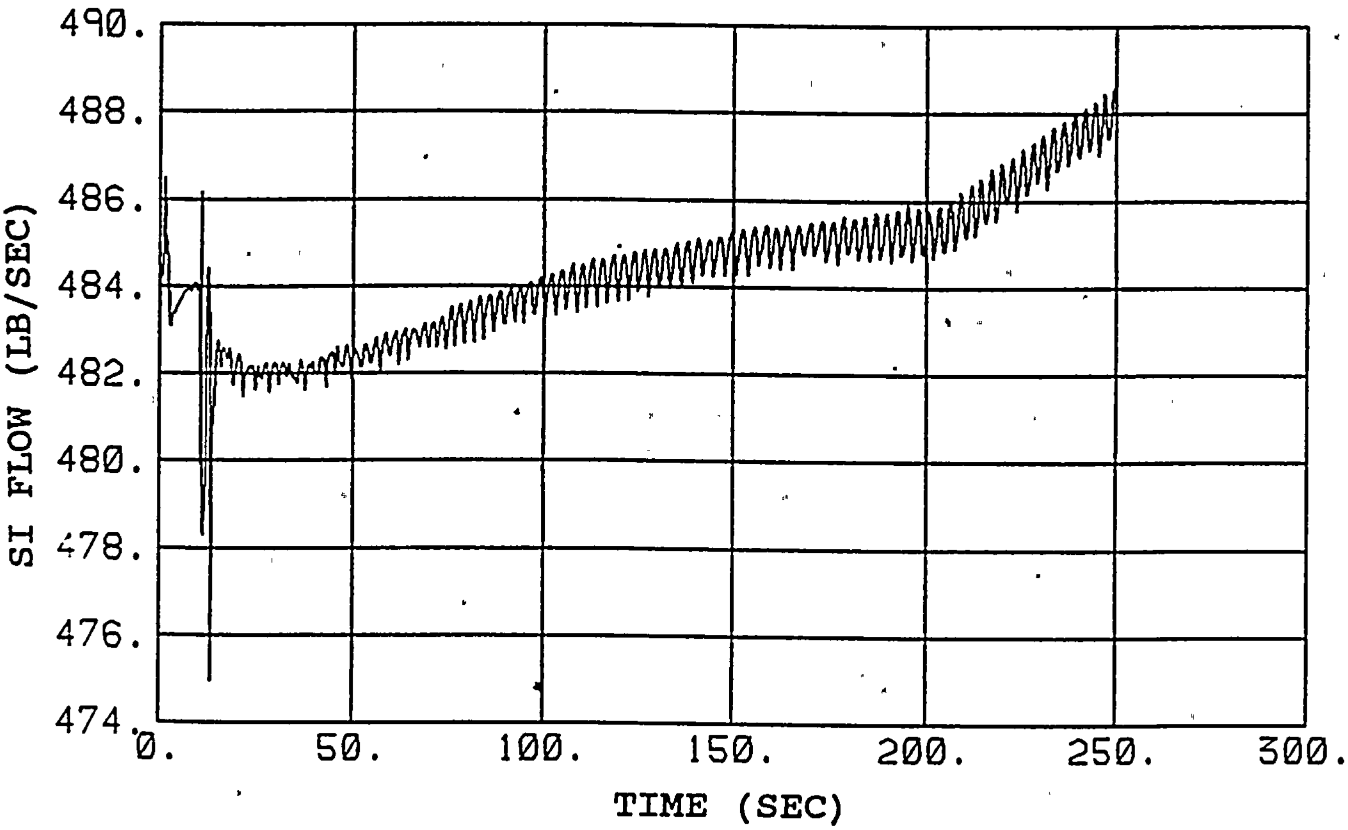

FIGURE C.3.1-10a
SI FLOW
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

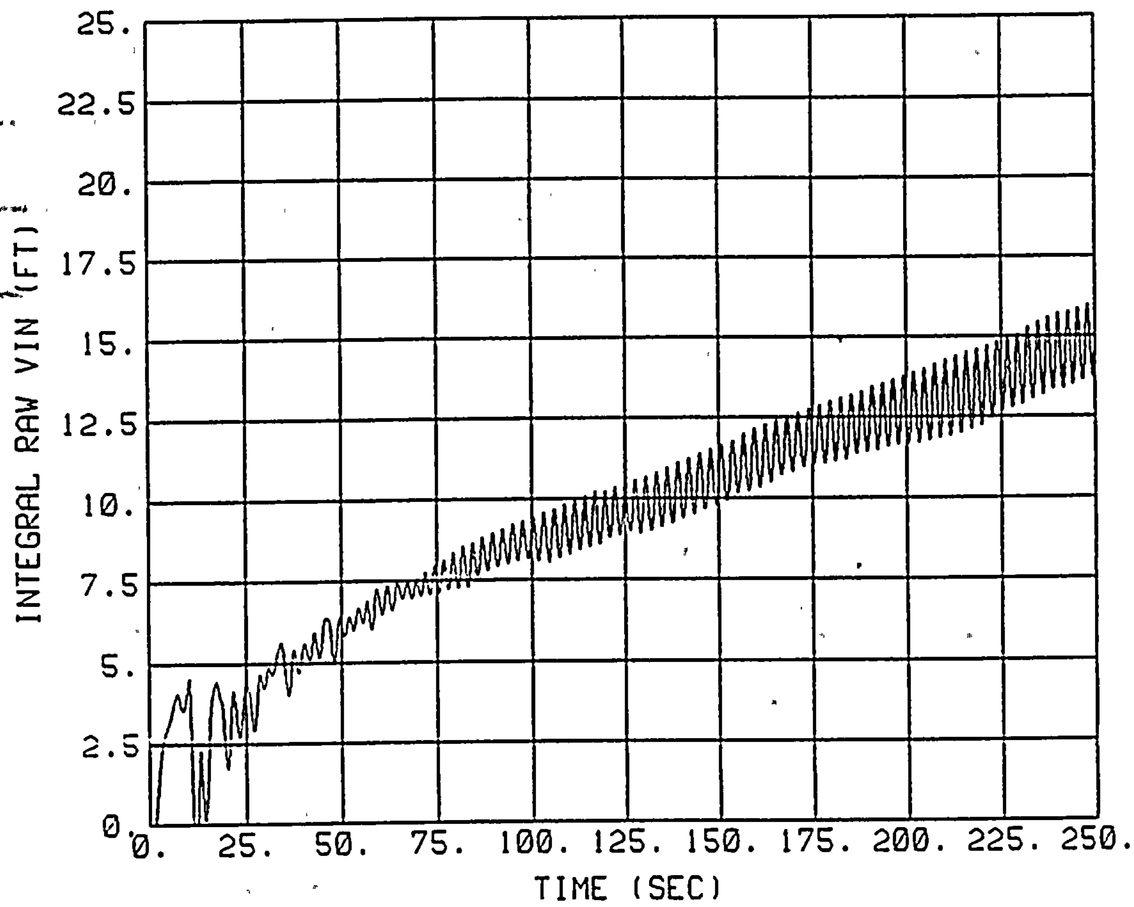

FIGURE C.3.1-11a
INTEGRAL OF CORE INLET FLOW
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

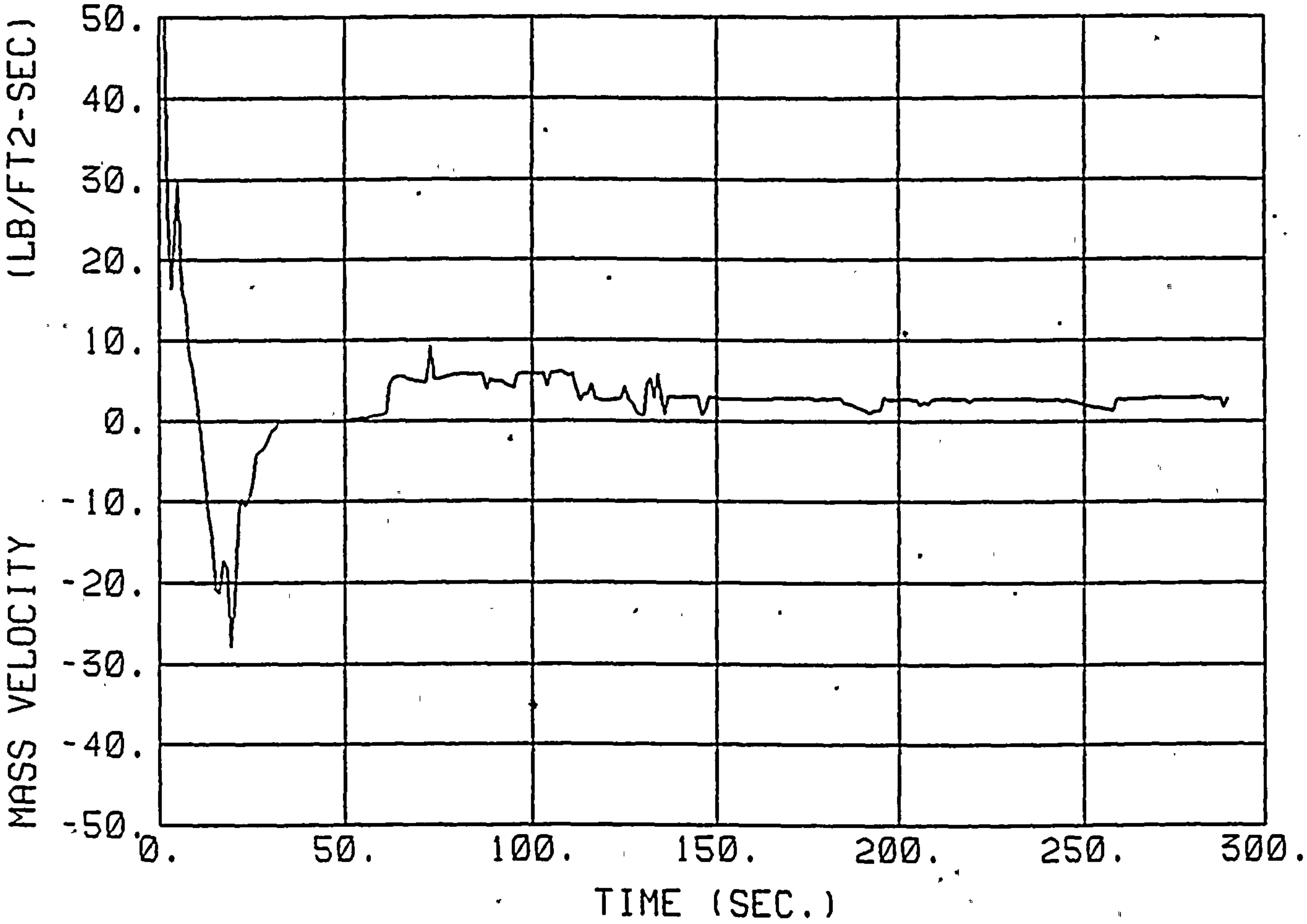

FIGURE C.3.1-12a
MASS FLUX AT THE PEAK
TEMPERATURE ELEVATION
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

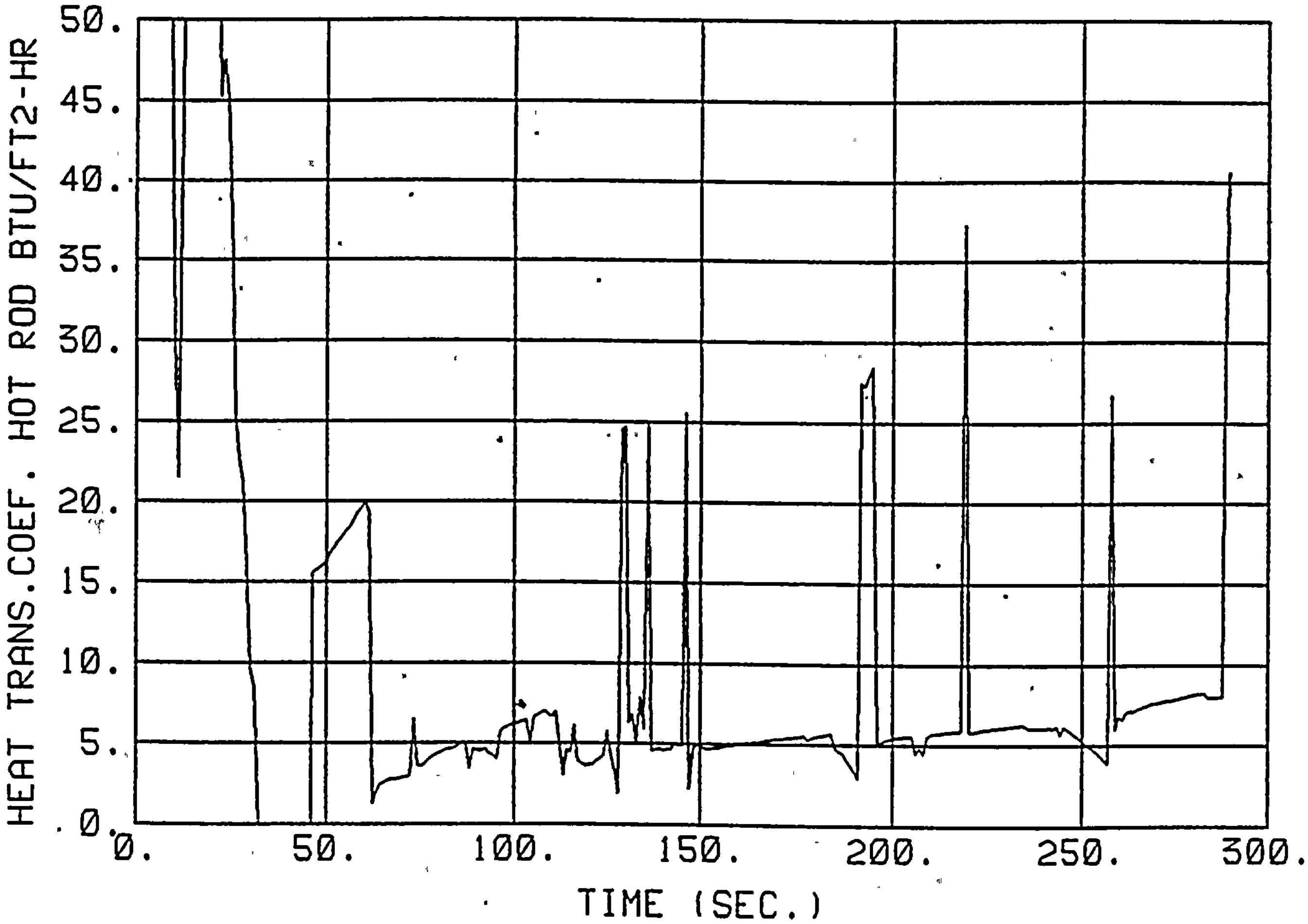

FIGURE C.3.1-13a
ROD HEAT TRANSFER COEFFICIENT AT
THE PEAK TEMPERATURE ELEVATION
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

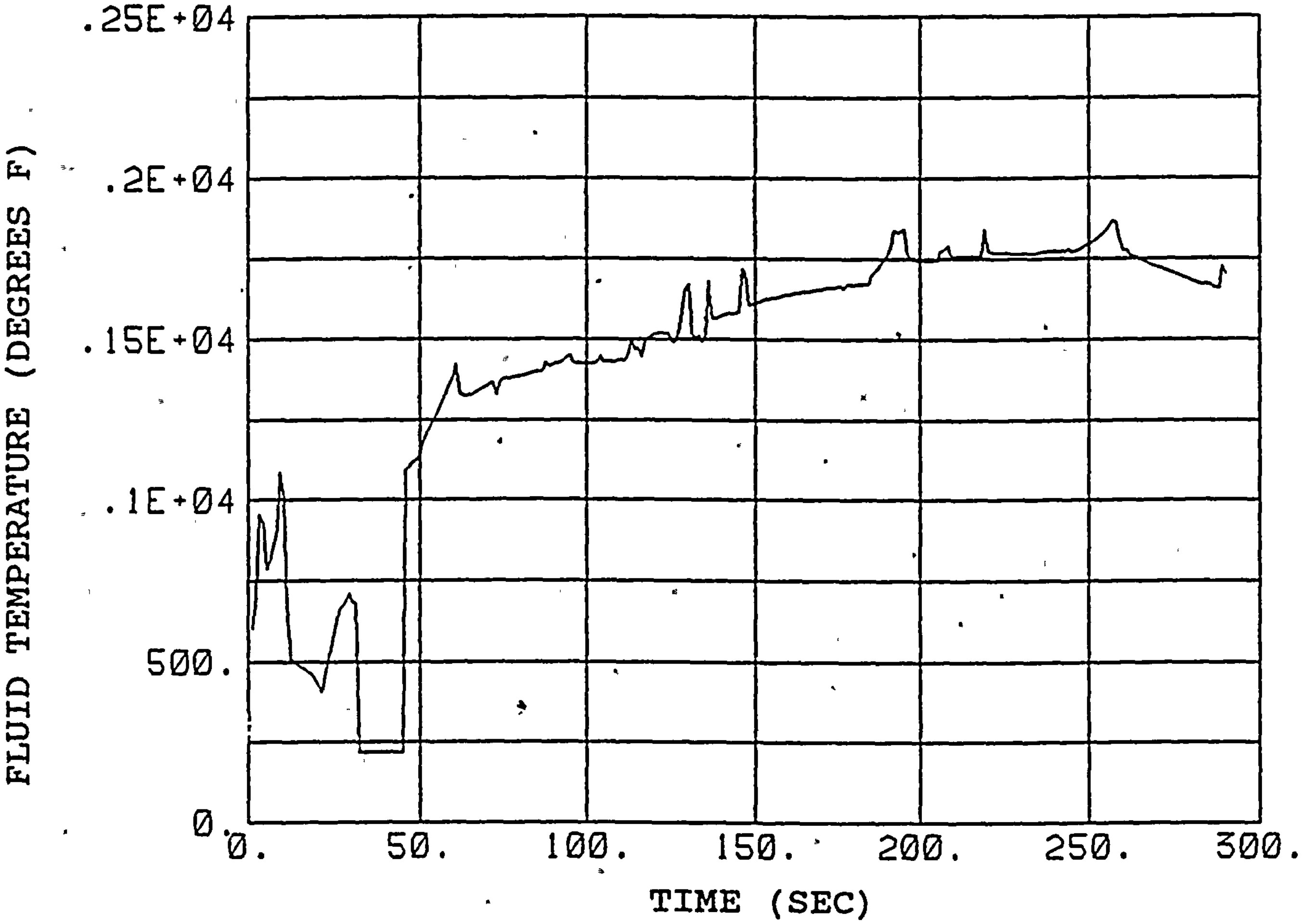

FIGURE C.3.1-14a
FLUID TEMPERATURE
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

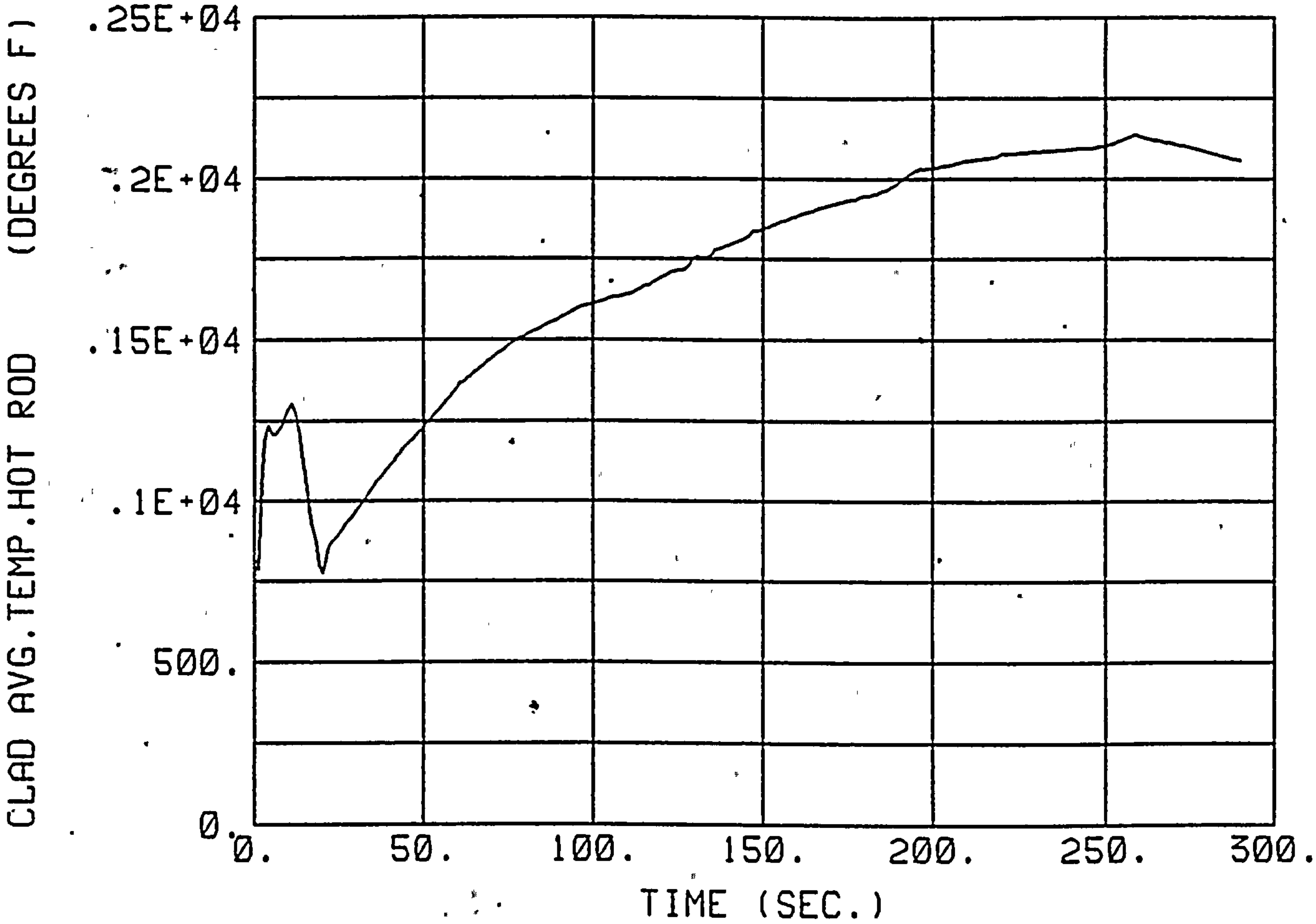

FIGURE C.3.1-15a
FUEL ROD PEAK CLAD TEMPERATURE
CD=0.6, Thot=615.2 °F
Donald C. Cook Unit 2

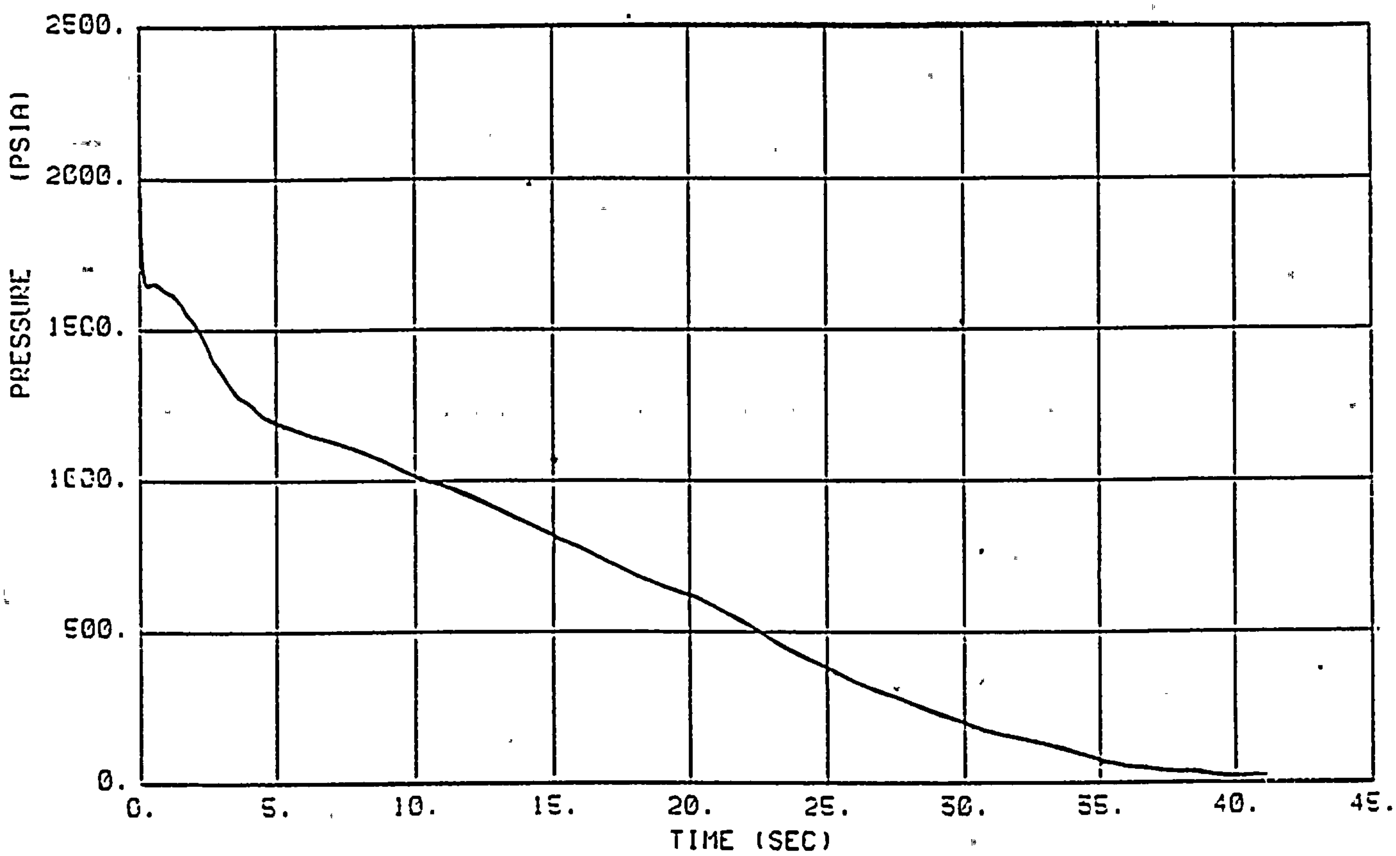

FIGURE C.3.1-3b
REACTOR COOLANT SYSTEM PRESSURE
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

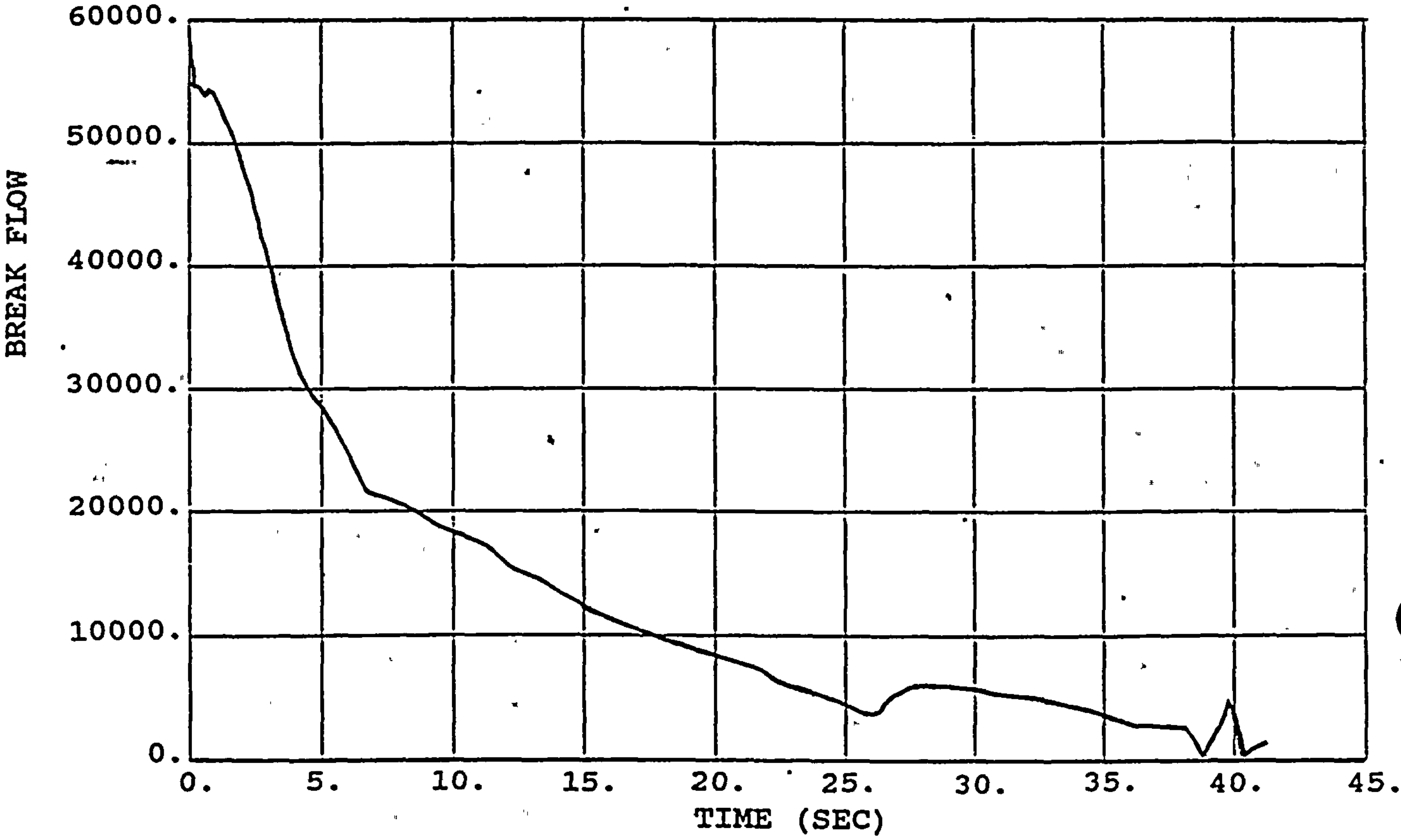

FIGURE C.3.1-4b
BREAK FLOW DURING BLOWDOWN
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

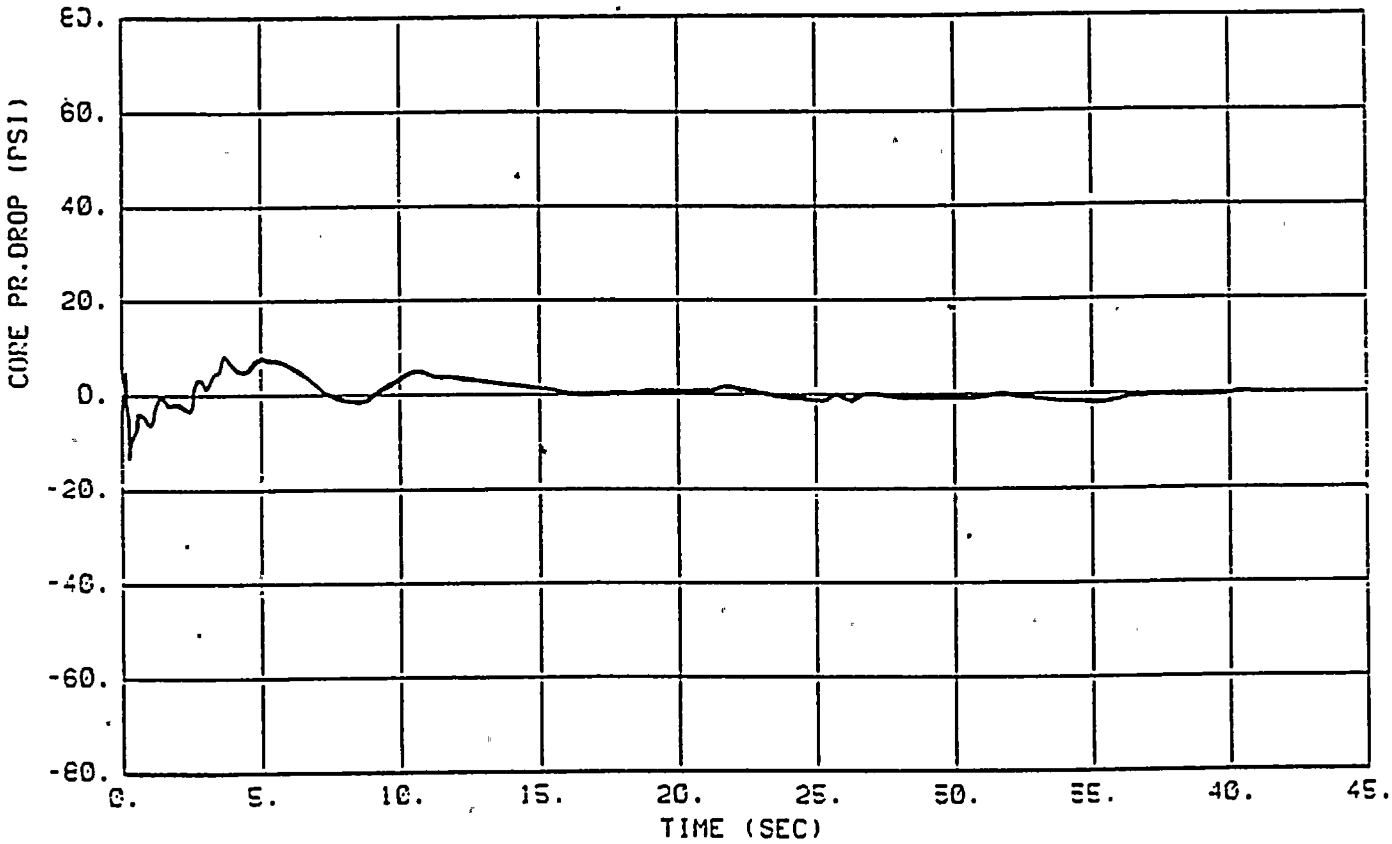

FIGURE C.3.1-5b
CORE PRESSURE DROP
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

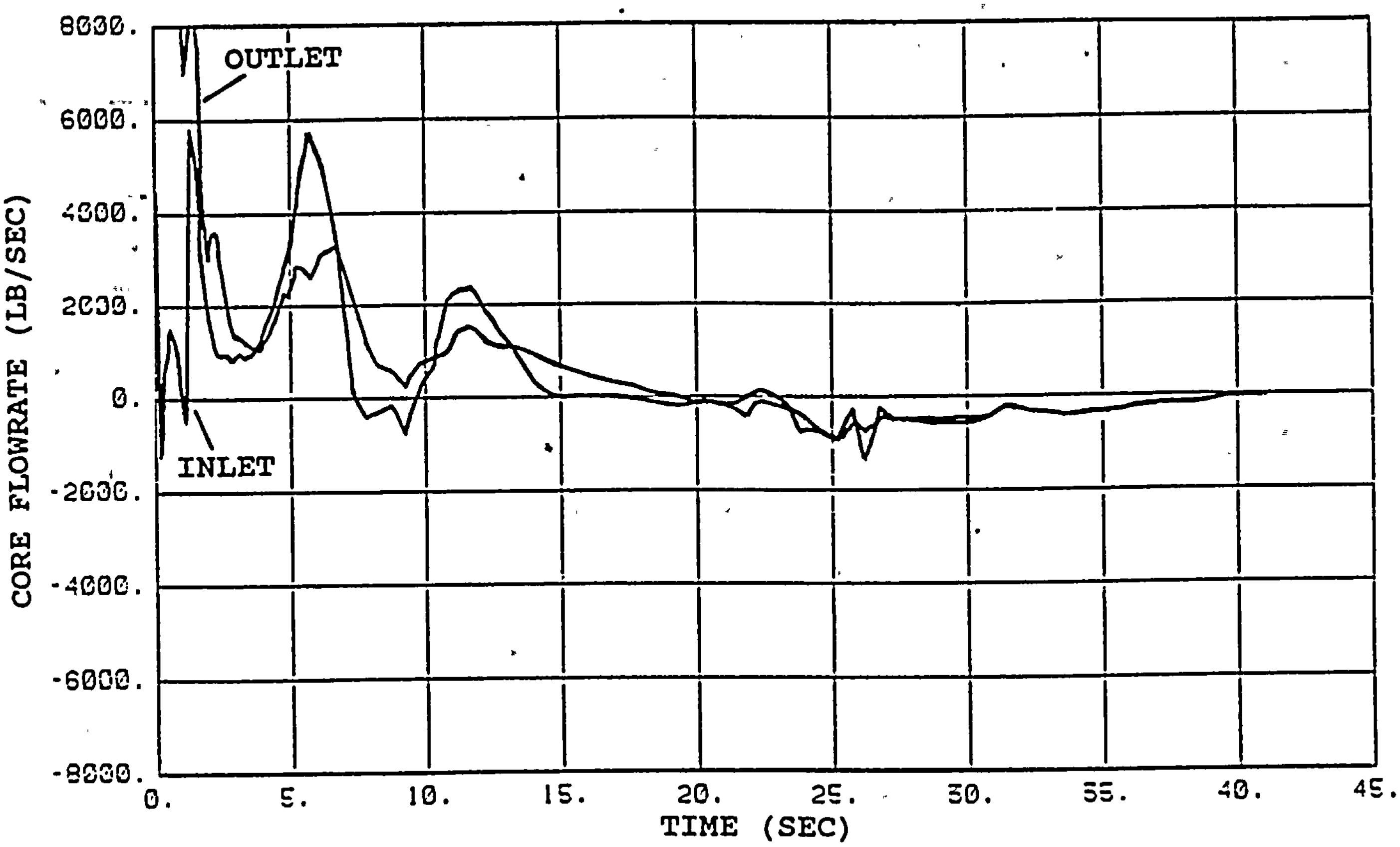

FIGURE C.3.1-6b
CORE FLOWRATE
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

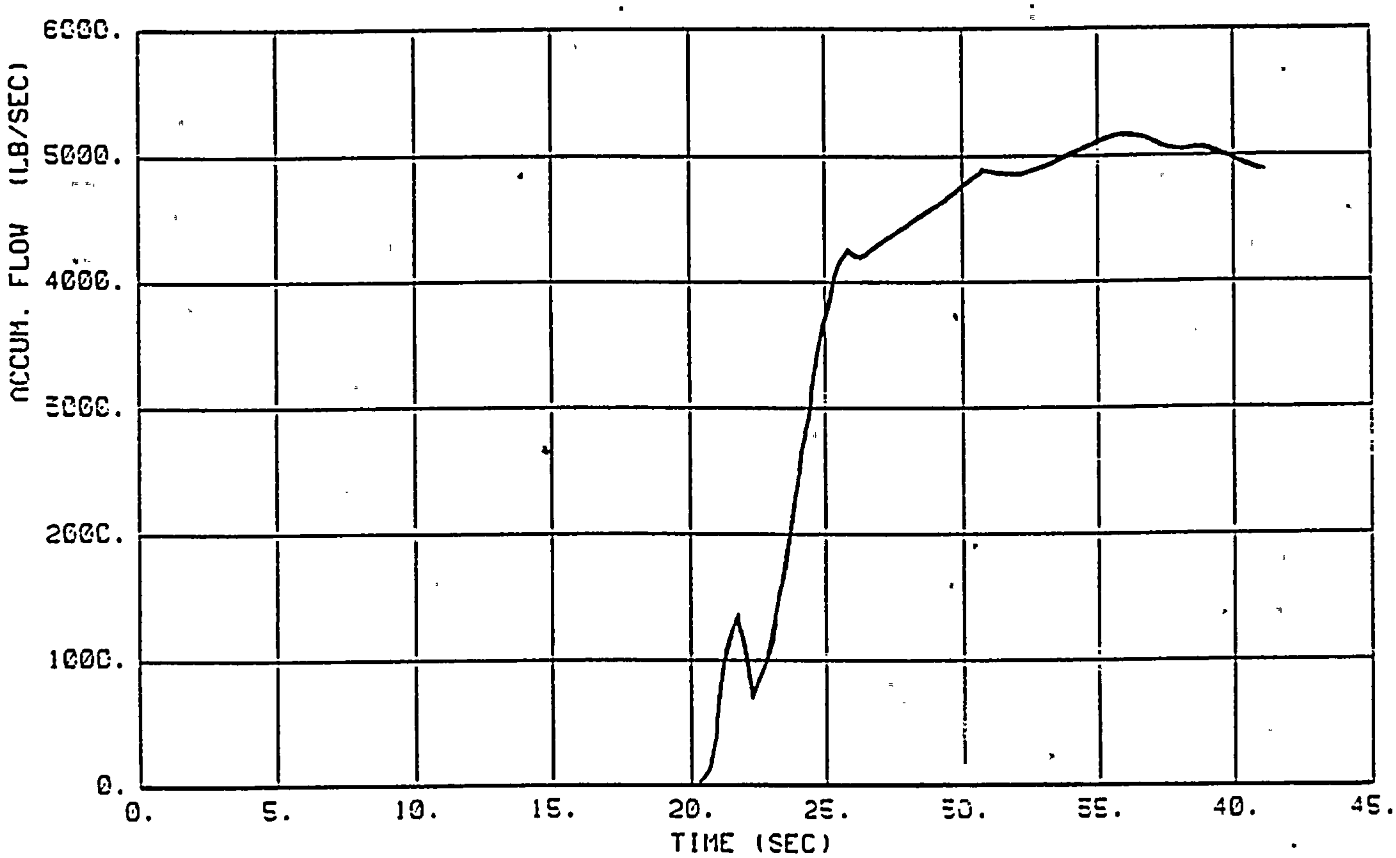

FIGURE C.3.1-7b
ACCUMULATOR FLOW DURING BLOWDOWN
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

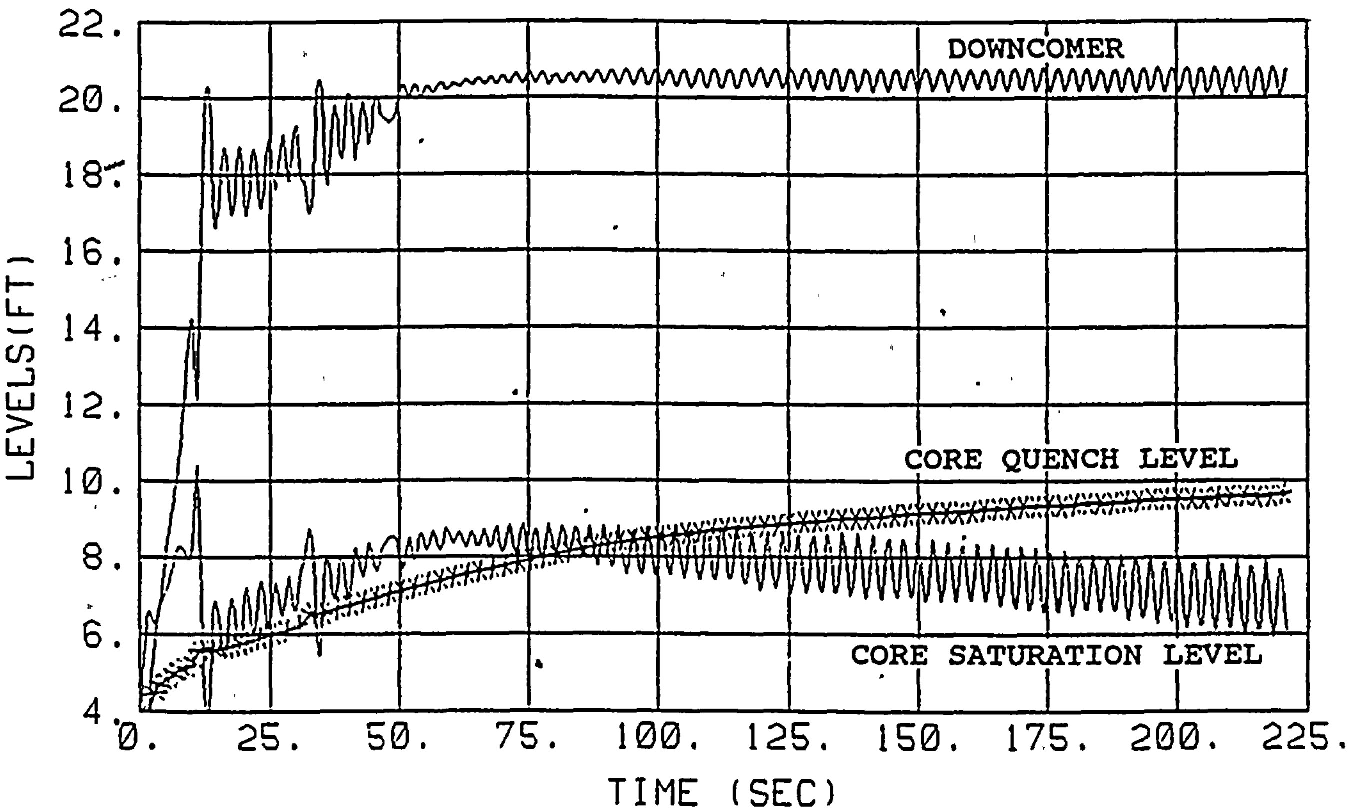

FIGURE C.3.1-8b
CORE AND DOWNCOMER LIQUID LEVELS
DURING REFLOOD
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

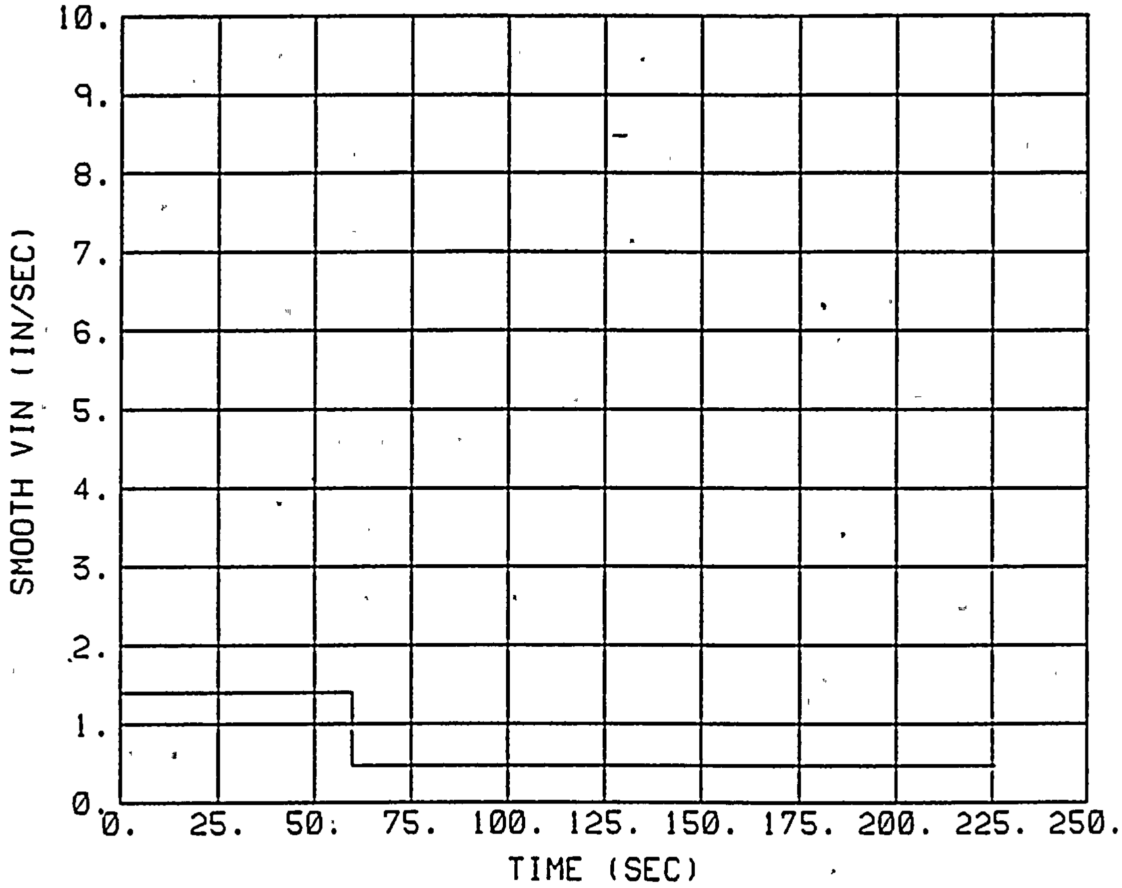

FIGURE C.3.1-9b
CORE INLET FLOW DURING REFLOOD
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

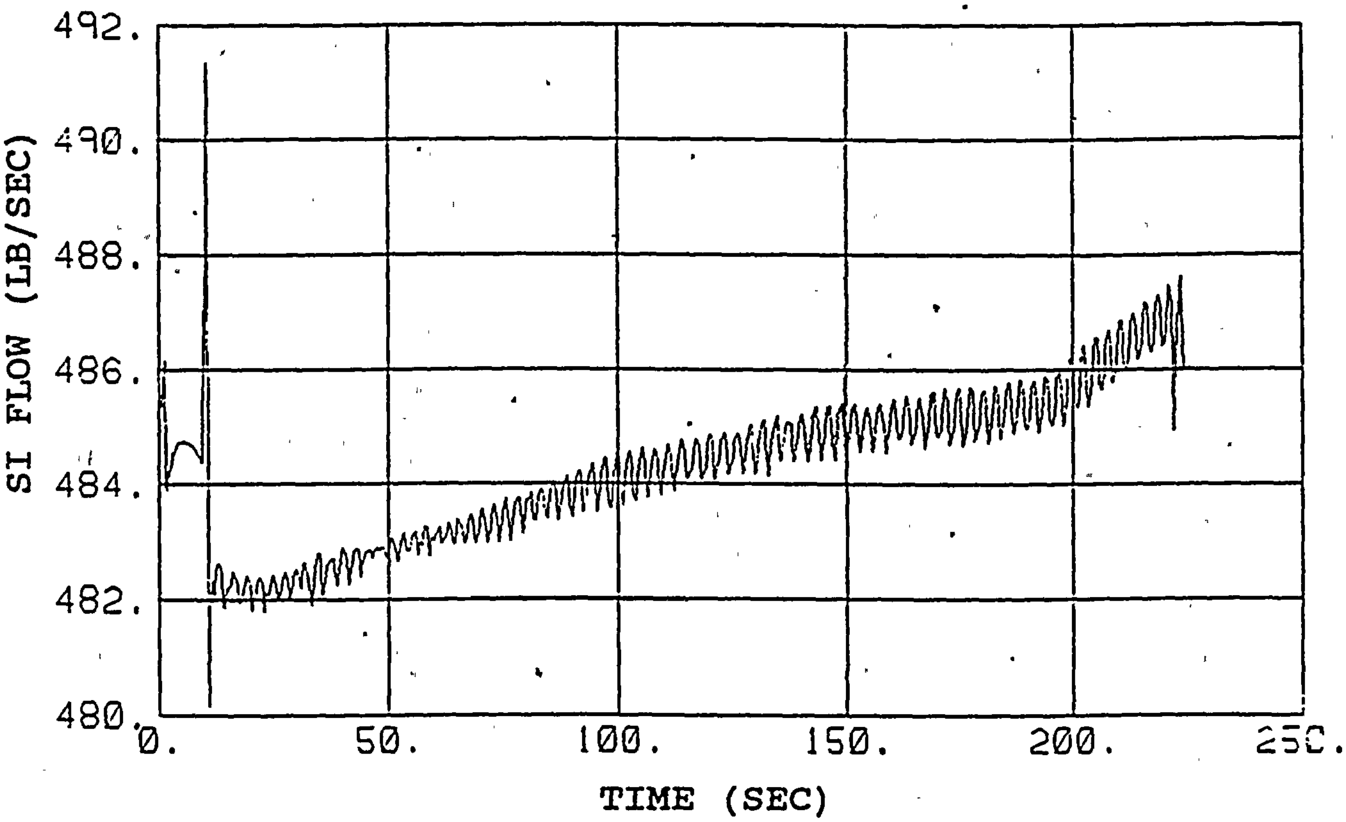

FIGURE C.3.1-10b
SI FLOW
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

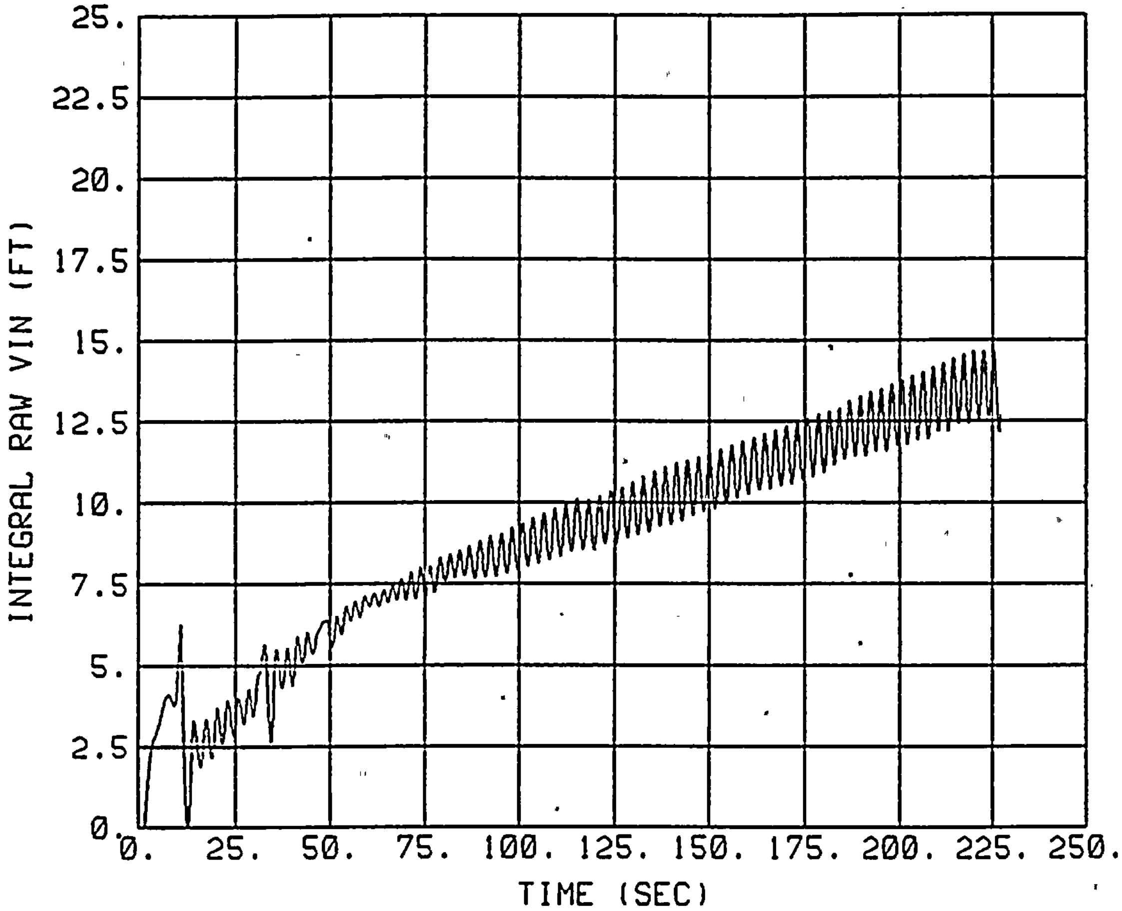

FIGURE C.3.1-11b
INTEGRAL OF CORE INLET FLOW
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

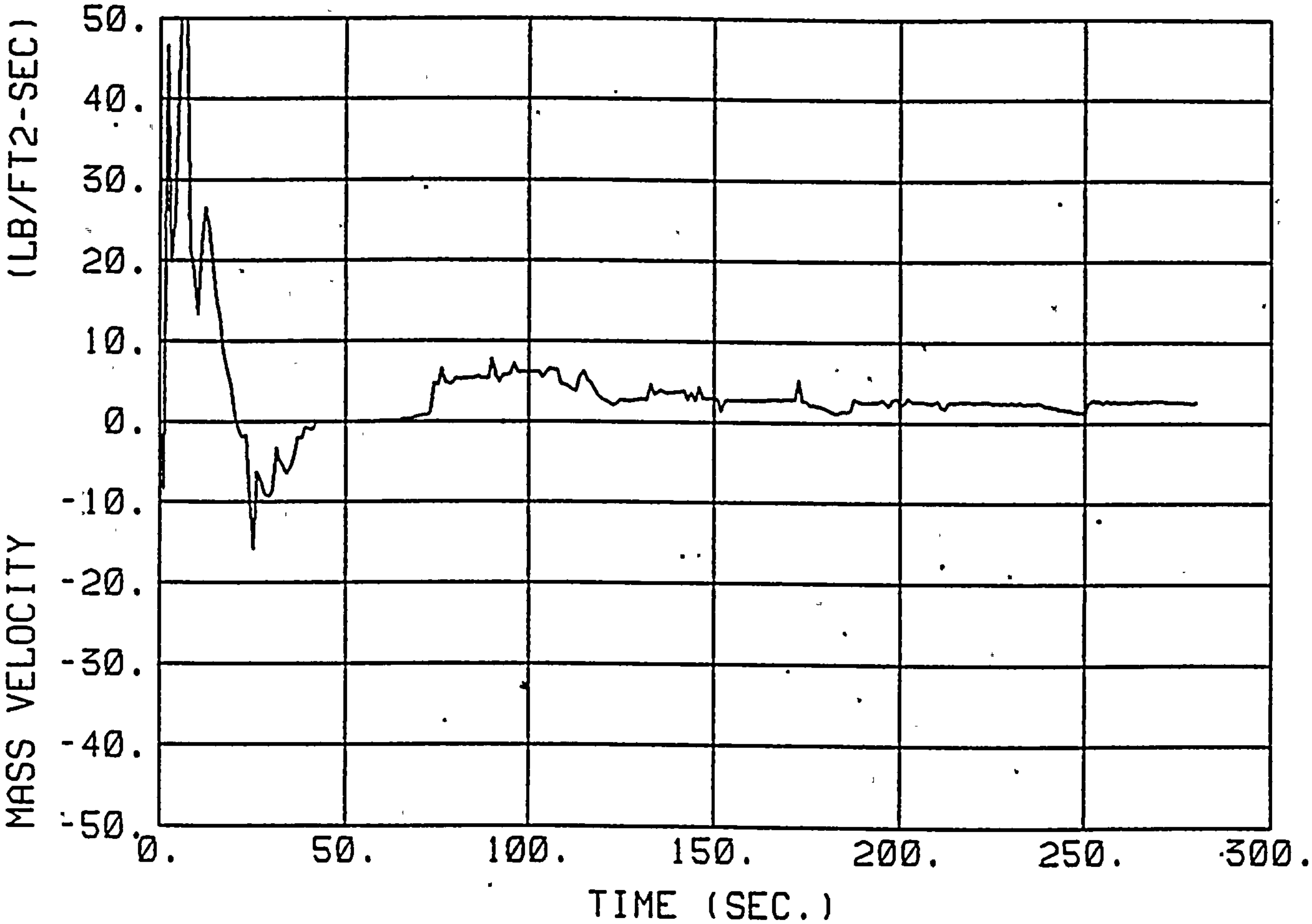

FIGURE C.3.1-12b
MASS FLUX AT THE PEAK
TEMPERATURE ELEVATION
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

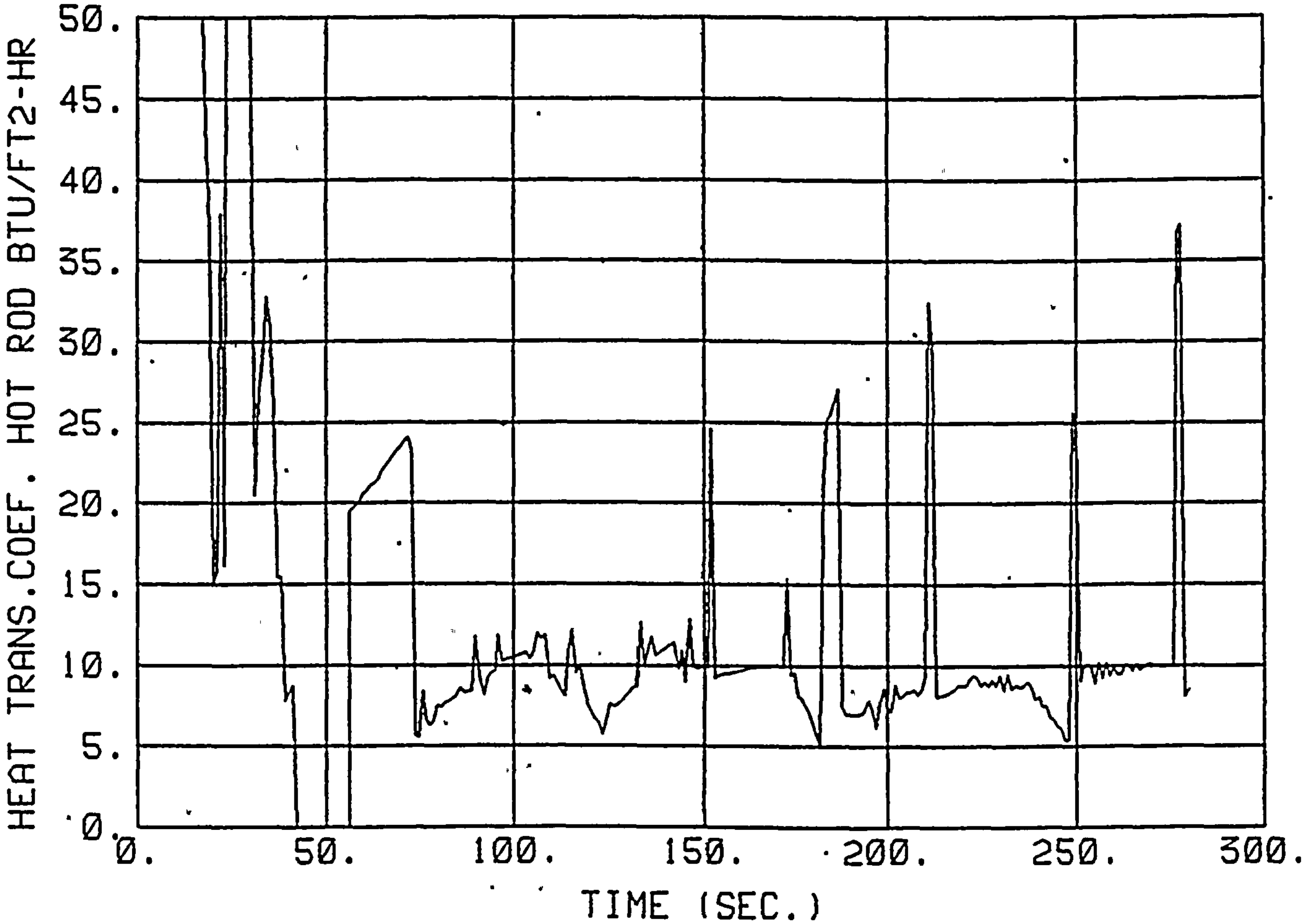

FIGURE C.3.1-13b
ROD HEAT TRANSFER COEFFICIENT AT THE PEAK TEMPERATURE ELEVATION
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

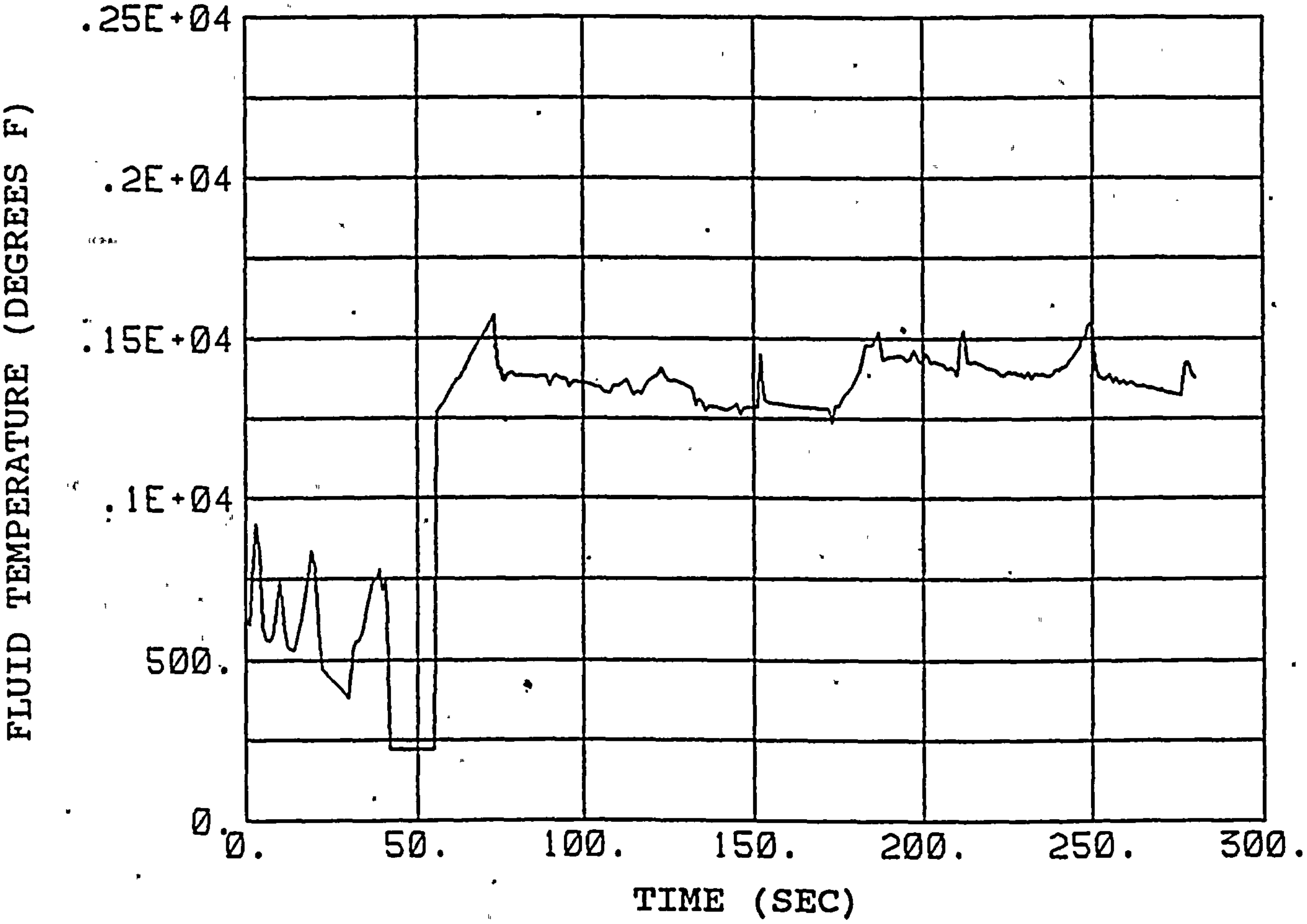

FIGURE C.3.1-14b
FLUID TEMPERATURE
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

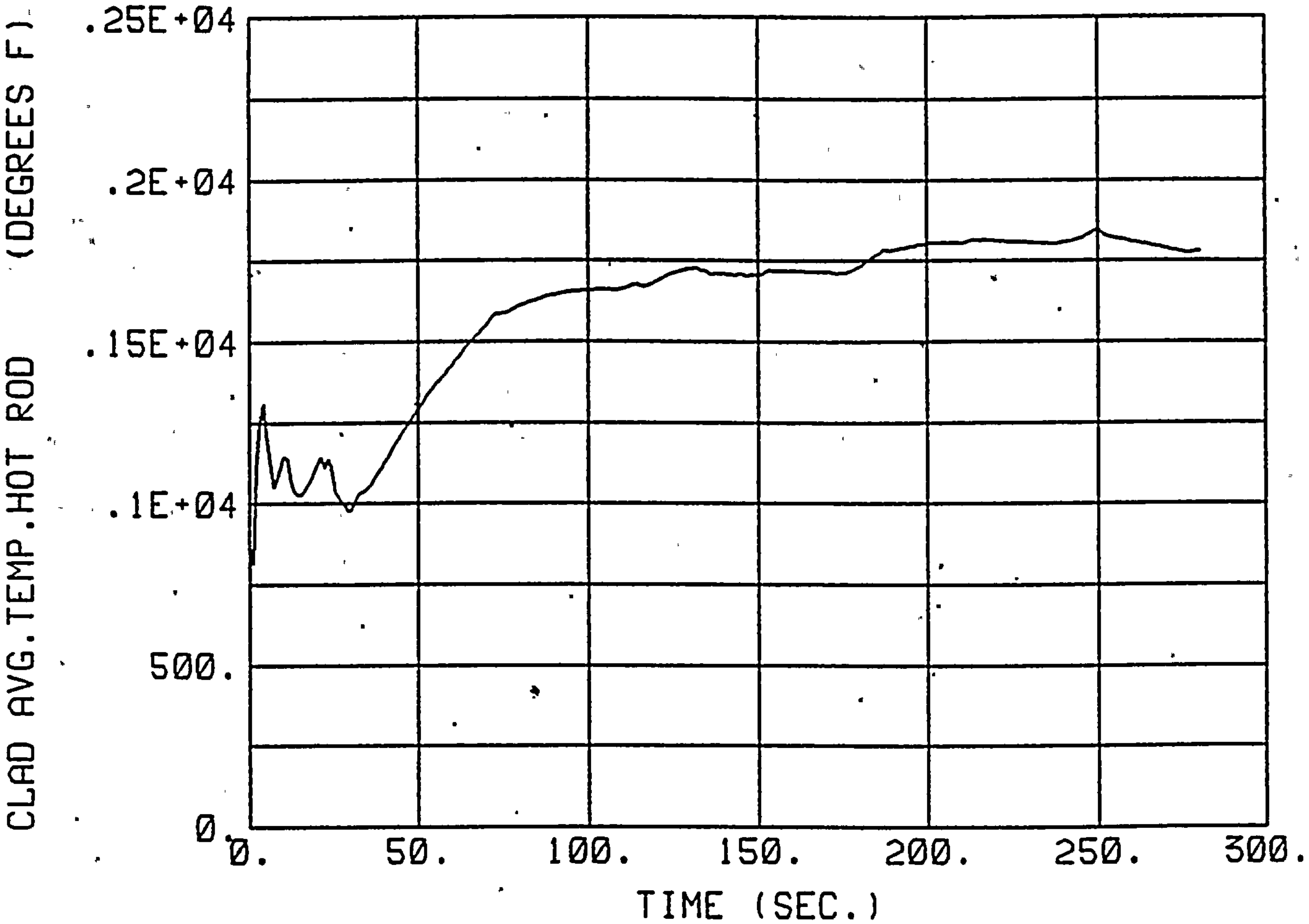

FIGURE C.3.1-15b
FUEL ROD PEAK CLAD TEMPERATURE
CD=0.4, Thot=615.2 °F
Donald C. Cook Unit 2

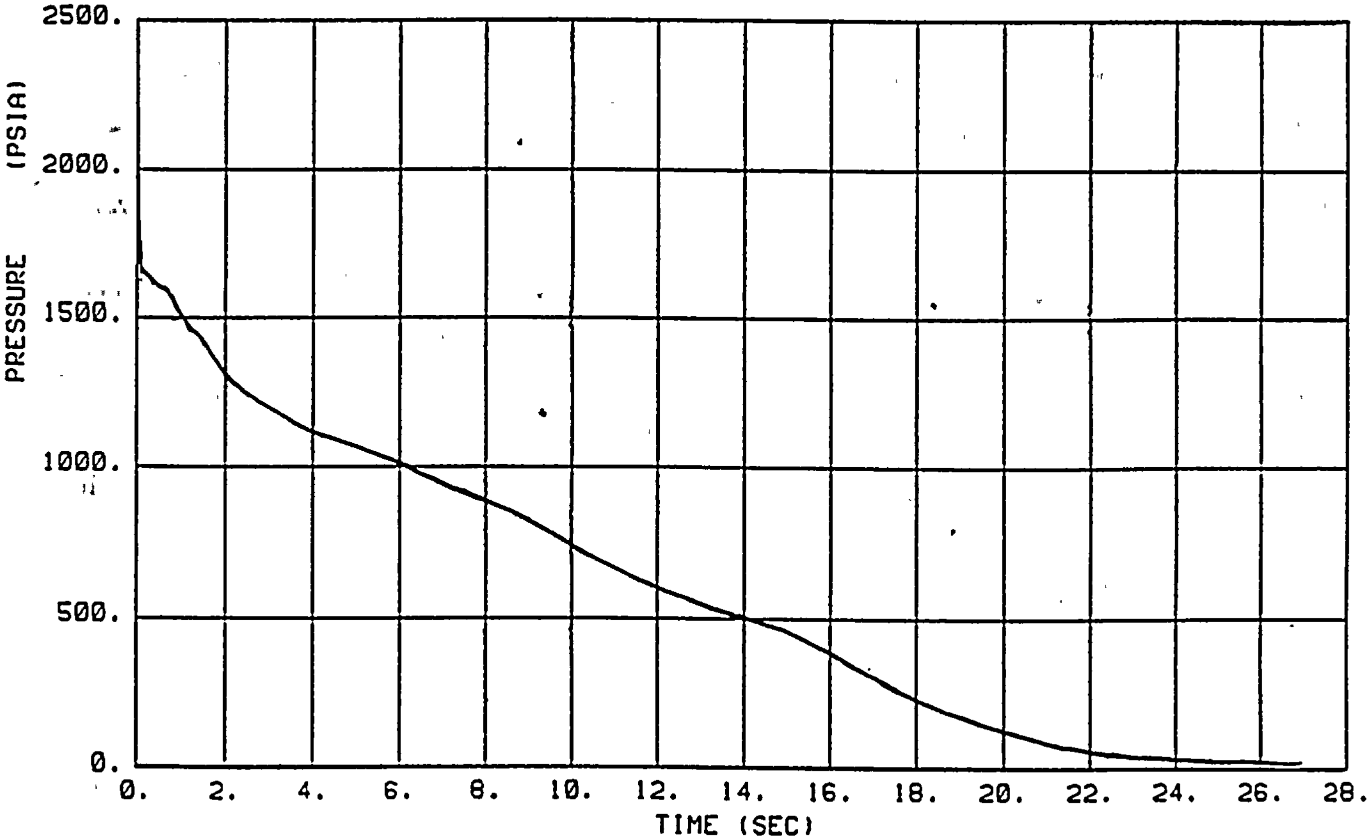

FIGURE C.3.1-3c
REACTOR COOLANT SYSTEM PRESSURE
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

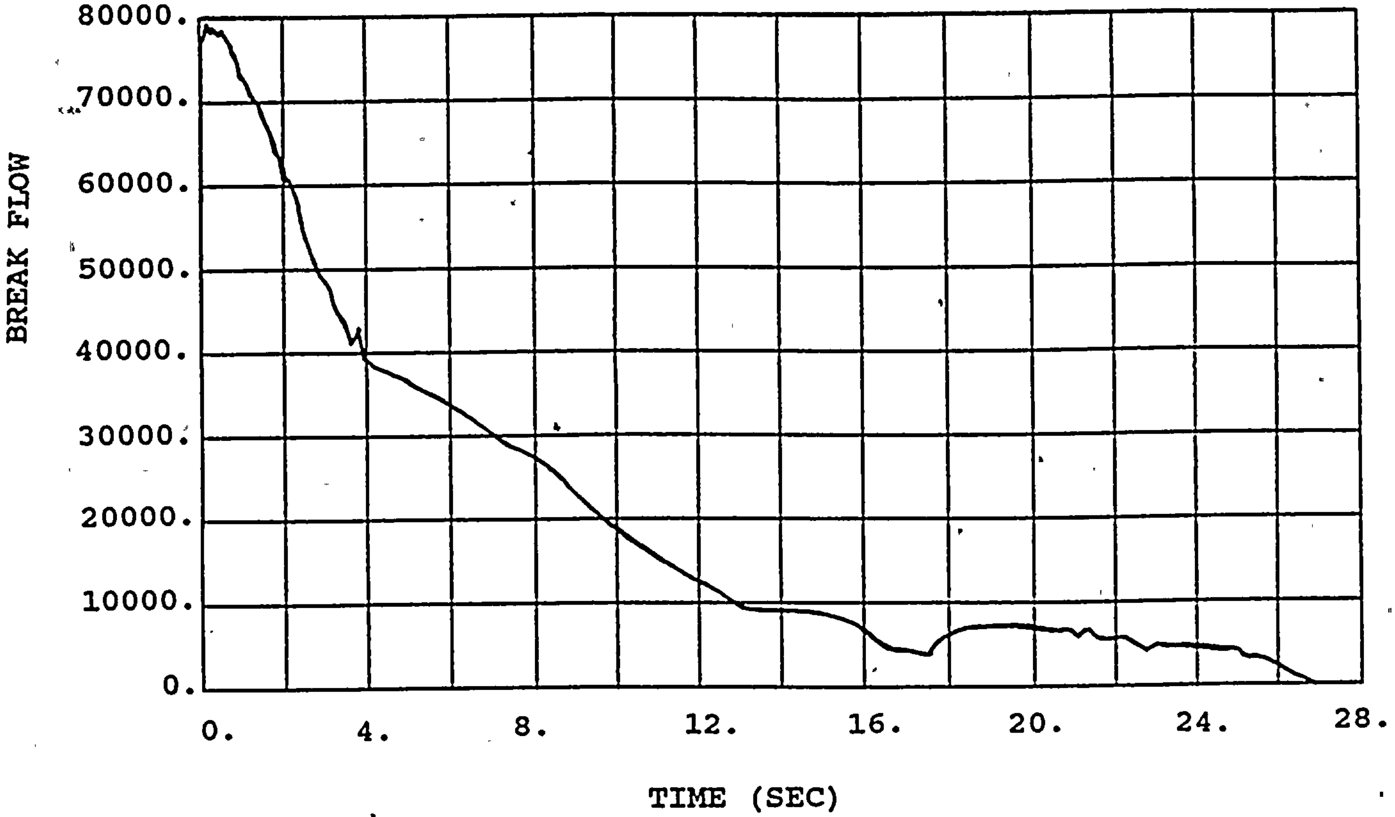

FIGURE C.3.1-4c
BREAK FLOW DURING BLOWDOWN
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

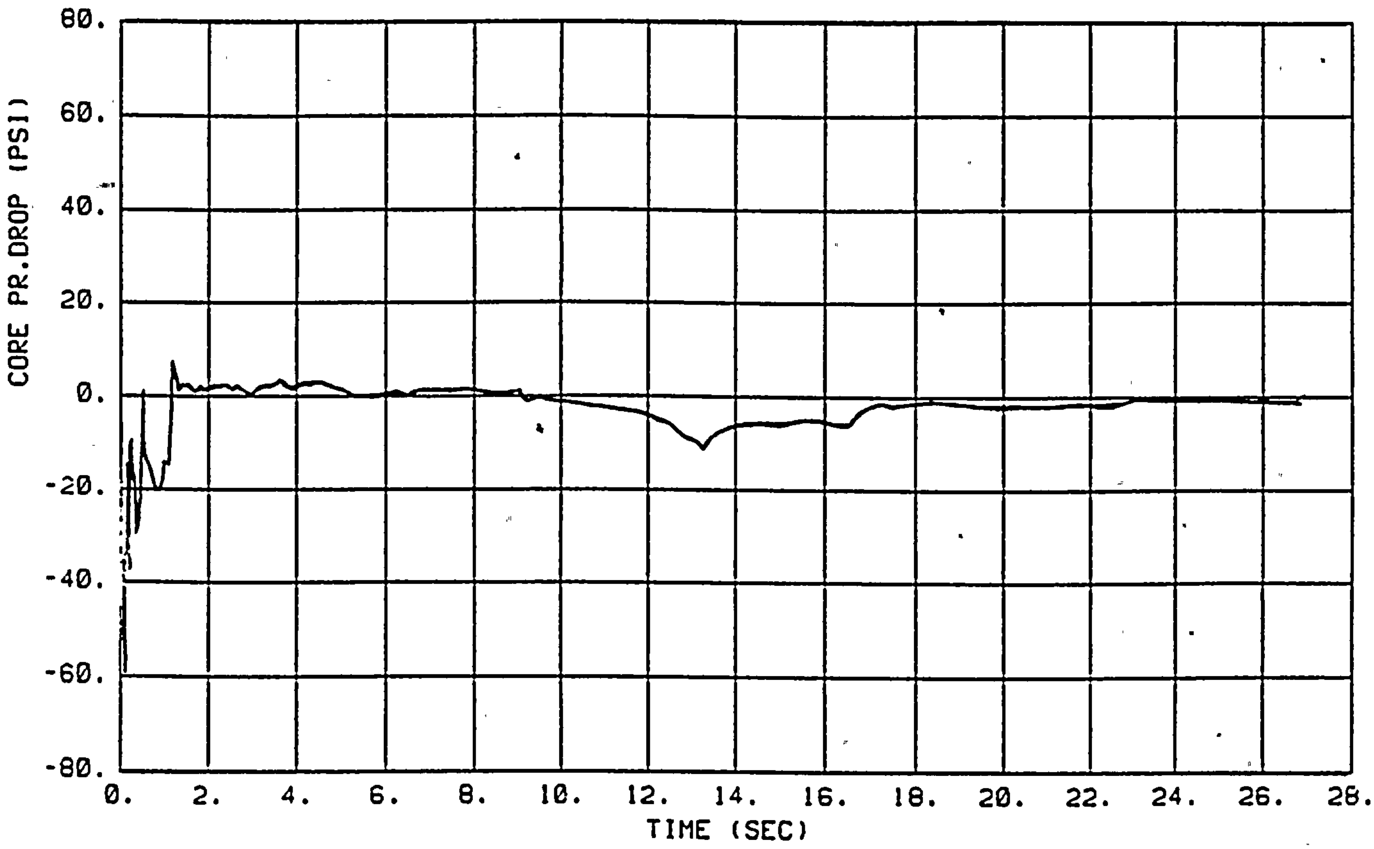

FIGURE C.3.1-5c
CORE PRESSURE DROP
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

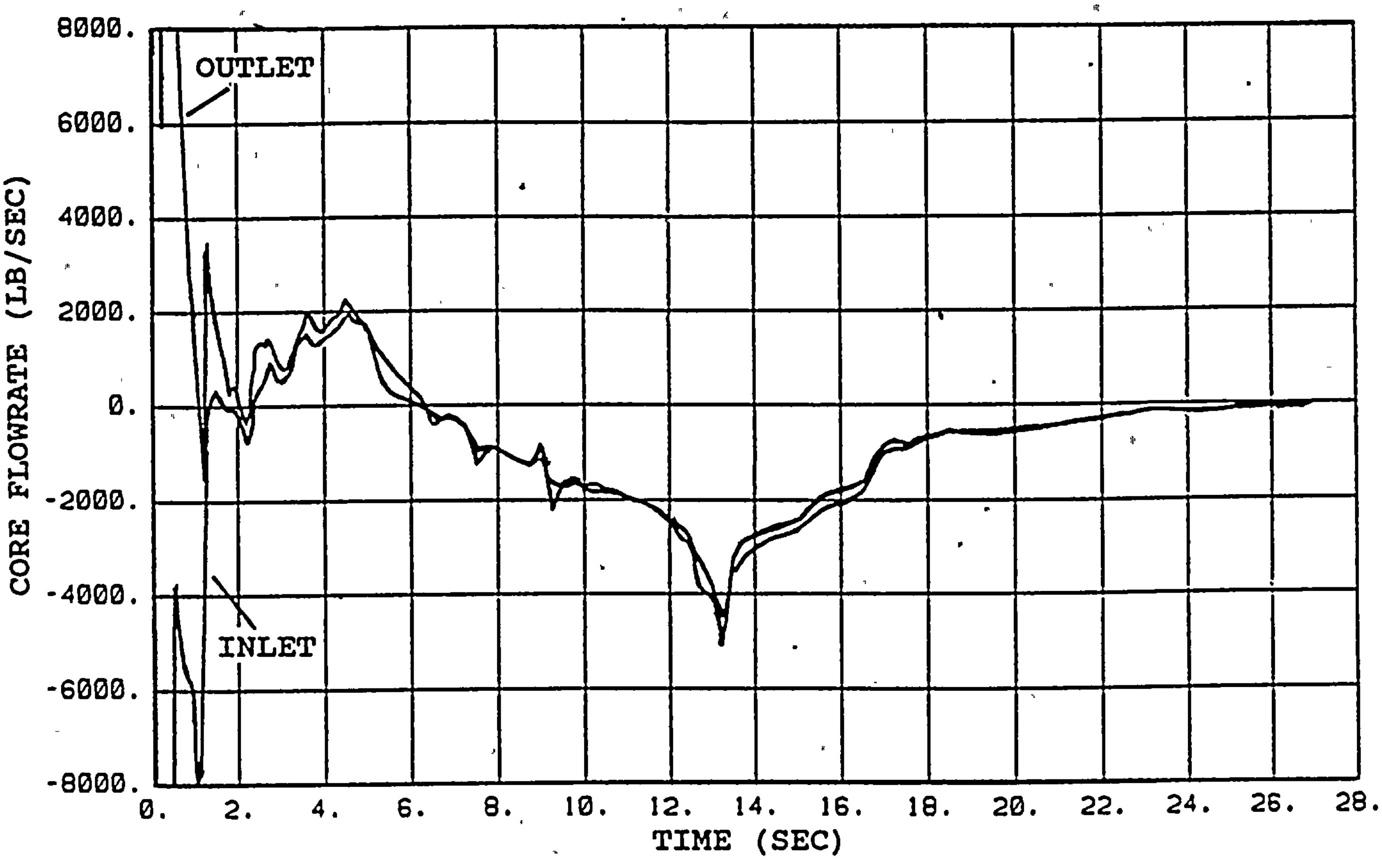

FIGURE C.3.1-6c
CORE FLOWRATE
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

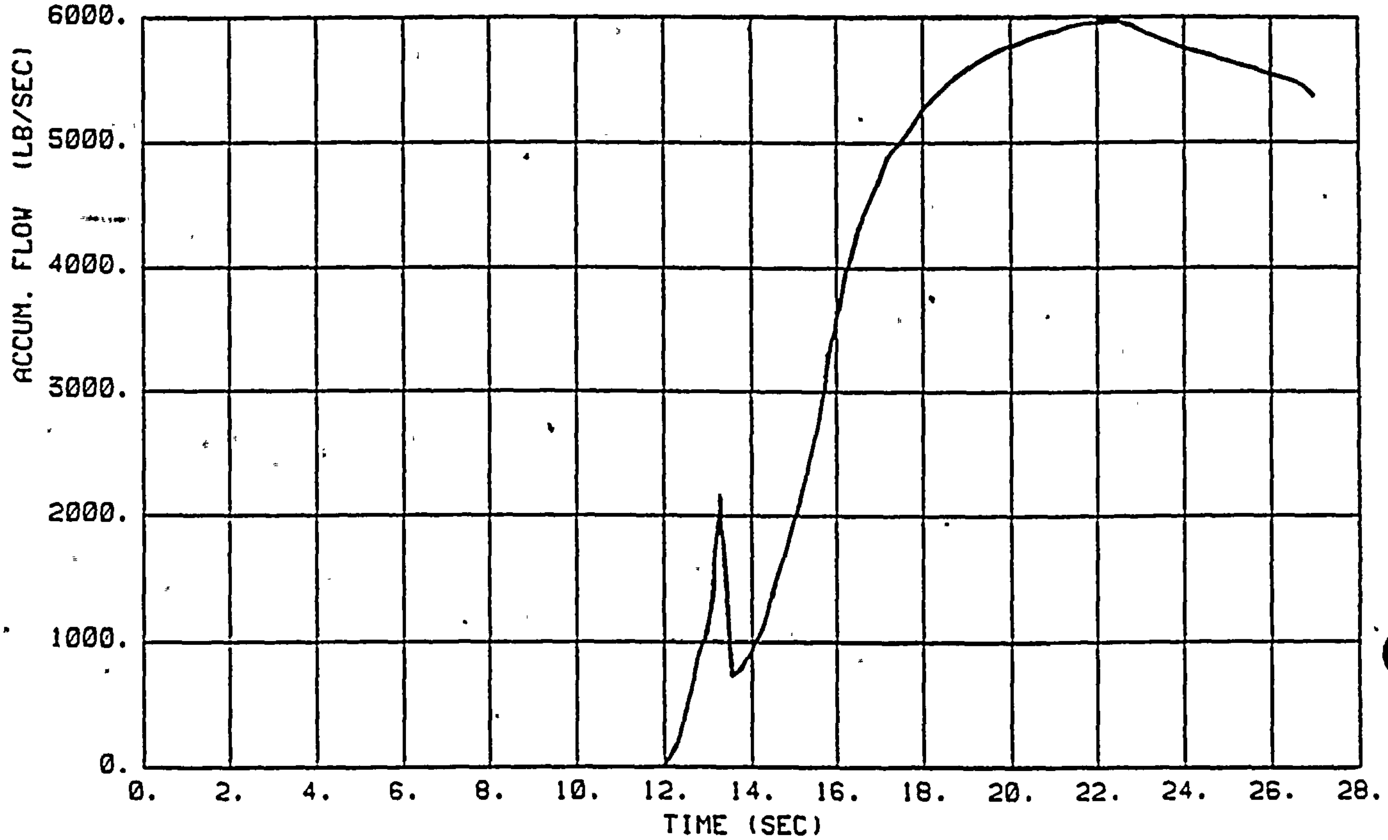

FIGURE C.3.1-7c
ACCUMULATOR FLOW DURING BLOWDOWN
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

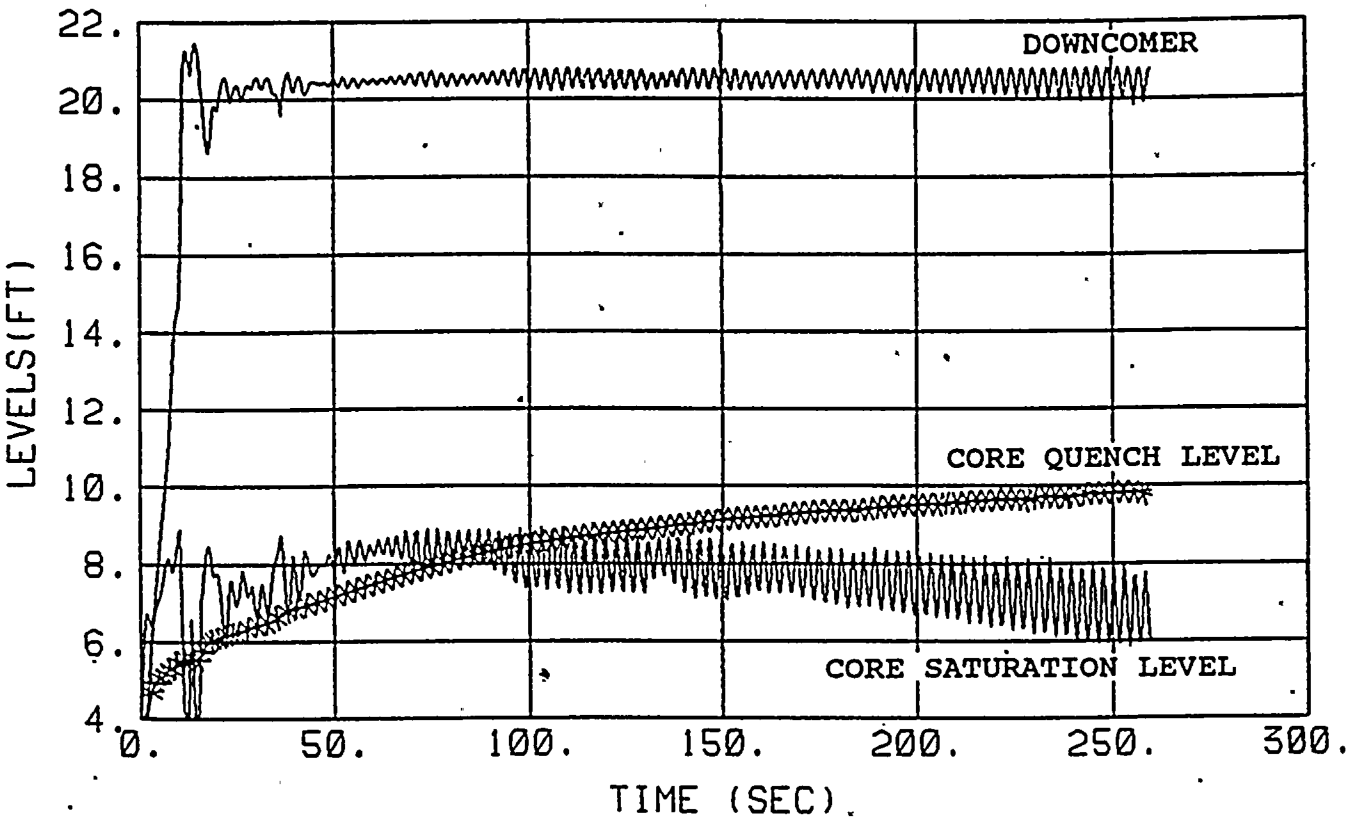

FIGURE C.3.1-8c
CORE AND DOWNCOMER LIQUID LEVELS
DURING REFLOOD
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

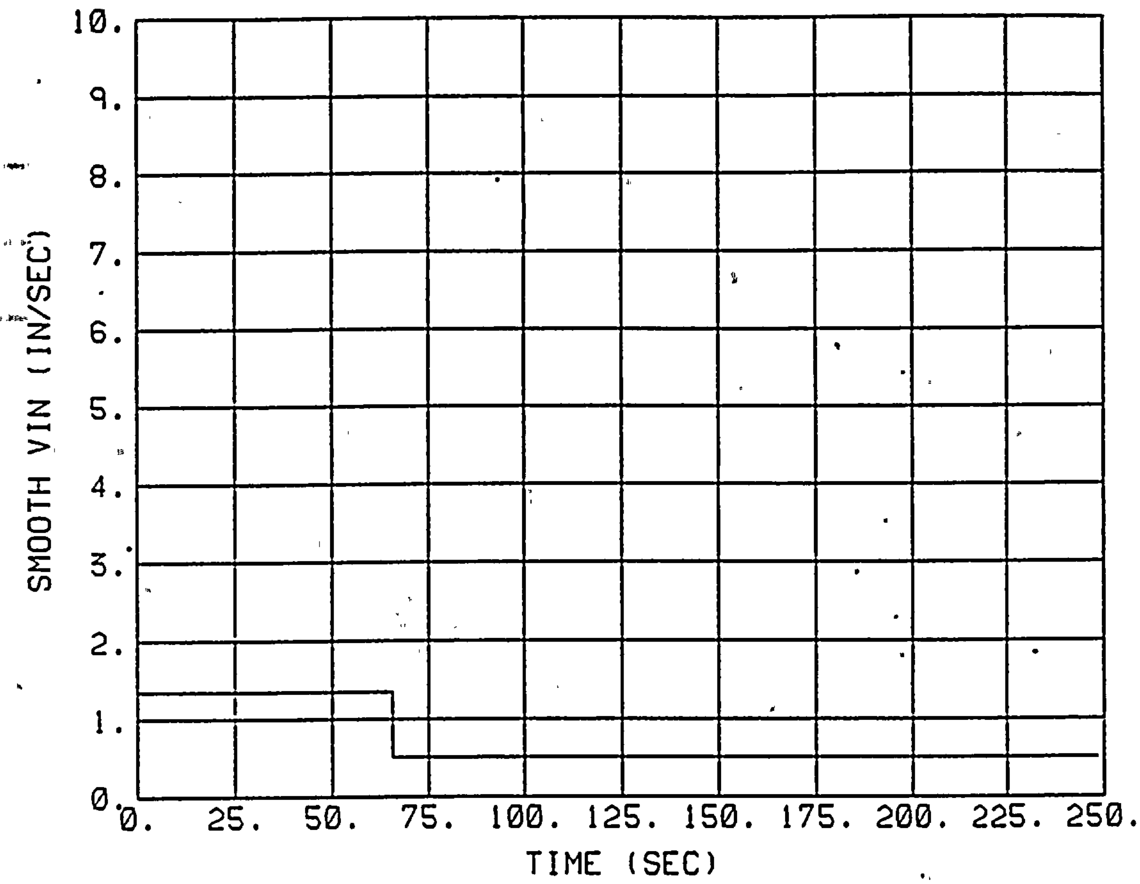

FIGURE C.3.1-9c
CORE INLET FLOW DURING REFLOOD
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

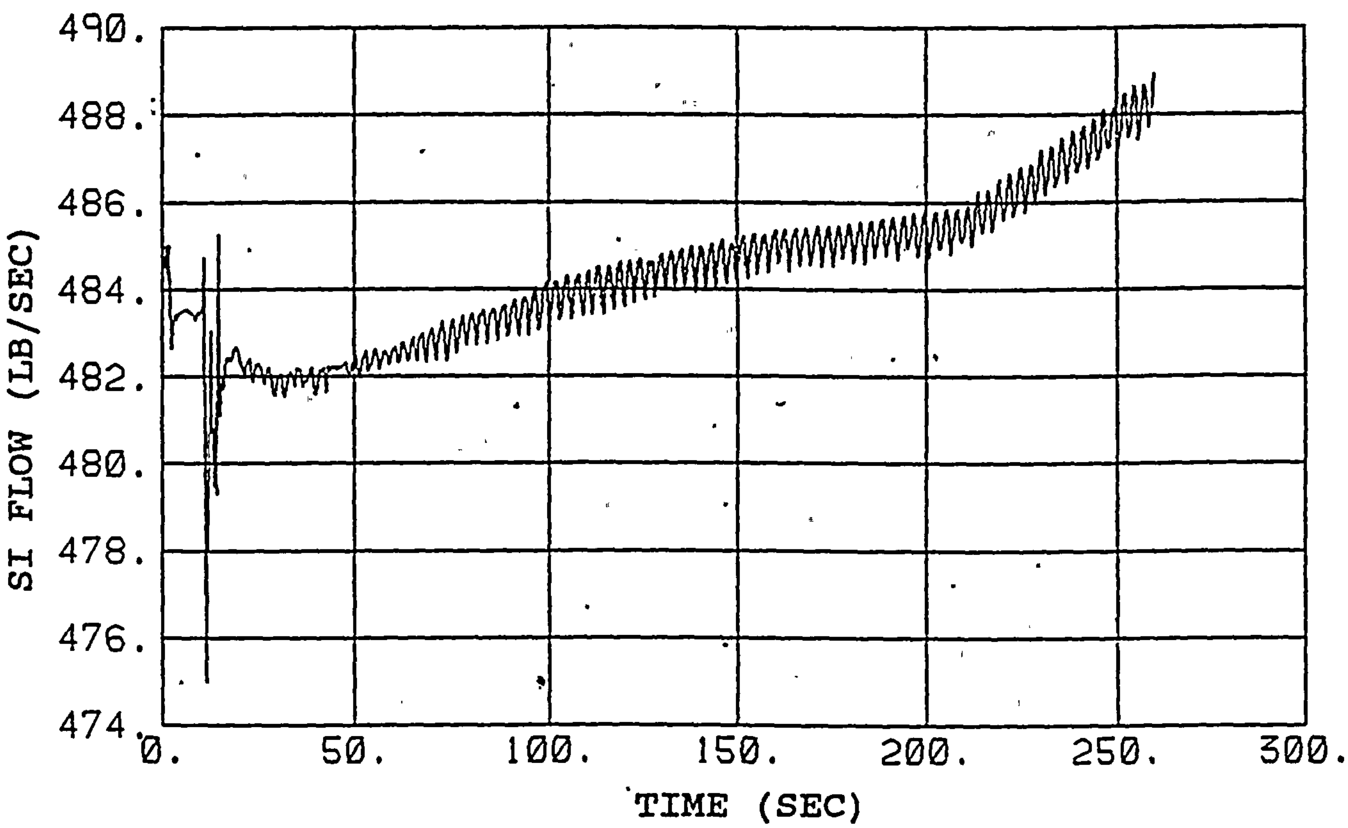

FIGURE C.3.1-10c
SI FLOW
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

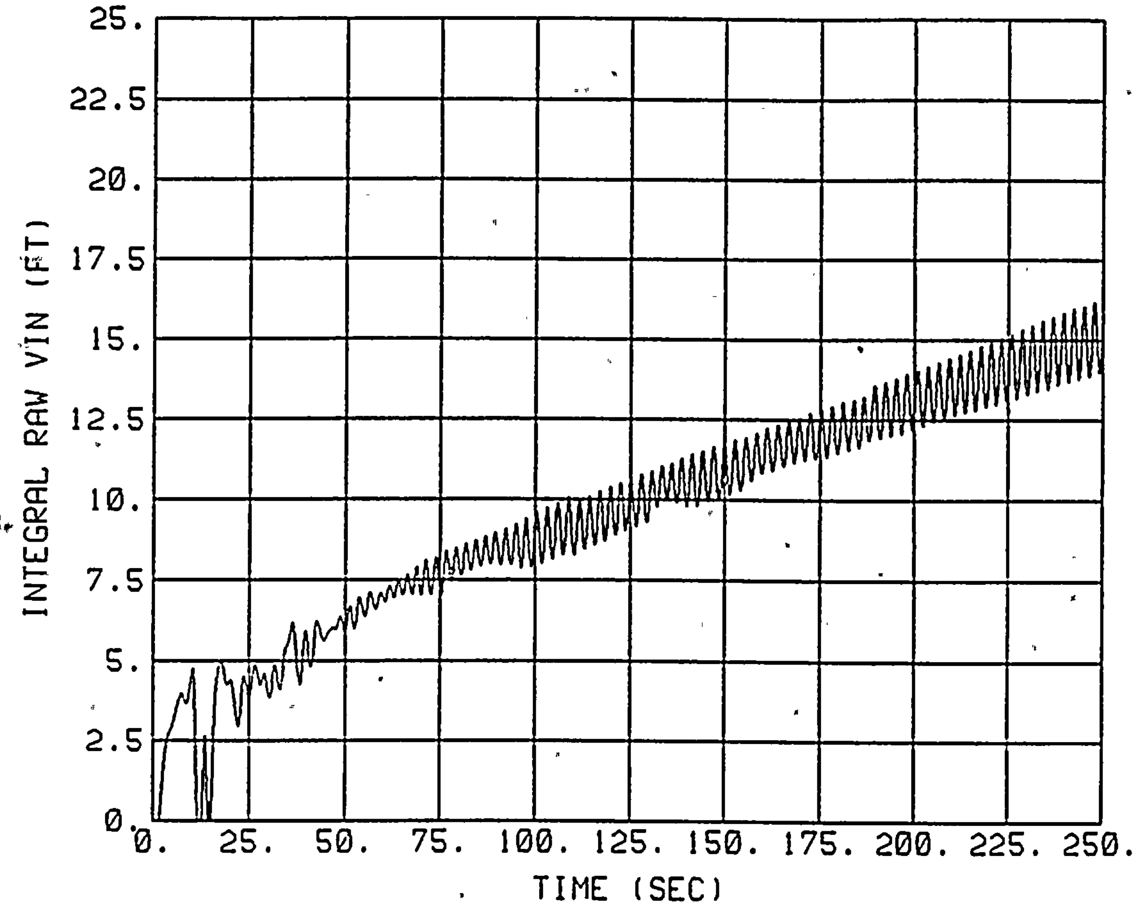

FIGURE C.3.1-11c
INTEGRAL OF CORE INLET FLOW
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

* Time is measured after BOC

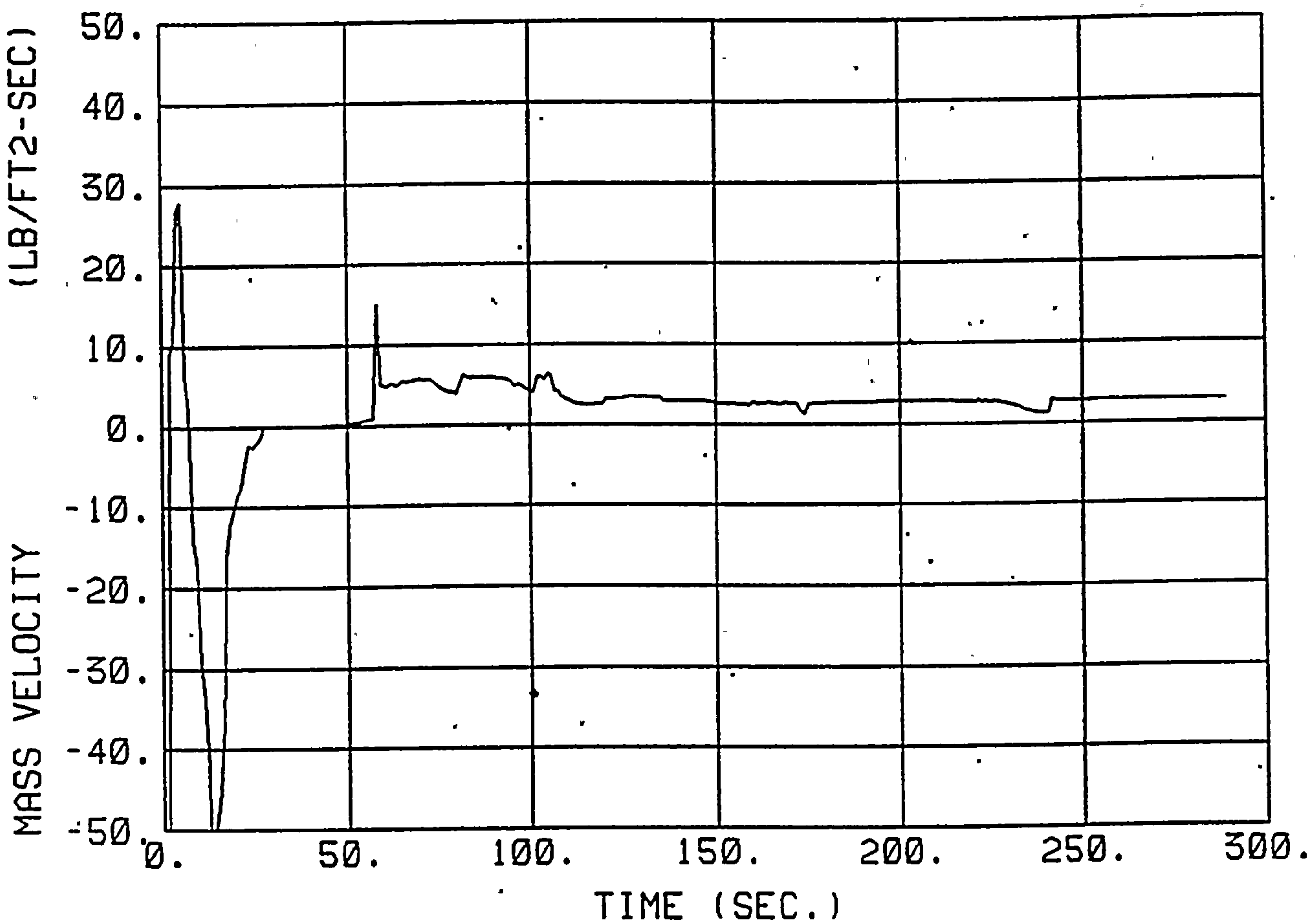

FIGURE C.3.1-12c
MASS FLUX AT THE PEAK
TEMPERATURE ELEVATION
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

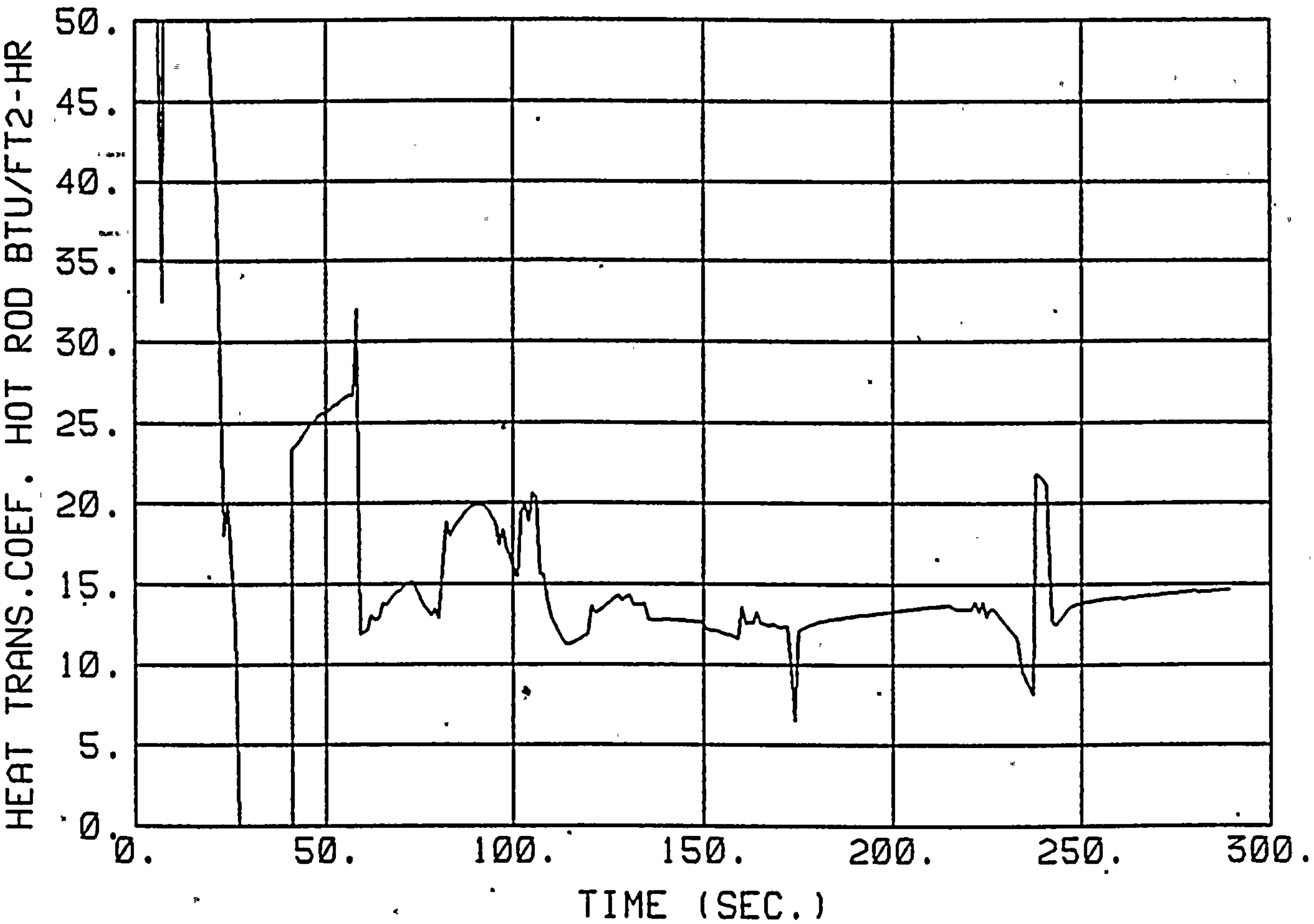

FIGURE C.3.1-13c
ROD HEAT TRANSFER COEFFICIENT AT
THE PEAK TEMPERATURE ELEVATION
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

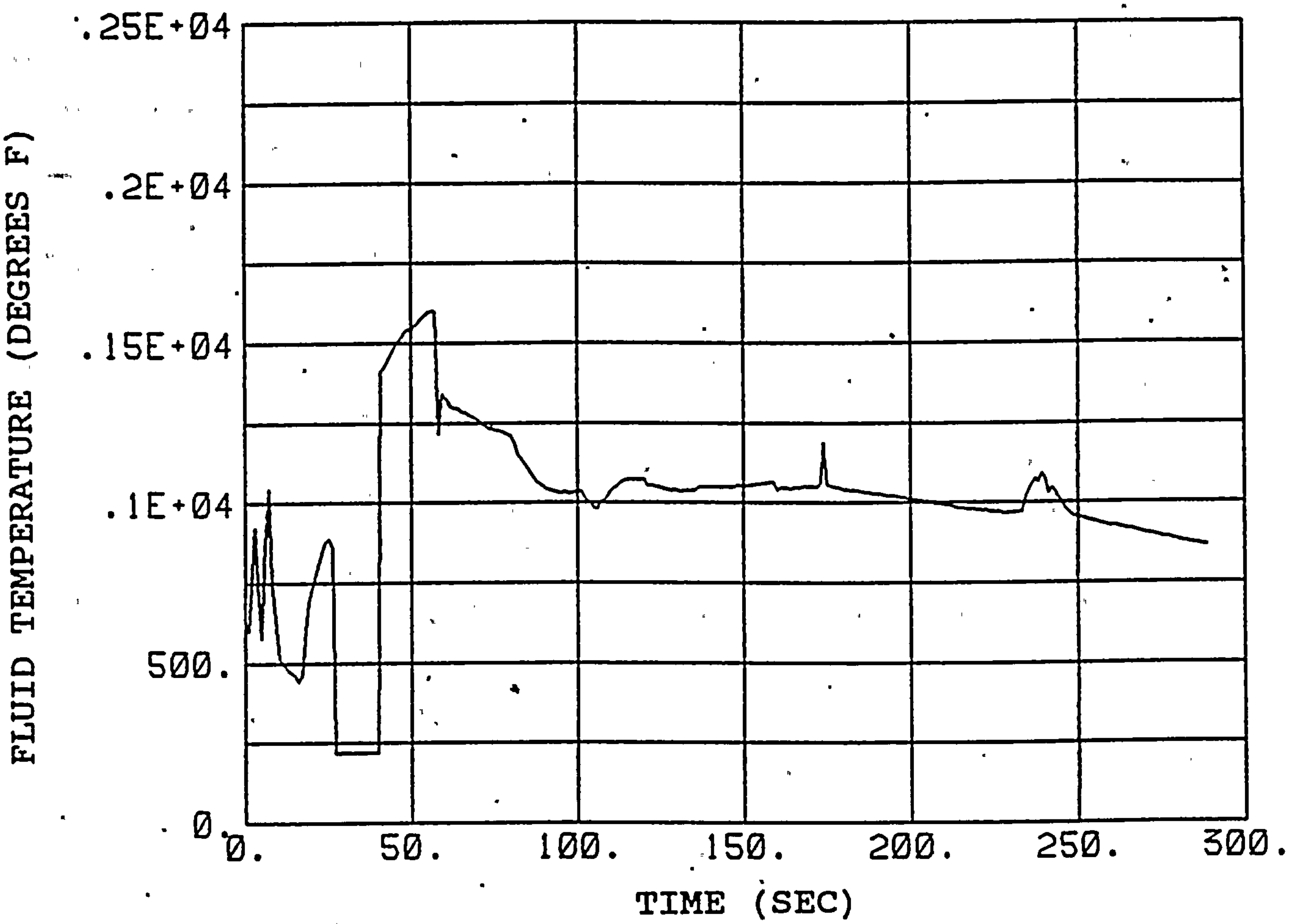

FIGURE C.3.1-14c
FLUID TEMPERATURE
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

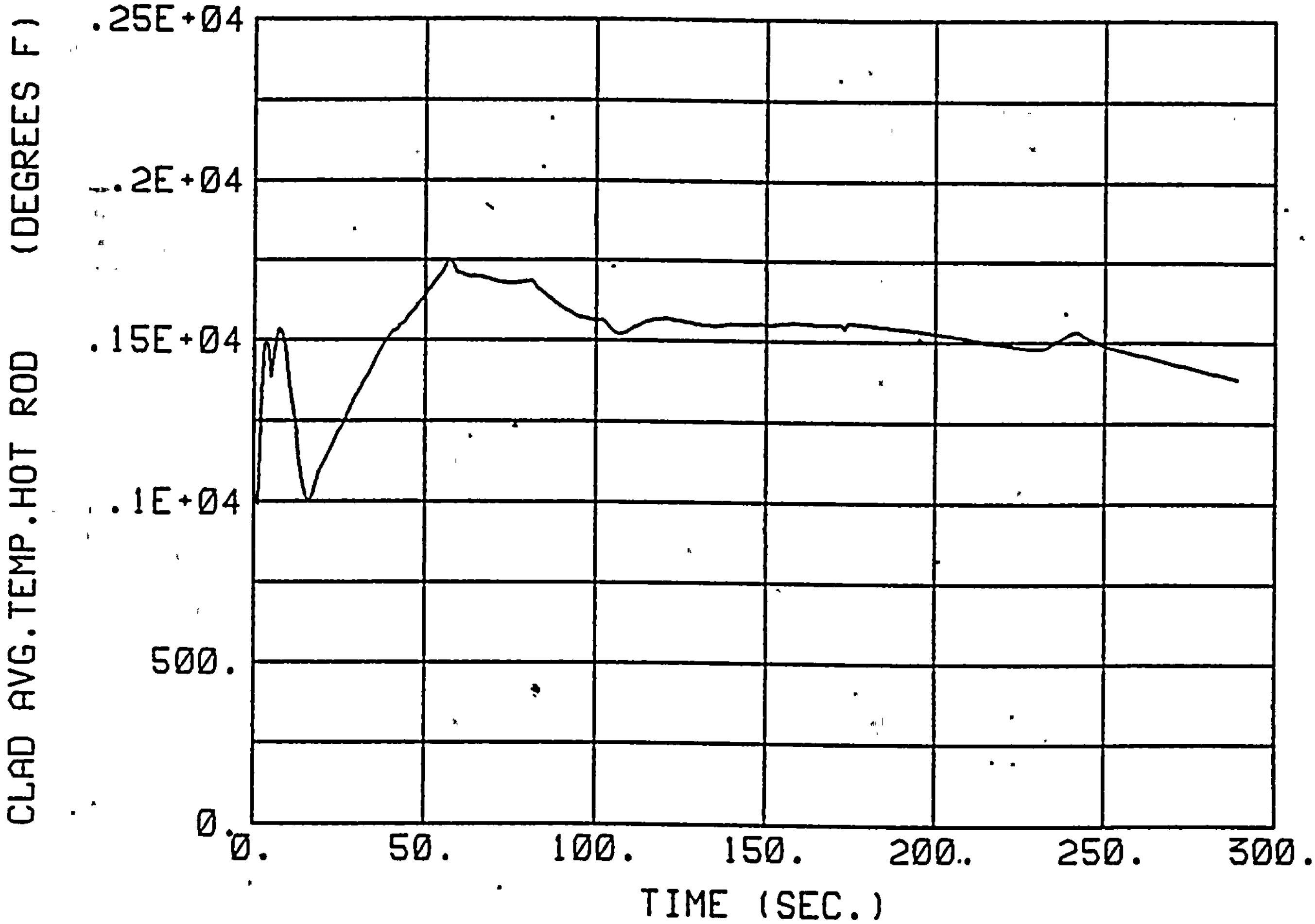

FIGURE C.3.1-15c
FUEL ROD PEAK CLAD TEMPERATURE
CD=0.8, Thot=615.2 °F
Donald C. Cook Unit 2

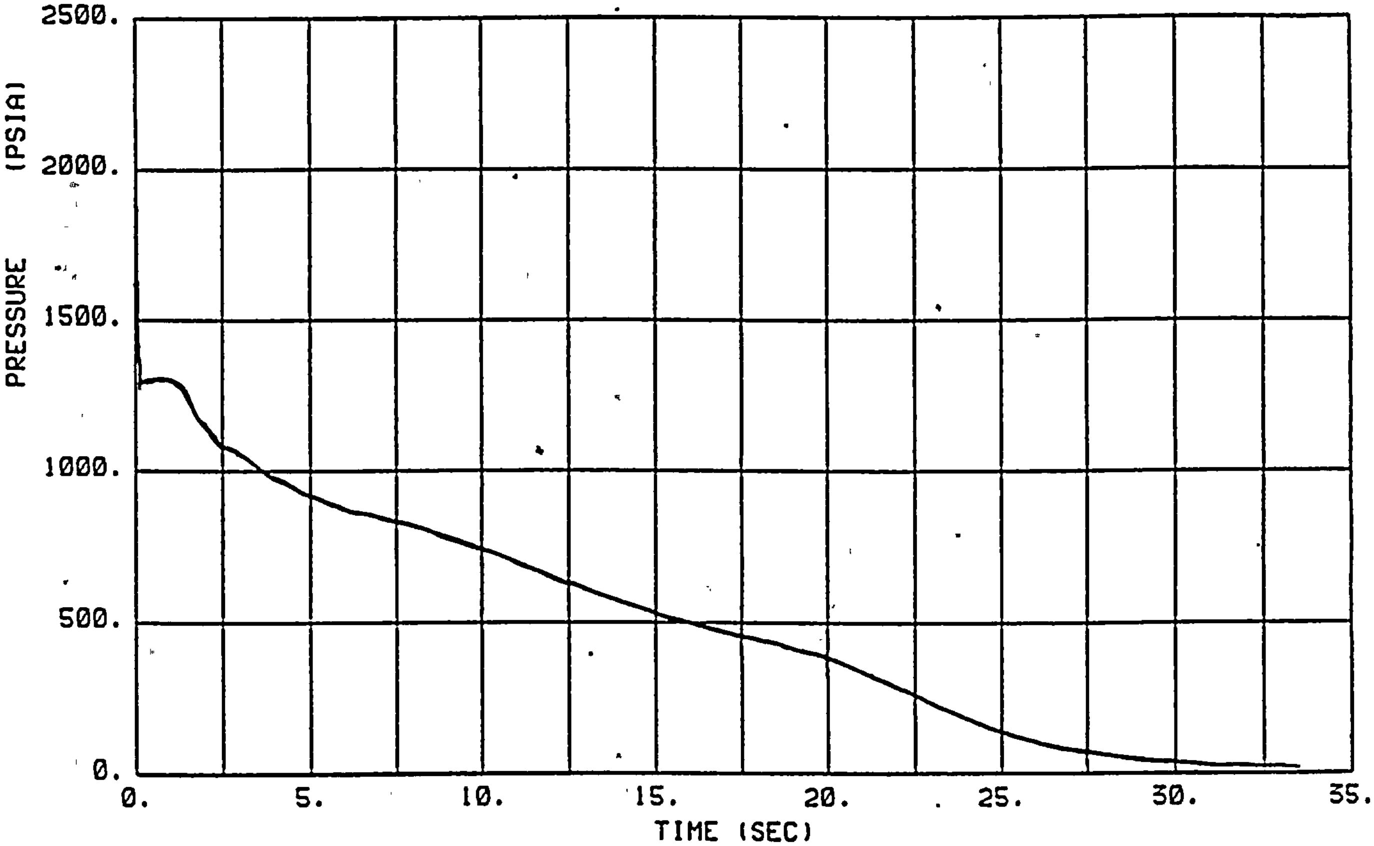

FIGURE C.3.1-3d
REACTOR COOLANT SYSTEM PRESSURE
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

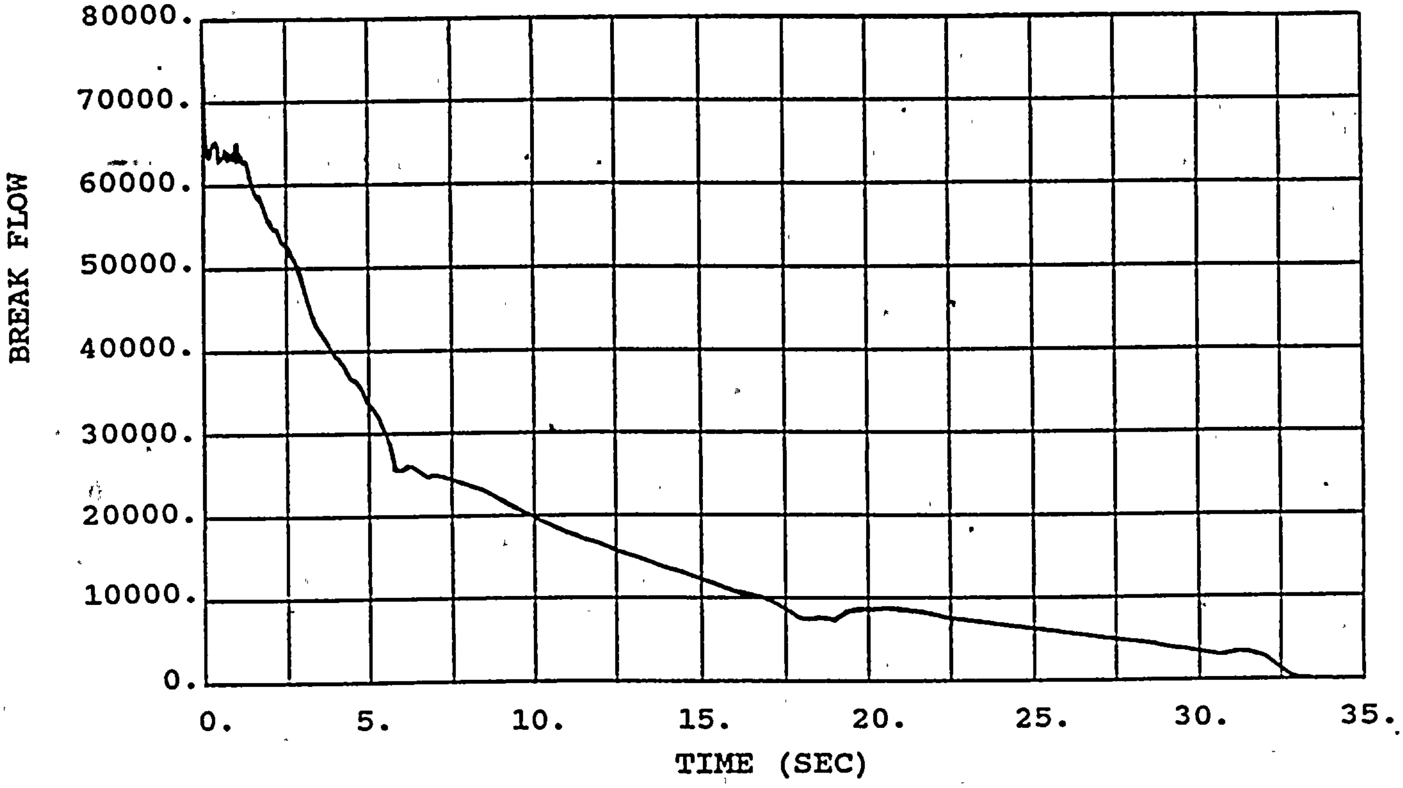

FIGURE C.3.1-4d
BREAK FLOW DURING BLOWDOWN
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

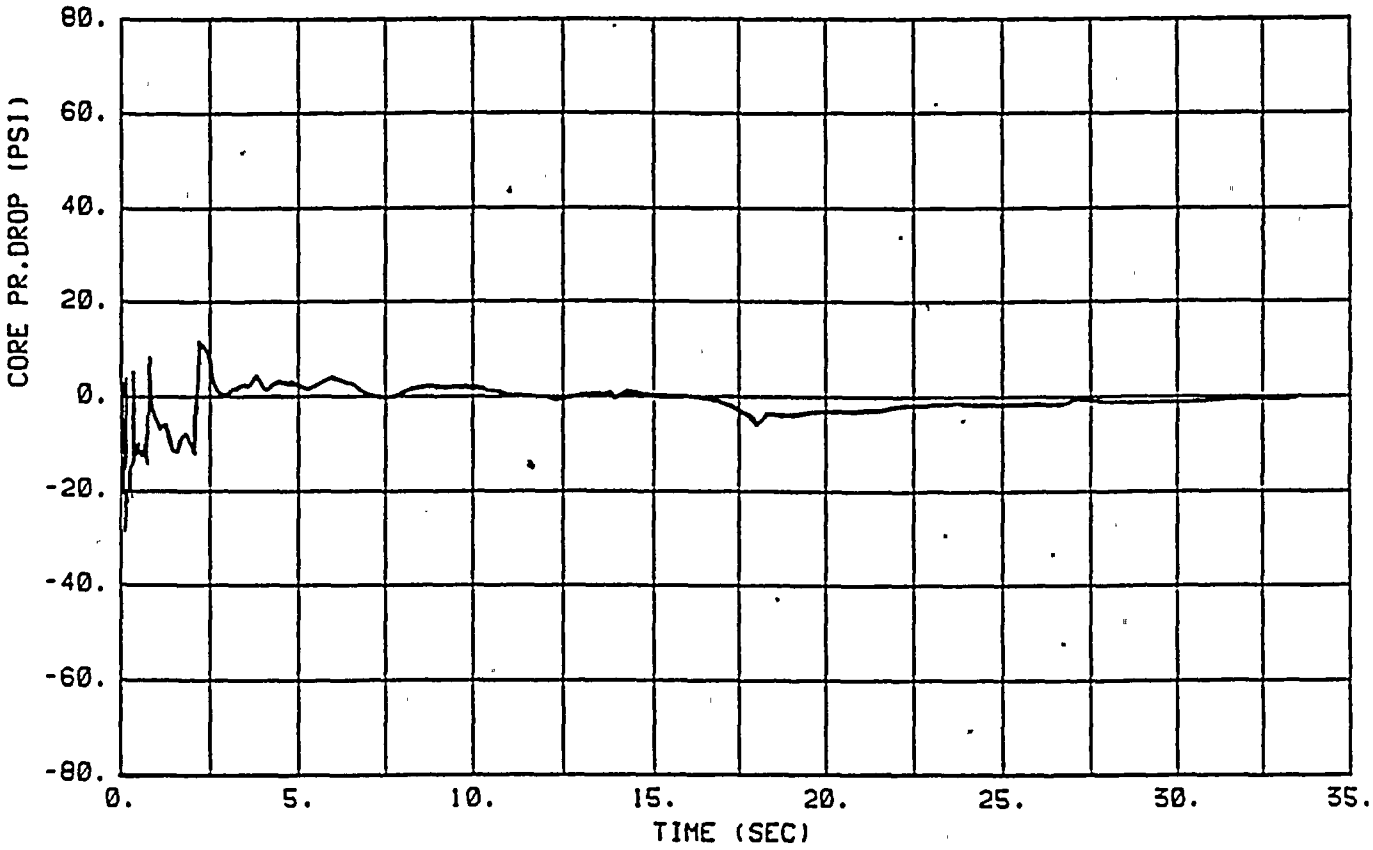

FIGURE C.3.1-5d
CORE PRESSURE DROP
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

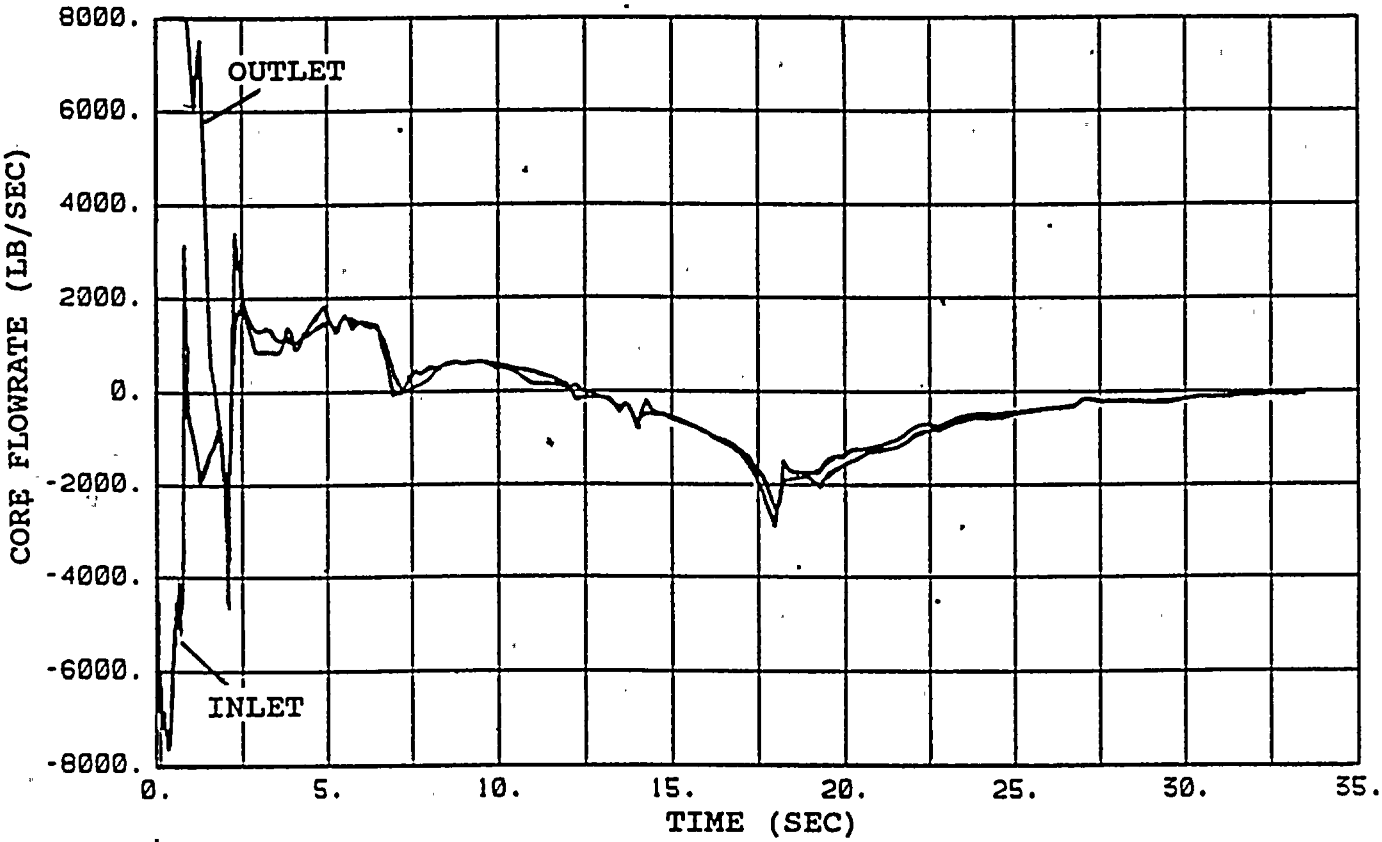

FIGURE C.3.1-6d
CORE FLOWRATE
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

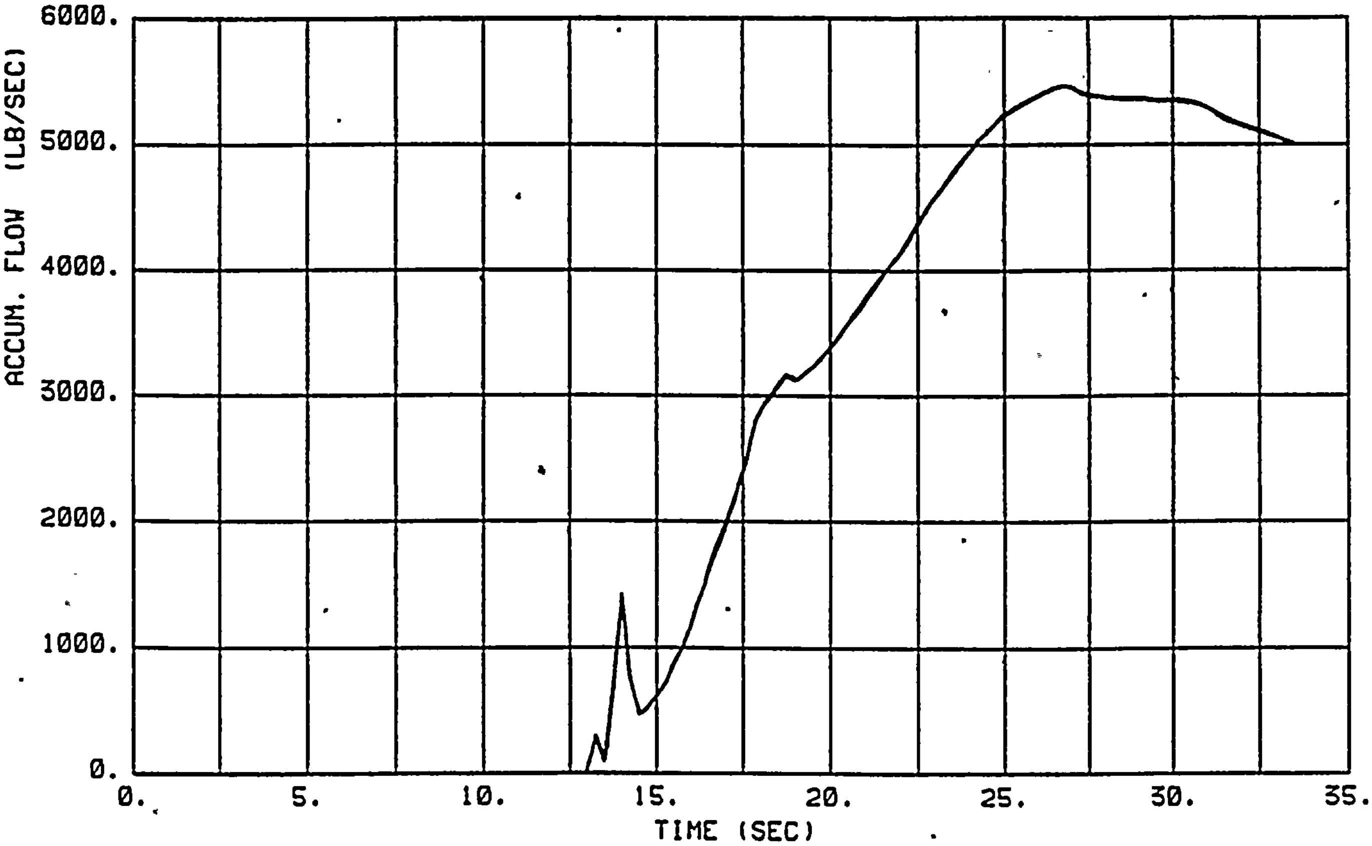

FIGURE C.3.1-7d
ACCUMULATOR FLOW DURING BLOWDOWN
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

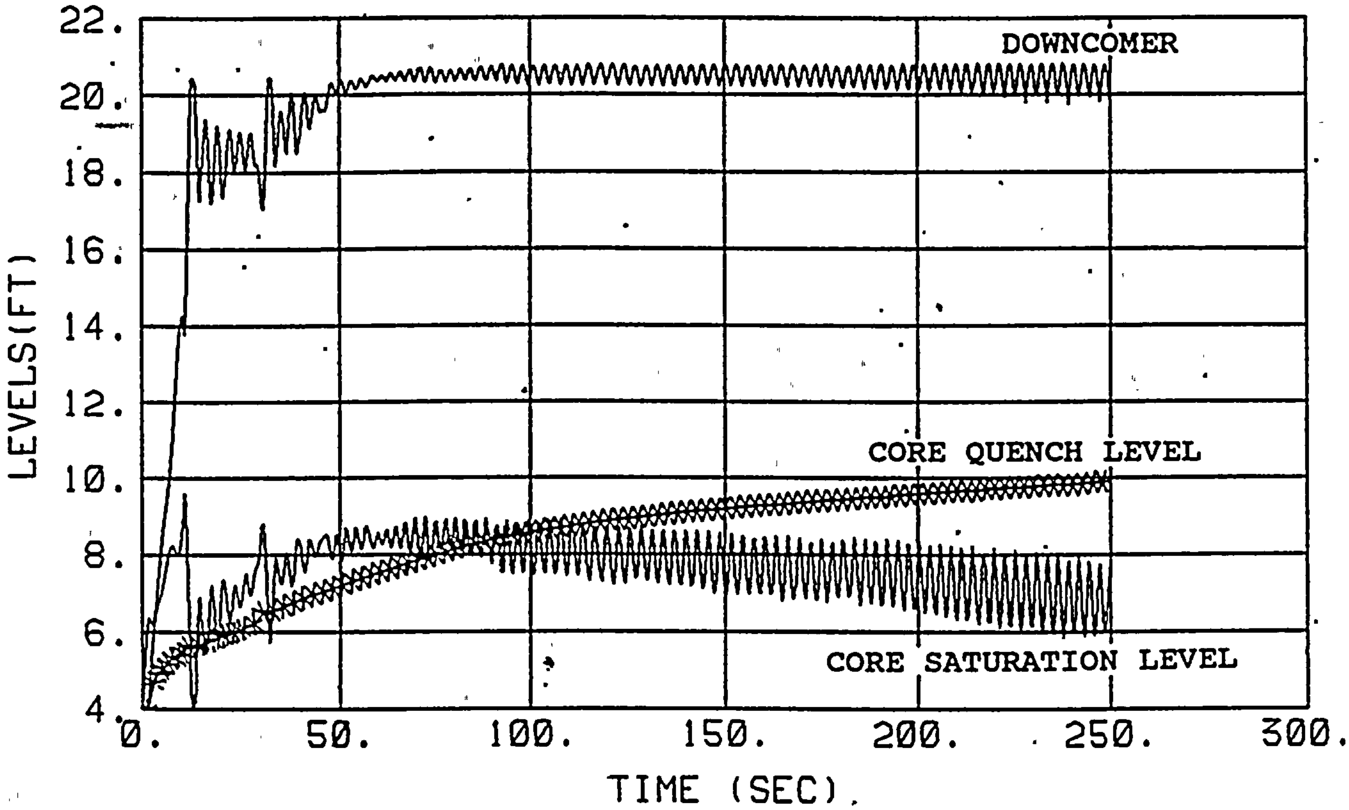

FIGURE C.3.1-8d
CORE AND DOWNCOMER LIQUID LEVELS
DURING REFLOOD
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

* Time is measured after BOC

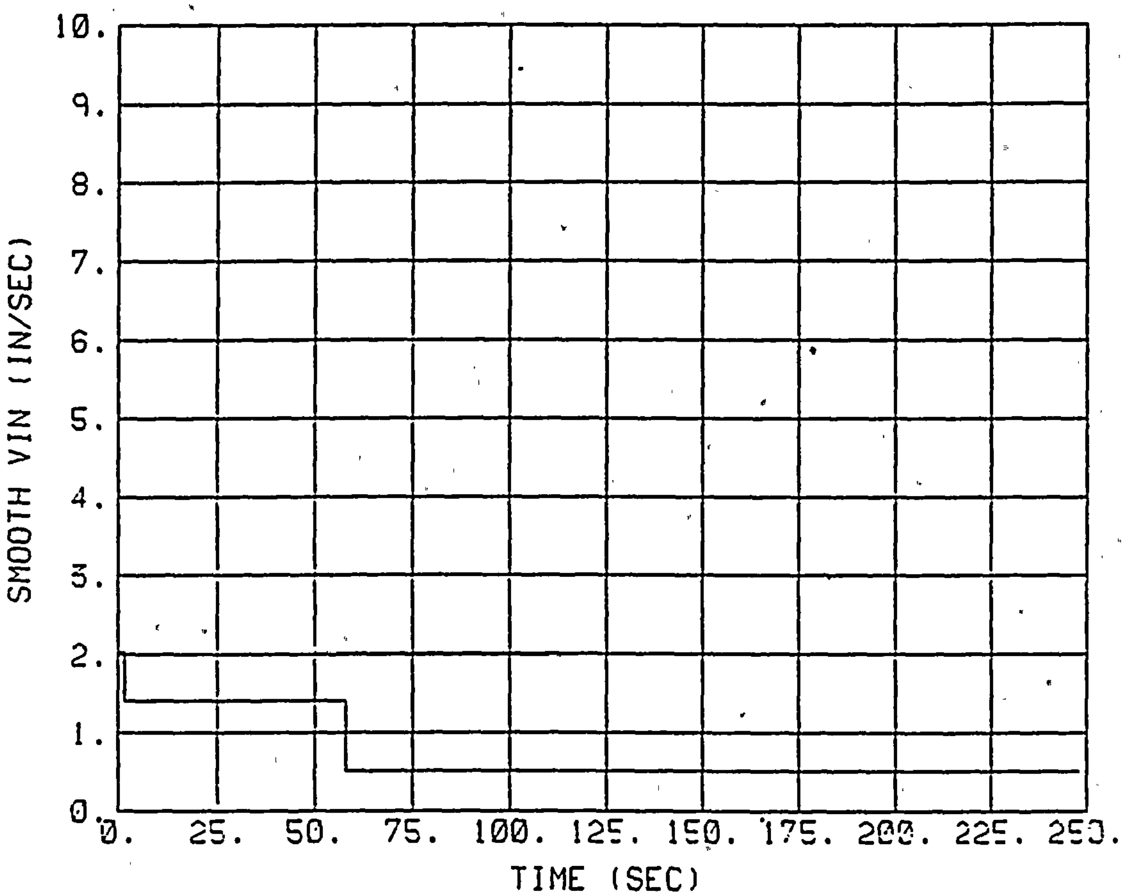

FIGURE C.3.1-9d
CORE INLET FLOW DURING REFLOOD
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

* Time is measured after BOC

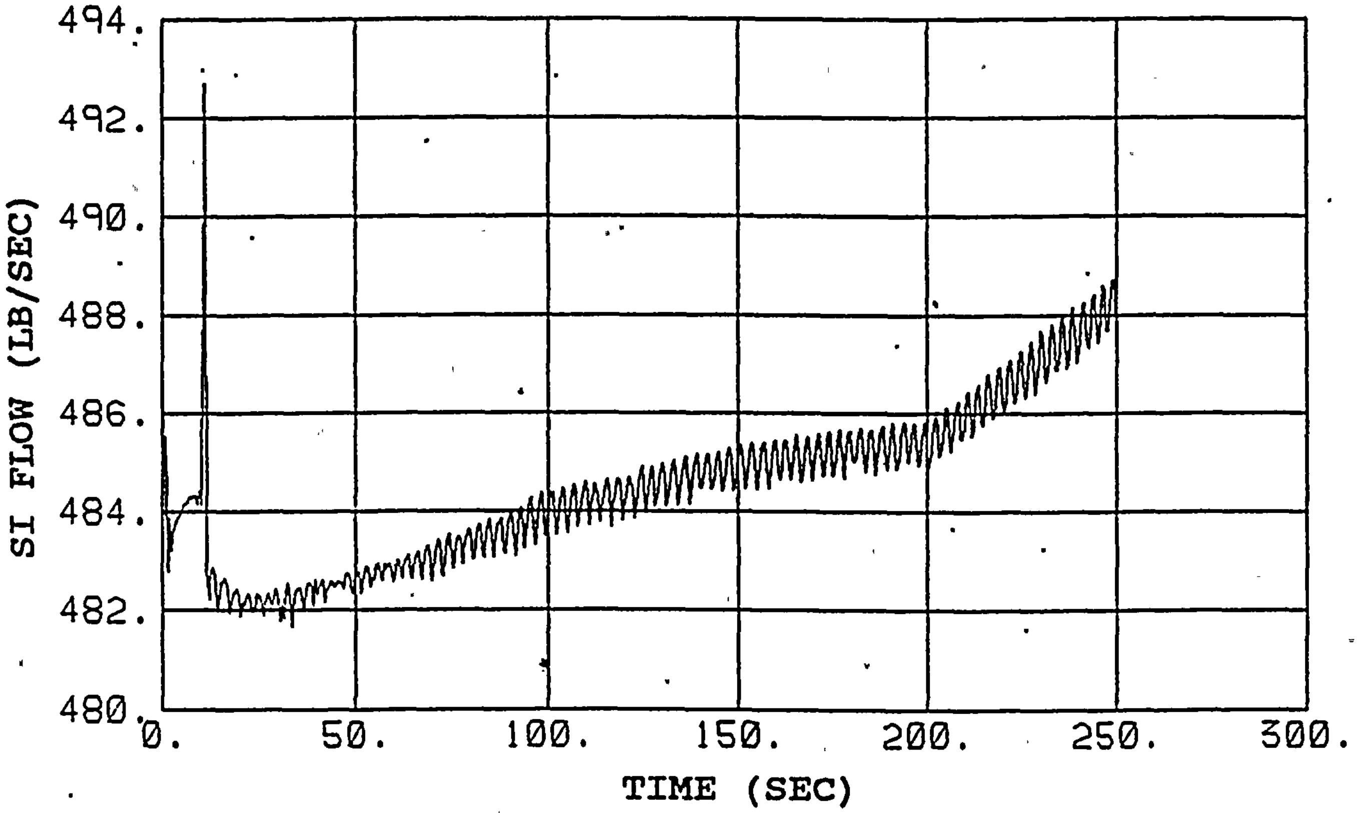

FIGURE C.3.1-10d
SI FLOW
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

* Time is measured after BOC

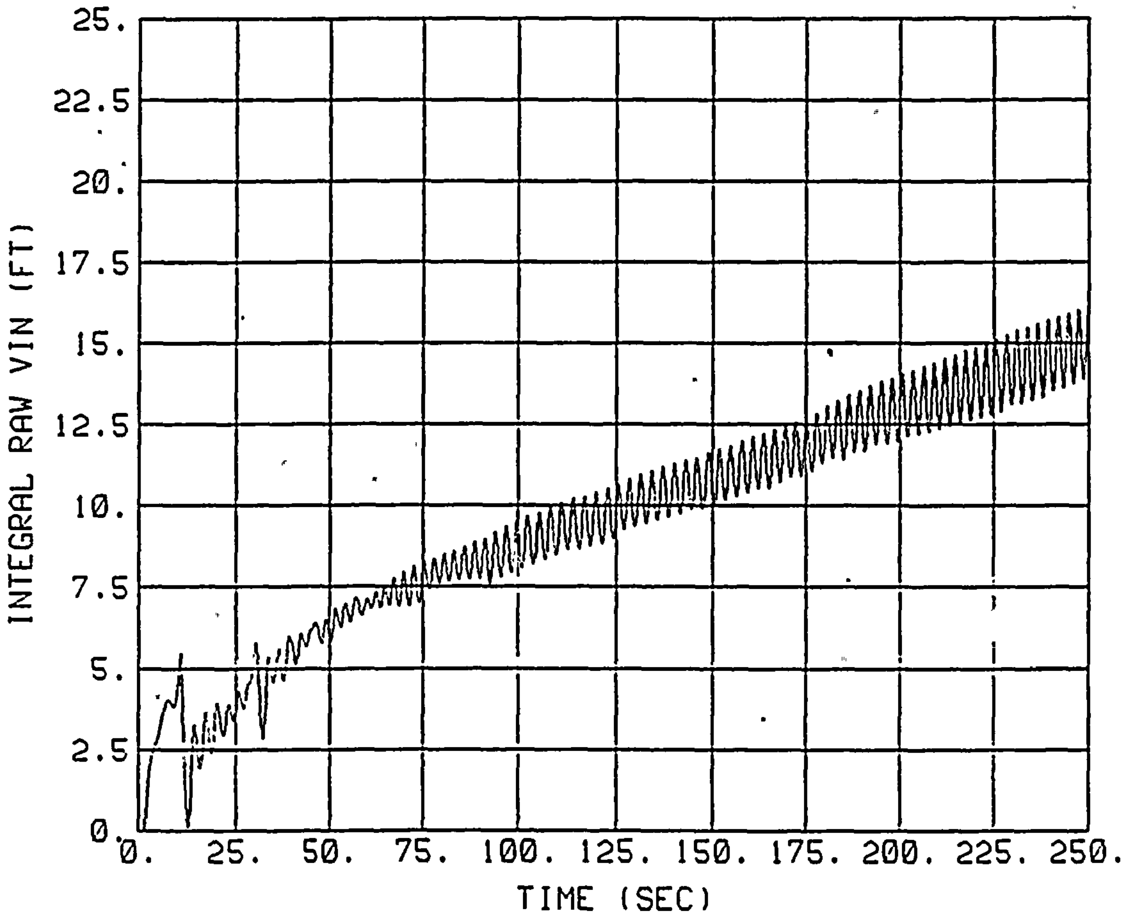

FIGURE C.3.1-11d
INTEGRAL OF CORE INLET FLOW
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

* Time is measured after BOC

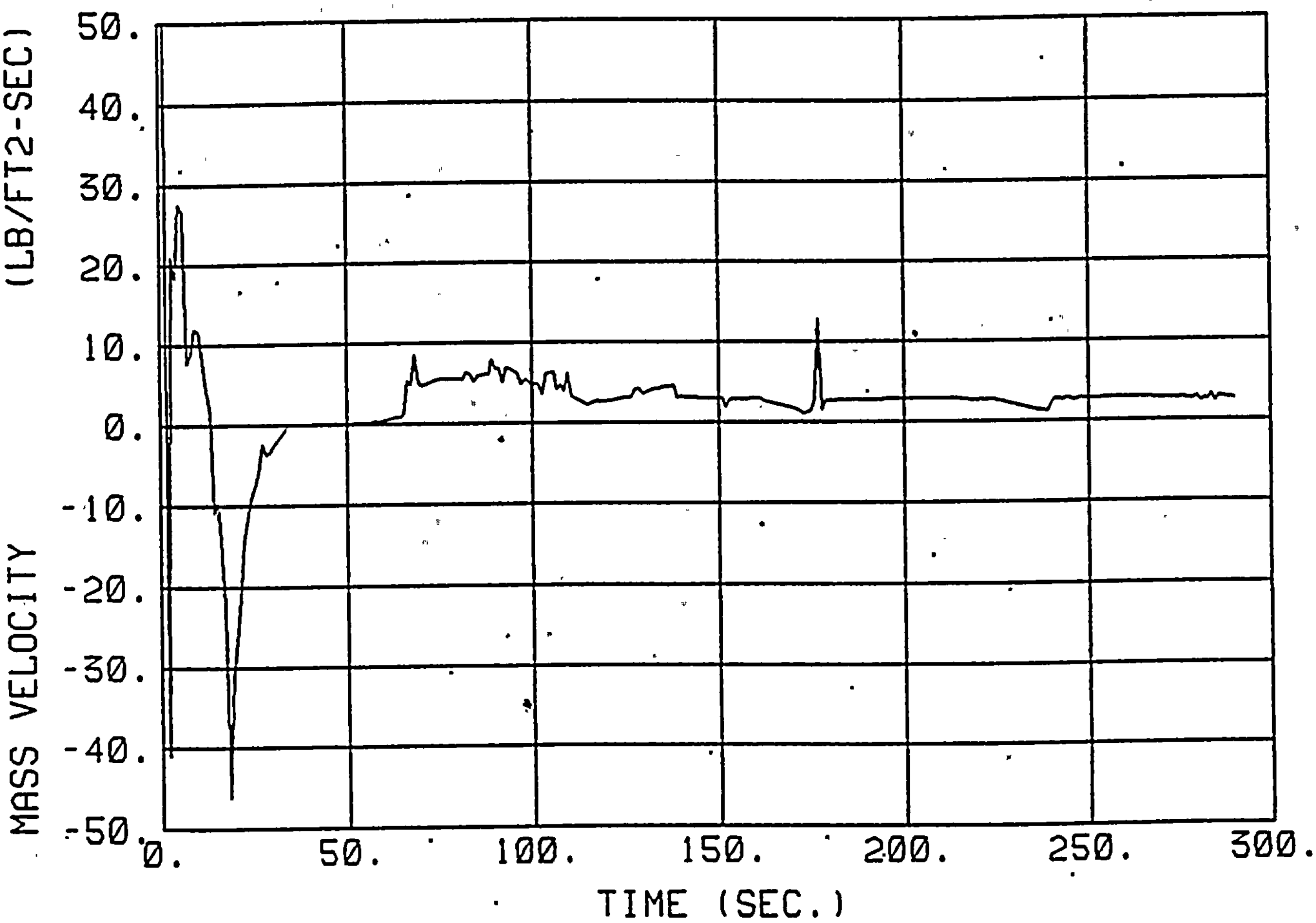

FIGURE C.3.1-12d
MASS FLUX AT THE PEAK
TEMPERATURE ELEVATION
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

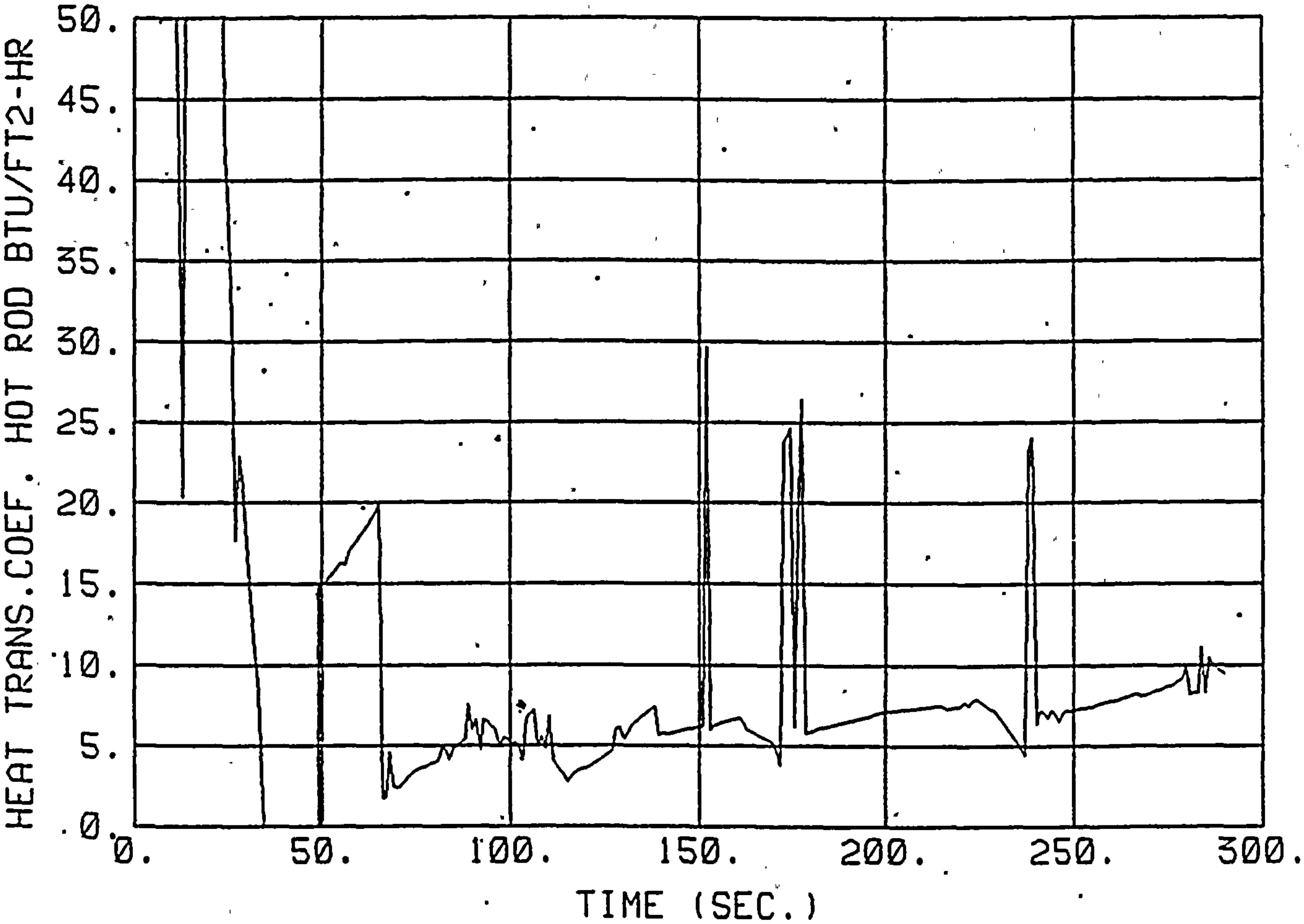

FIGURE C.3.1-13d
ROD HEAT TRANSFER COEFFICIENT AT
THE PEAK TEMPERATURE ELEVATION
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

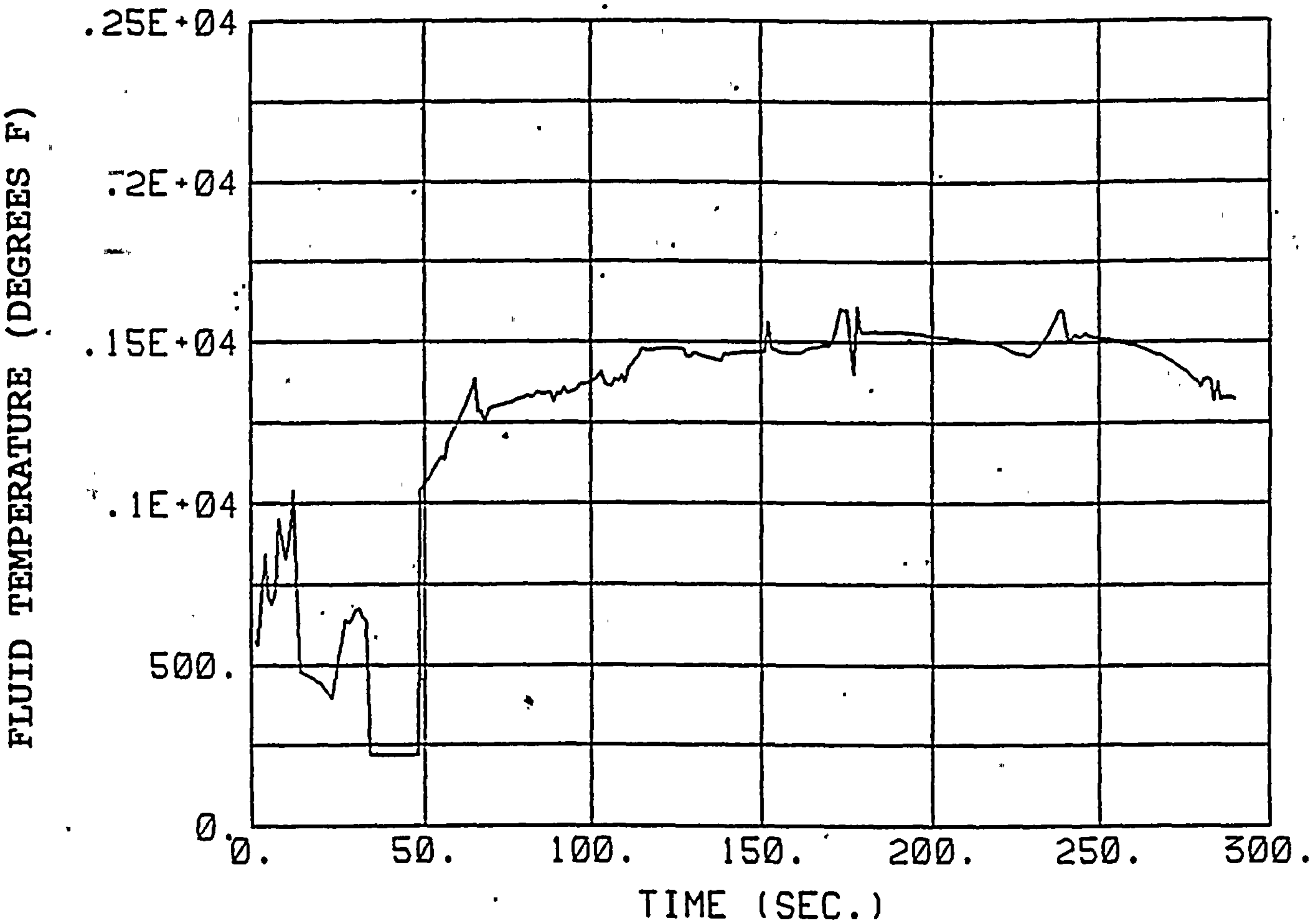

FIGURE C.3.1-14d
FLUID TEMPERATURE
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

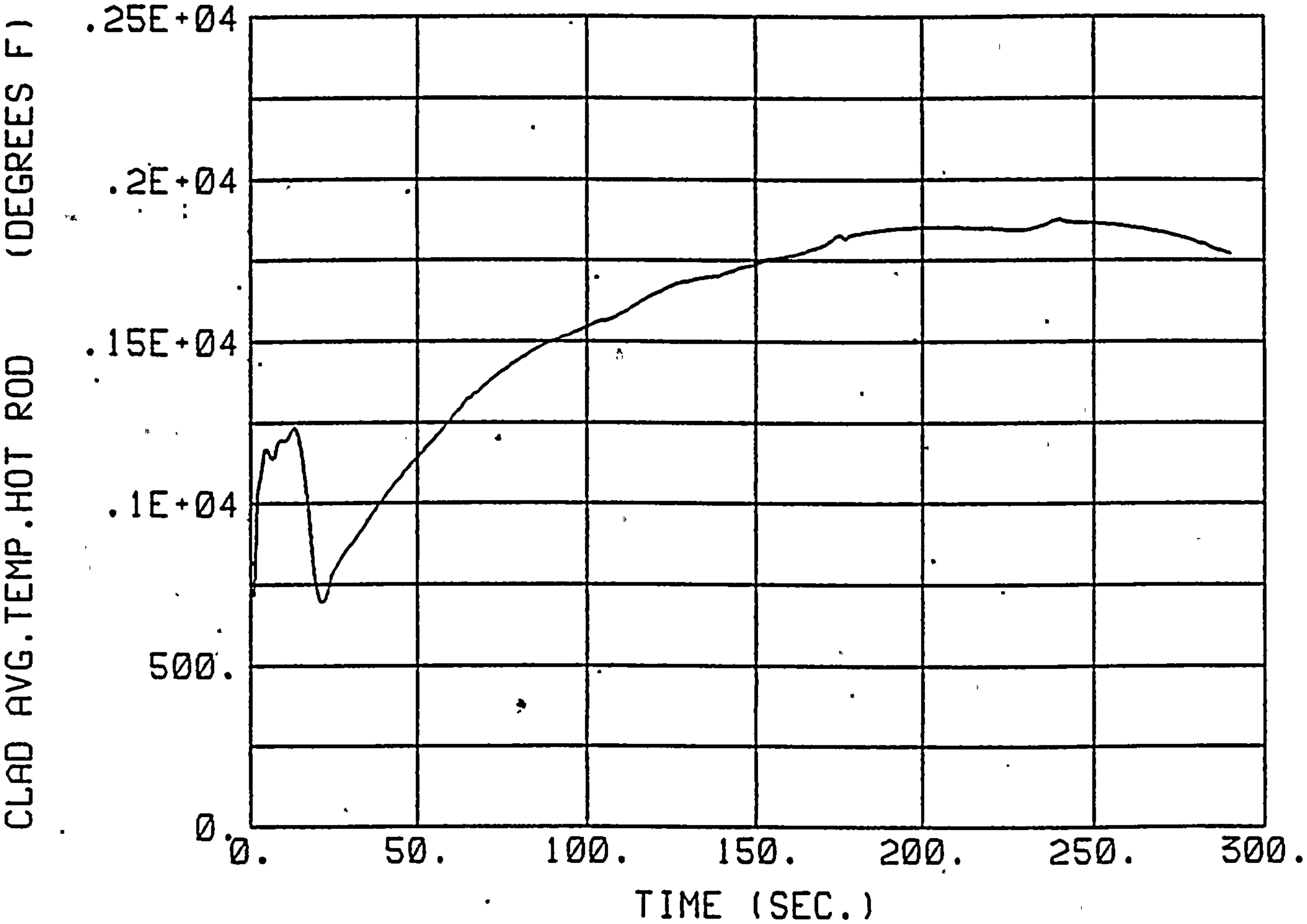

FIGURE C.3.1-15d
FUEL ROD PEAK CLAD TEMPERATURE
CD=0.6, Thot=582.3 °F
Donald C. Cook Unit 2

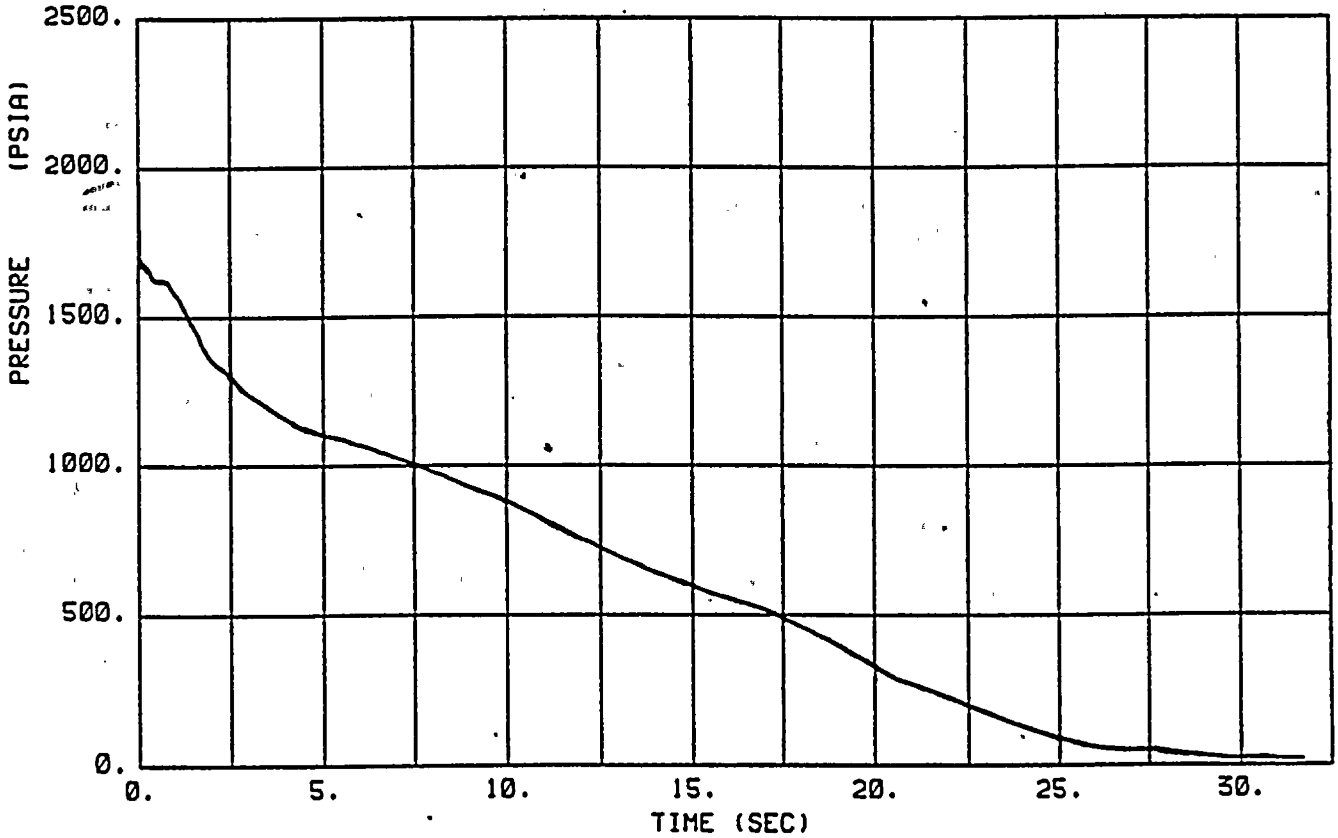

FIGURE C.3.1-3e
REACTOR COOLANT SYSTEM PRESSURE
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

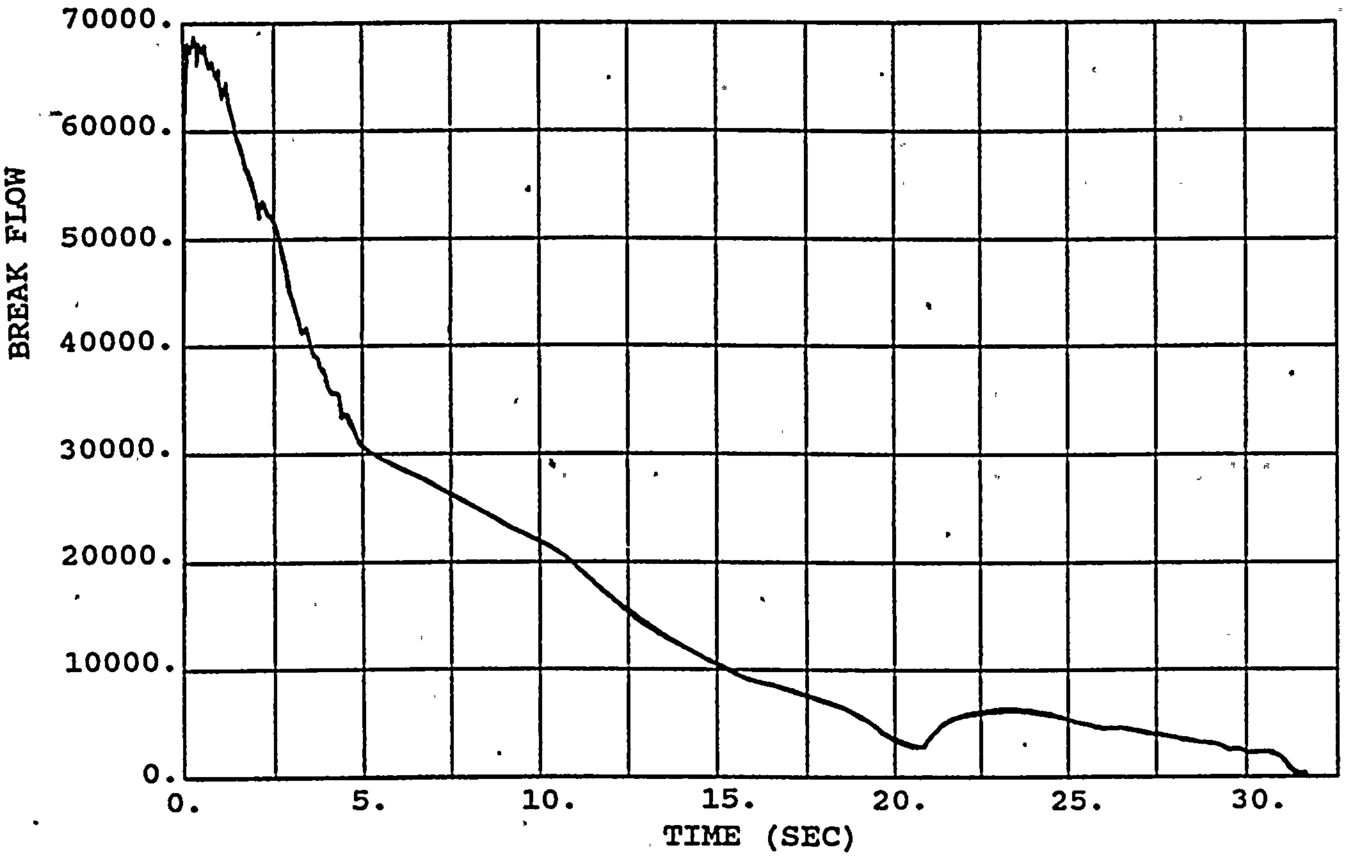

FIGURE C.3.1-4e
BREAK FLOW DURING BLOWDOWN
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

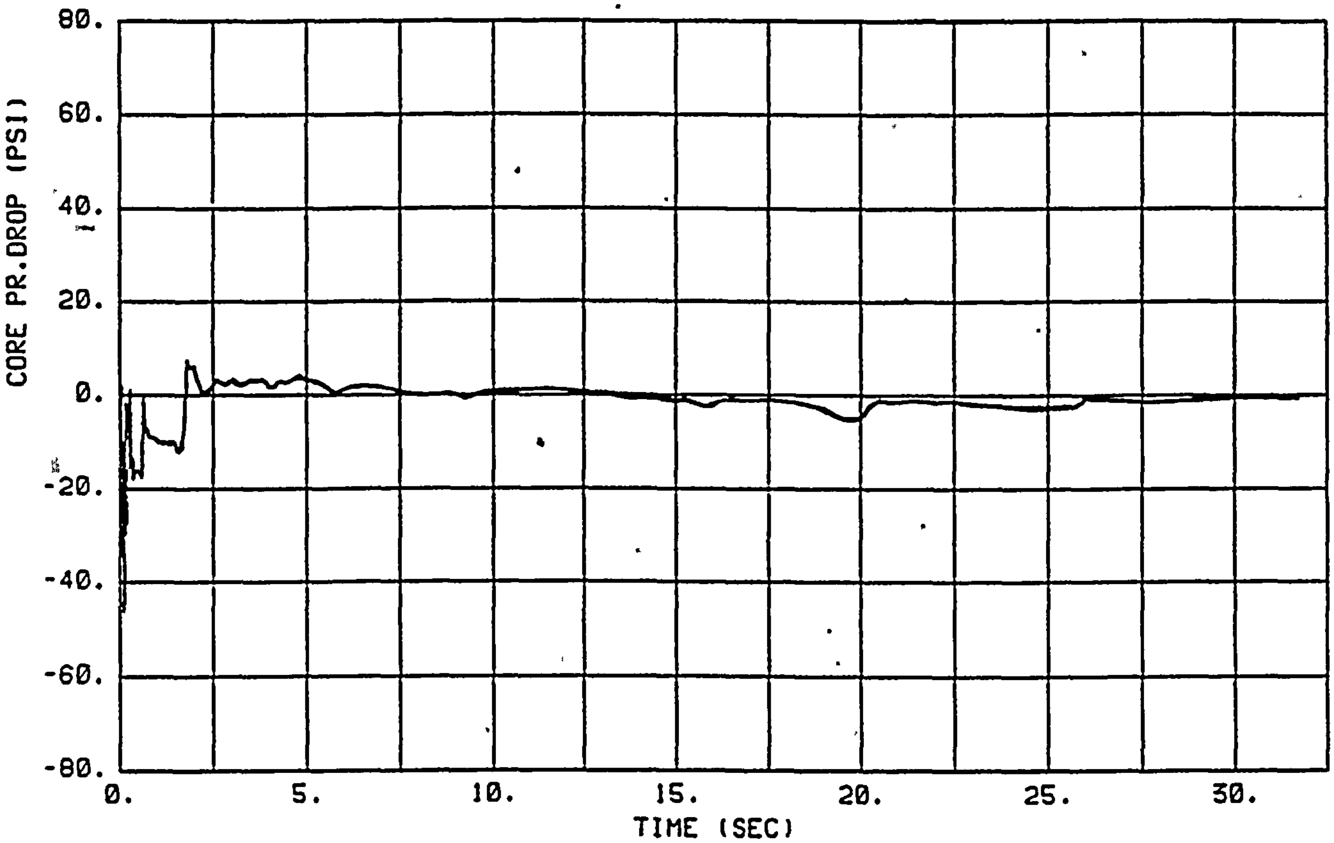

FIGURE C.3.1-5e
CORE PRESSURE DROP
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

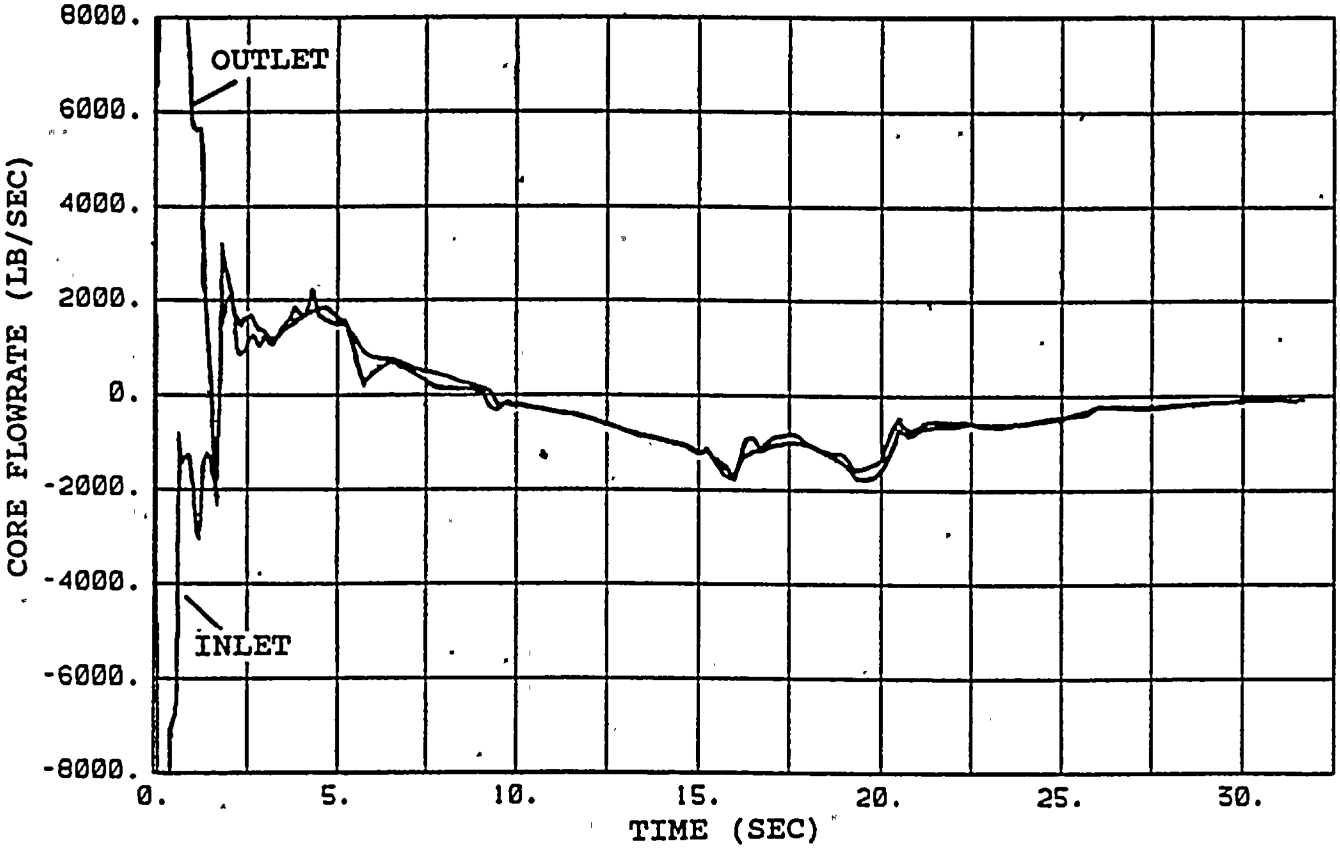

FIGURE C.3.1-6e
CORE FLOWRATE
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

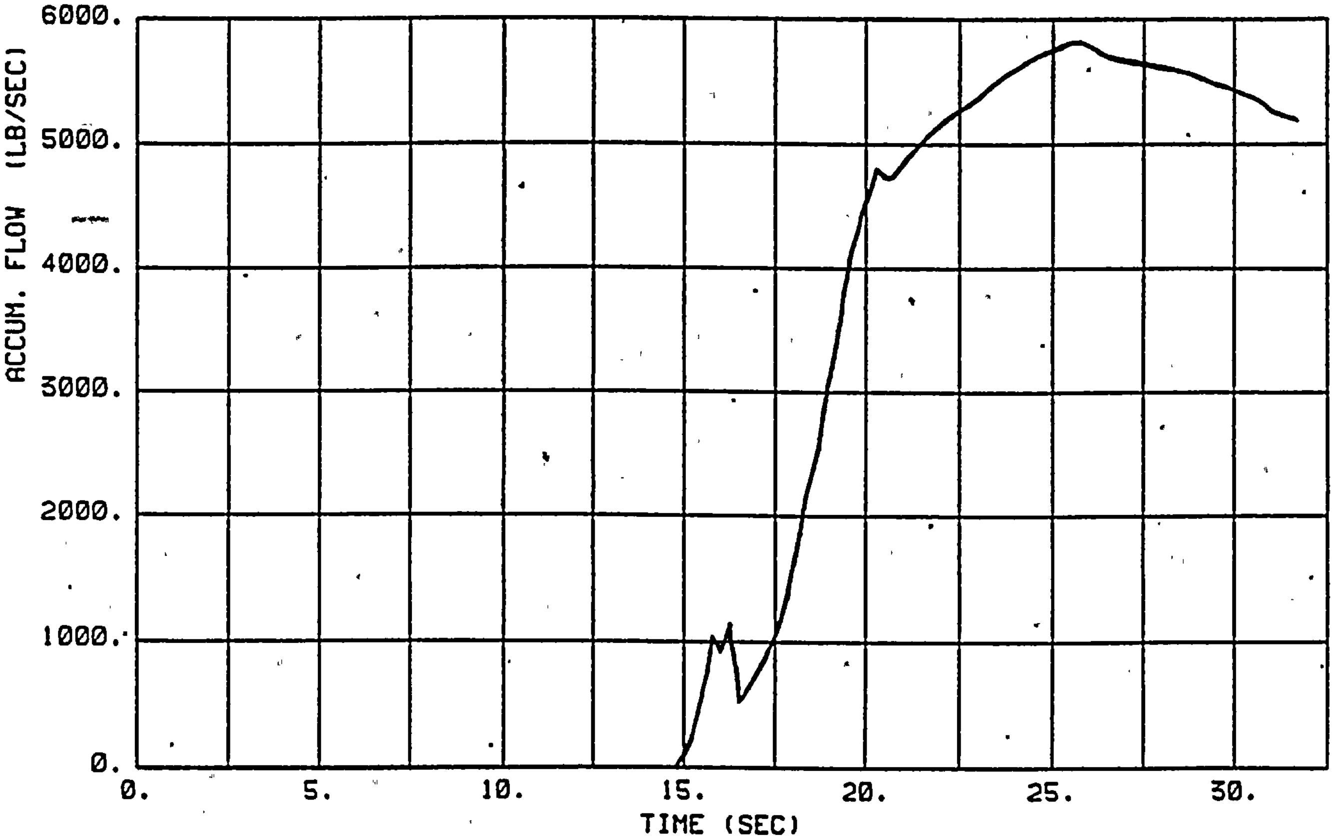

FIGURE C.3.1-7e
ACCUMULATOR FLOW DURING BLOWDOWN
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

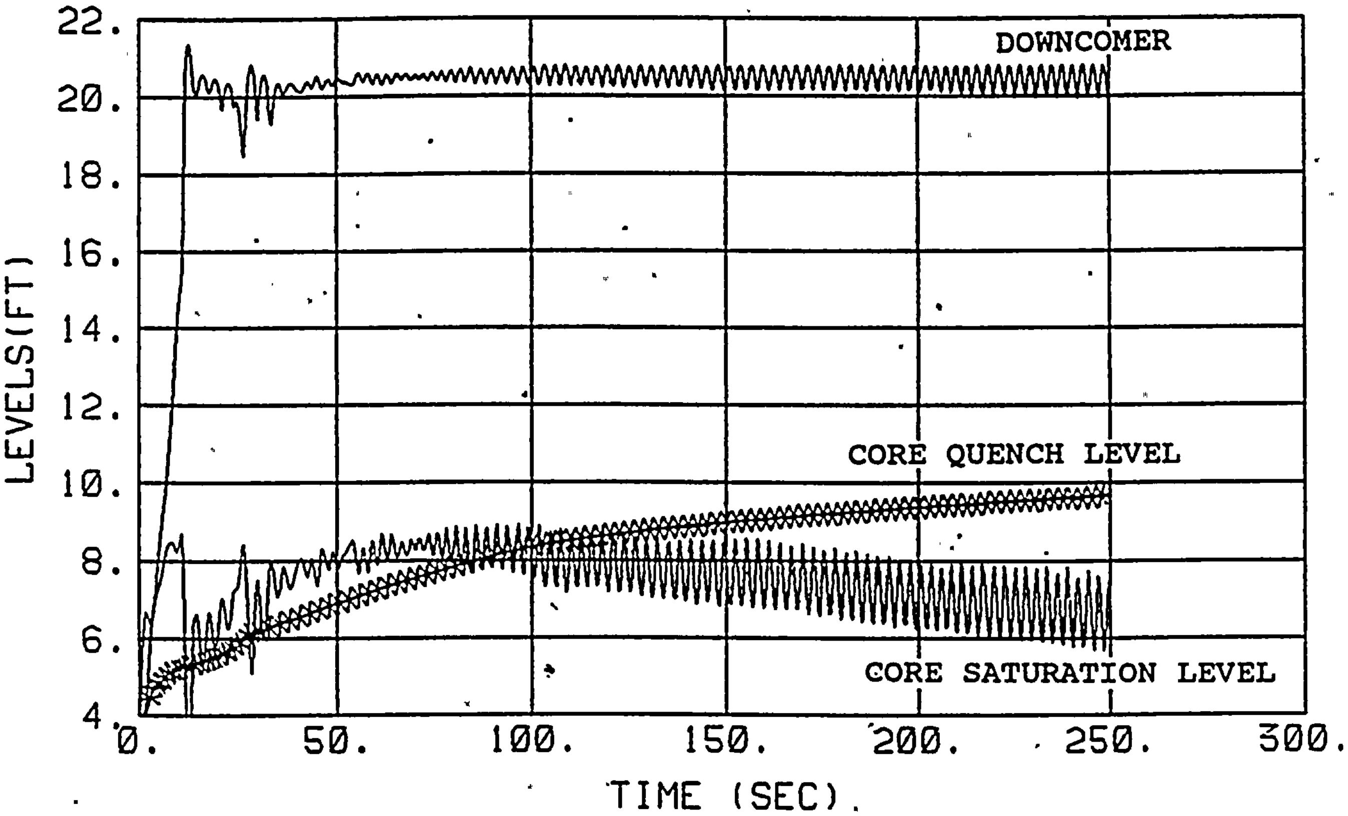

FIGURE C.3.1-8e
CORE AND DOWNCOMER LIQUID LEVELS
DURING REFLOOD
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

* Time is measured after BOC

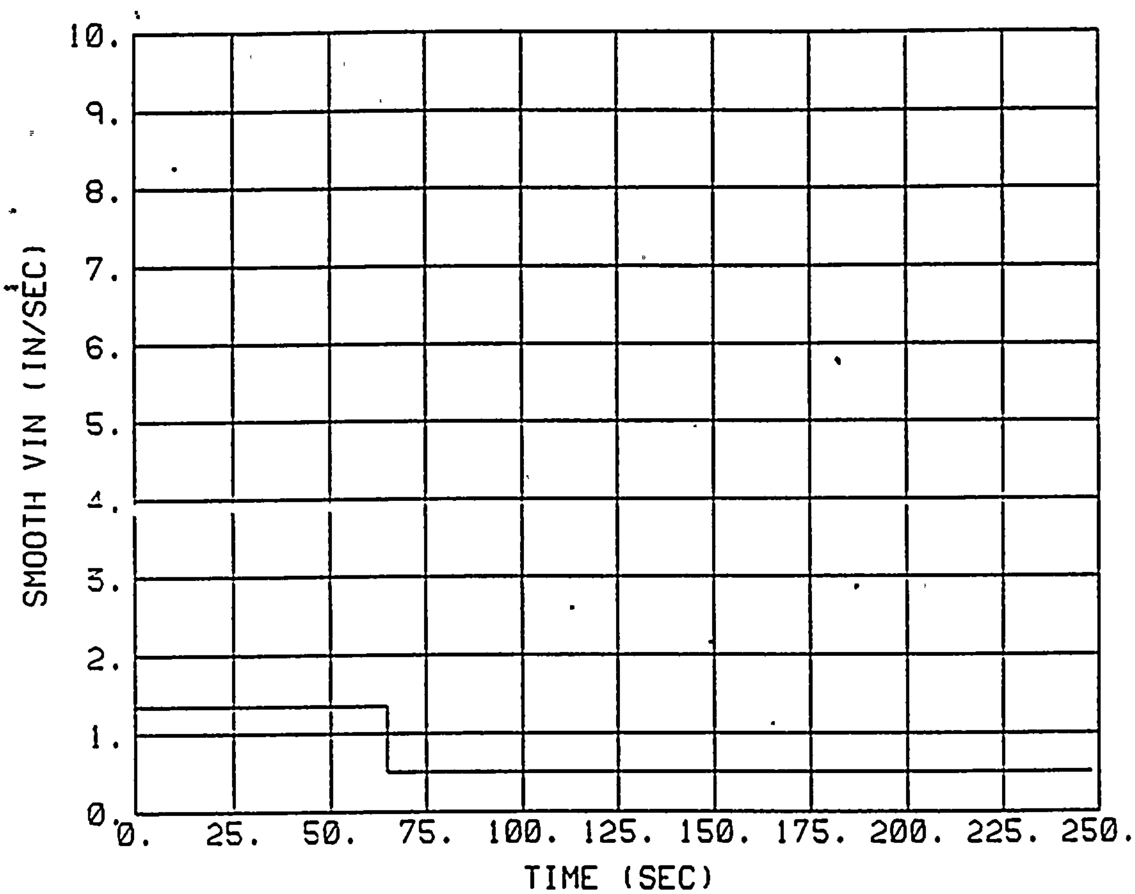

FIGURE C.3.1-9e
CORE INLET FLOW DURING REFLOOD
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

* Time is measured after BOC

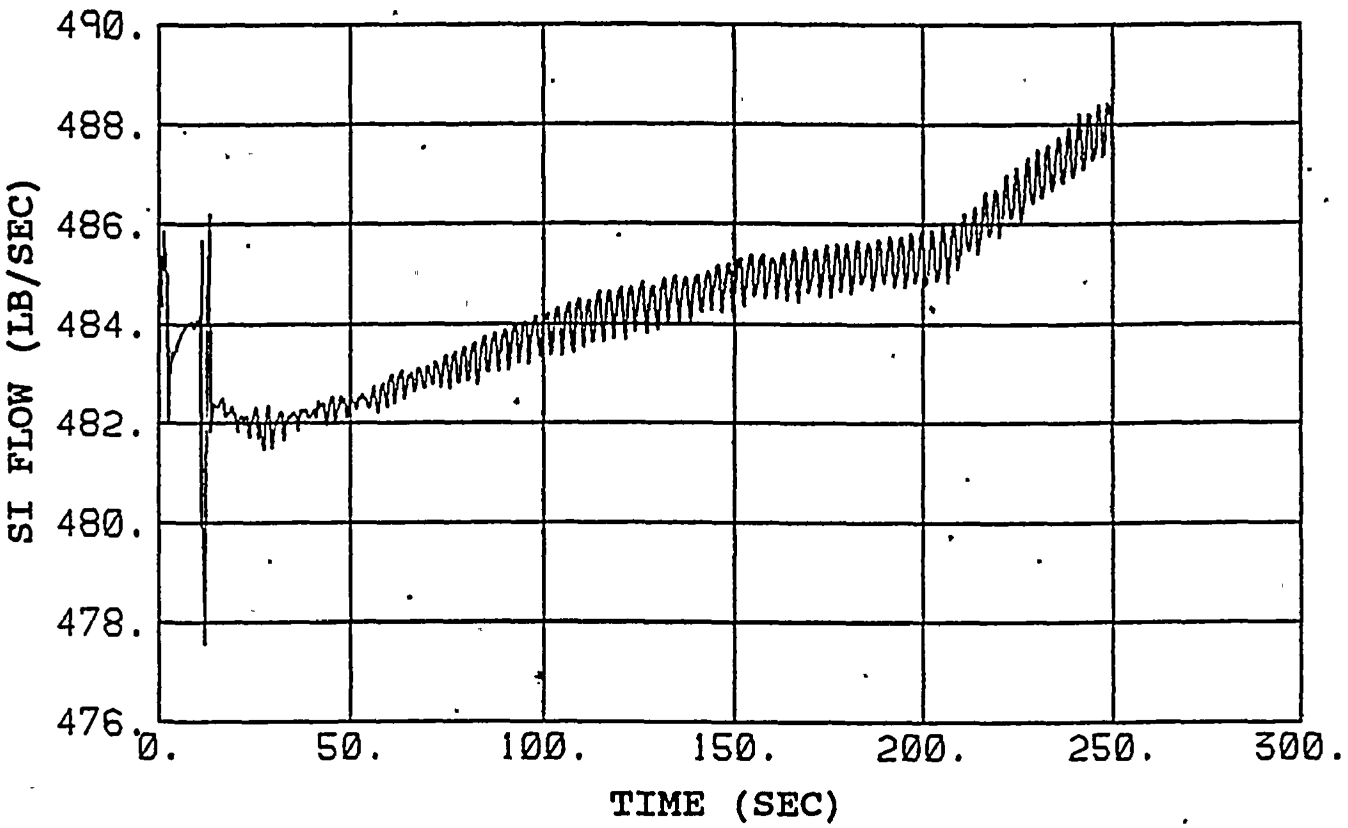

FIGURE C.3.1-10e
SI FLOW
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

* Time is measured after BOC

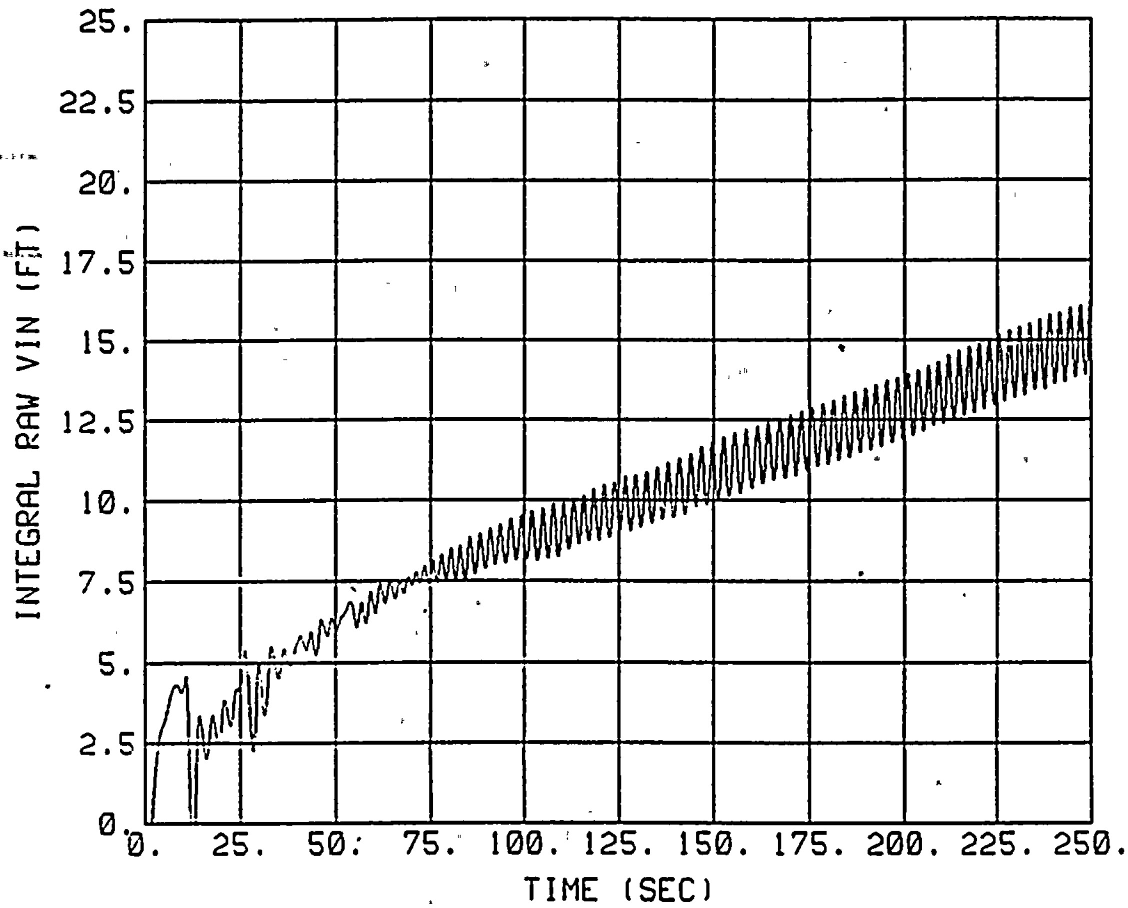

FIGURE C.3.1-11e
INTEGRAL OF CORE INLET FLOW
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

* Time is measured after BOC

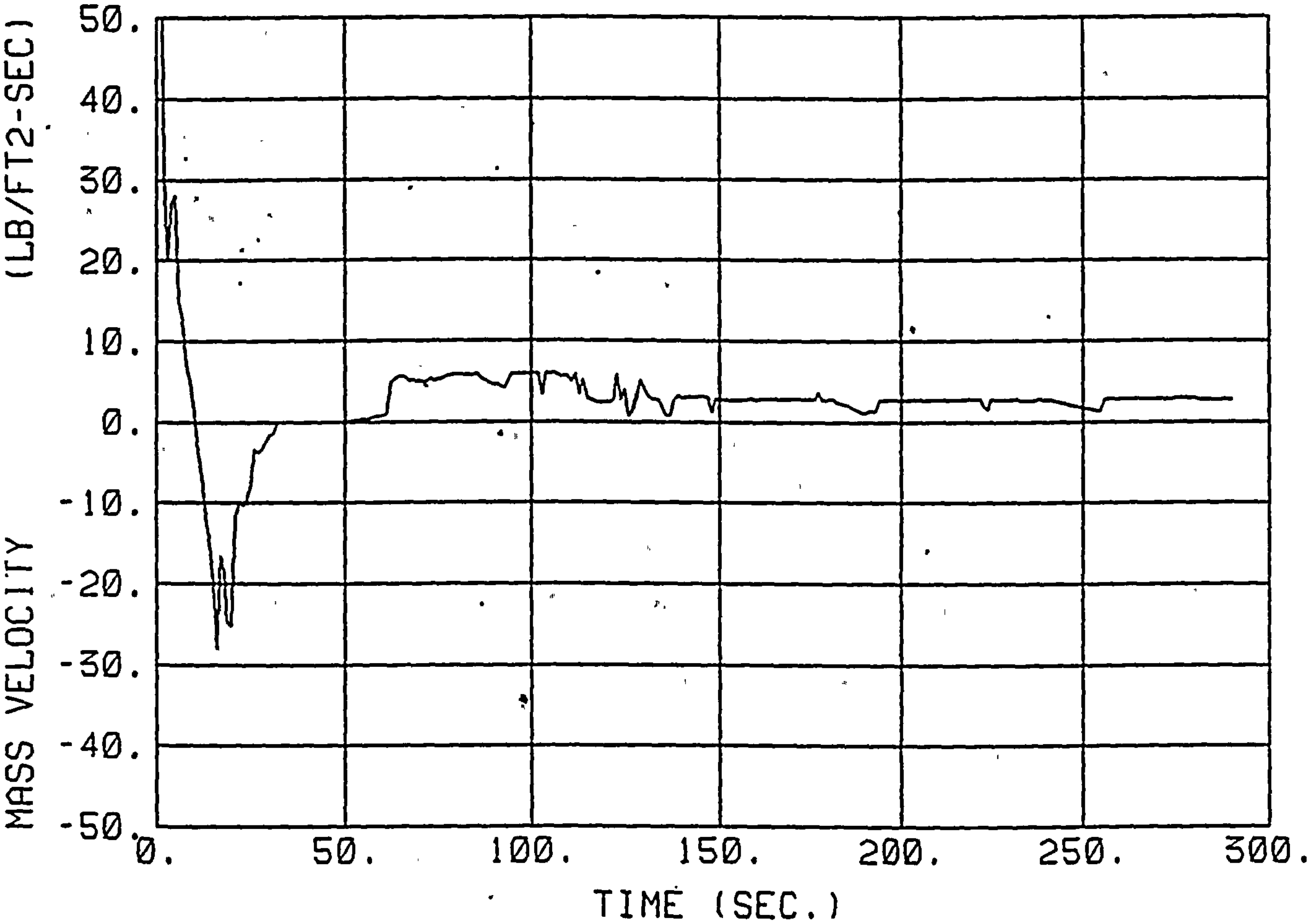

FIGURE C.3.1-12e
MASS FLUX AT THE PEAK
TEMPERATURE ELEVATION
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

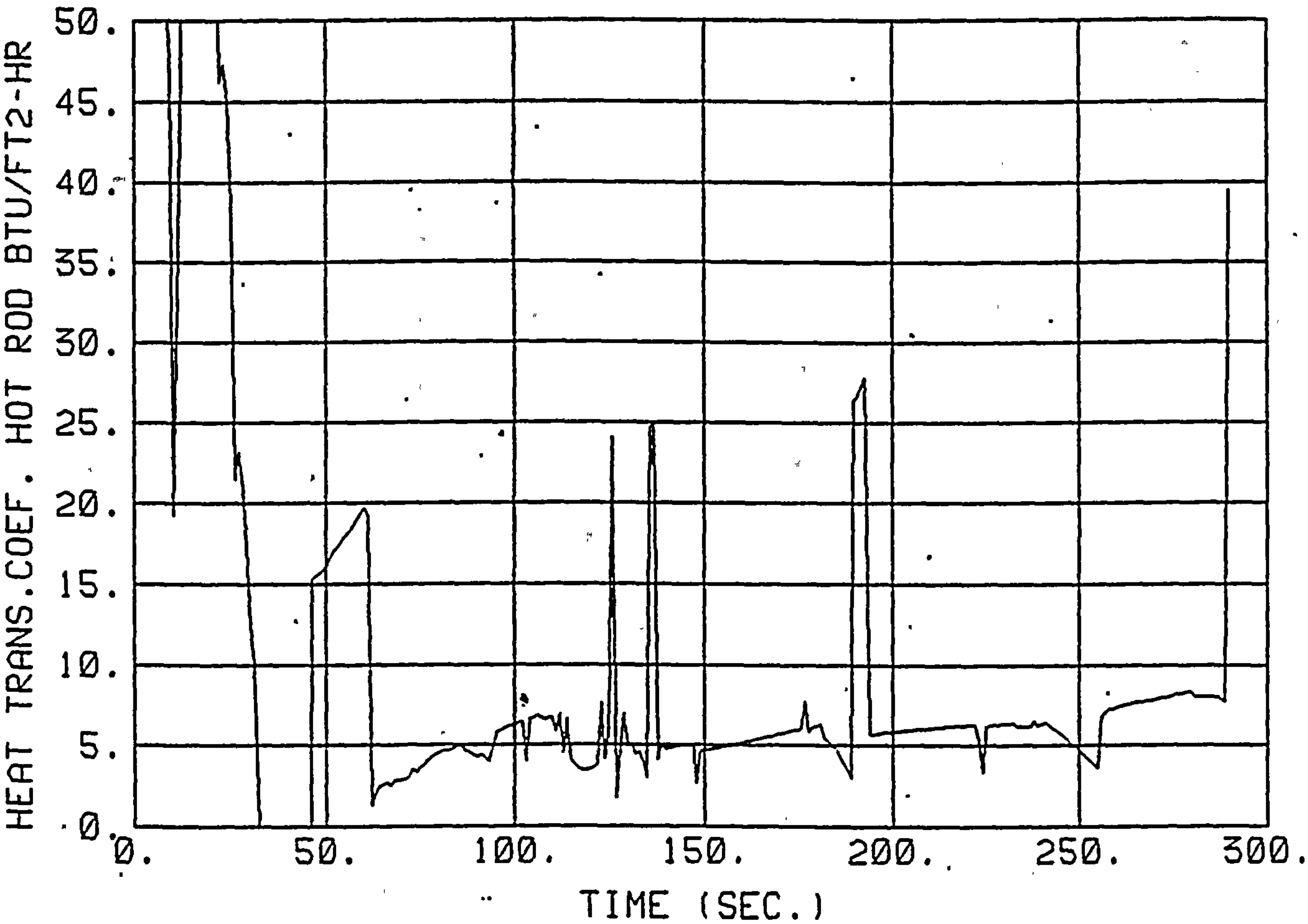

FIGURE C.3.1-13e
ROD HEAT TRANSFER COEFFICIENT AT
THE PEAK TEMPERATURE ELEVATION
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

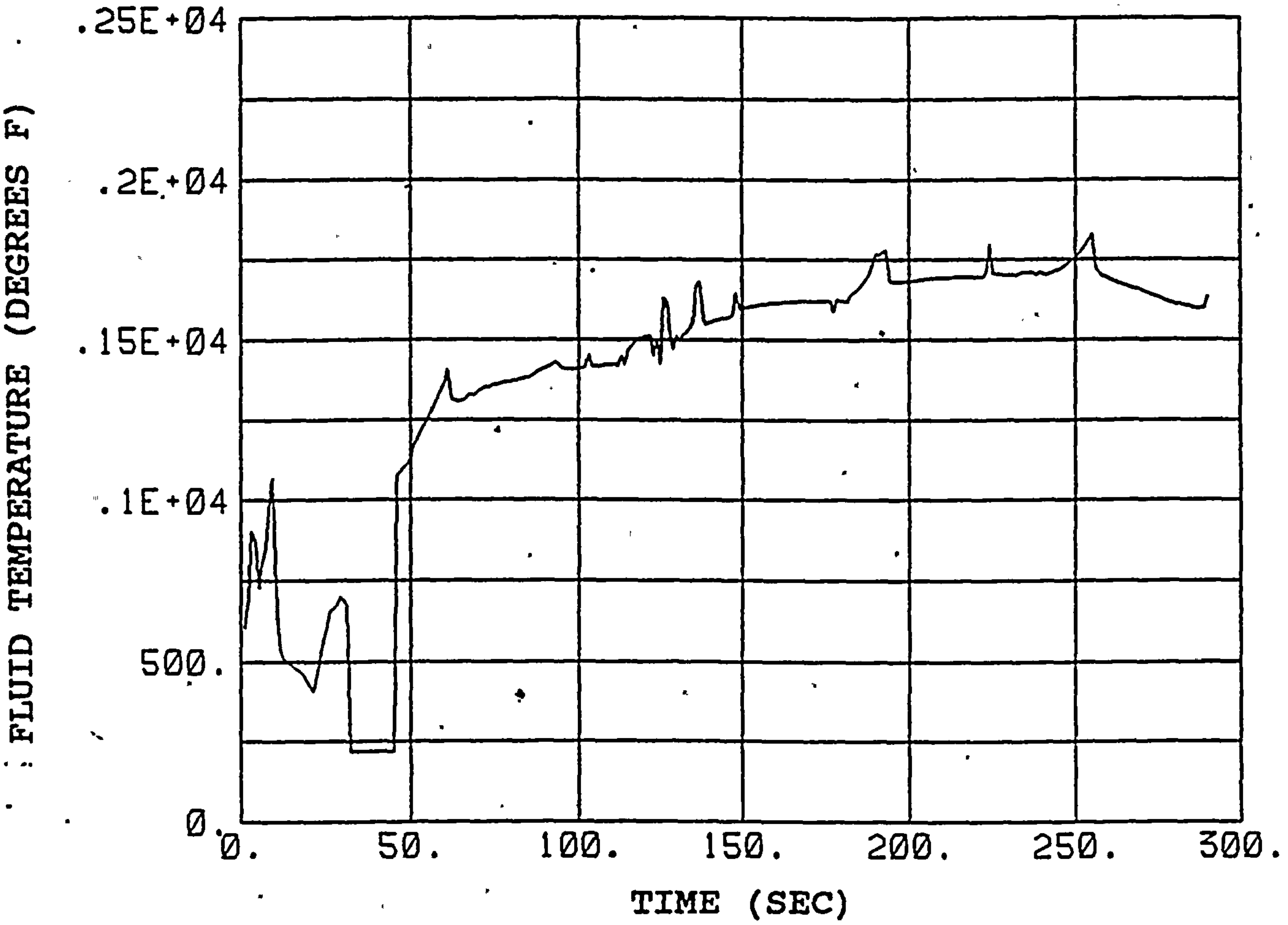

FIGURE C.3.1-14e
FLUID TEMPERATURE
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

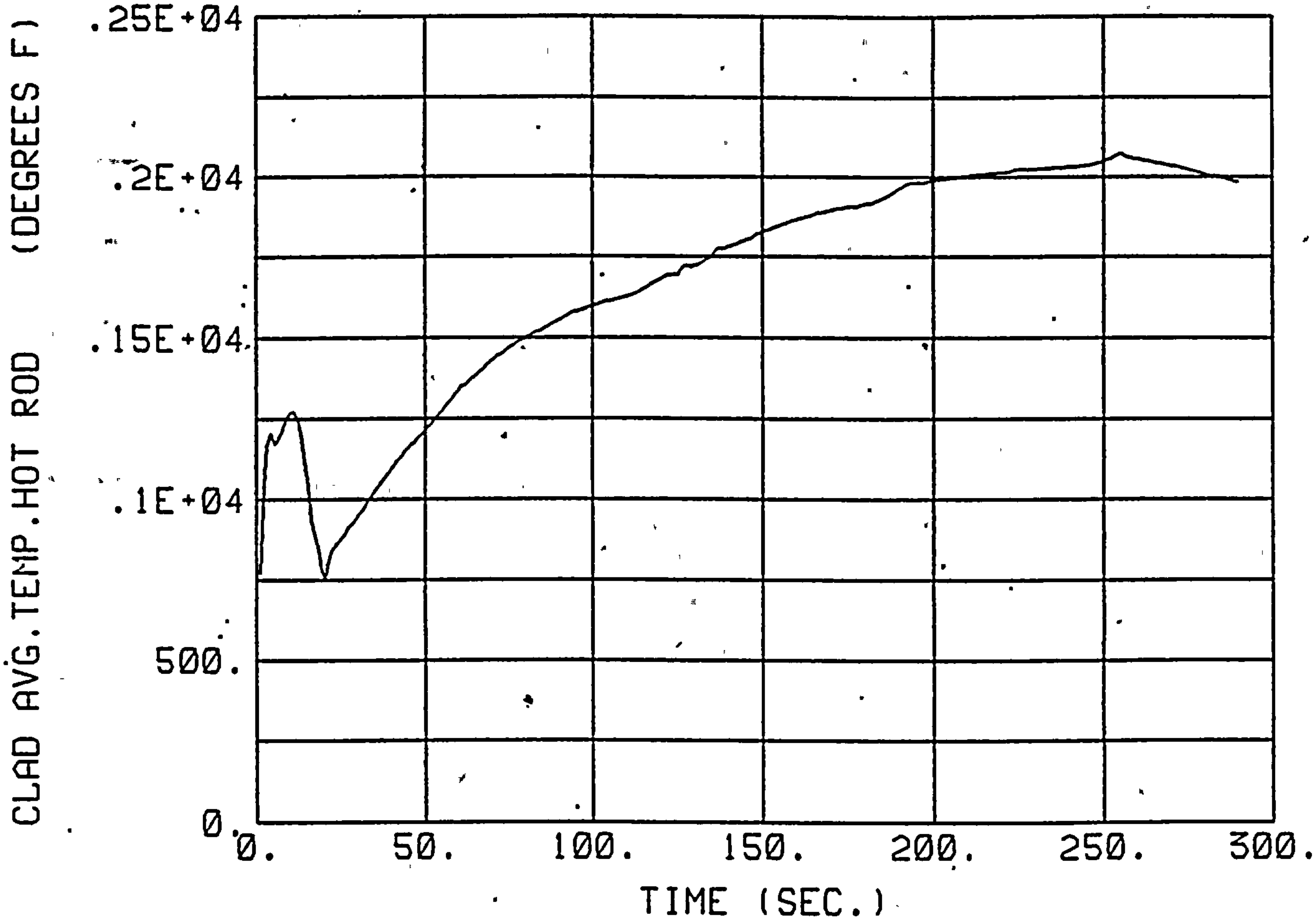

FIGURE C.3.1-15e
FUEL ROD PEAK CLAD TEMPERATURE
CD=0.6, P_{RCS}=2037 PSIA
Donald C. Cook Unit 2

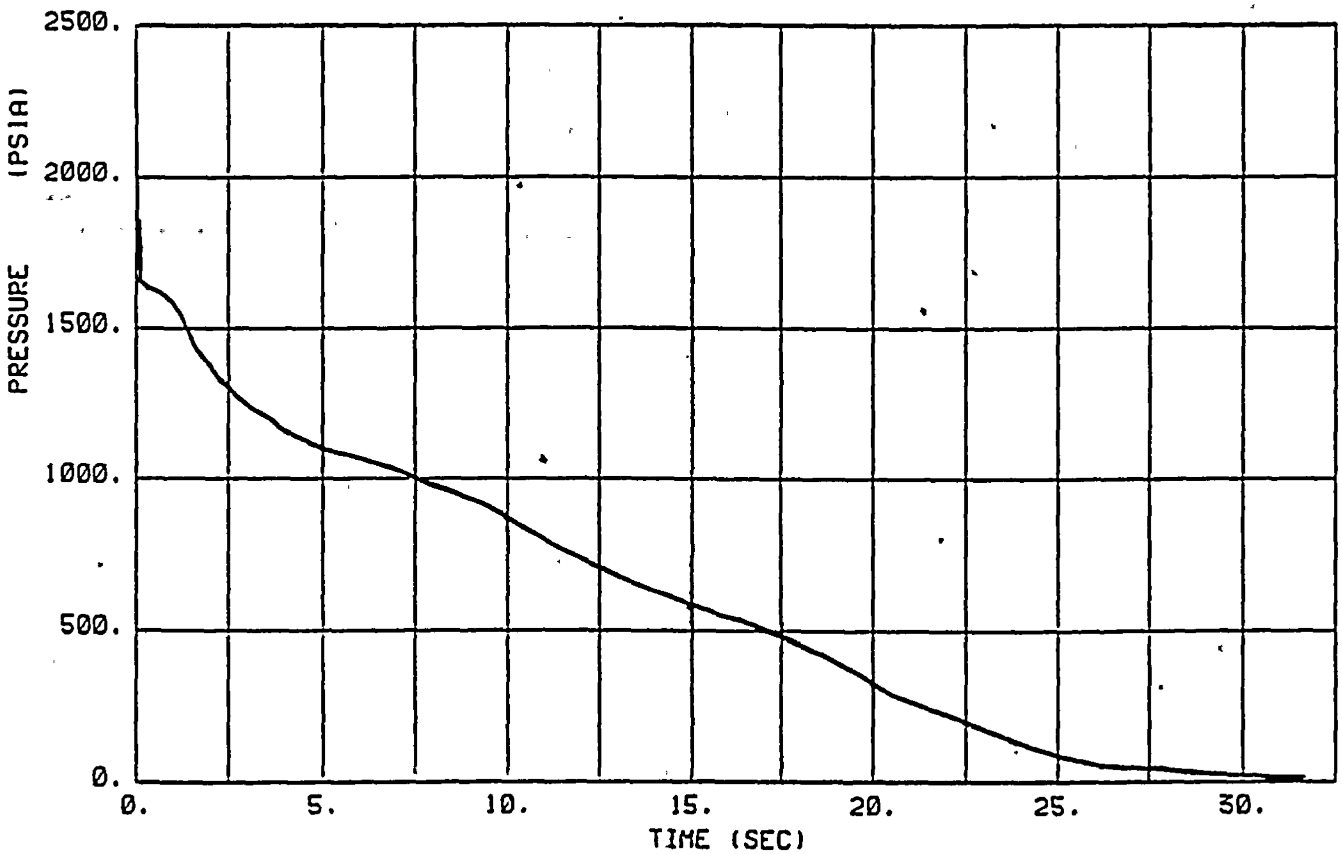

FIGURE C.3.1-3f
REACTOR COOLANT SYSTEM PRESSURE
CD=0.6, MAX SI
Donald C. Cook Unit 2

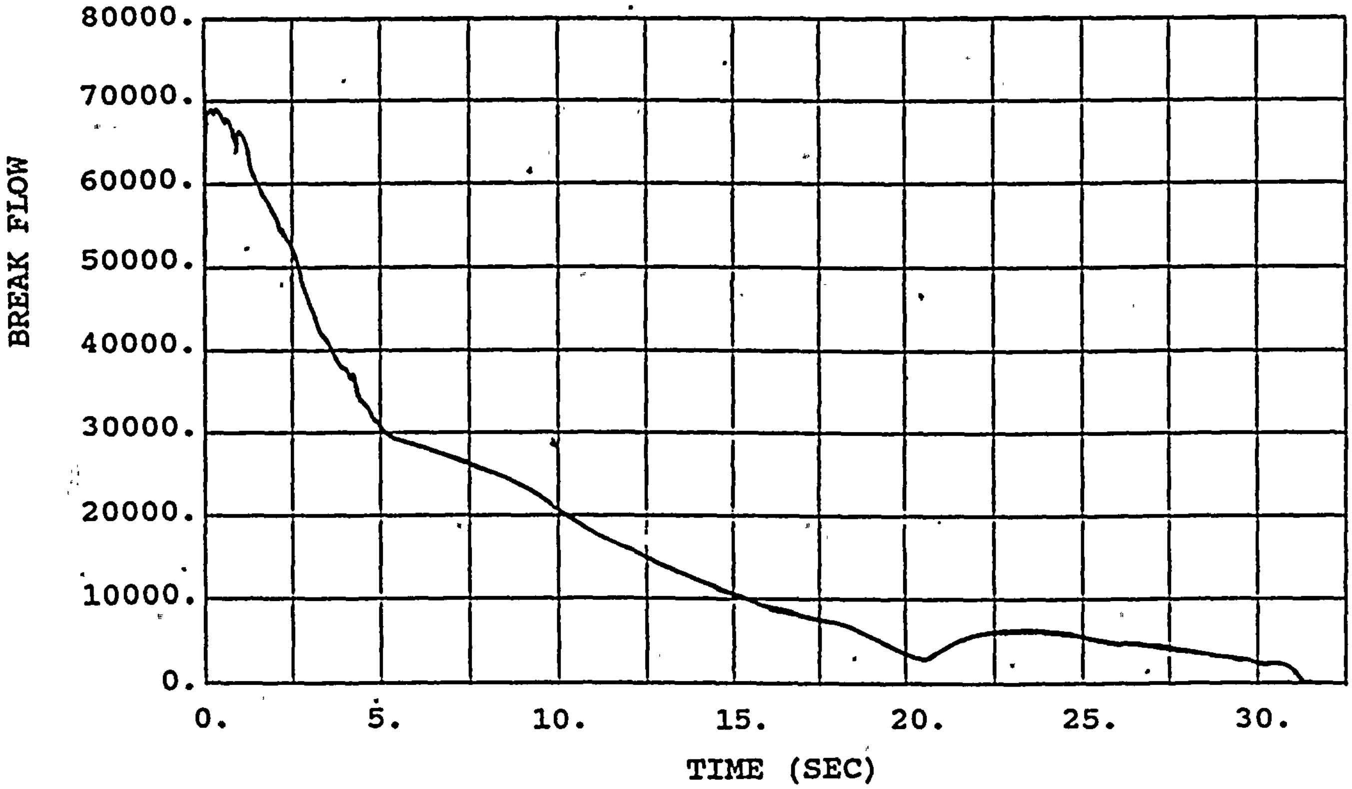

FIGURE C.3.1-4f
BREAK FLOW DURING BLOWDOWN
CD=0.6, MAX SI
Donald C. Cook Unit 2

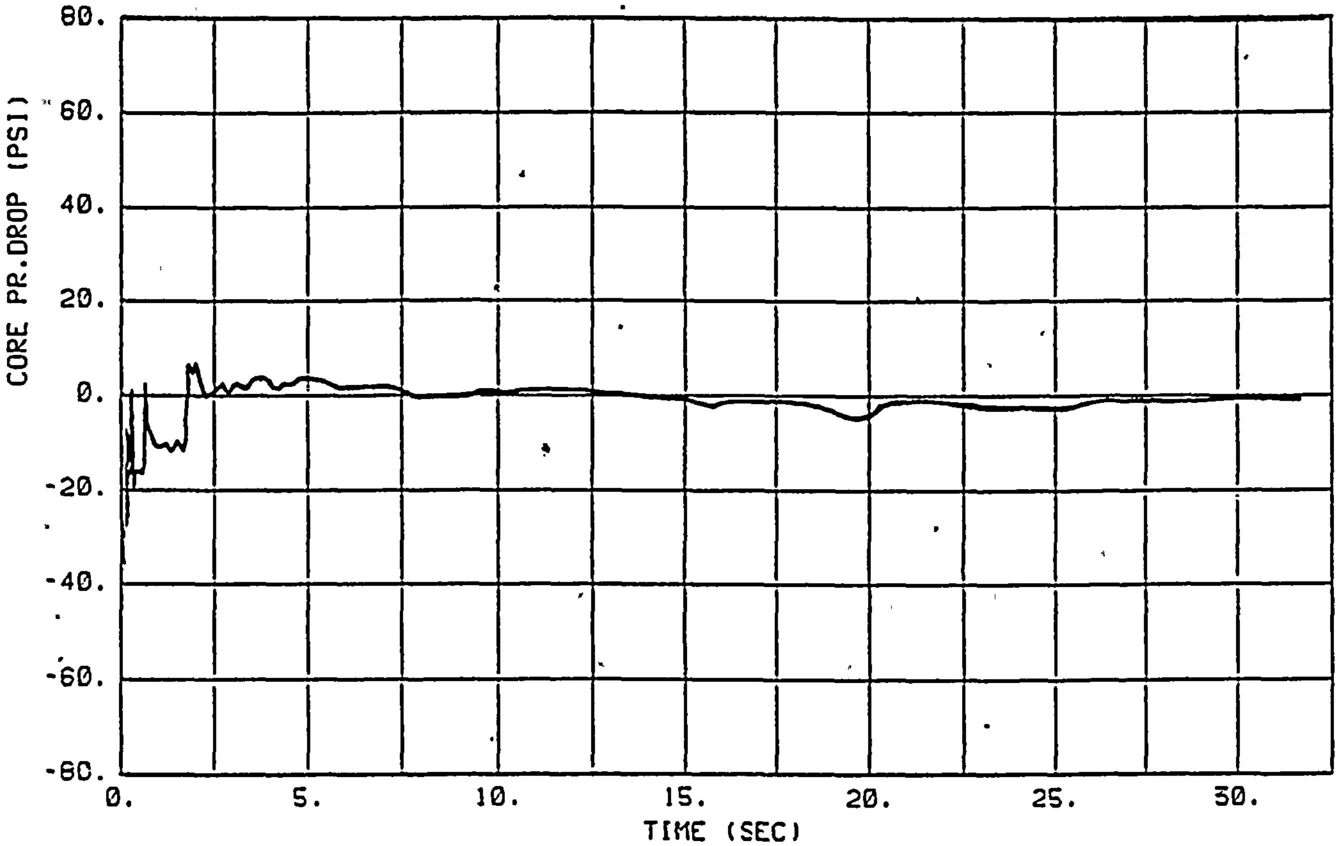

FIGURE C.3.1-5f
CORE PRESSURE DROP
CD=0.6, MAX SI
Donald C. Cook Unit 2

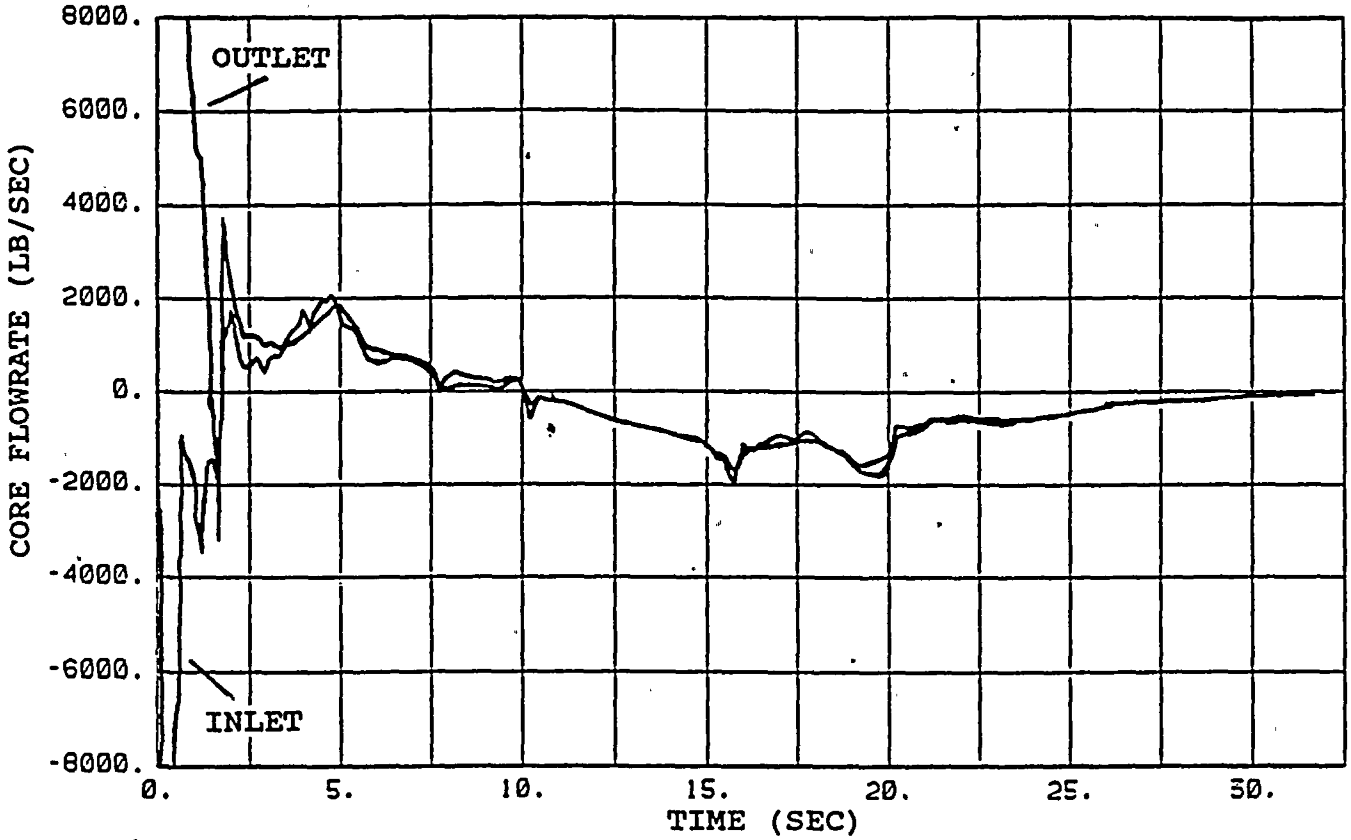

FIGURE C.3.1-6f
CORE FLOWRATE
CD=0.6, MAX SI
Donald C. Cook Unit 2

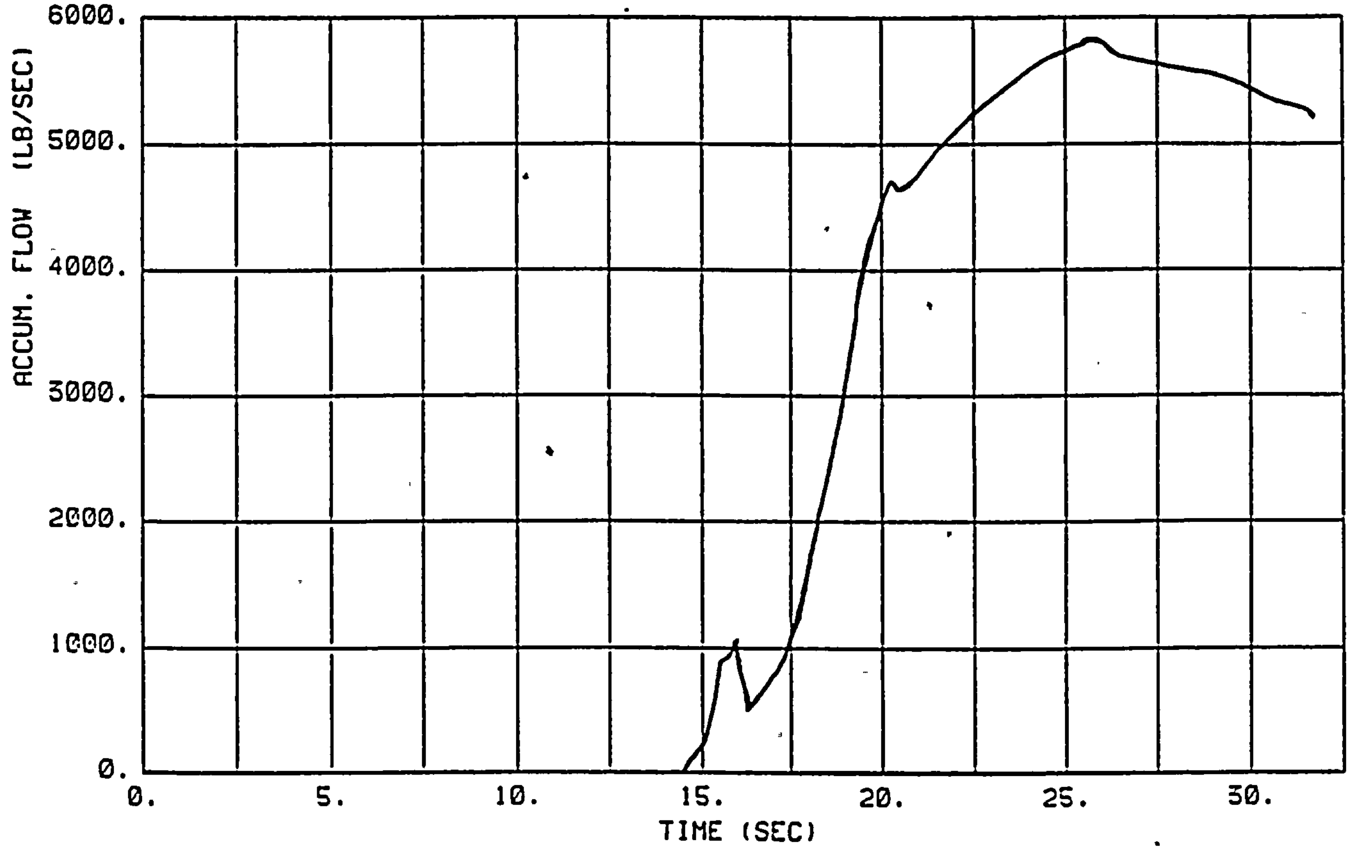

FIGURE C.3.1-7f
ACCUMULATOR FLOW DURING BLOWDOWN
CD=0.6, MAX SI
Donald C. Cook Unit 2

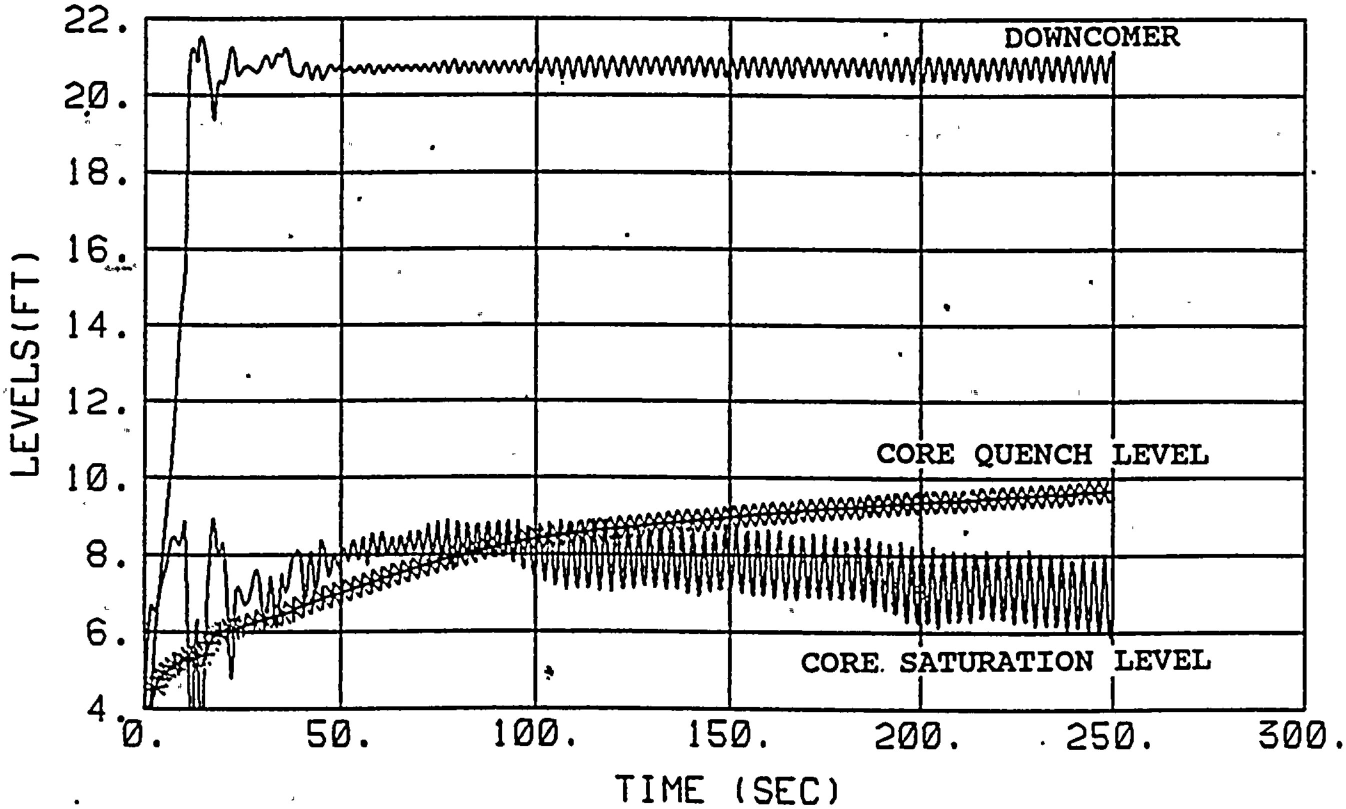

FIGURE C.3.1-8f
CORE AND DOWNCOMER LIQUID LEVELS
DURING REFLOOD
CD=0.6, MAX SI
Donald C. Cook Unit 2

* Time is measured after BOC

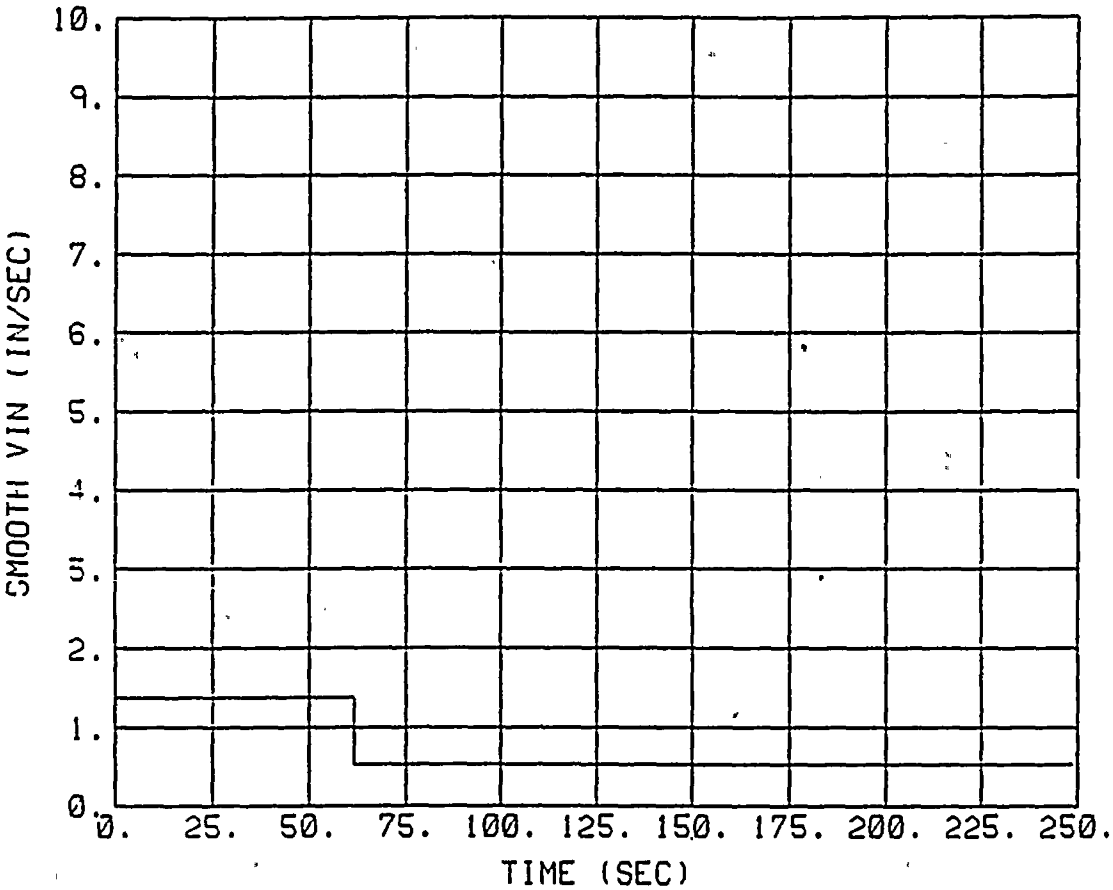

FIGURE C.3.1-9f
CORE INLET FLOW DURING REFLOOD
CD=0.6, MAX SI
Donald C. Cook Unit 2

* Time is measured after BOC

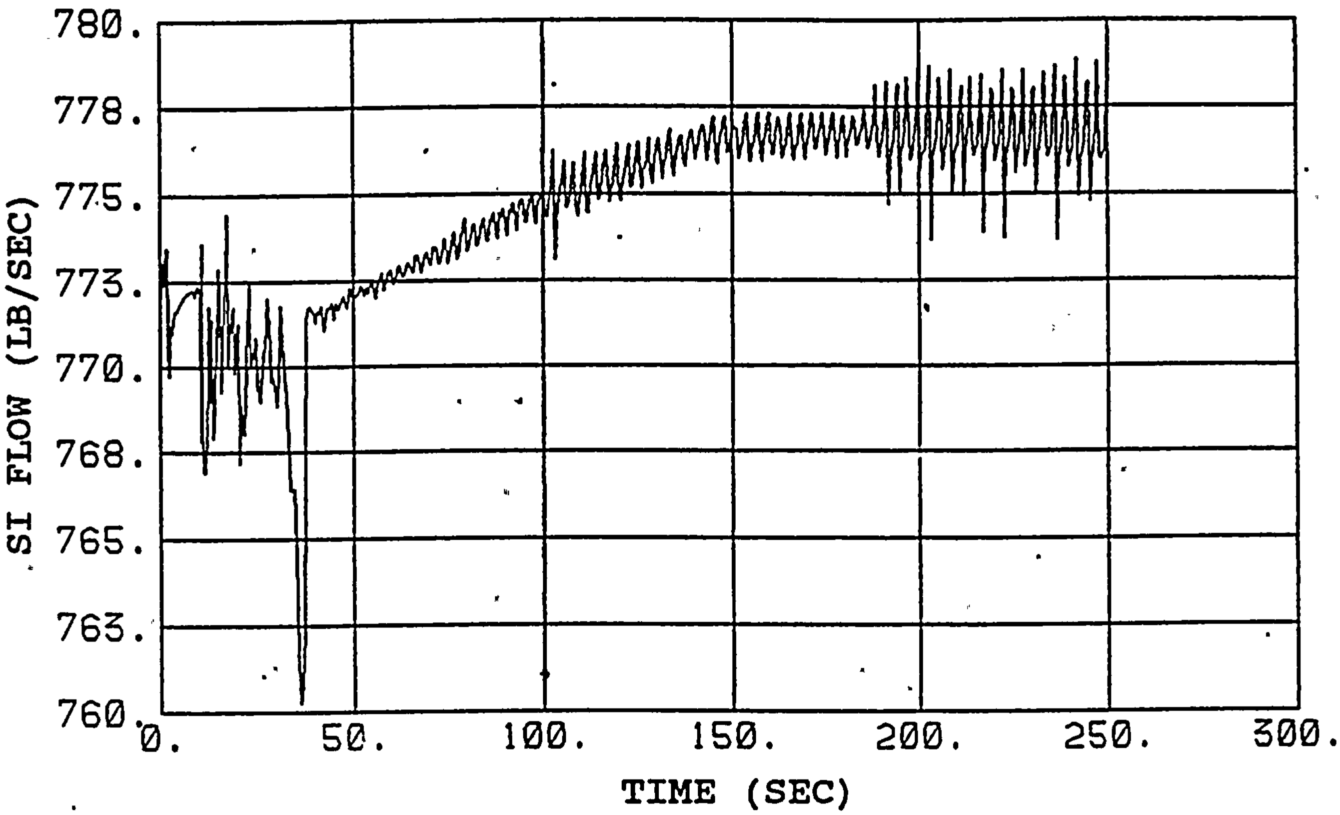

FIGURE C.3.1-10f
SI FLOW
CD=0.6, MAX SI
Donald C. Cook Unit 2

* Time is measured after BOC

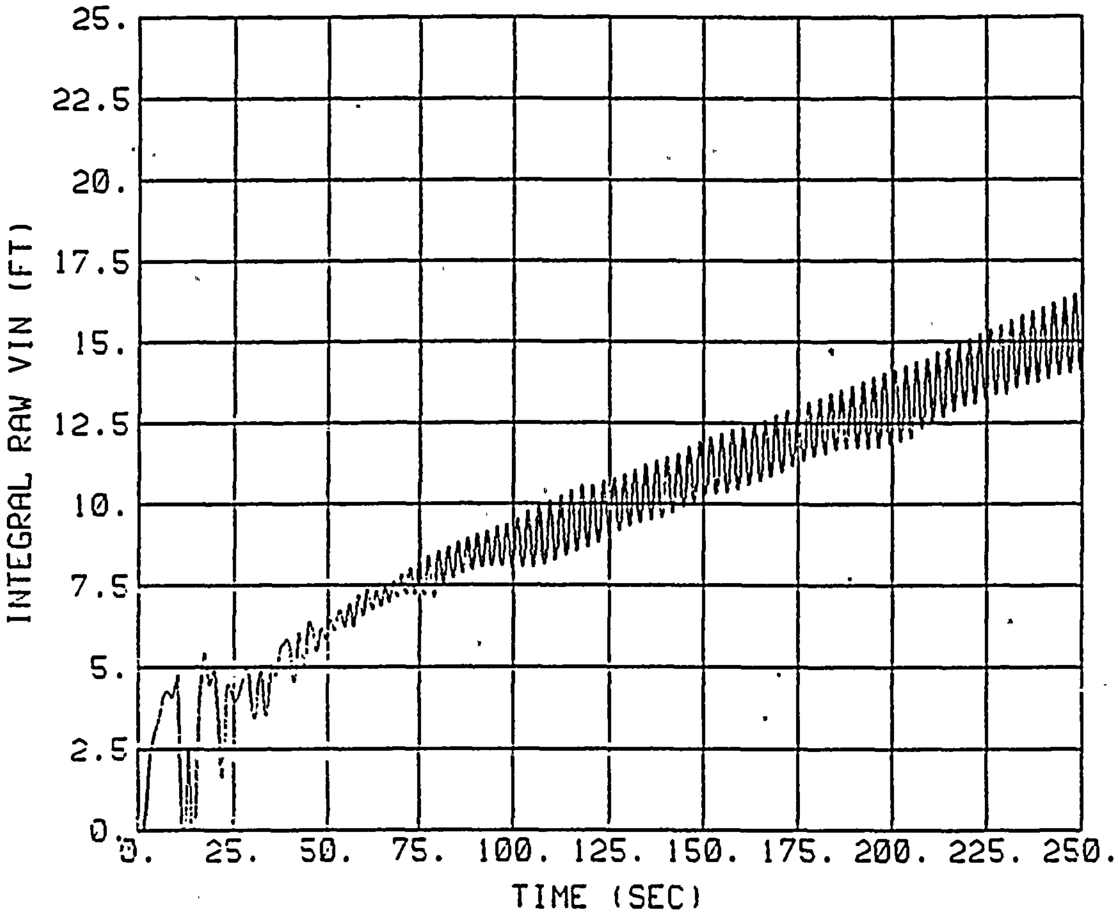

FIGURE C.3.1-11f
INTEGRAL OF CORE INLET FLOW
CD=0.6, MAX SI
Donald C. Cook Unit 2

* Time is measured after BOC

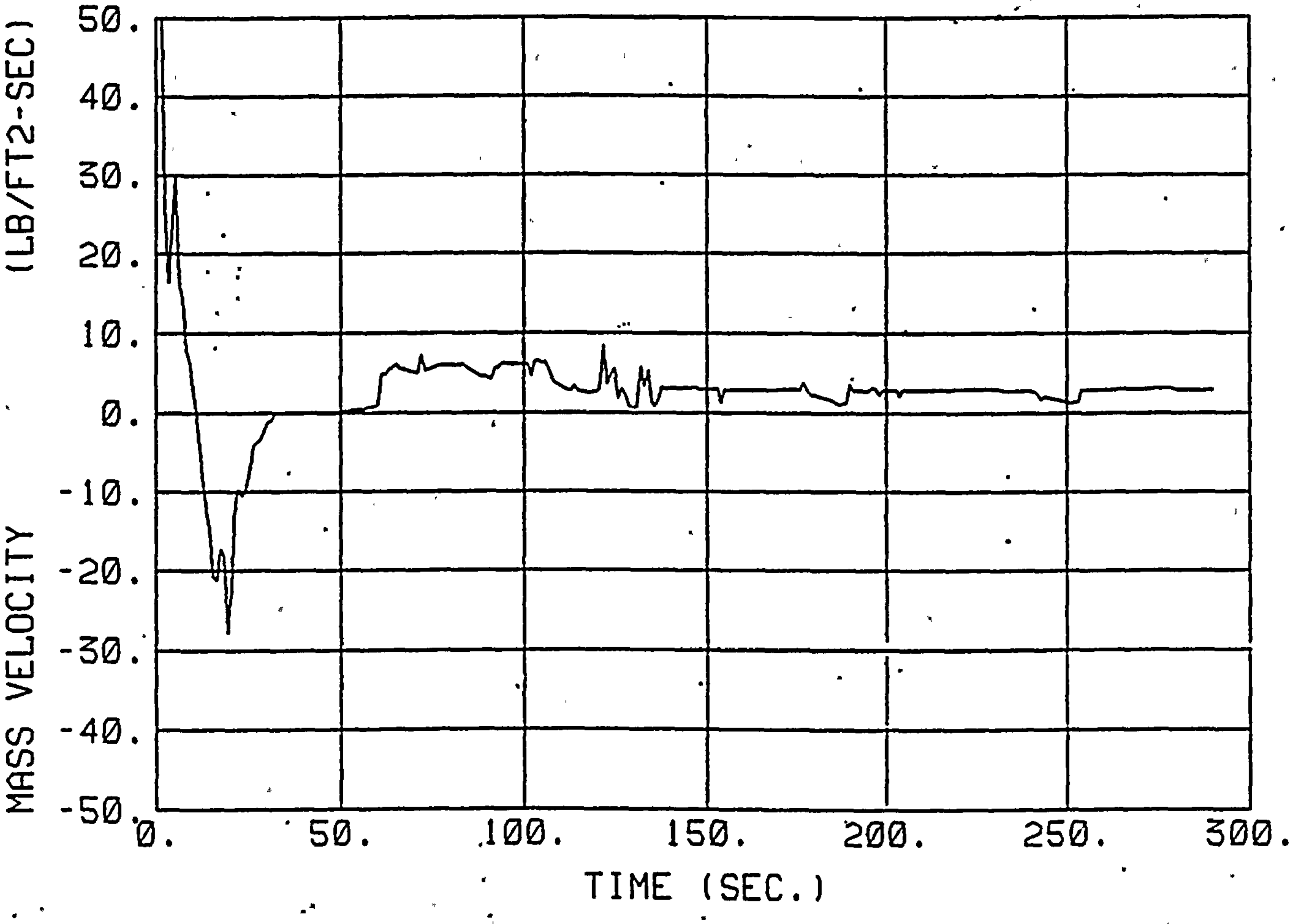

FIGURE C.3.1-12f
MASS FLUX AT THE PEAK
TEMPERATURE ELEVATION
CD=0.6, MAX SI
Donald C. Cook Unit 2

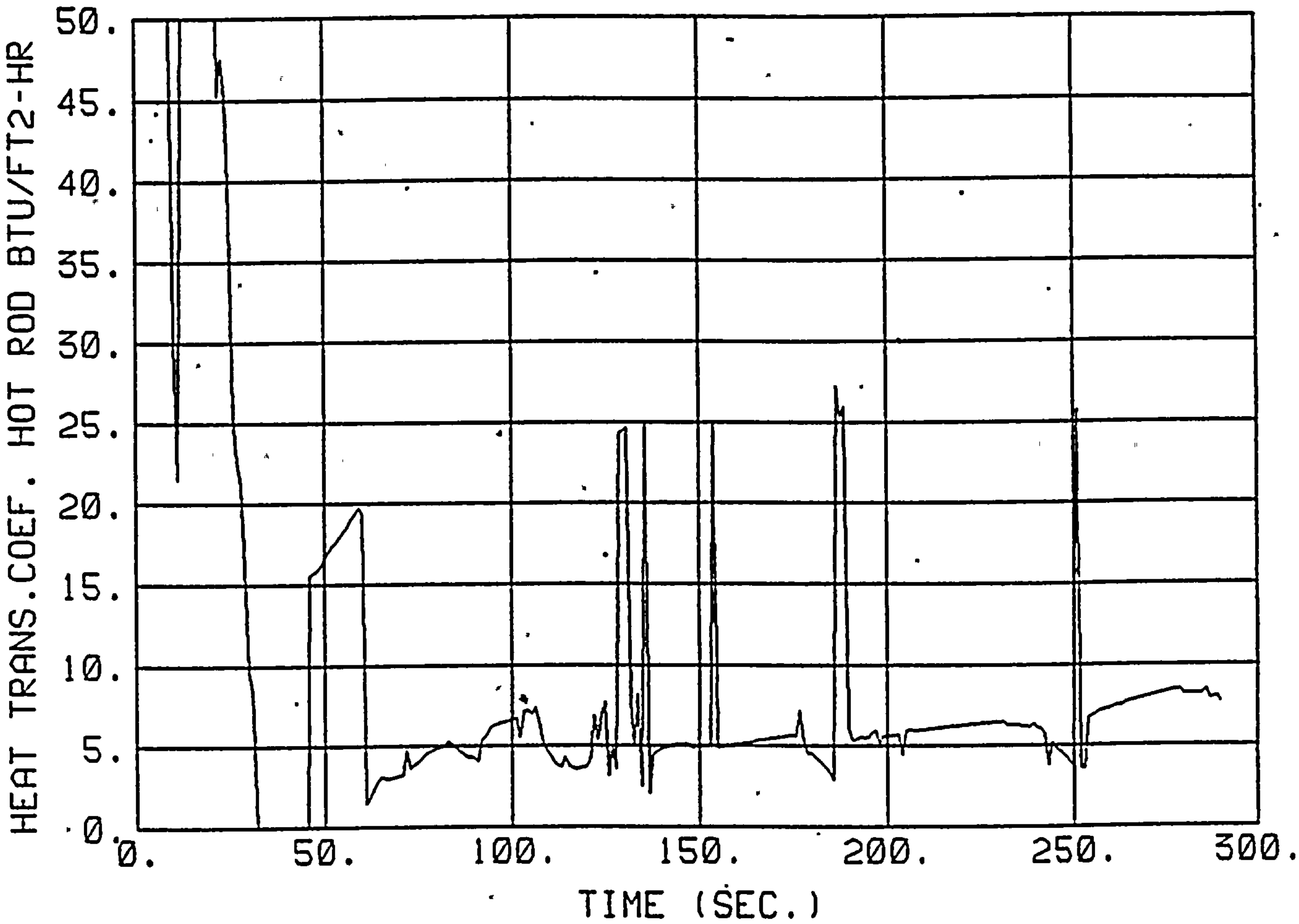

FIGURE C.3.1-13f
ROD HEAT TRANSFER COEFFICIENT AT
THE PEAK TEMPERATURE ELEVATION
CD=0.6, MAX SI
Donald C. Cook Unit 2

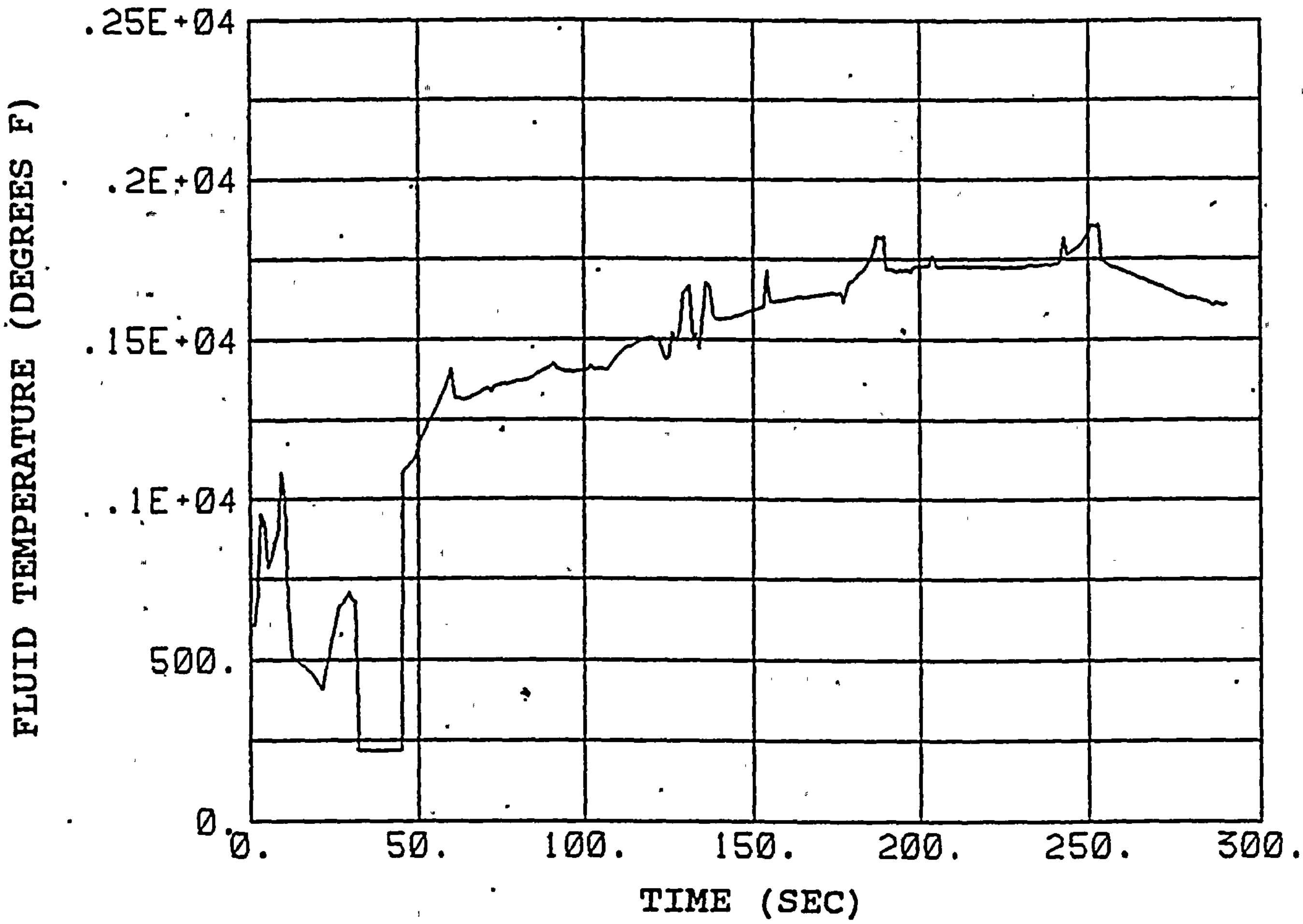

FIGURE C.3.1-14f
FLUID TEMPERATURE
CD=0.6, MAX SI
Donald C. Cook Unit 2

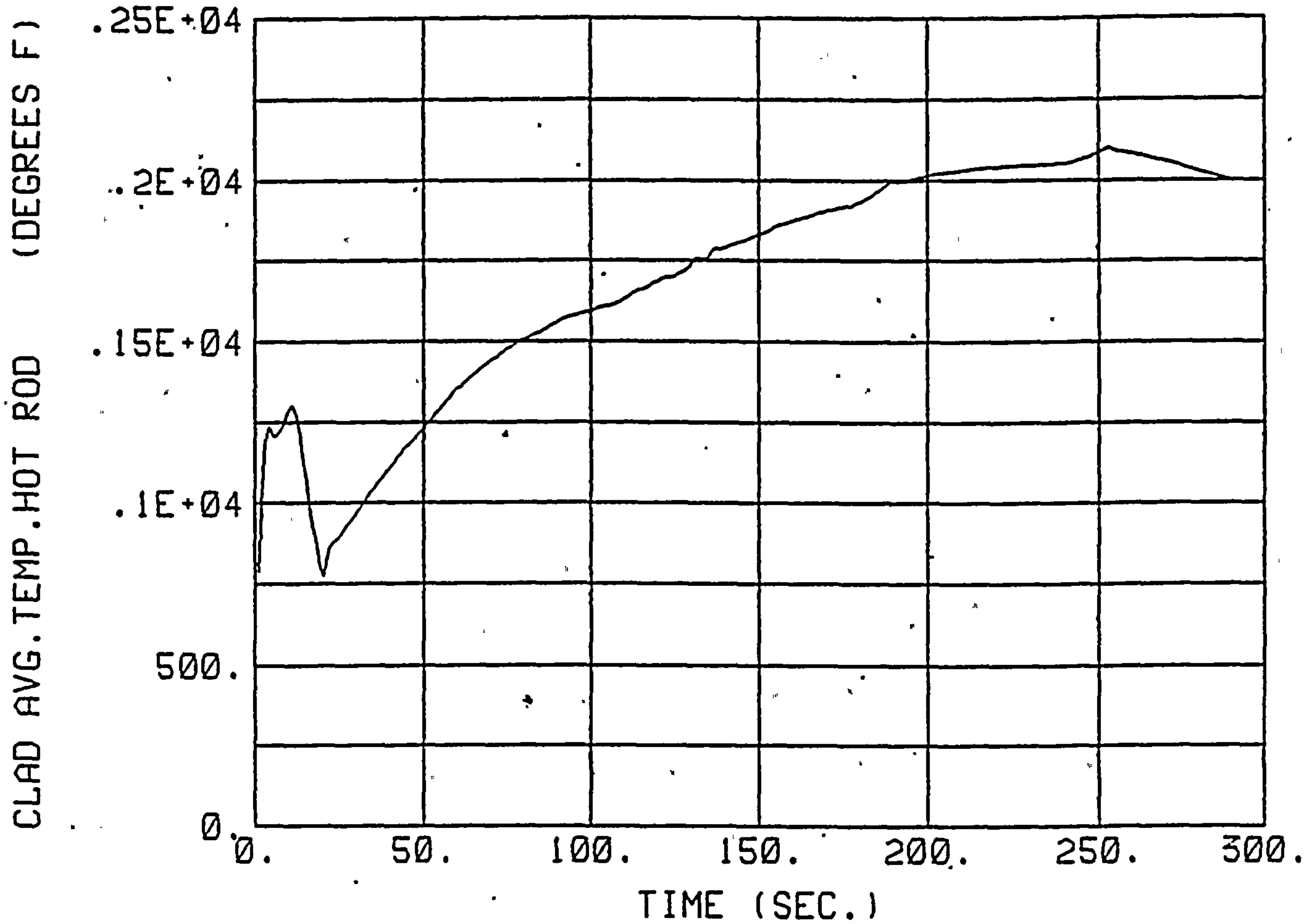

FIGURE C.3.1-15f
FUEL ROD PEAK CLAD TEMPERATURE
CD=0.6, MAX SI
Donald C. Cook Unit 2

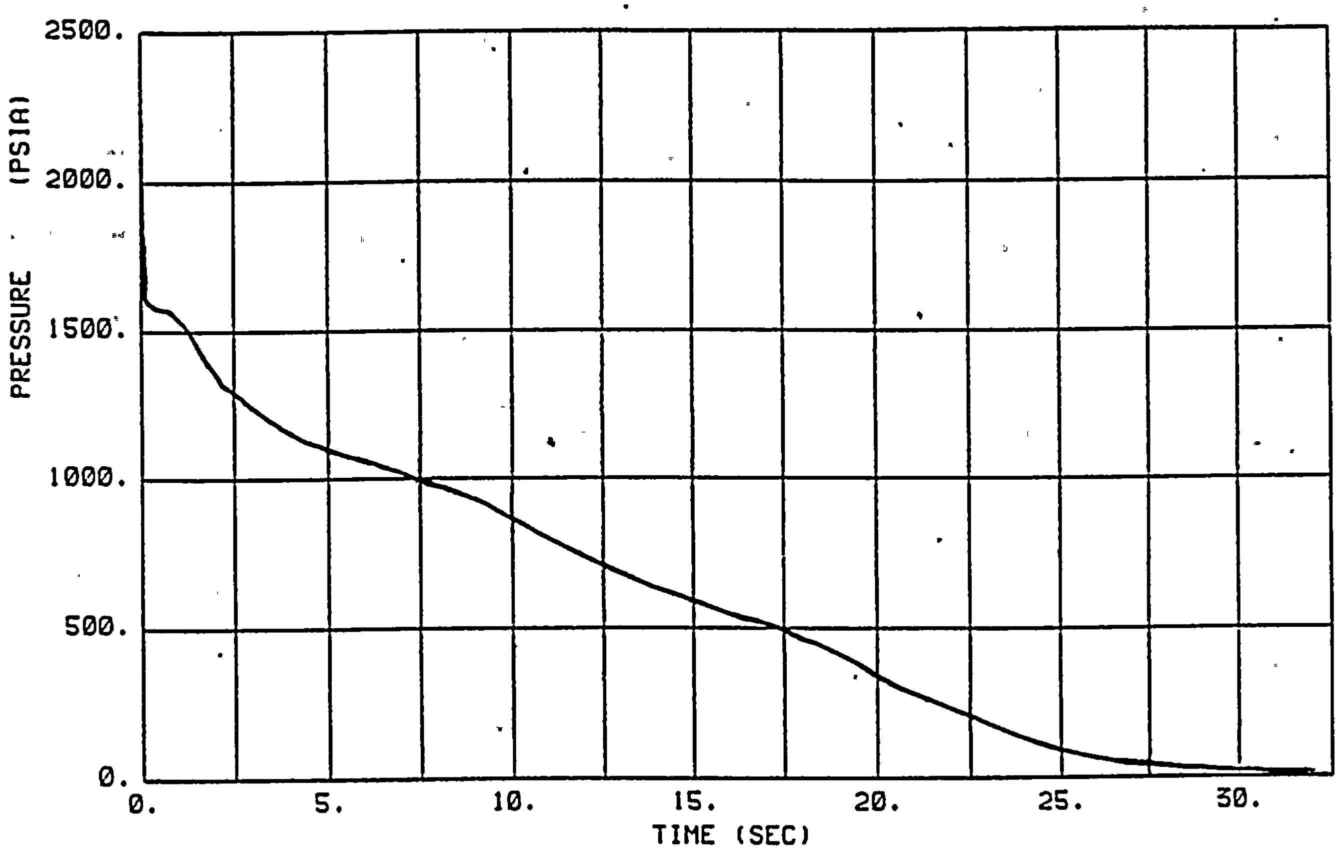

FIGURE C.3.1-3g
REACTOR COOLANT SYSTEM PRESSURE
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

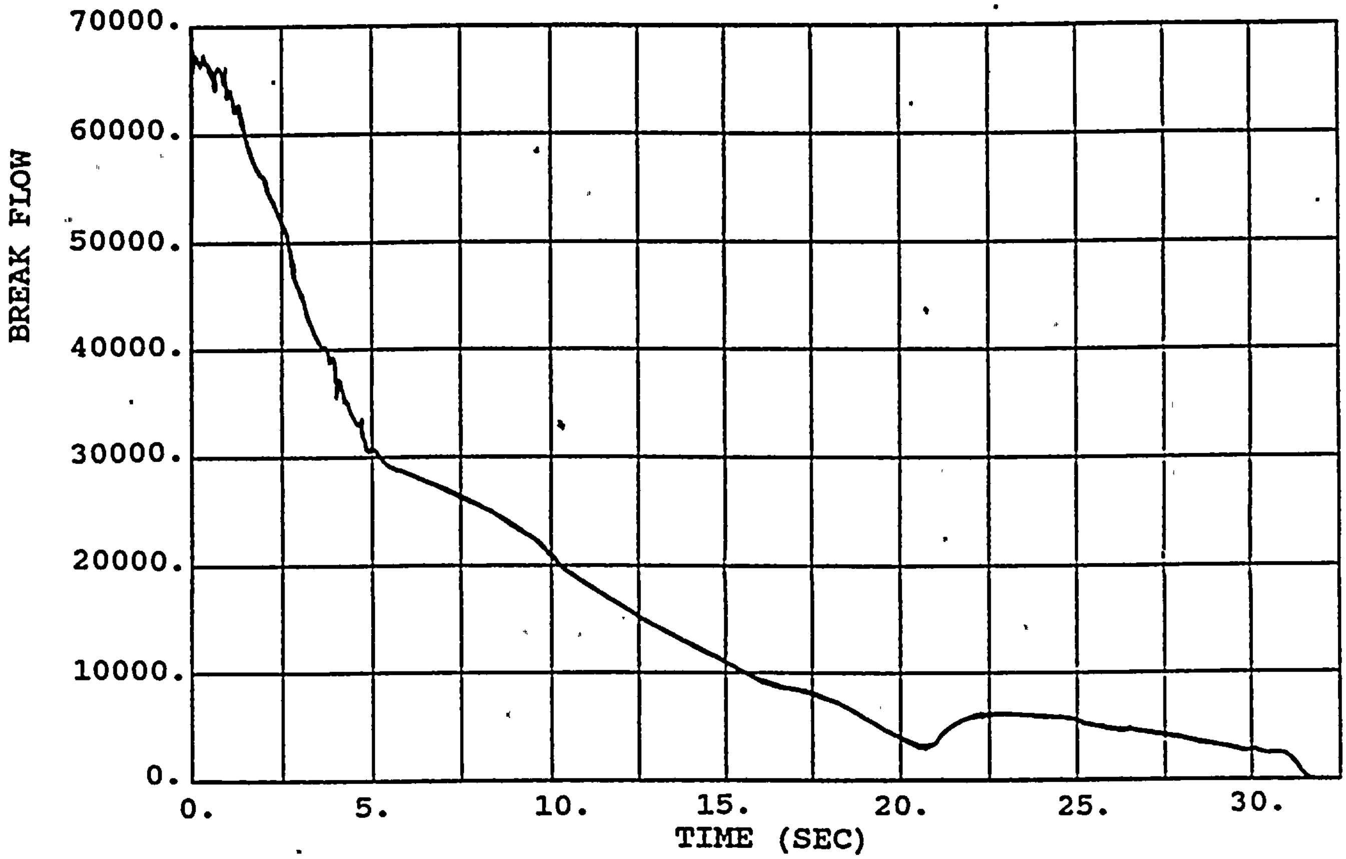

FIGURE C.3.1-4g
BREAK FLOW DURING BLOWDOWN
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

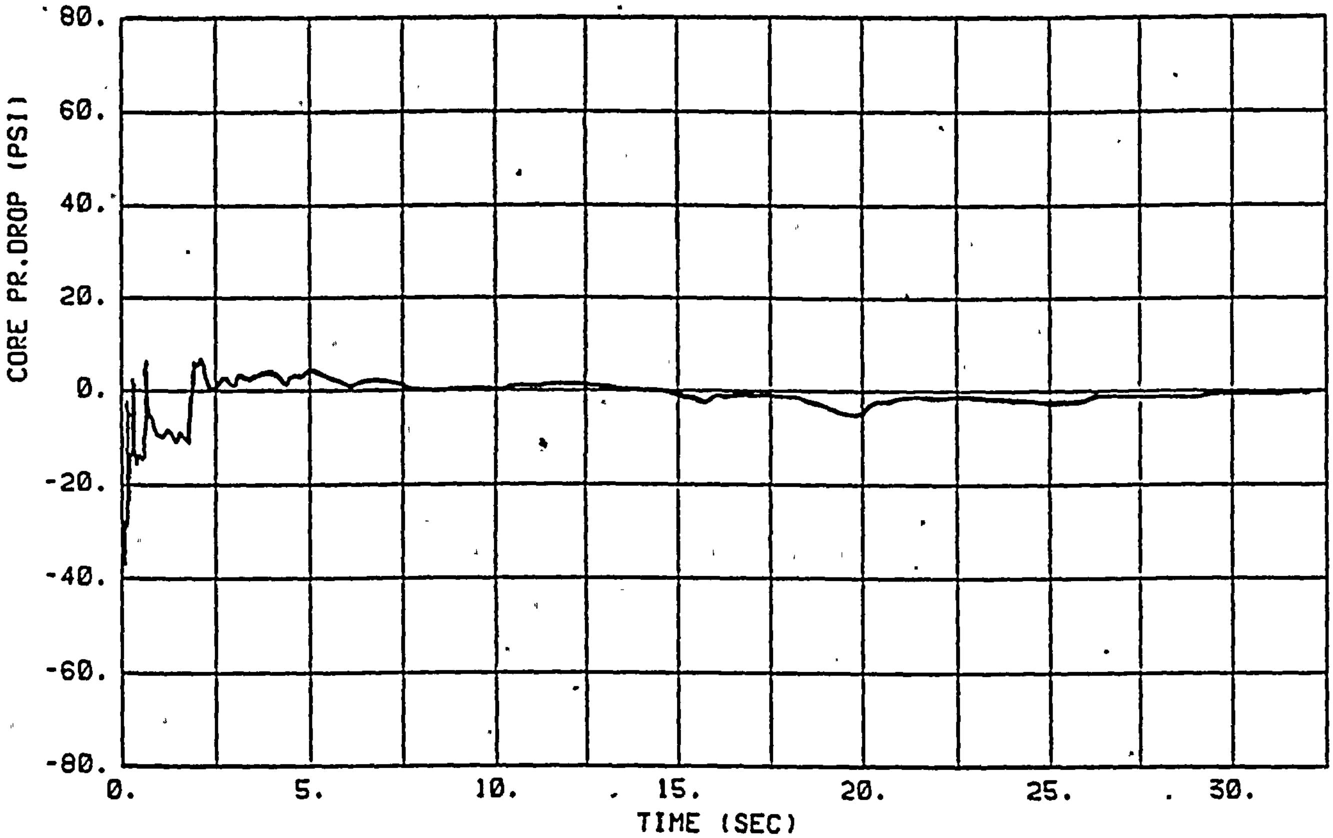

FIGURE C.3.1-5g
CORE PRESSURE DROP
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

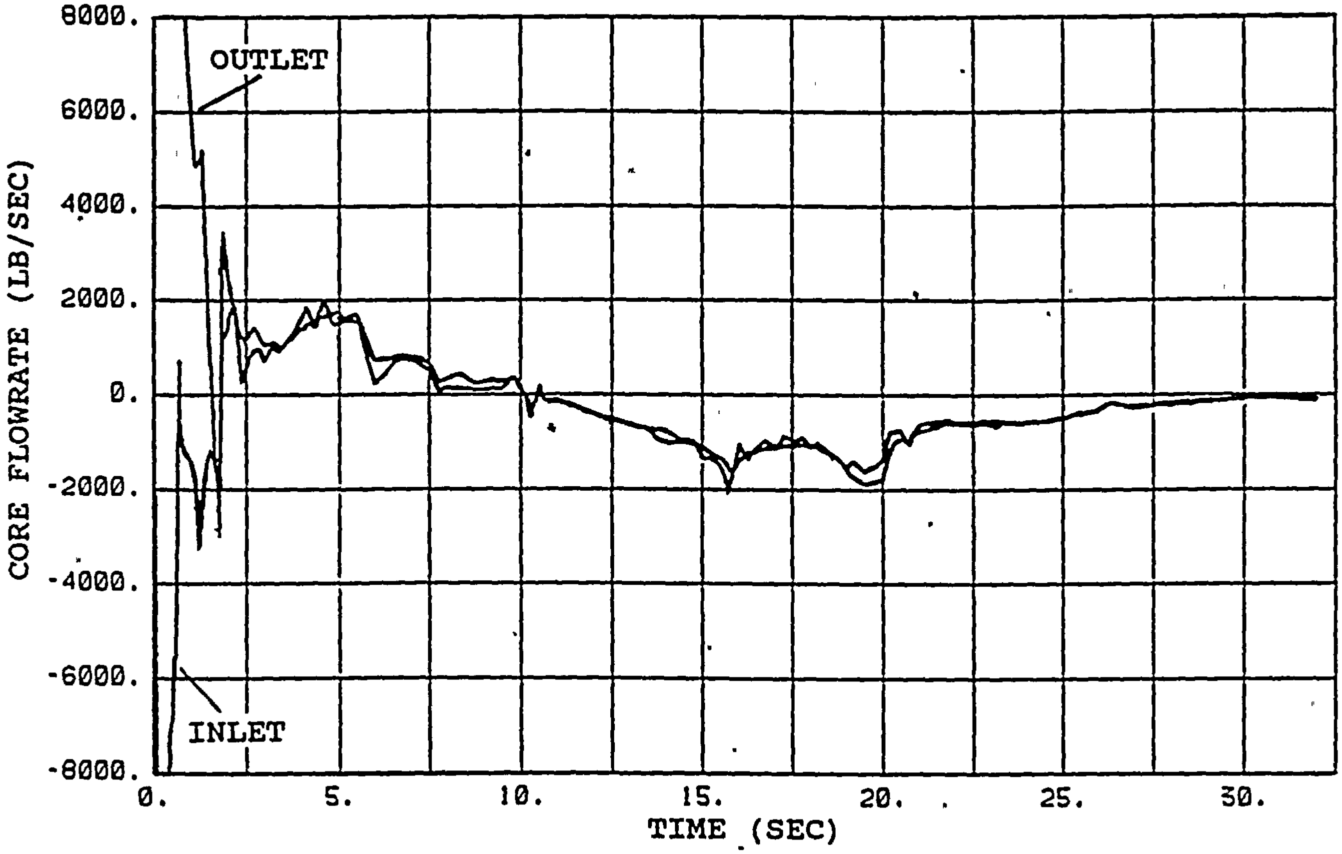

FIGURE C.3.1-6g
CORE FLOWRATE
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

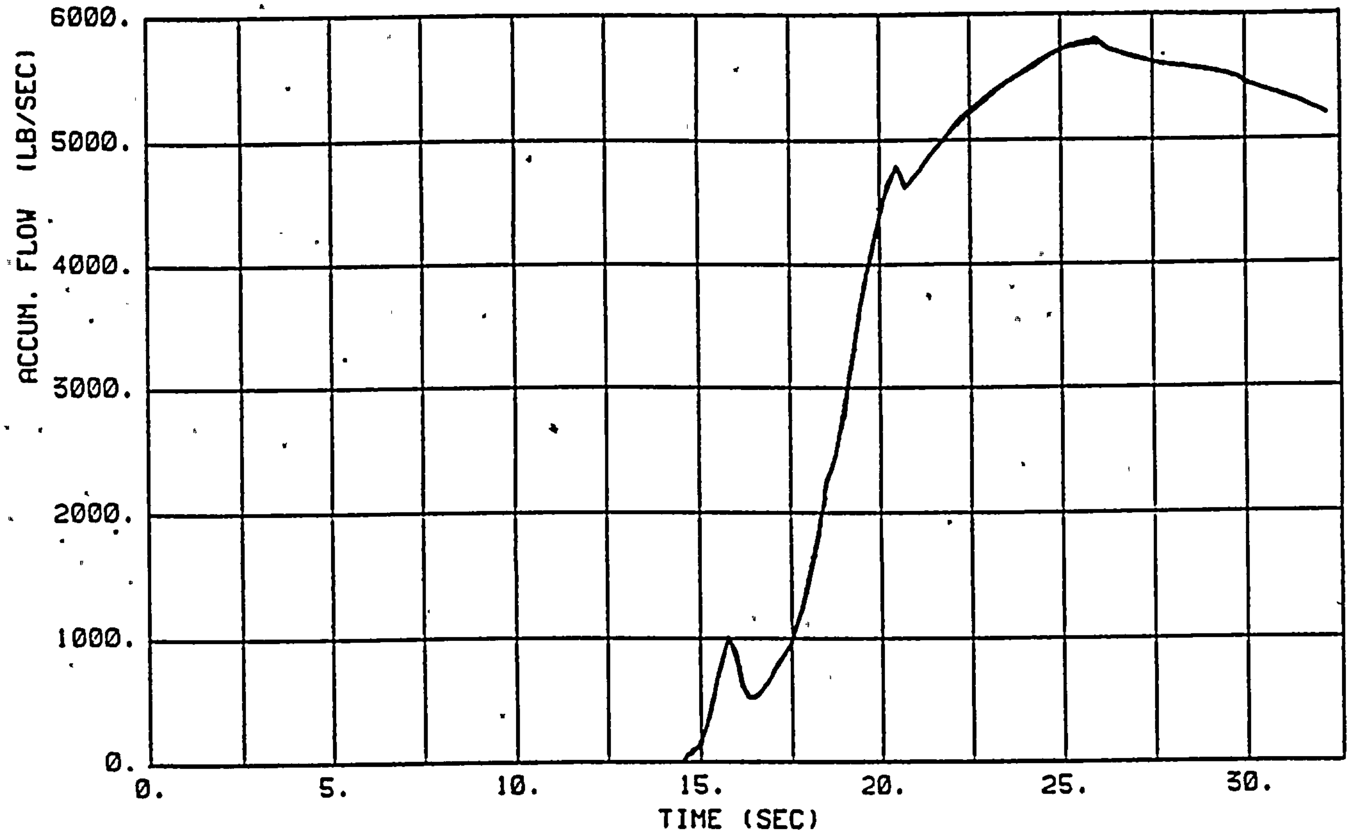

FIGURE C.3.1-7g
ACCUMULATOR FLOW DURING BLOWDOWN
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

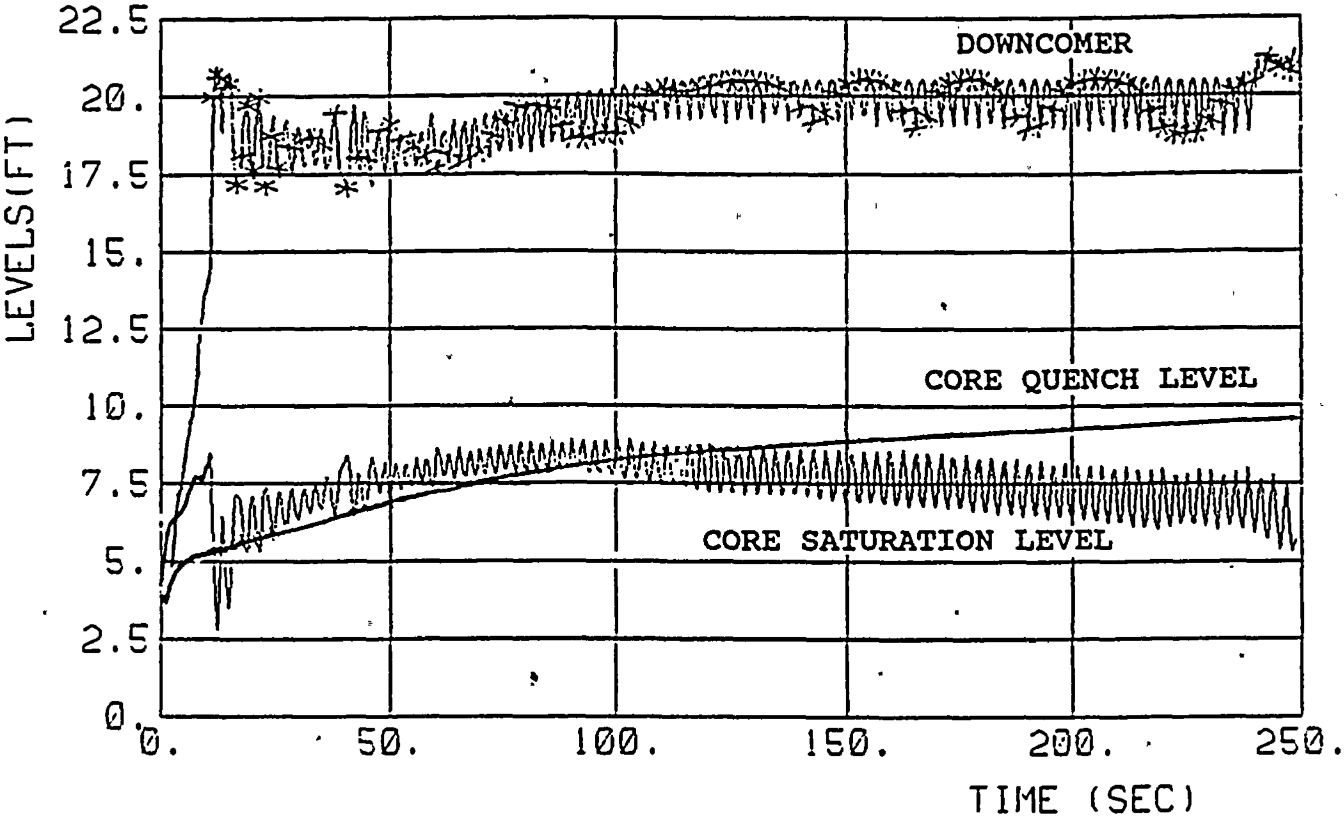

FIGURE C.3.1-8g
CORE AND DOWNCOMER LIQUID LEVELS
DURING REFLOOD
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

* Time is measured after BOC

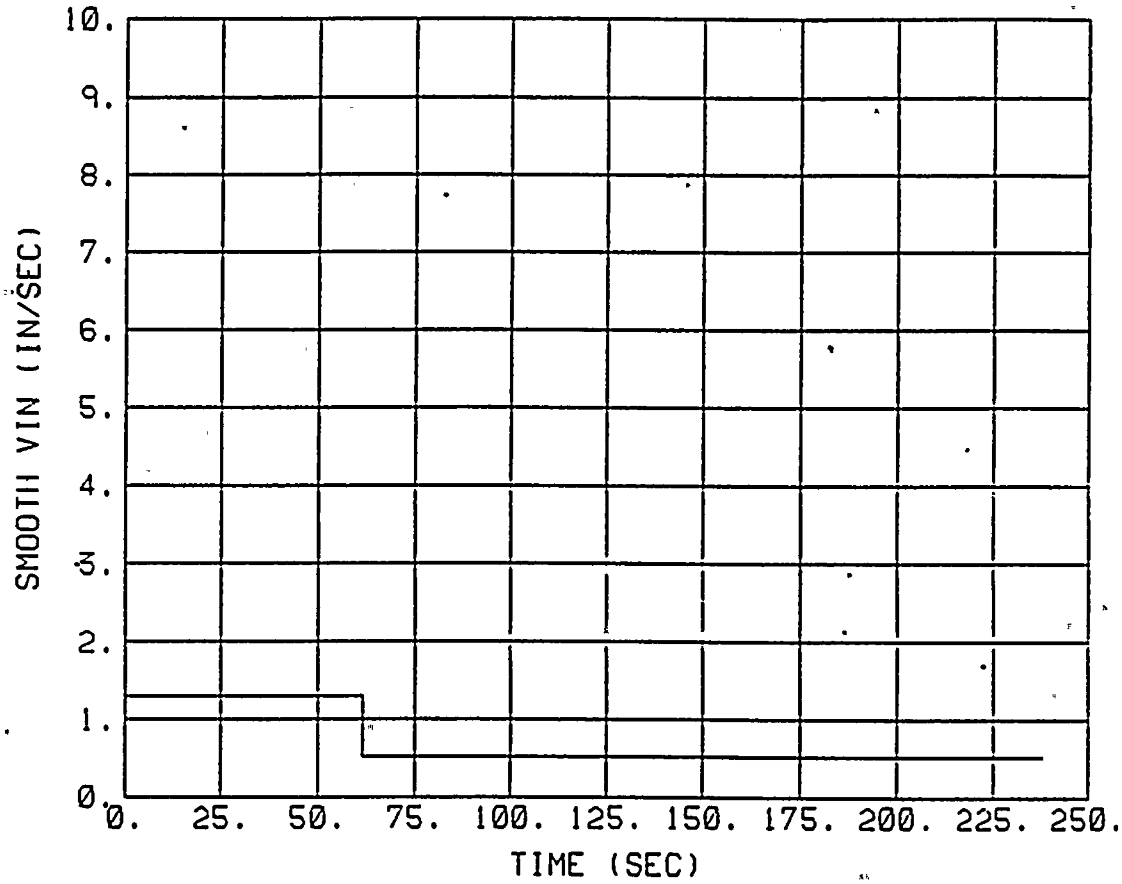

FIGURE C.3.1-9g
CORE INLET FLOW DURING REFLOOD
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

* Time is measured after BOC

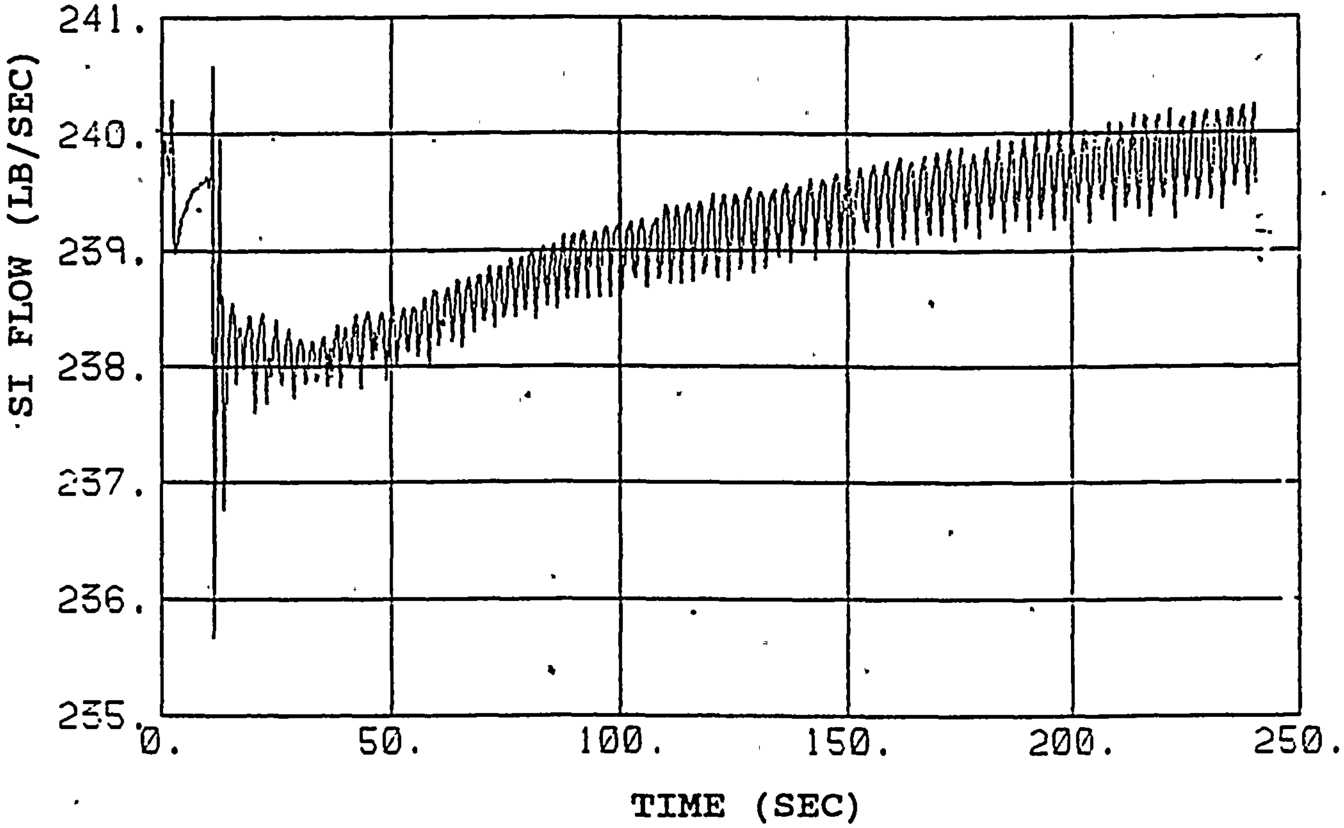

FIGURE C.3.1-10g
SI FLOW
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

* Time is measured after BOC

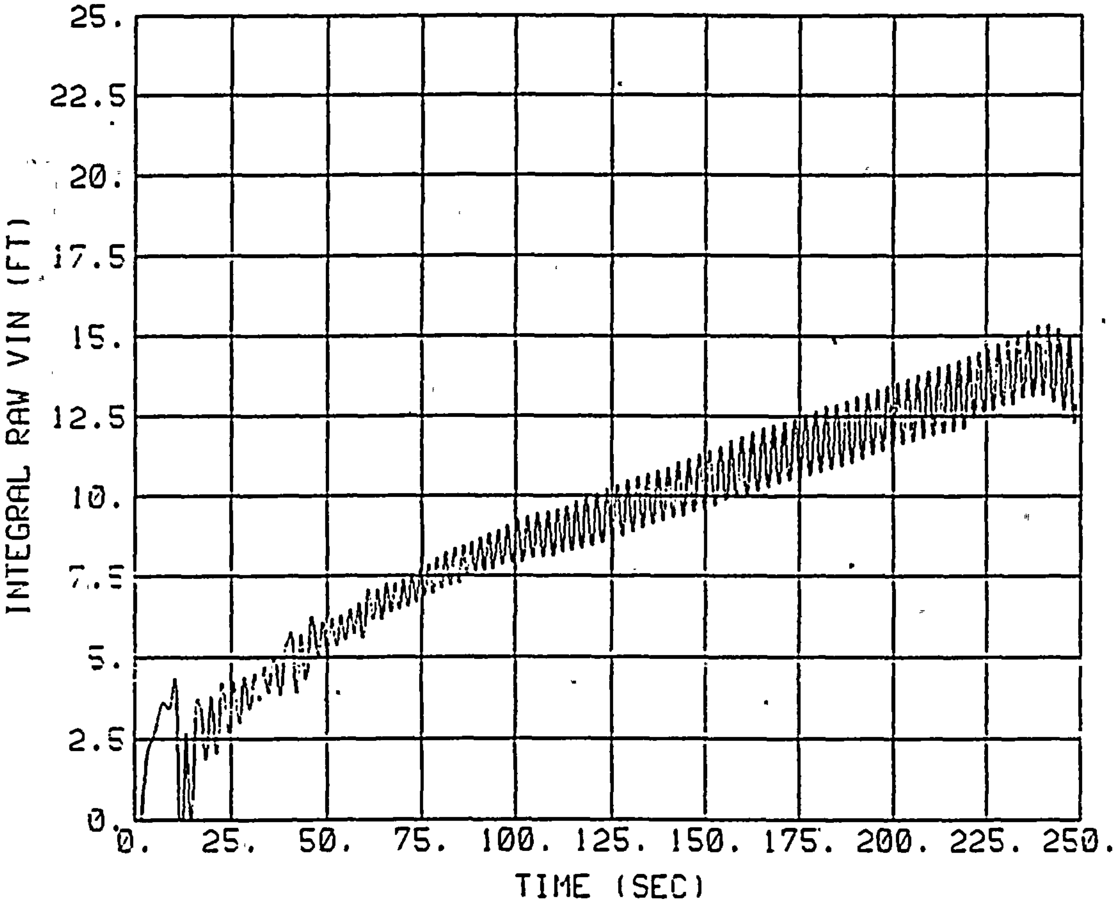

FIGURE C.3.1-11g
INTEGRAL OF CORE INLET FLOW
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

* Time is measured after BOC

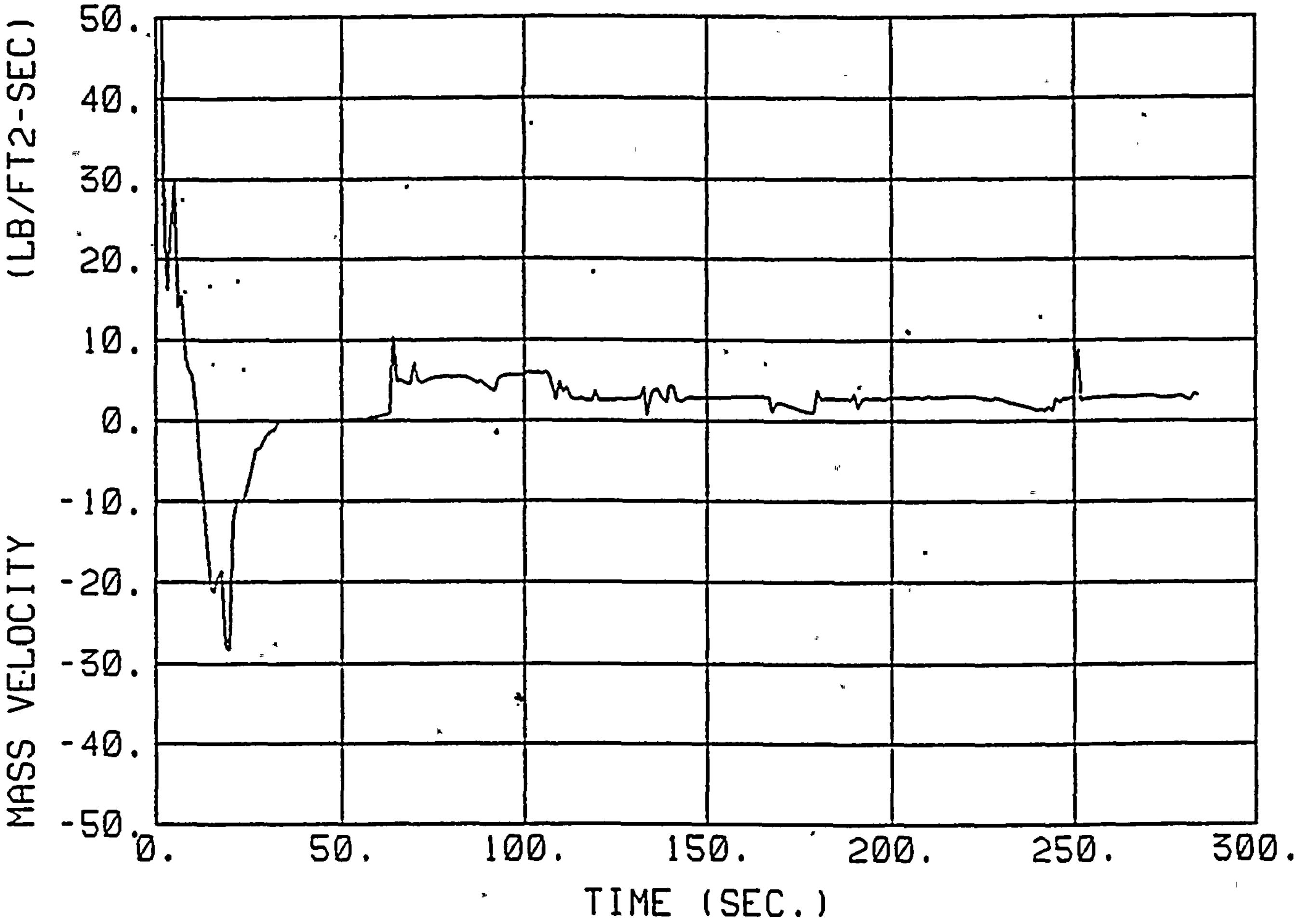

FIGURE C.3.1-12g
MASS FLUX AT THE PEAK
TEMPERATURE ELEVATION
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

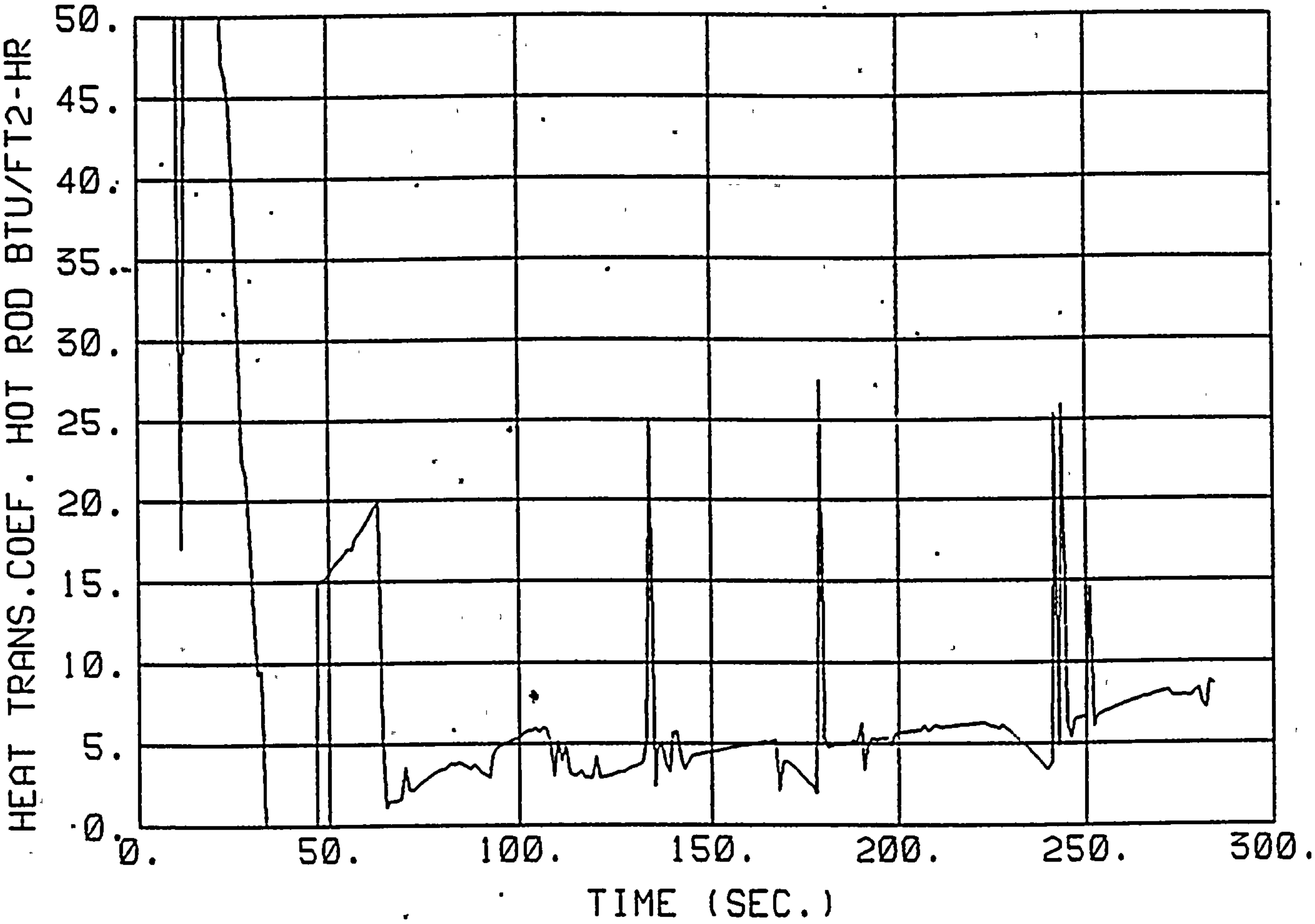

FIGURE C.3.1-13g
ROD HEAT TRANSFER COEFFICIENT AT
THE PEAK TEMPERATURE ELEVATION
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

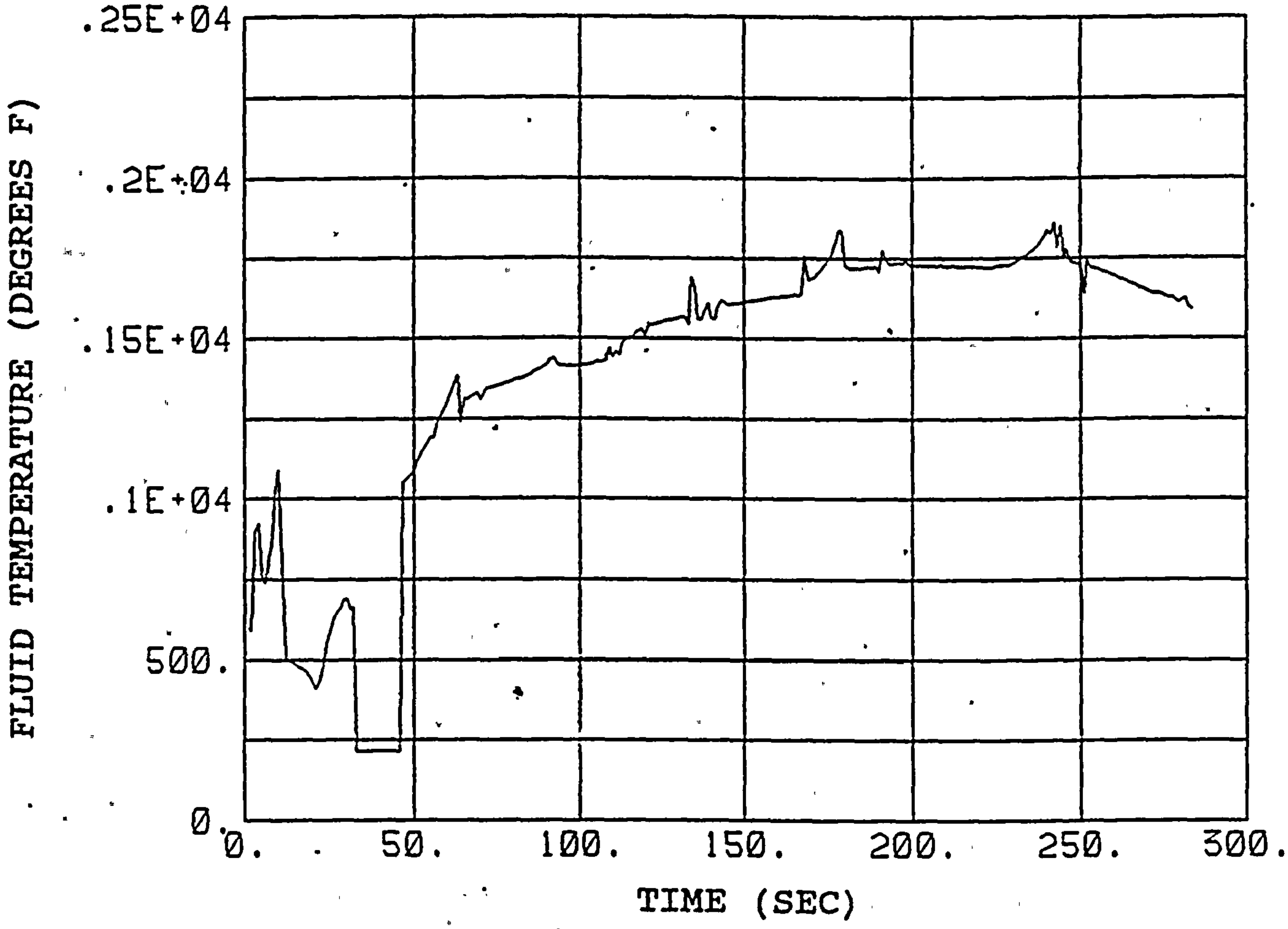

FIGURE C.3.1-14g
FLUID TEMPERATURE
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

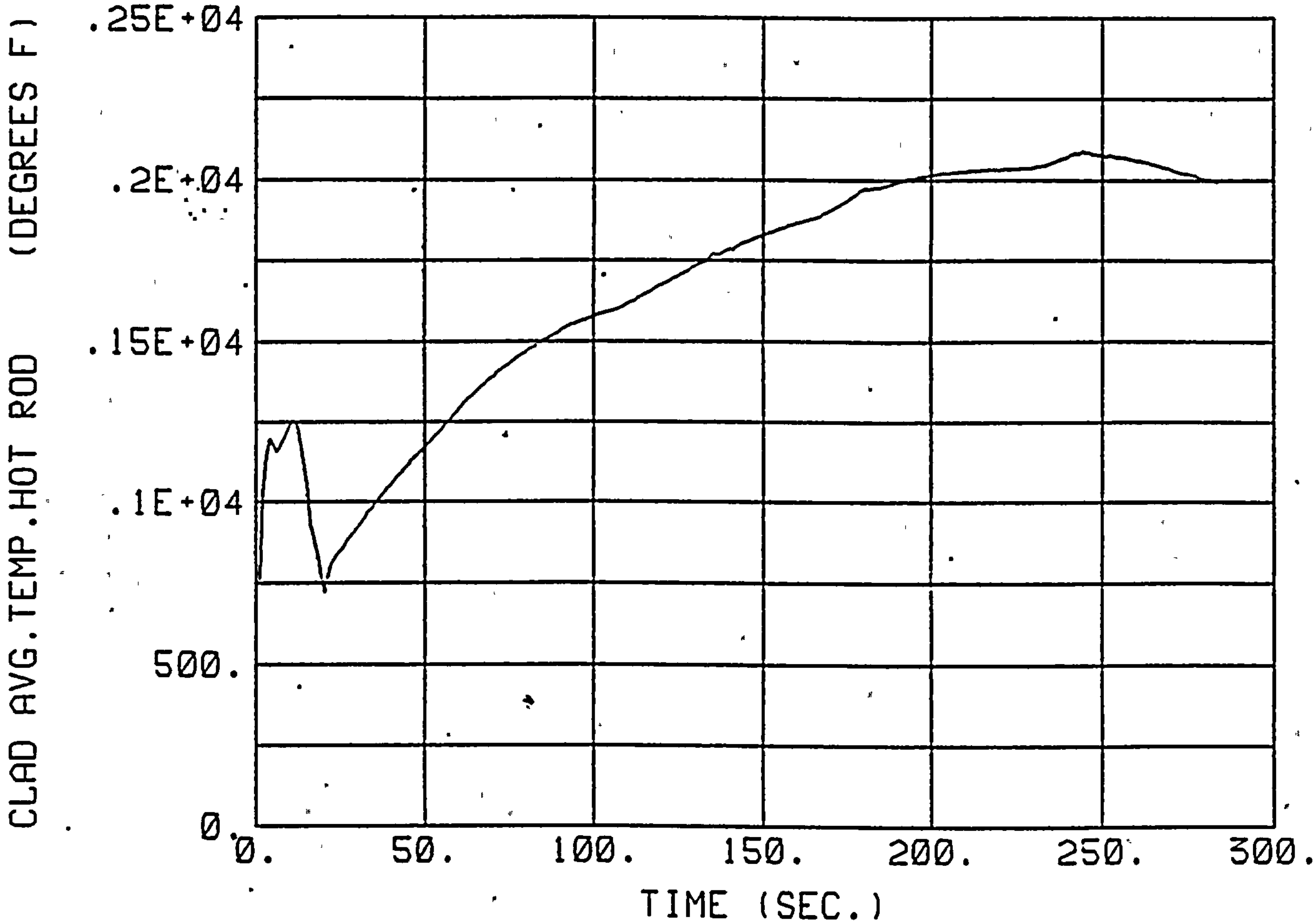

FIGURE C.3.1-15g
FUEL ROD PEAK CLAD TEMPERATURE
CD=0.6, RHR CROSS TIE CLOSED
Donald C. Cook Unit 2

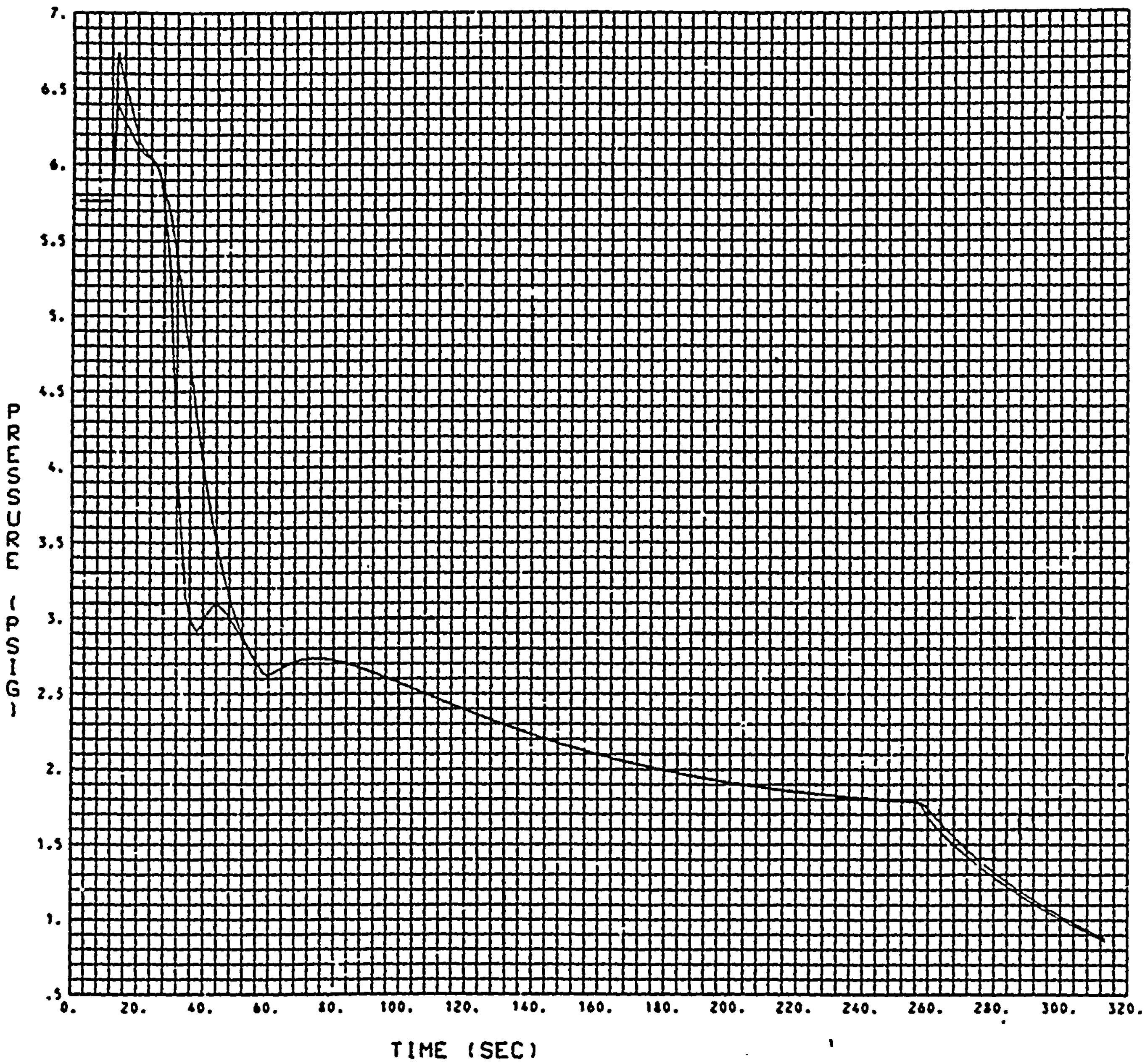

FIGURE C.3.1-16
CONTAINMENT PRESSURE
CD=0.6, MIN SI
Donald C. Cook Unit 2

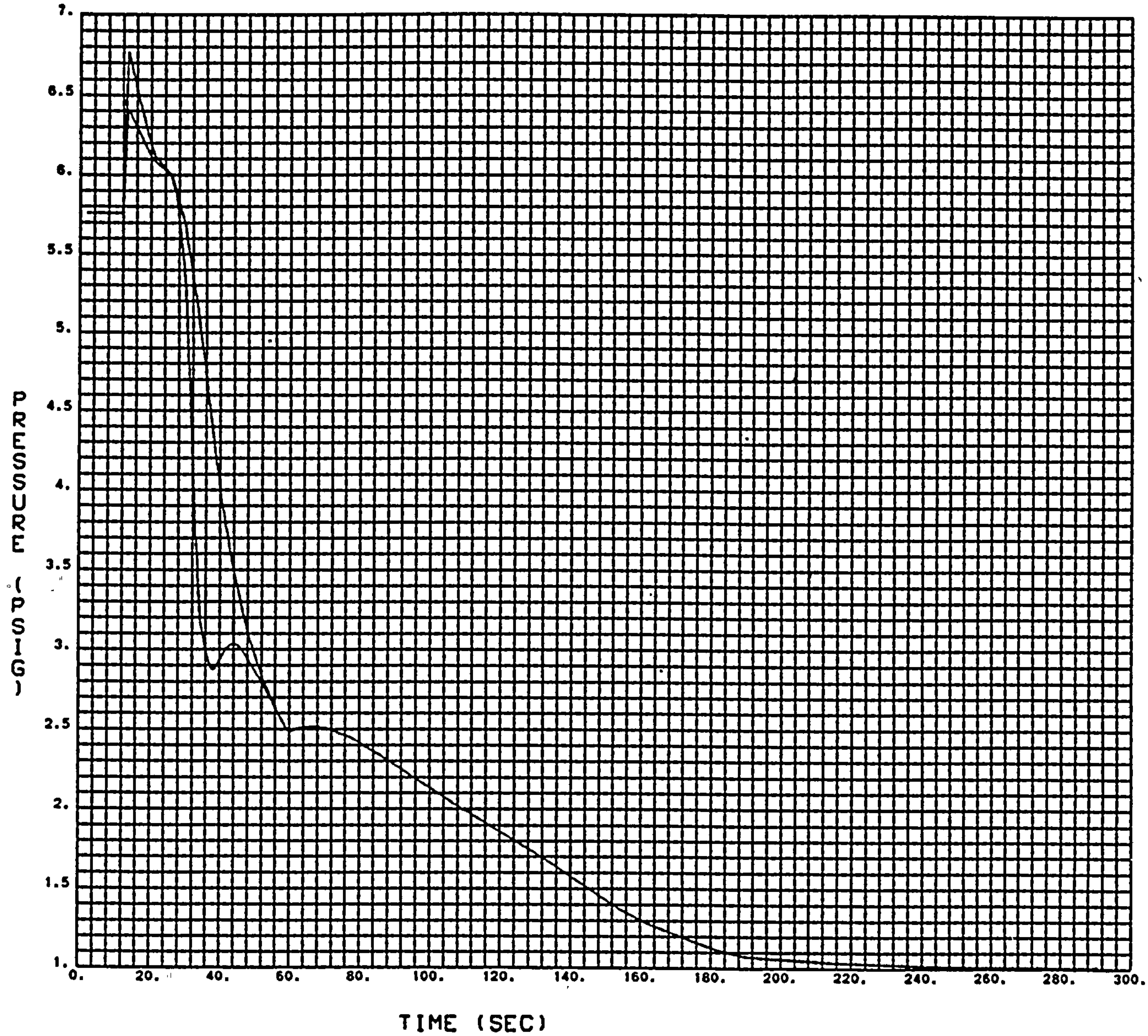

FIGURE C.3.1-17
CONTAINMENT PRESSURE
CD=0.6, MAX SI
Donald C. Cook Unit 2

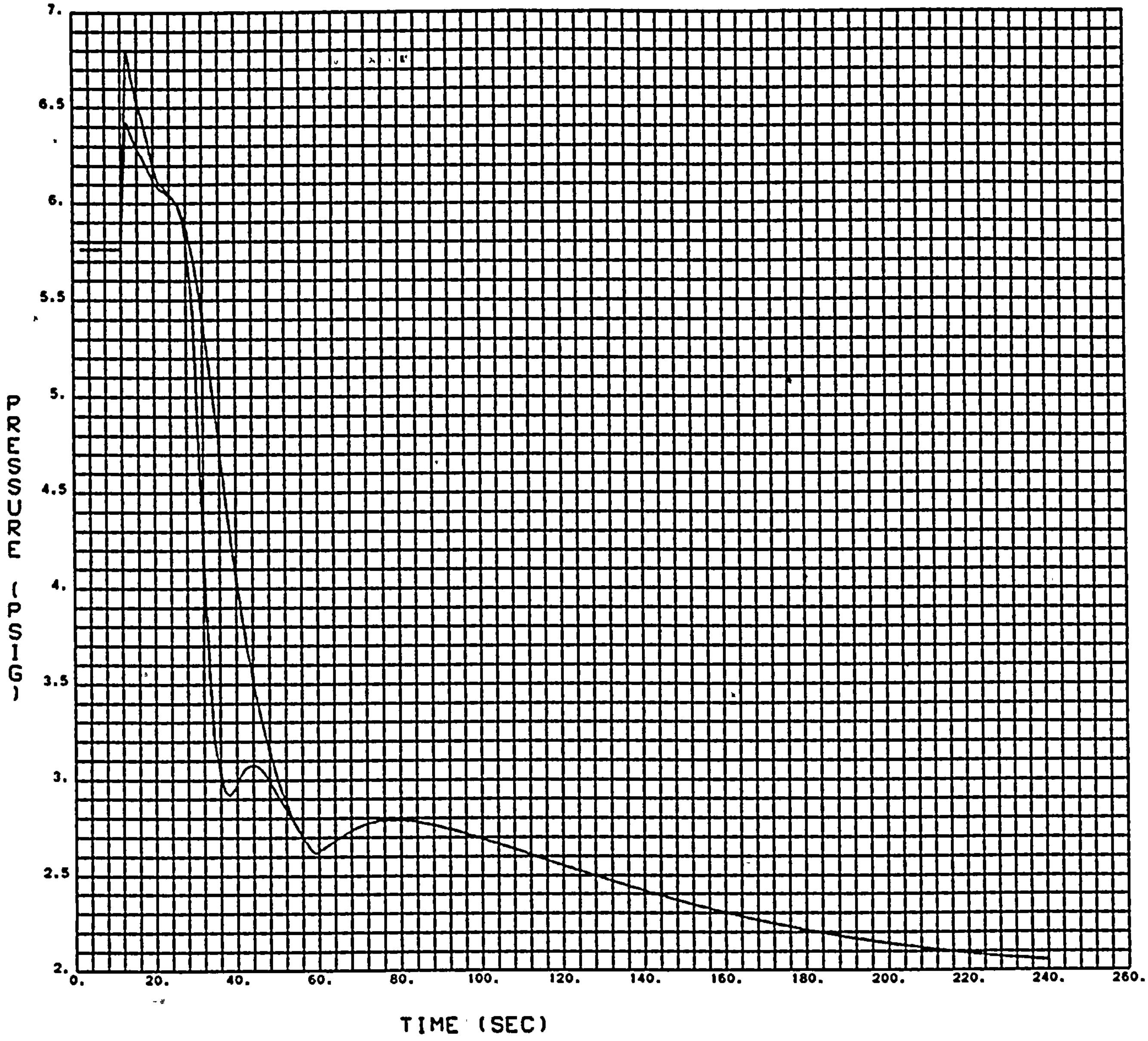

FIGURE C.3.1-18
CONTAINMENT PRESSURE
CD=0.6, CROSS-TIE VALVE CLOSED
Donald C. Cook Unit 2

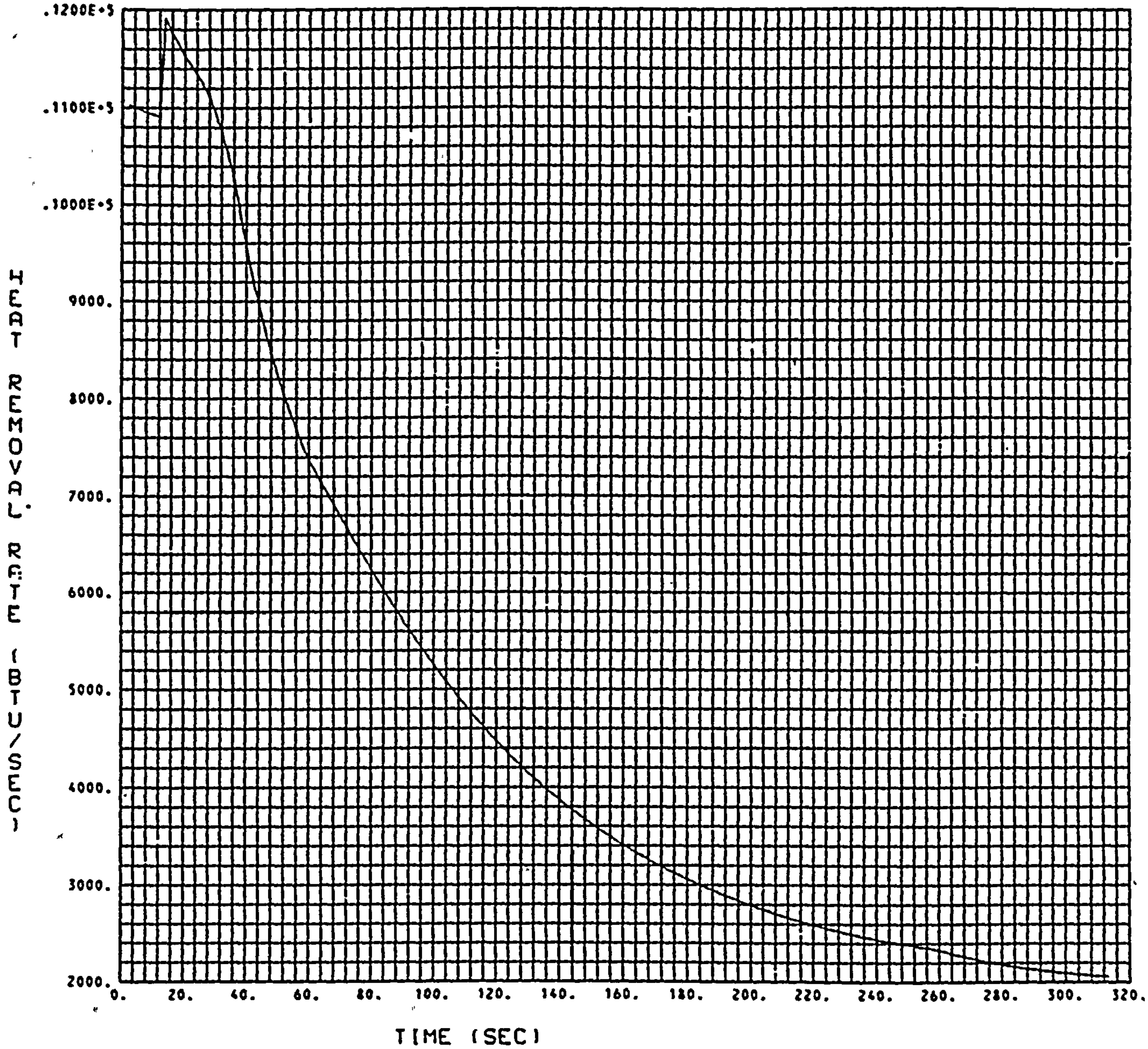

FIGURE C.3.1-19
UPPER COMPARTMENT STRUCTURAL
HEAT REMOVAL RATE
CD=0.6, MIN SI
Donald C. Cook Unit 2

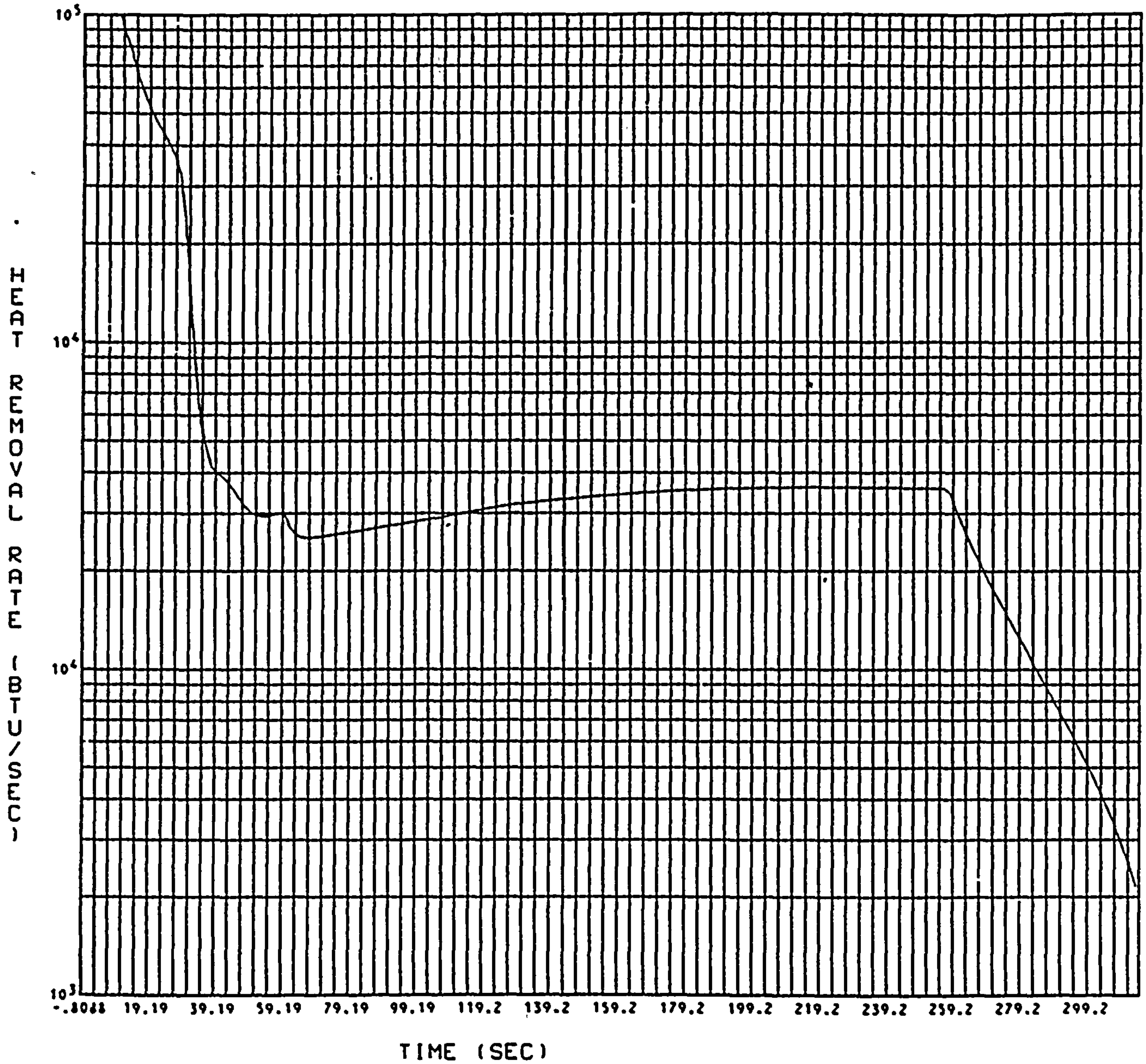

FIGURE C.3.1-20
LOWER COMPARTMENT STRUCTURAL
HEAT REMOVAL RATE
CD=0.6, MIN SI
Donald C. Cook Unit 2

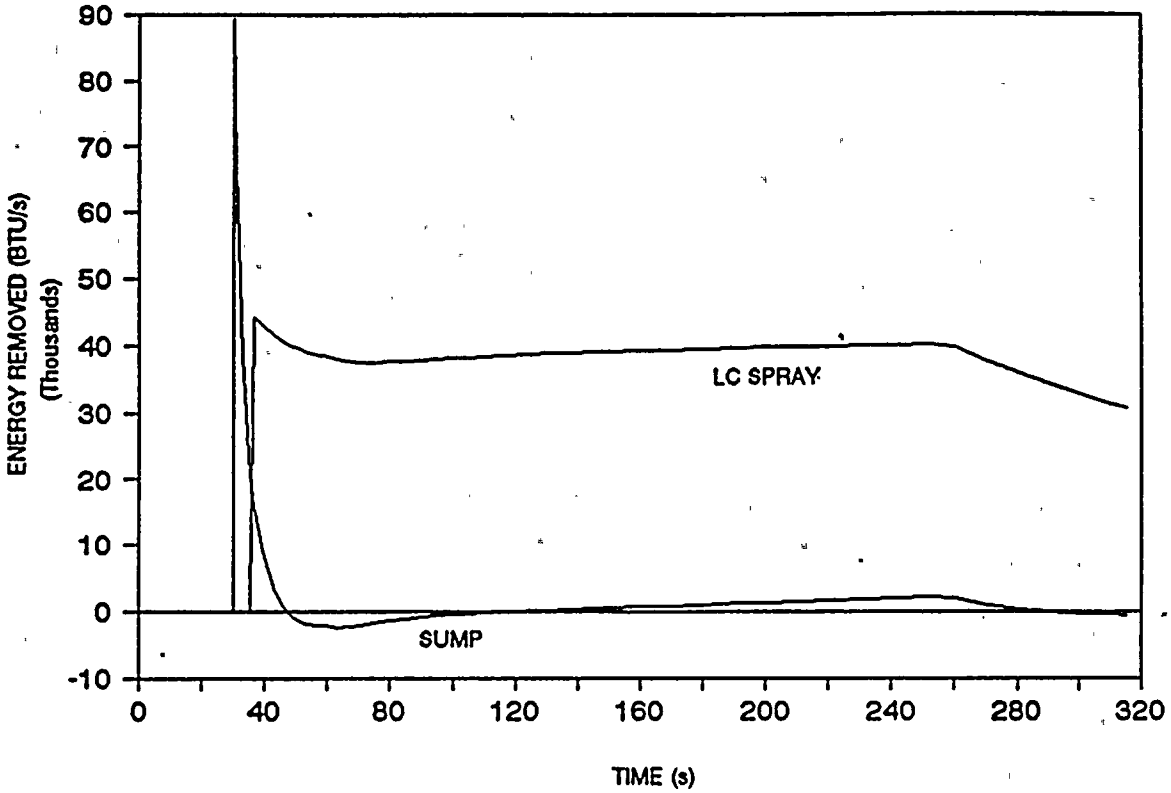

FIGURE C.3.1-21
HEAT REMOVAL BY SUMP AND
LC SPRAY
CD=0.6, MIN SI
Donald C. Cook Unit 2

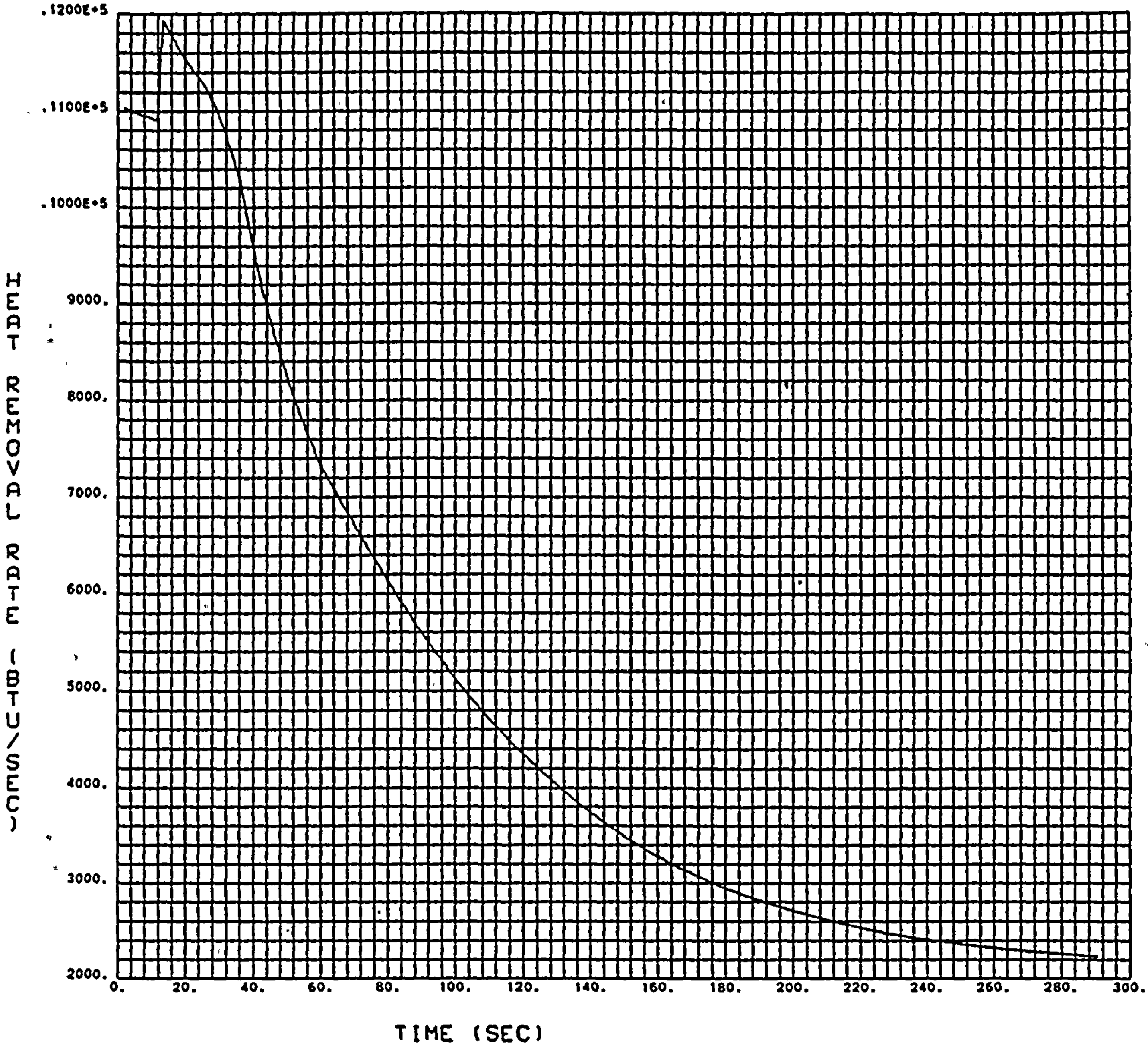

FIGURE C.3.1-22
UPPER COMPARTMENT STRUCTURAL
HEAT REMOVAL RATE
CD=0.6, MAX SI
Donald C. Cook Unit 2

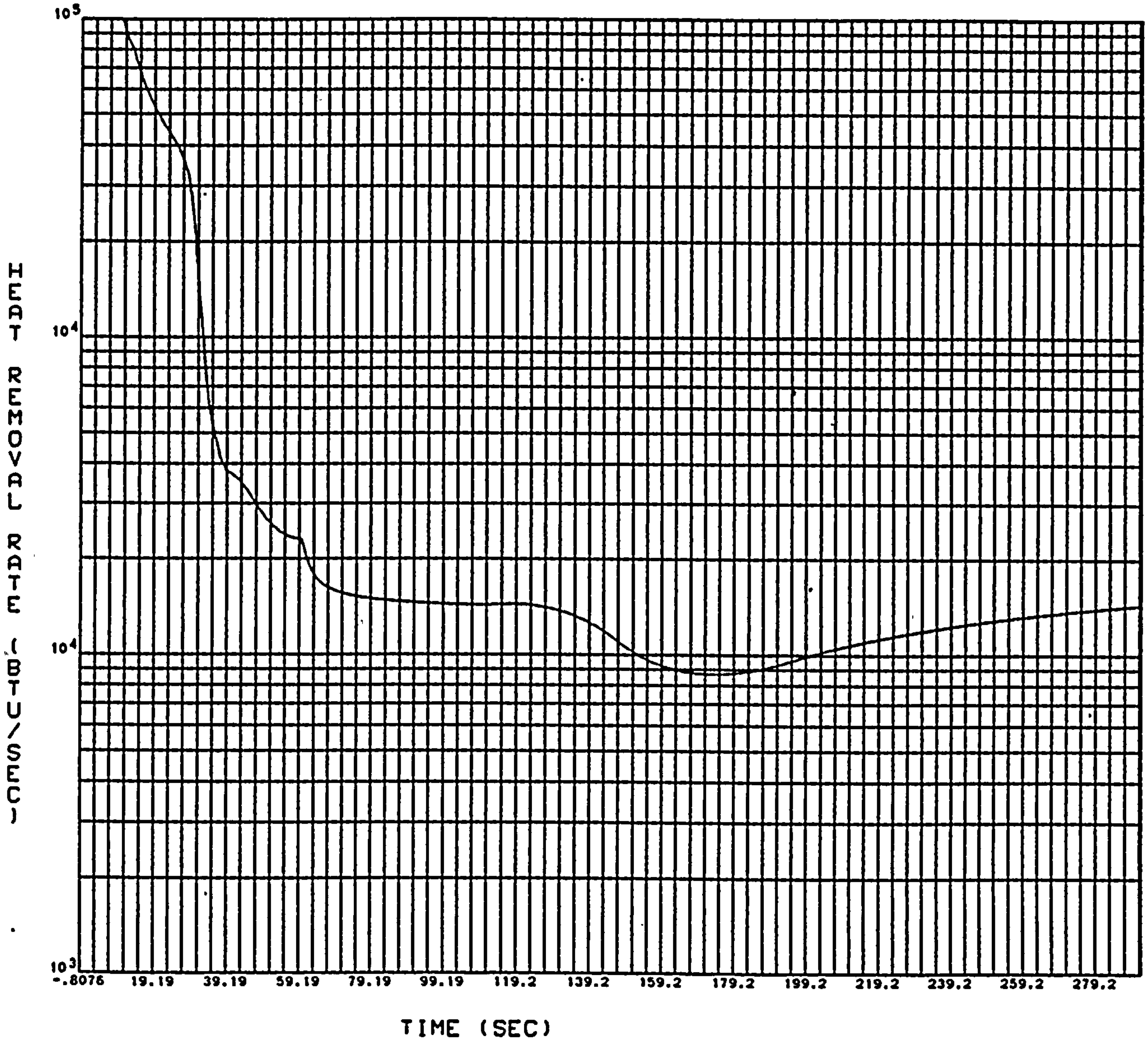

FIGURE C.3.1-23
LOWER COMPARTMENT STRUCTURAL
HEAT REMOVAL RATE
CD=0.6, MAX SI
Donald C. Cook Unit 2

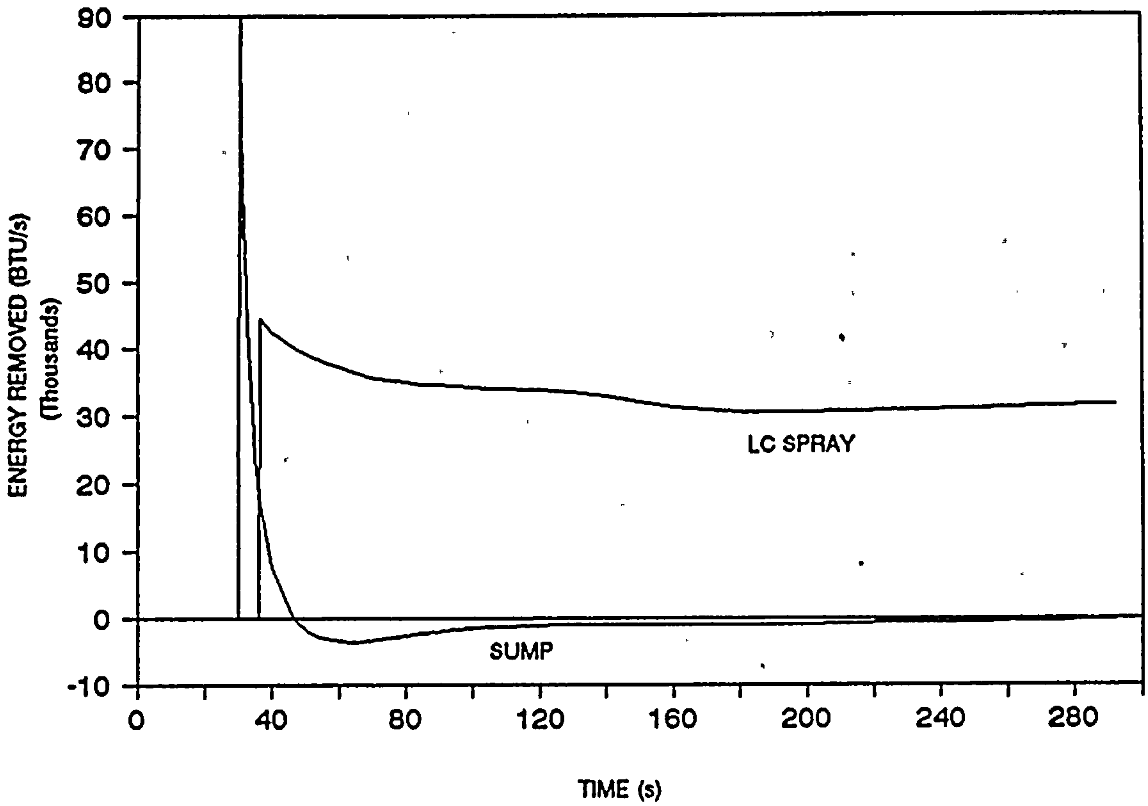

FIGURE C.3.1-24
HEAT REMOVAL BY SUMP AND
LC SPRAY
CD=0.6, MAX SI
Donald C. Cook Unit 2

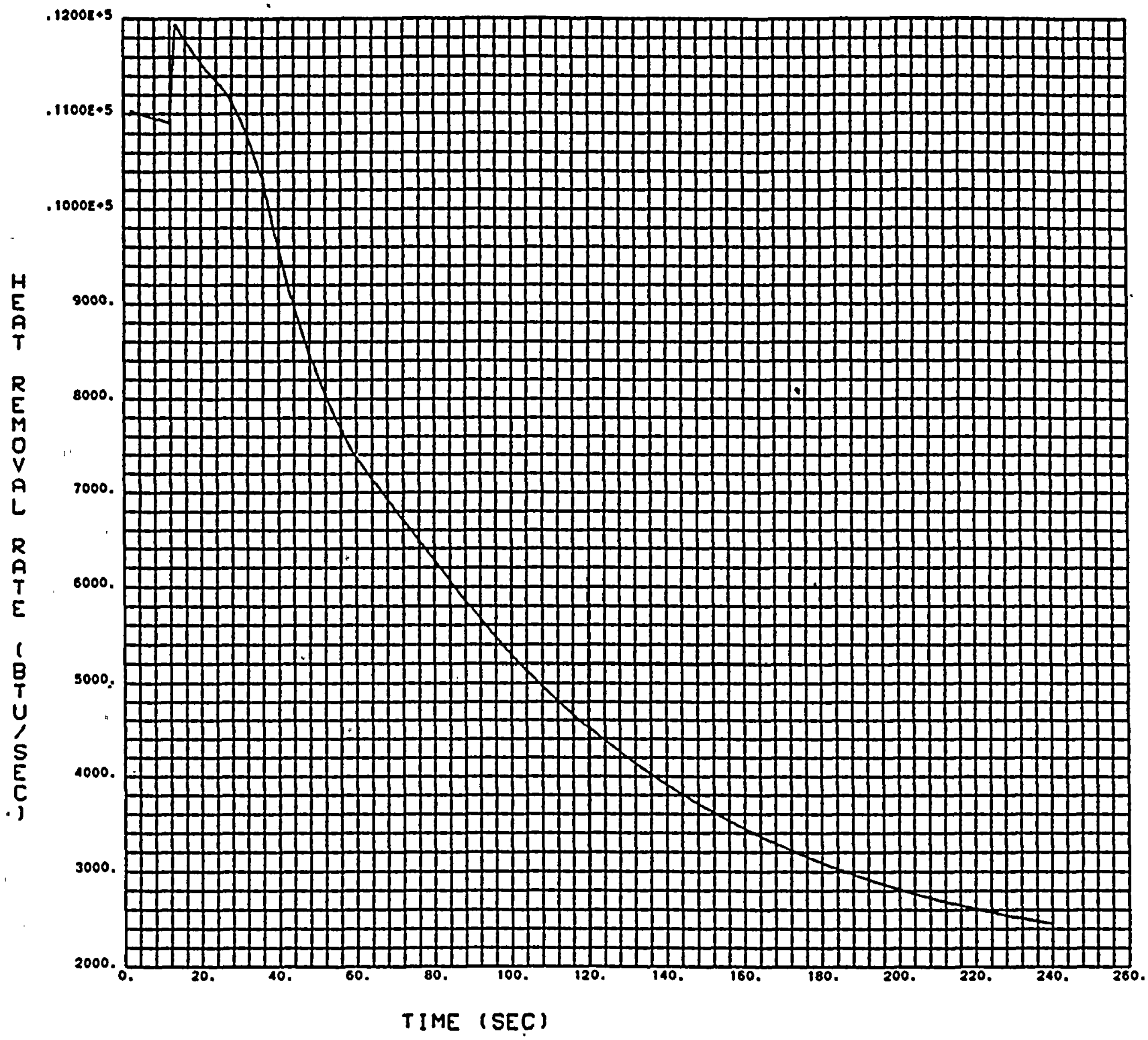

FIGURE C.3.1-25
UPPER COMPARTMENT STRUCTURAL
HEAT REMOVAL RATE
CD=0.6, CROSS-TIE VALVE CLOSED
Donald C. Cook Unit 2

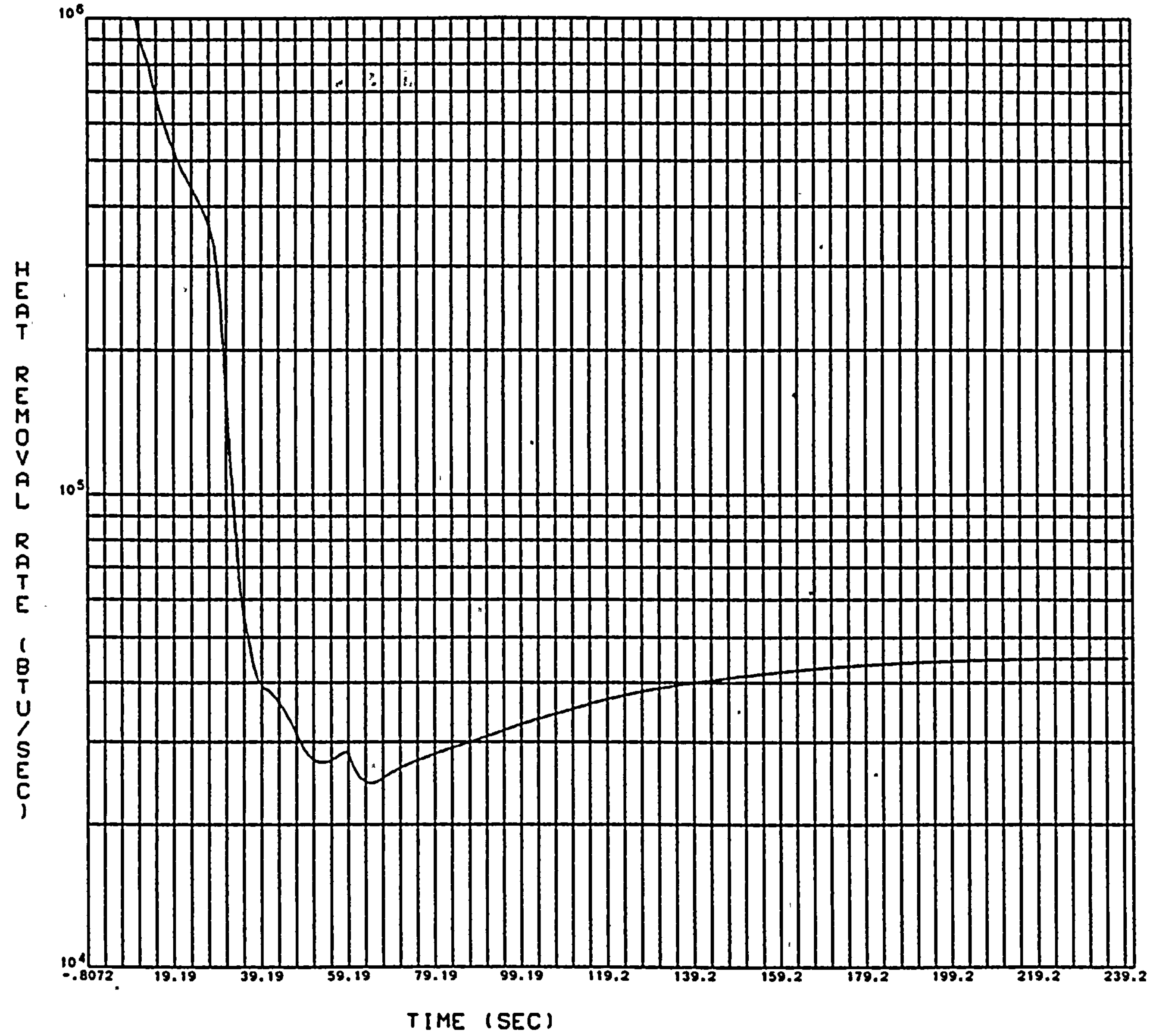

FIGURE C.3.1-26
LOWER COMPARTMENT STRUCTURAL
HEAT REMOVAL RATE
CD=0.6, CROSS-TIE VALVE CLOSED
Donald C. Cook Unit 2

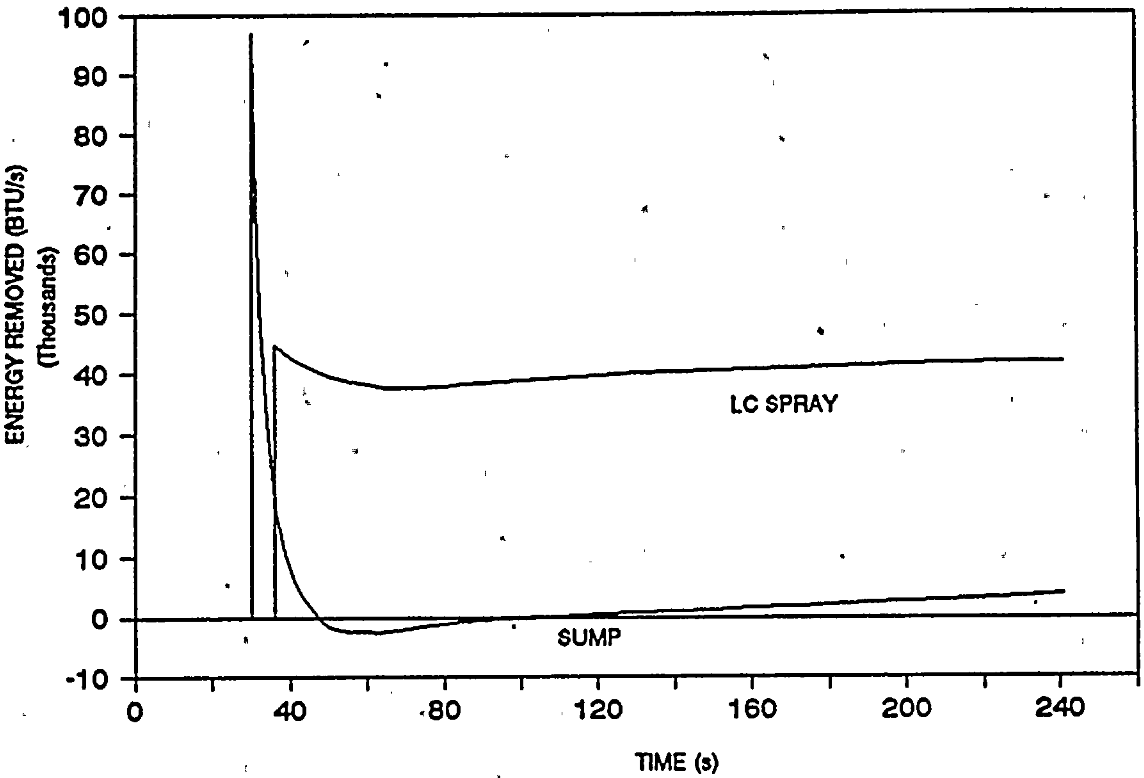

FIGURE C.3.1-27
HEAT REMOVAL BY SUMP AND
LC SPRAY
CD=0.6, CROSS-TIE VALVE CLOSED
Donald C. Cook Unit 2

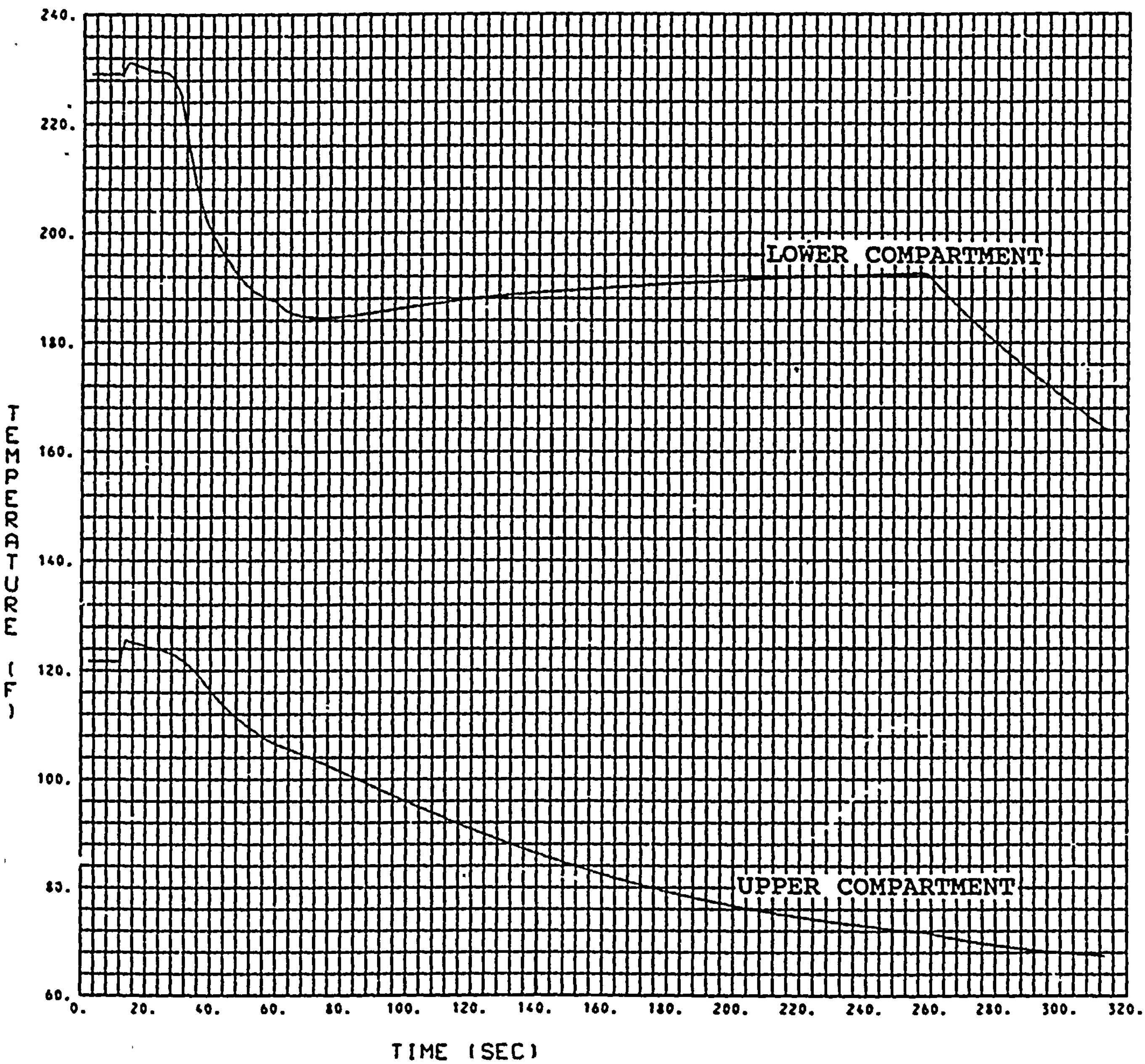

FIGURE C.3.1-28
LOWER AND UPPER COMPARTMENT
TEMPERATURES
CD=0.6, MIN SI
Donald C. Cook Unit 2

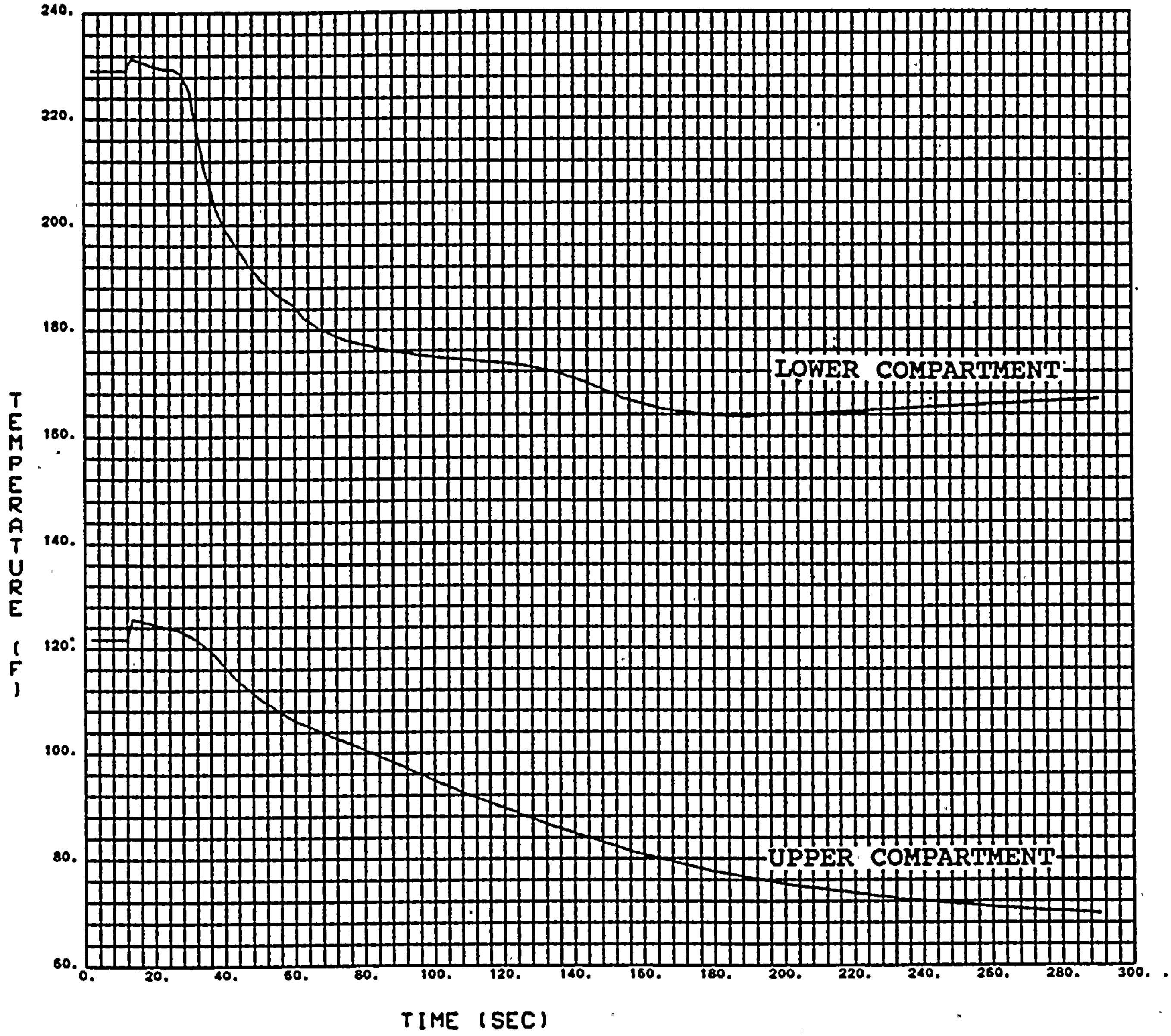

FIGURE C.3.1-29
LOWER AND UPPER COMPARTMENT
TEMPERATURES
CD=0.6, MAX SI
Donald C. Cook Unit 2

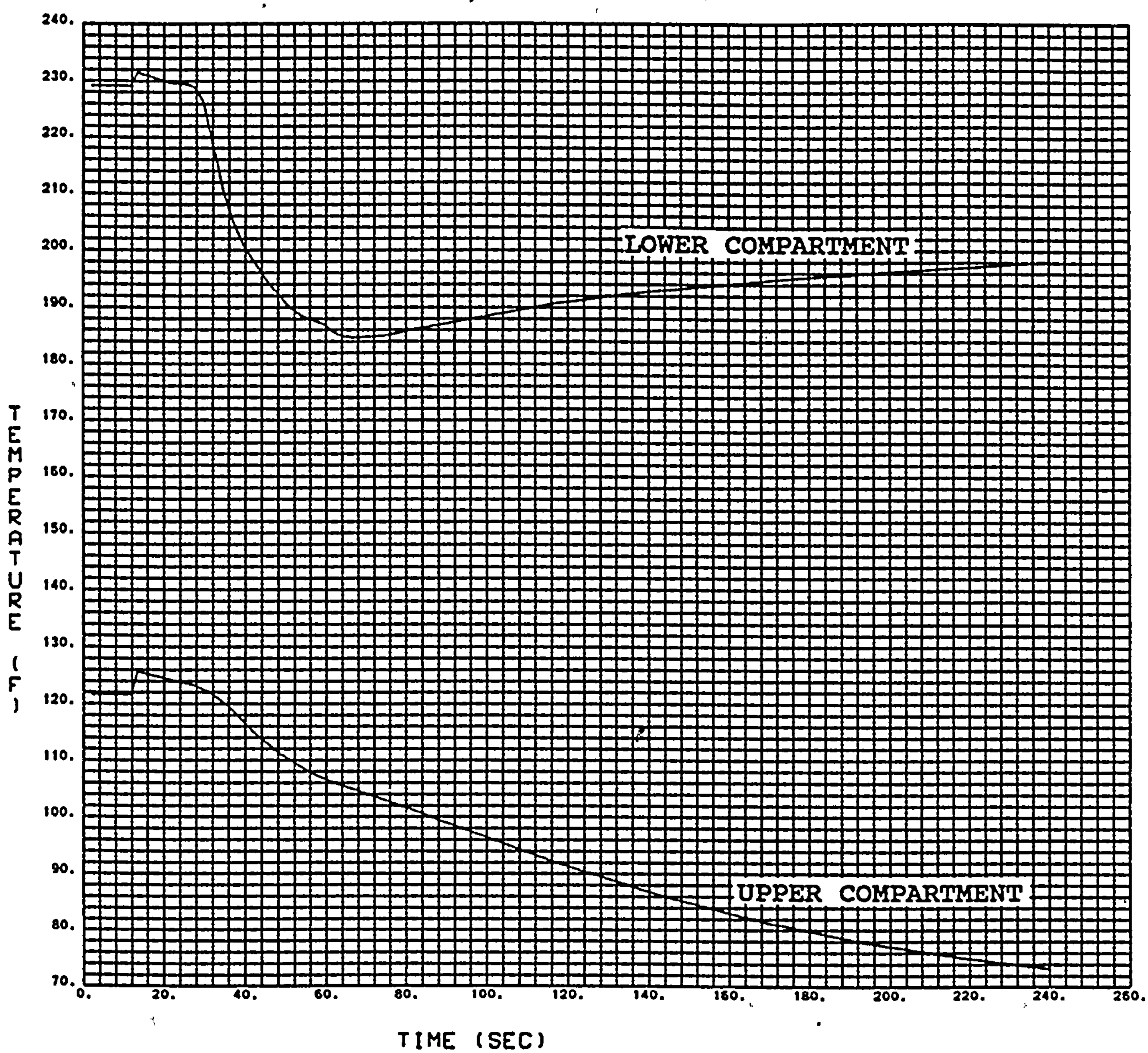

FIGURE C.3.1-30
LOWER AND UPPER COMPARTMENT
TEMPERATURES
CD=0.6, CROSS-TIE VALVE CLOSED
Donald C. Cook Unit 2

C.3.2 LOSS OF REACTOR COOLANT FROM SMALL RUPTURED PIPES OR FROM CRACKS IN LARGE PIPES WHICH ACTUATES THE EMERGENCY CORE COOLING SYSTEM

Analysis of Effects and Consequences

Method of Analysis

For small breaks (less than 1.0 ft2) the NOTRUMP[10][11] digital computer code is employed to calculate the transient depressurization of the Reactor Coolant System as well as to describe the mass and enthalpy of the fluid flow through the break.

Small Break LOCA Analysis Using NOTRUMP

For loss-of-coolant accidents due to small breaks less than 1 square foot, the NOTRUMP computer code[10][11] is used to calculate the transient depressurization of the RCS as well as to describe the mass and enthalpy of the fluid flow through the break. The NOTRUMP computer code is a state-of-the-art one-dimensional general network code incorporating a number of advanced features. Among these are calculation of thermal non-equilibrium in all fluid volumes, flow regime-dependent drift flux calculations with counter-current flooding limitations, mixture level tracking logic in multiple-stacked fluid nodes and regime-dependent heat transfer correlations. The NOTRUMP small-break LOCA emergency core cooling system (ECCS) evaluation model was developed to determine the RCS response to design basis small break LOCAs, and to address NRC concerns expressed in NUREG-0611, "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse-Designed Operating Plants".

The reactor coolant system model is nodalized into volumes interconnected by flowpaths. The broken loop is modelled explicitly, while the three intact loops are lumped into a second loop. Transient behavior of the system is determined from the governing conservation equations of mass, energy, and momentum. The multinode capability of the program enables explicit, detailed spatial representation of various system components which, among other capabilities, enables a proper calculation of the behavior of the loop seal during a loss-of-coolant accident. The reactor core is represented as heated control volumes with associated phase separation models to permit transient mixture height calculations. Detailed descriptions of the NOTRUMP code and the evaluation model are provided in References 10 and 11.

After the small break LOCA is initiated, reactor trip occurs due to a low pressurizer pressure signal (1860 psia). Soon after the reactor trip signal is generated, the safety injection signal is actuated due to low pressurizer pressure (1715 psia). Safety injection systems consist of gas pressurized accumulator tanks and pumped injection systems. The small break LOCA analysis assumed an accumulator water volume equal to the average of that allowed in the technical specification with a cover gas pressure of 600 psia. This is the minimum of the cover gas pressure allowed in the Technical Specifications. Minimum emergency core cooling system availability is assumed for the analysis at the maximum RWST temperature. Assumed pumped safety injection characteristics as a function of RCS pressure used as boundary conditions in the analysis are shown in Figure C.3.2-1 and in Table C.3.2-6. The safety injection flow rates presented are based on pump performance curves degraded 10 percent from the design head and an assumed charging system branch line imbalance of 25 gpm. The effect of flow from the RHR pumps is not considered in the small break LOCA analyses since their shutoff head is lower than the RCS pressure during the time portion of the transient considered here. Safety injection (SI) is delayed 27 seconds after the occurrence of the injection signal to account for diesel generator startup and emergency power bus loading in case of a loss of offsite power coincident with a LOCA. The small break LOCA analysis also assumed that the auxiliary feedwater pumps were degraded by 15 percent and that the rod drop time was 2.7 seconds.

Peak clad temperature calculations are performed with the LOCTA-IV[2] code using the NOTRUMP calculated core pressure, fuel rod power history, uncovered core steam flow and mixture heights as boundary conditions. Figure C.3.2-10 depicts the hot rod axial power shape used to perform the small break LOCA analysis. This shape was chosen because it represents a distribution with power concentrated in the upper regions of the core. Such a distribution is limiting for small-break LOCAs because it minimizes coolant level swell, while maximizing vapor superheating and fuel rodheat generation at the uncovered elevations. The small break LOCA analysis assumes the core continues to operate at full power until the control rods are completely inserted.

Results

This section presents results of the limiting small break LOCA analysis (as determined by the highest calculated peak clad temperature) for a range of break sizes and RCS pressures and temperatures. The limiting break was found to be a 4-inch diameter cold leg break initiated at

reduced RCS pressurizer pressure (2100 psia) and high temperature (core Tavg = 581.3 °F) conditions. The peak clad temperature attained during the transient was 1357 °F. A list of input assumptions used in the low pressure and high temperature analysis is provided in Table C.3.2-1. The results of a three break spectrum analysis performed at the reduced RCS pressure and high temperature conditions are summarized in Table C.3.2-4, while the key transient event times are listed in Table C.3.2-2.

Figures C.3.2-2 through 9 show for the limiting four-inch break transient, respectively:

- RCS pressure
- Core mixture level
- Peak clad temperature
- Core outlet steam flow rate
- Hot spot rod surface heat transfer coefficient
- Hot spot fluid temperature
- Cold leg break mass flow rate
- Safety injection mass flow rate

During the initial period of the small-break transient the effect of the break flow rate is not strong enough to overcome the flow rate maintained by the reactor coolant pumps as they coast down. Normal upward flow is maintained through the core and core heat is adequately removed. At the low heat generation rates following reactor trip the fuel rods continue to be well cooled as long as the core is covered by a two-phase mixture level. From the clad temperature transient for the 4-inch break calculation shown in Figure C.3.2-4, it is seen that the peak clad temperature occurs near the time when the core is most deeply uncovered and the top of the core is steam cooled. This time is also accompanied by the highest vapor superheating above the mixture level. A comparison of the total break flow rate to containment shown in Figure C.3.2-8 to the safety injection flow rate shown in Figure C.3.2-1 shows that at the time the transient was terminated, either when the safety injection flow rate that was delivered to the RCS exceeded the mass flow rate out the break or when the core was covered as in Figure C.3.2-20. Although the inner vessel core mixture level has not yet covered the entire core, there is no longer a concern of exceeding the 10 CFR 50.46 criteria since the pressure is gradually decaying and there is a net mass inventory gain. As the RCS inventory continues to gradually increase, the core mixture level will continue to increase and the fuel clad temperatures will continue to decline.

Conclusions

Analyses presented in this section show that the high head charging and safety injection subsystems of the Emergency Core Cooling System, together with the accumulators, provide sufficient core flooding to keep the calculated peak clad temperatures below the required limit of 10 CFR 50.46. Hence adequate protection is afforded by the Emergency Core Cooling System in the event of a small break loss-of-coolant accident.

Additional Break Cases

Studies documented in Reference 3 determined that the limiting small-break size occurred for breaks less than 10 inches in diameter. To insure that the 4-inch diameter break was limiting, calculations were run with breaks of 3 inches and 6 inches. The results of these calculations are shown in the Sequence of Events Table C.3.2-2, and the Results Table C.3.2-4. Plots of the following parameters are shown in Figures C.3.2-11 through 18 for the 3-inch break, and Figures C.3.2-19 through 26 for the 6-inch break.

- RCS pressure
- Core mixture level
- Peak clad temperature
- Core outlet steam flow rate
- Hot spot rod surface heat transfer coefficient
- Cold leg break mass flow rate
- Safety injection mass flow rate

As seen in Table C.3.2-4 the peak clad temperatures were calculated to be less than that for the 4-inch break.

Additional Analysis

Calculations were also performed for Cook Nuclear Plant Unit 2 with the NOTRUMP[10][11] and LOCTA-IV[2] codes to examine the influence of initial RCS coolant operating temperatures and operating pressures on small break LOCA peak clad temperature. The analyses performed demonstrated that the reduced pressure and high temperature conditions analyzed resulted in the limiting PCT for the 4-inch diameter break.

To support operation of Cook Nuclear Plant Unit 2 at RCS pressures of 2100 psia and 2250 psia for a range of loop operating temperatures, two additional analyses were performed. Calculations were performed for a four-inch diameter break for an initial RCS pressurizer pressure of 2250 psia at initial RCS coolant operating temperatures corresponding to core Tavg program setpoints of 581.3 °F and at a Tavg of 547.0 °F. The results of these calculations are shown in the Sequence of Events Table C.3.2-3, and the Results Table C.3.2-5.

Plots of the following parameters are shown in Figures C.3.2-27 through 34 for the high pressure, high temperature case, and Figures C.3.2-35 through 42 for the high pressure, low temperature case.

- RCS pressure
- Core mixture level,
- Peak clad temperature,
- Core outlet steam flow rate,
- Hot spot rod surface heat transfer coefficient,
- Hot spot fluid temperature,
- Cold leg break mass flow rate, and
- Safety injection mass flow rate.

As seen in Table C.3.2-5, the peak clad temperatures were calculated to be less than that for the 4-inch break initiated at reduced pressure and high temperature conditions.

Additional calculations were made to support closure of the high head safety injection cross tie valves. Since the amount of pumped injection flow would be reduced with the high head cross tie valves closed, it was necessary to lower core power in order to maintain the peak clad temperature within the 10 CFR 50.46 limit. Thus the calculation which supports plant operation with the high head cross tie valves closed assumed an initial RCS pressurizer pressure at 2100 psia and core Tavg at 581.3 °F at a core power level of 3413 Mwt. This calculation also assumed a charging system flow rate imbalance of 25 gpm. The assumed pumped ECCS flow performance for the high head cross tie valve closed case is listed in Table C.3.2-9.

Past analyses have shown that a reduction in pumped safety injection flow rate increases the peak clad temperature for smaller breaks (3 inches) more than larger small breaks (4 and 6 inches). An important parameter in determining what will be the limiting break size is the reactor power to safety injection flow rate ratio. For the high head cross tie closure case the reactor power to safety injection flow rate ratio was reduced which shifted the limiting break size to the 3-inch diameter cold leg break. Evidence of this effect is the Cook Nuclear Plant Unit 1 small break LOCA analysis which was performed with the high head cross tie valves closed assuming a charging system flow rate imbalance of 10 gpm with a reactor power of 3588 Mwt. The Cook Nuclear Plant Unit 1 small break LOCA analysis had a reactor power to safety injection flow rate ratio approximately equal to Cook Nuclear Plant Unit 2 with the high head cross tie valves closed assuming 25 gpm charging system flow rate imbalance at a reactor power level of 3413 Mwt. It was concluded that with the high head cross tie valves closed and with reduced reactor power the limiting break would be shifted from the 4-inch diameter cold leg break to the 3-inch diameter break size. To verify this conclusion, two calculations were performed which assumed break sizes of 3- and 4-inch diameters at the reduced pressure, high temperature initial conditions. Table C.3.2-8 lists the results of the cross tie closed cases which show that with the reduced safety injection flow the 3-inch diameter break is limiting. The sequence of events for these calculations is listed in Table C.3.2-7. Past small break LOCA analyses that were performed for plants which are similar to Cook Nuclear Plant Unit 2 but have power to safety injection flow rate ratios less than that of Cook Nuclear Plant Unit 2, have shown that an assumed break size of 2 inches did not result in the limiting peak clad temperature. Thus, based on the comparision of power to safety injection flow rate ratio, it was concluded that a 2-inch diameter break would not yield a peak clad temperature more limiting that that of the 3-inch diameter break size. Plots for the 3- and 4-inch break with the HHSI cross tie valves closed are shown in figures C.3.2-43 through C.3.2-50 and C.3.2-51 through C.3.2-58 respectively.

NUREG-0737(13), Section II.K.3.31, required plant-specific small break LOCA analysis using an Evaluation Model revised per Section II.K.3.30. In accordance with NRC Generic Letter 83-65[14], generic analyses using NOTRUMP[10][11] were performed and are presented in WCAP-11145[17]. Those results demonstrate that in a comparison of cold leg, hot leg and pump suction leg break locations, the cold leg break location is limiting.

REFERENCES, SECTION C.3.2

1. "Acceptance Criteria for Emergency Core Cooling Systems for Water Cooled Nuclear Power Reactors" 10 CFR 50.46 and Appendix K of 10 CFR 50. Federal Register, Volume 39, Number 3, January 4, 1974.

2. Bordelon, F. M., et al., "LOCTA-IV Program: Loss-of-Coolant Transient Analysis," WCAP-8305, June 1974, WCAP-8201, (Proprietary), June 1974.

3. "Report on Small Break Accidents for Westinghouse NSSS System," Vols. I to III, WCAP-9600, June 1979.

4. Letter, AEP:NRC:00253, John E. Dolan (AEP) to Harold R. Denton (NRC), dated October 24, 1979.

5. "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse - Designed Operating Plants," NUREG-0611, January 1980.

6. Letter, B. J. Youngblood (NRC) to John E. Dolan (AEP) dated December 22, 1986 regarding plant specific calculations to show compliance with 10 CFR 50.46 for D. C. Cook Unit 2.

7. Leech, W. J., Davis D. D. and Benard, M. S., "Revised PAD Code Thermal Safety Model," WCAP-8720, Addenda Z, October 1982.

8. "Clarification of TMI Action Plan Requirements," NUREG-0737, November 1980.

9. NRC Generic Letter 83-35 from D. G. Eisenhut, "Clarification of TMI Action Plan Item II.K.3.31", November 2, 1983.

10. Meyer, P. E., "NOTRUMP - A nodal Transient Small Break and General Network Code," WCAP-10079-P-A, August 1985.

11. Lee, N. et al., "Westinghouse Small Break ECCS Evaluation Model Using The NOTRUMP Code," WCAP-10054-P-4, August 1985.

12. Rupprecht, S. D., et al., "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study With the NOTRUMP Code;" WCAP-11145-P-A, October 1986.

HISTORICAL

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1. "Acceptance Criteria for Emergency Core Cooling Systems for Water Cooled Nuclear Power Reactors" 10 CFR 50.46 and Appendix K of 10 CFR 50. Federal Register, Volume 39, Number 3, January 4, 1974.

2. "Westinghouse ECCS Evaluation Model-Summary," WCAP-8339, Bordelon, F. M, Massie, H. W., and Zordan, T. A., July 1974, WCAP-8341 (Proprietary), June 1974.

3. Esposito, V. J., Kesaven, K., Maul, B. A., "WFLASH-A FORTRAN IV, Computer Program for Simulation of Transients in a Multi-Loop PWR," WCAP-8261 Rev. 1, July 1974, WCAP-8200, (Proprietary), June 1974.

4. Porsching. T. A., Murphy, J. H., Redfield, J. A., and Davis, V. C., "FLASH-4: A Fully Implicit FORTRAN-IV Program for the Digital Simulation of Transients in a Reactor Plant, "WADP-TM-84; Bettis Atomic Power Laboratory (March, 1969).

5. Bordelon, F. M., et al., "LOCTA-IV Program: Loss-of-Coolant Transient Analysis," WCAP-8305, June 1974, WCAP-8201, (Proprietary), June 1974.

6. Bordelon, F. M., et al., "SATAN-VI Program: Comprehensive Space-Time Dependent Analysis of Loss-of-Coolant," WCAP-8306, June 1974, WCAP-8204, (Proprietary), June 1974.

7. "Report on Small Break Accidents for Westinghouse NSSS System," Vols. I to III, WCAP-9600, June 1979.

8. Letter, AEP:NRC:00253, John E. Dolan (AEP) to Harold R. Denton (NRC), dated October 24, 1979.

9. "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse - Designed Operating Plants," NUREG-0611, January 1980.

TABLE C.3.2-1

PLANT INPUT PARAMETERS USED IN SMALL BREAK LOCA ANALYSIS

Core Power	102% of 3588 MWt
Total Core Peaking Factor	2.32
Steam Generator Tube Plugging Level	15% (peak uniform)
Accumulator Conditions:	
Cover Gas Pressure	600 psia
Water Volume	946.0 ft^3
Total Volume	1350 ft^3
RCS Initial Conditions:	
Reduced Pressure, High Temperature Case	
Loop Temperatures Consistent	
With Tavg Program Setpoint of,	581.3 °F
Pressure	2100 psia
Vessel Flowrate	354000 gpm
Reactor Trip Signal	1860 psia
Safety Injection Signal	1715 psia
Safety Injection Delay Time	27 seconds
Rod Drop Time	2.7 seconds

TABLE C.3.2-2

TIME SEQUENCE OF EVENTS FOR CONDITION III EVENTS

Small-break Loss of Coolant Accident

Event	Time (s) High Temperature, Reduced Pressure		
	Break Size: 3-Inch	4-Inch	6-inch
Break occurs	0	0	0
Reactor trip signal	12.17	7.26	4.97
Safety injection signal	21.53	14.99	10.59
Start of safety injection delivery	48.53	41.99	37.59
Loop seal venting	589.7	333.1	154.9
Loop seal core uncovery	N/A	335.2	141.2
Loop seal core recovery	N/A	345.3	173.4
Boil-off core uncovery	1072.	640.9	388.3
Accumulator injection begins	1960.	861.6	366.4
Peak clad temperature occurs	1662.	919.7	168.6
Top of core covered	N/A	N/A	425.2
SI flow rate exceeds break flow rate	1515.	1606.	N/A

TABLE C.3.2-3

TIME SEQUENCE OF EVENTS FOR CONDITION III EVENTS

Small-break Loss of Coolant Accident

Event	Time (s) High Temp. High Pressure 4-Inch	Time (s) Reduced Temp. High Pressure 4-Inch
Break occurs	0	0
Reactor trip signal	11.75	9.85
Safety injection signal	18.95	13.08
Start of safety injection delivery	45.95	40.08
Loop seal venting	333.7	346.9
Loop seal core uncovery	327.4	407.8
Loop seal core recovery	344.0	428.1
Boil-off core uncovery	673.1	664.7
Accumulator injection begins	878.7	874.3
Peak clad temperature occurs	943.6	942.0
Top of core covered	1722.0	1658.0
SI flow rate exceeds break flow rate	1515.0	1516.0

TABLE C.3.2-4

SMALL-BREAK LOSS OF COOLANT ACCIDENT CALCULATION RESULTS

PARAMETER		VALUE High Temperature, Reduced Pressure		
	Break Size:	3-Inch	4-Inch	6-Inch
Peak clad temperature (°F)		1133	1357	959
Elevation (ft)		11.50	11.50	10.50
Zr/H_2O cumulative reaction				
Maximum local (%)		0.07	0.15	0.03
Elevation (ft)		11.50	11.50	10.50
Total core (%)		< 0.3	< 0.3	< 0.3
Rod Burst		None	None	None

CALCULATION:

Core Power MWt 102% of	3588
Peak Linear Power kw/ft 102% of	12.825
Hot Rod Linear Power Distribution (kw/ft)	See Figure C.3.2-10
Accumulator Water Volume, cu. ft.	946

TABLE C.3.2-5

SMALL-BREAK LOSS OF COOLANT ACCIDENT CALCULATION

RESULTS

PARAMETER	VALUE High Temp. High Pressure 4-Inch	 Reduced Temp. High Pressure 4-Inch
Peak clad temperature (°F)	1325	1315
Elevation (ft)	11.50	11.50
Zr/H_2O cumulative reaction		
Maximum local (%)	0.13	0.11
Elevation (ft)	11.50	11.50
Total core (%)	< 0.3	< 0.3
Rod Burst	None	None

CALCULATION:

Core Power MWt 102% of	3588
Peak Linear Power kw/ft 102% of	12.825
Hot Rod Linear Power Distribution (kw/ft)	See Figure C.3.2-10
Accumulator Water Volume, cu. ft.	946

TABLE C.3.2-6

SAFETY INJECTION FLOW RATE WITH
HHSI CROSS TIE VALVES OPEN

RCS Pressure [psia]	SI Flow Rate [lb/sec]	HH Charging Flow Rate [lb/sec]	Total Flow Rate [lb/sec]
415	49.07	33.81	82.88
515	46.31	32.31	78.62
615	43.44	30.71	74.15
715	40.43	29.07	69.50
815	37.20	27.25	64.45
915	33.85	24.87	58.72
1015	30.13	22.41	52.54
1115	25.26	19.92	45.18
1215	19.88	17.32	37.20
1315	10.82	14.65	25.47
1415	0.00	11.76	11.76
1515	0.00	9.18	9.18

TABLE C.3.2-7

TIME SEQUENCE OF EVENTS FOR CONDITION III EVENTS

Small-break Loss of Coolant Accident

HHSI Cross Tie Valves Closed @ 3413 Mwt

Event	Time (s) High Temp. Reduced Pressure 3-Inch	Time (s) High Temp. Reduced Pressure 4-Inch
Break occurs	0	0
Reactor trip signal	10.88	6.74
Safety injection signal	20.36	13.46
Start of safety injection delivery	47.36	40.46
Loop seal venting	611.9	357.1
Loop seal core uncovery	N/A	359.2
Loop seal core recovery	N/A	368.3
Boil-off core uncovery	962.0	611.2
Accumulator injection begins	1566.	839.2
Peak clad temperature occurs	1640.	908.0
Top of core covered	N/A	2356.
SI flow rate exceeds break flow rate	1915.	N/A

TABLE C.3.2-8

SMALL-BREAK LOSS OF COOLANT ACCIDENT CALCULATION

Results HHSI Cross Tie Valves Closed @ 3413 Mwt

PARAMETER	VALUE High Temp. Reduced Pressure 3-Inch	VALUE High Temp. Reduced Pressure 4-Inch
Peak clad temperature (°F)	2124	1530
Elevation (ft)	12.00	11.50
Zr/H_2O cumulative reaction		
Maximum local (%)	8.64	0.37
Elevation (ft)	12.00	11.50
Total core (%)	< 0.3	< 0.3
Rod Burst	None	None

CALCULATION:

Core Power MWt 102% of	3413
Peak Linear Power kw/ft 102% of	12.756
Hot Rod Linear Power Distribution (kw/ft)	See Figure C.3.2-59
Accumulator Water Volume, cu. ft.	946

TABLE C.3.2-9

SAFETY INJECTION FLOW RATE WITH

HHSI CROSS TIE VALVES CLOSED

RCS Pressure [psia]	SI Flow Rate [lb/sec]	HH Charging Flow Rate [lb/sec]	Total Flow Rate [lb/sec]
415	20.62	33.81	54.43
515	19.50	32.31	51.81
615	18.29	30.71	49.00
715	17.00	29.07	46.07
815	15.64	27.25	42.89
915	14.18	24.87	39.05
1015	12.58	22.41	34.99
1115	10.52	19.92	30.44
1215	8.05	17.32	25.37
1315	4.81	14.65	19.46
1415	0.00	11.76	11.76
1515	0.00	9.18	9.18

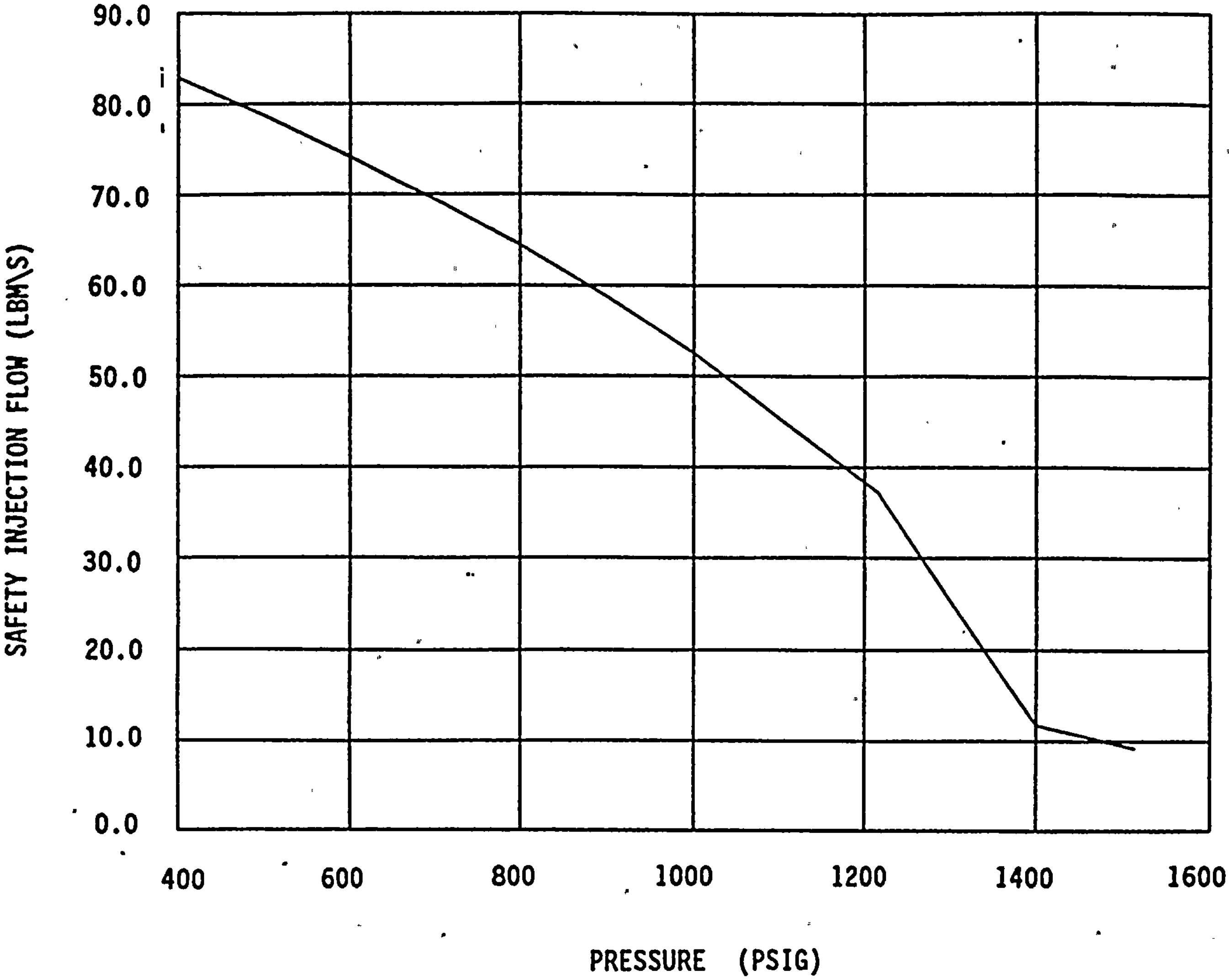


Figure C.3.2-1
SAFETY INJECTION FLOWRATE
CROSS TIE VALVES OPEN
Donald C. Cook Unit 2

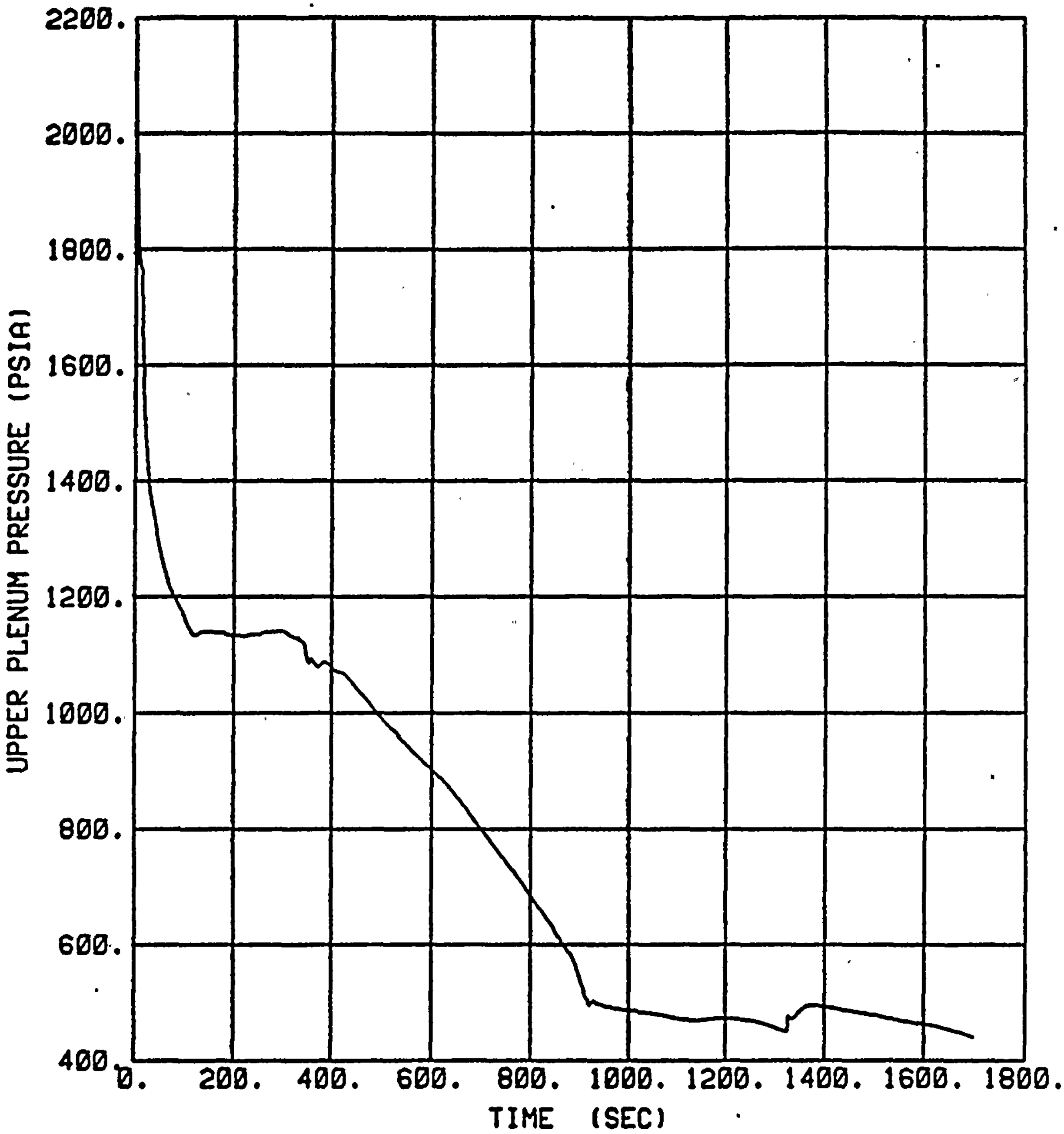


Figure C.3.2-2
RCS PRESSURE (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

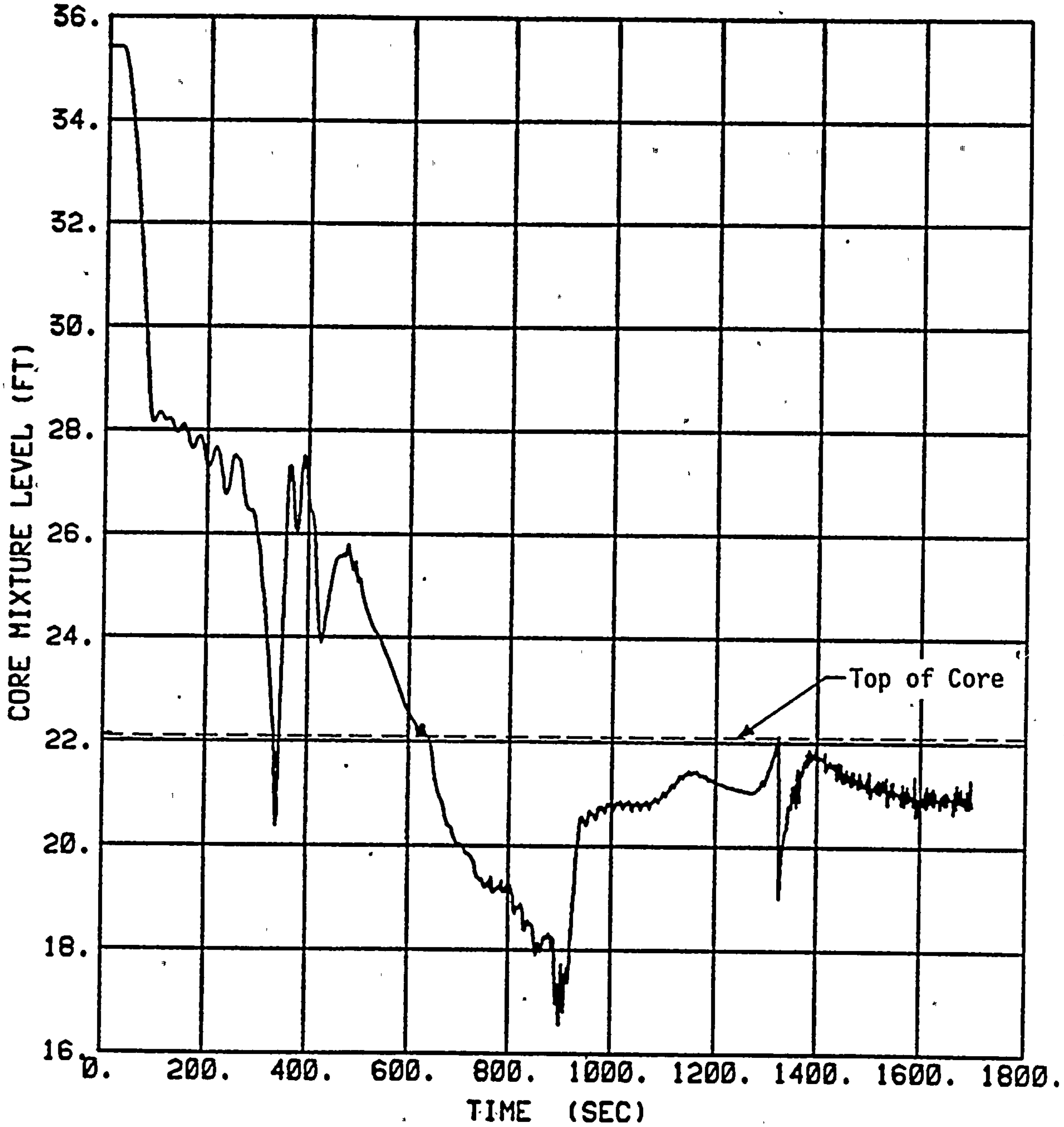


Figure C.3.2-3
CORE MIXTURE HEIGHT (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

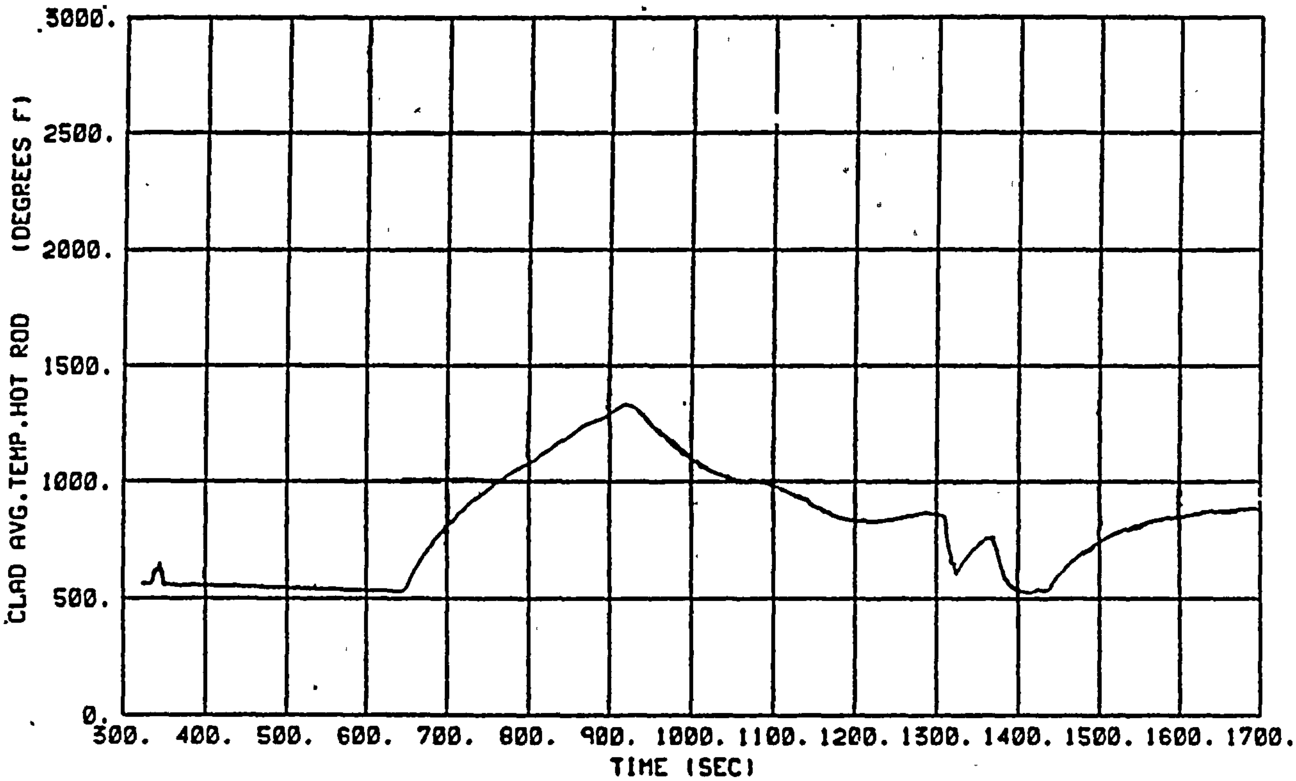


Figure C.3.2-4
HOT SPOT CLAD TEMPERATURE (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

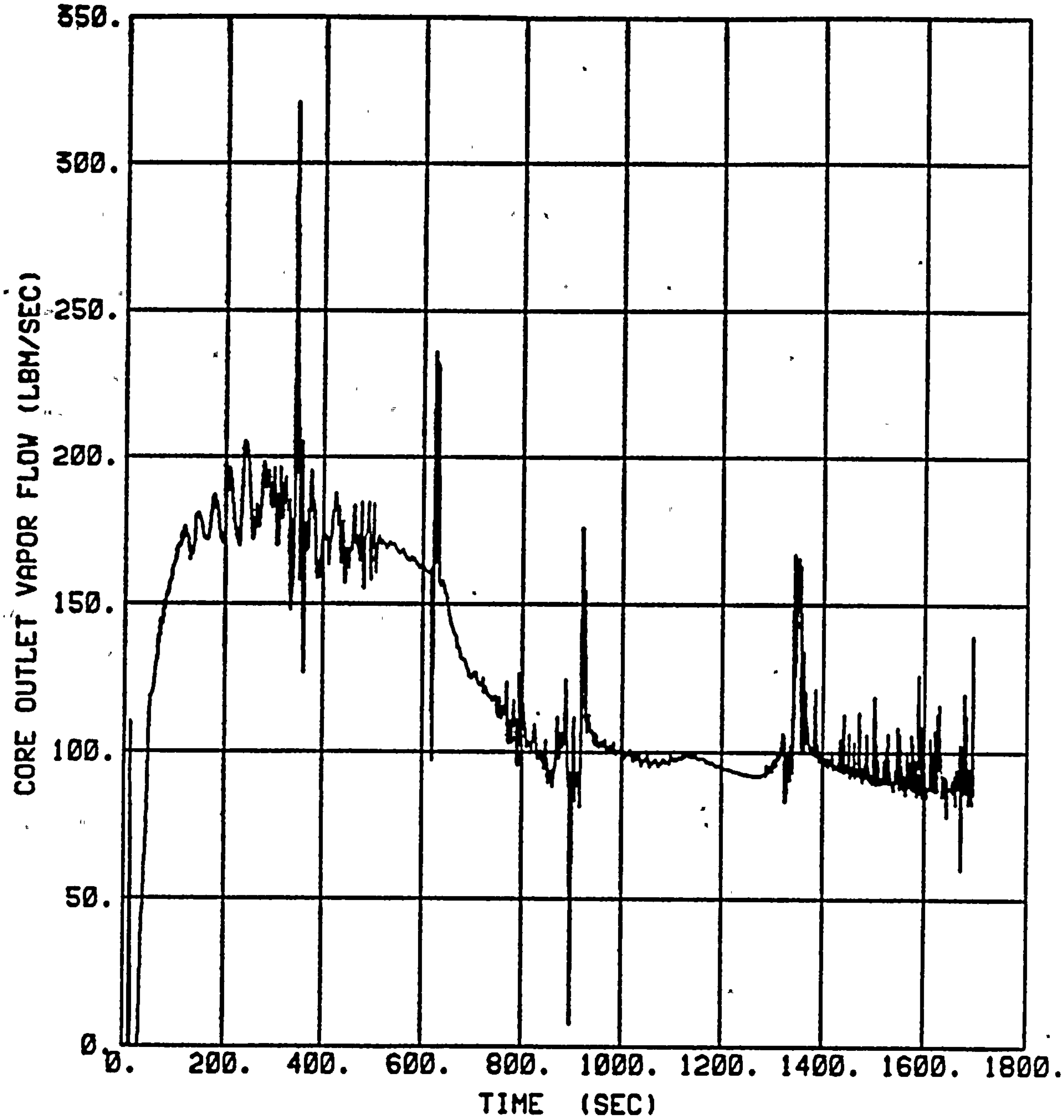


Figure C.3.2-5
CORE STEAM FLOWRATE (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

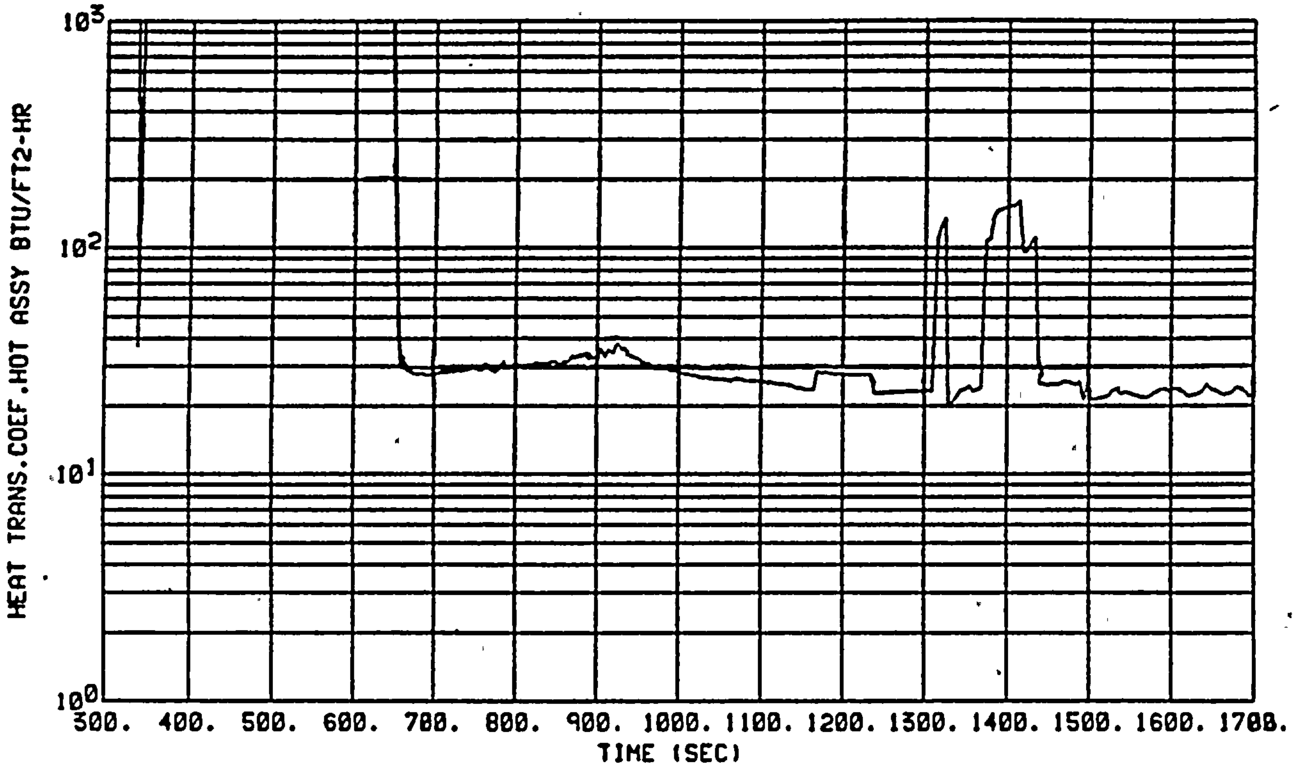


Figure C.3.2-6
HOT SPOT HEAT TRANSFER COEFFICIENT (4 INCH)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

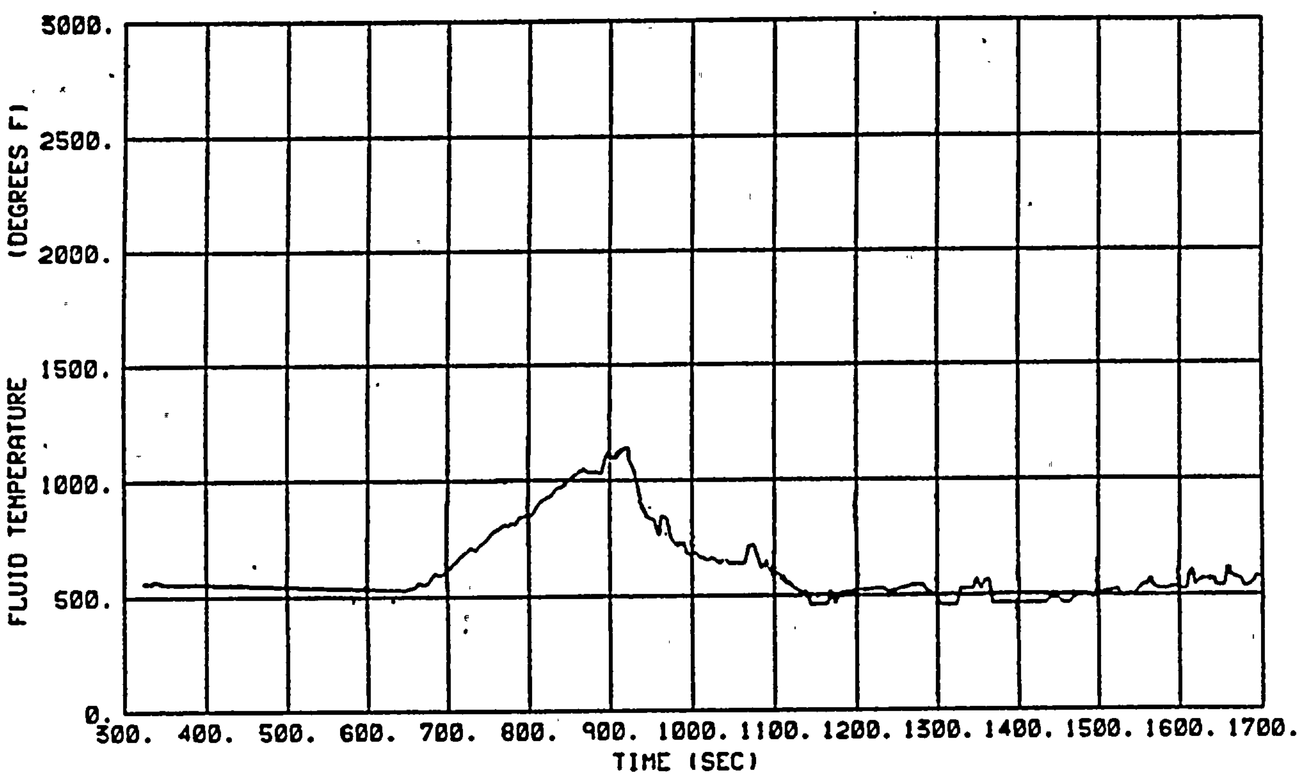


Figure C.3.2-7
HOT SPOT FLUID TEMPERATURE (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

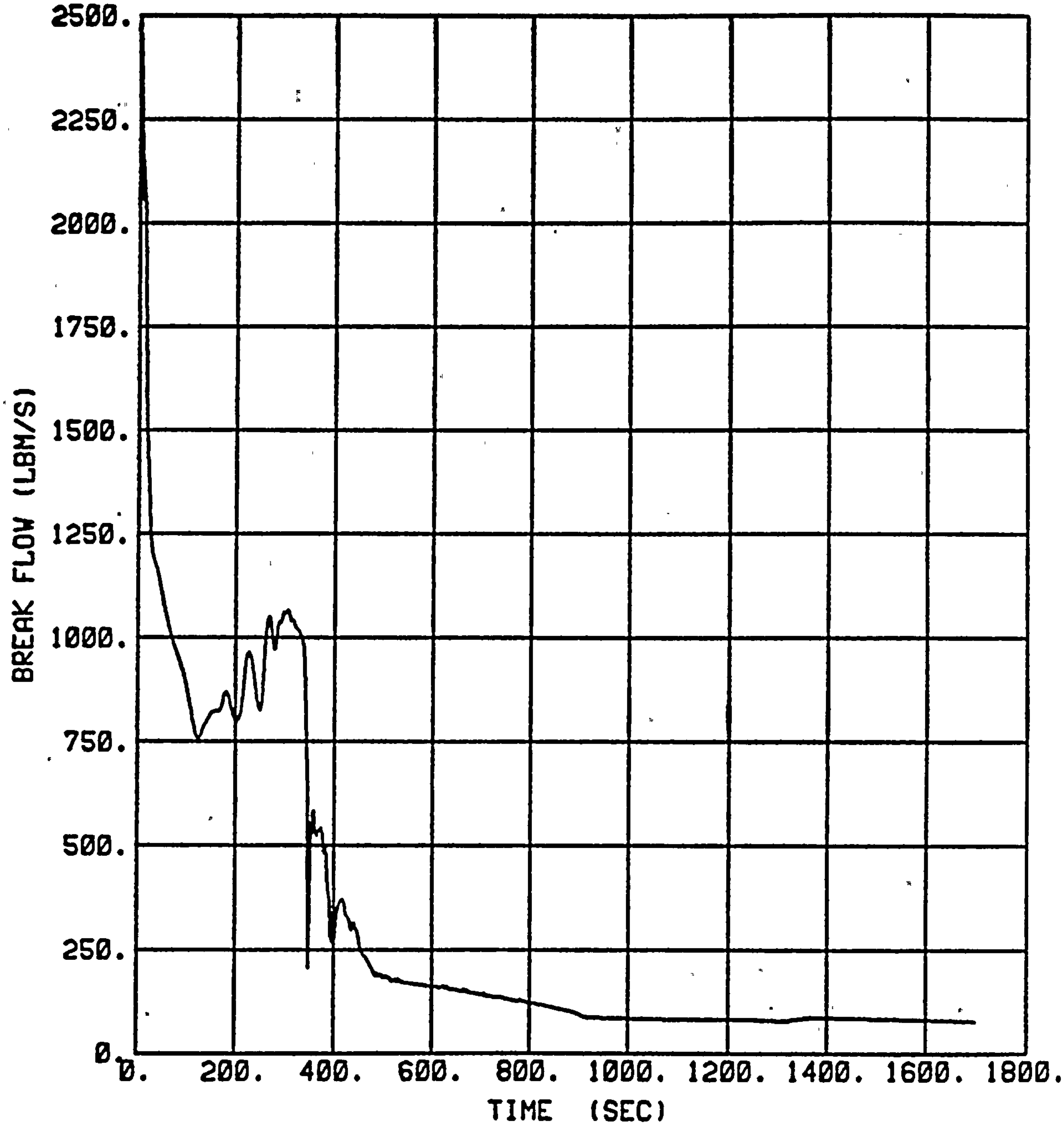


Figure C.3.2-8
TOTAL BREAK FLOW (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

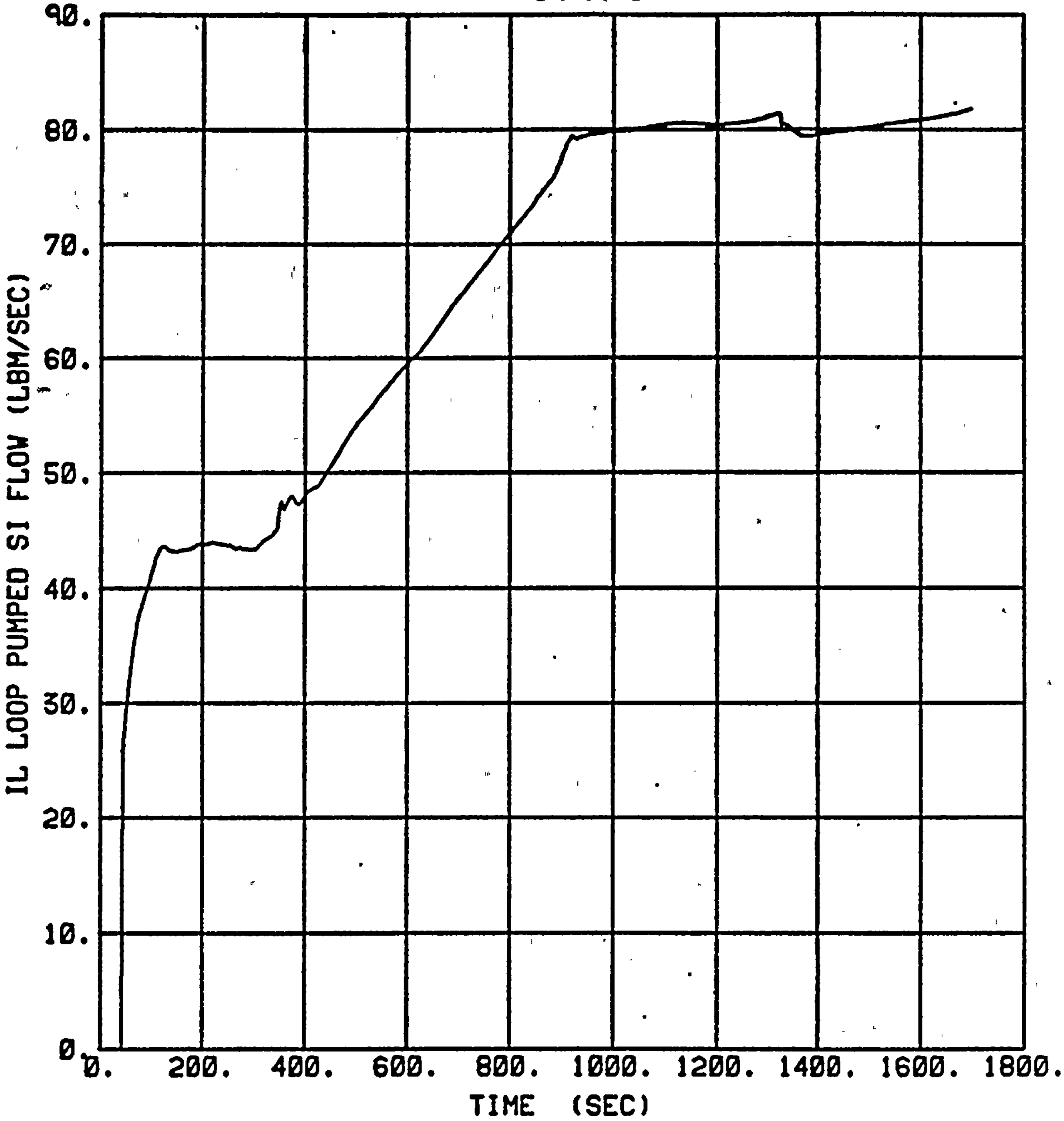


Figure C .3.2-9
INTACT LOOP PUMPED SI FLOW (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

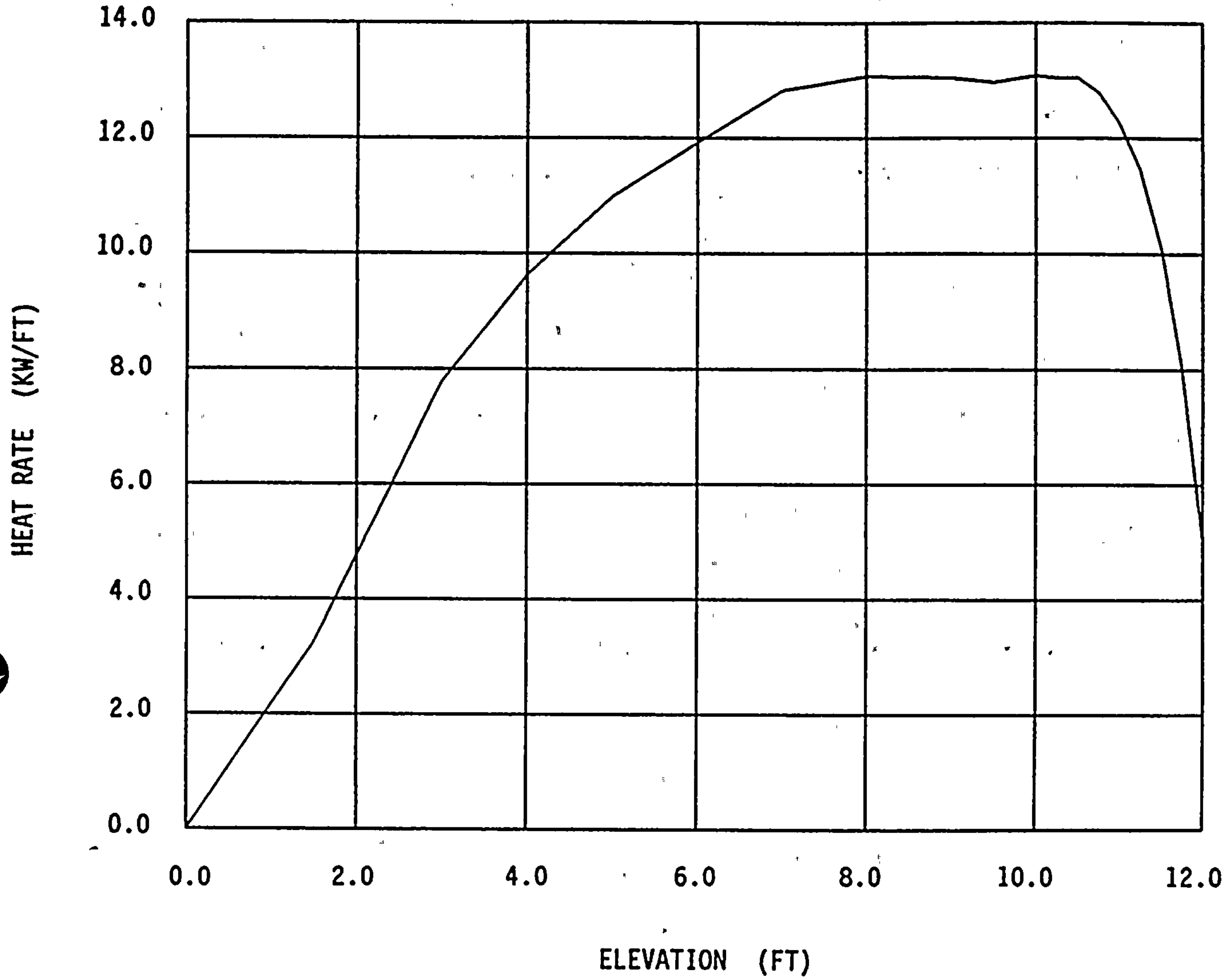


Figure C.3.2-10
HOT ROD POWER DISTRIBUTION
Donald C. Cook Unit 2

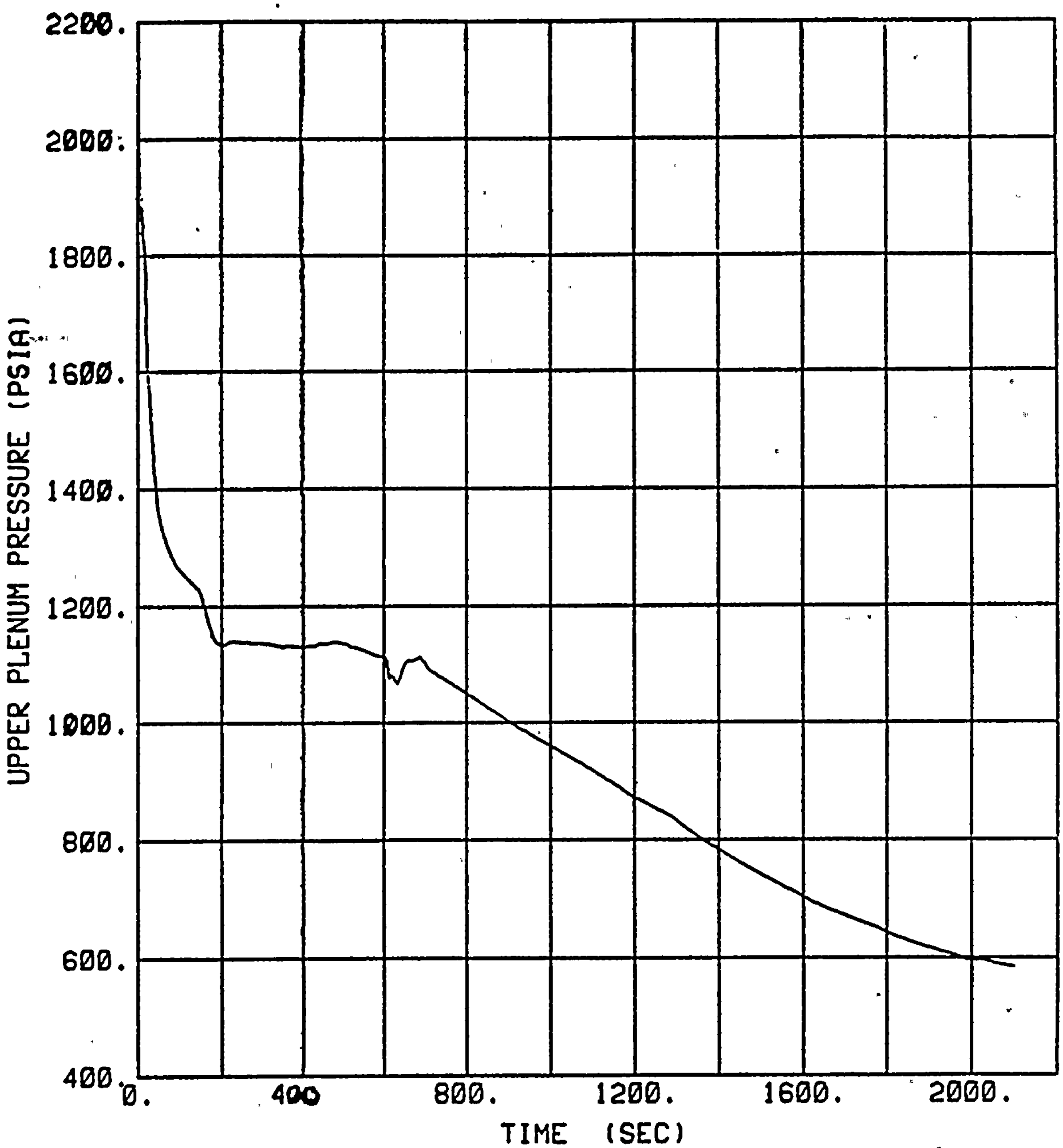


Figure C .3.2-11
RCS PRESSURE (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

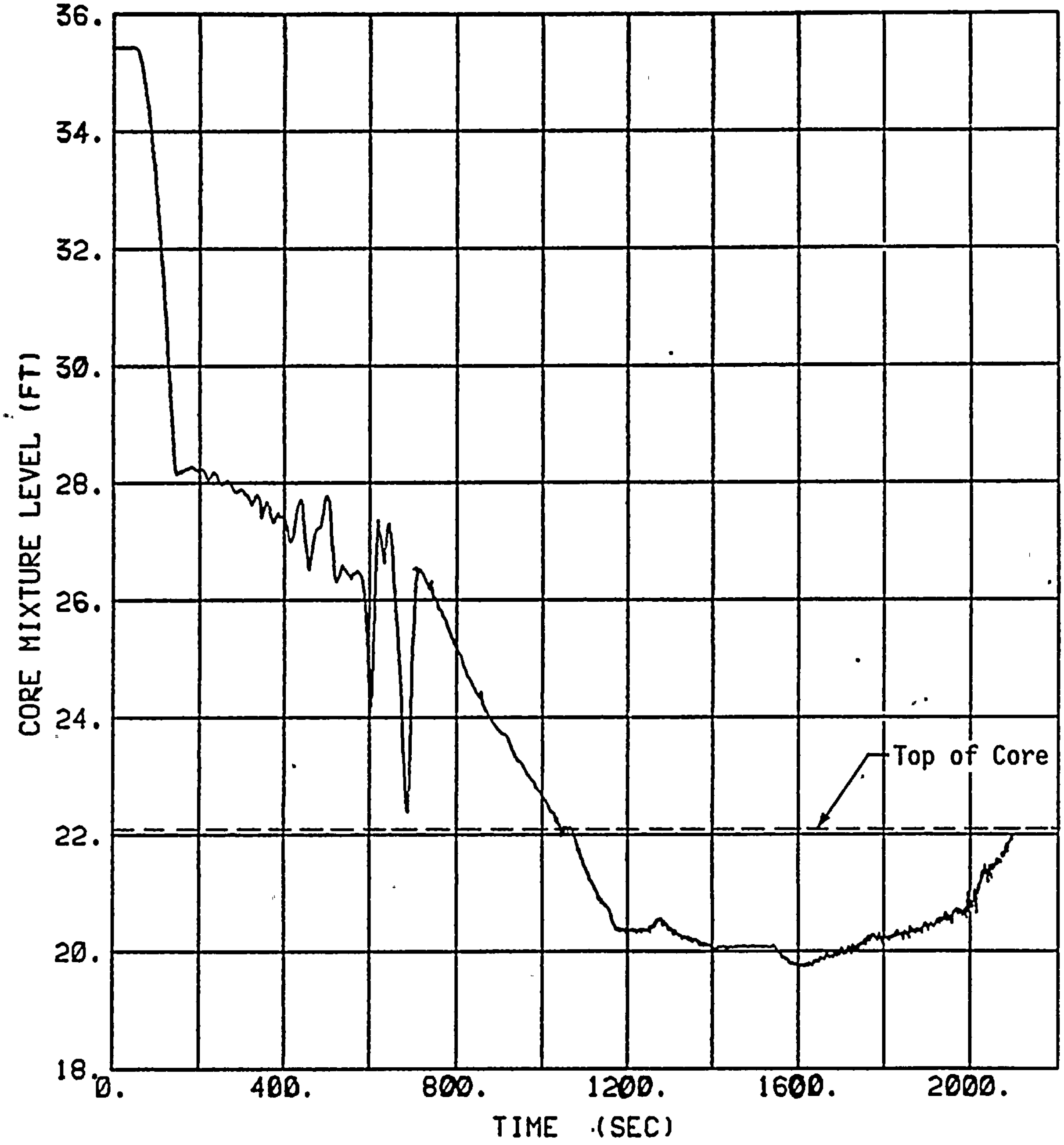


Figure C.3.2-12
CORE MIXTURE HEIGHT (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

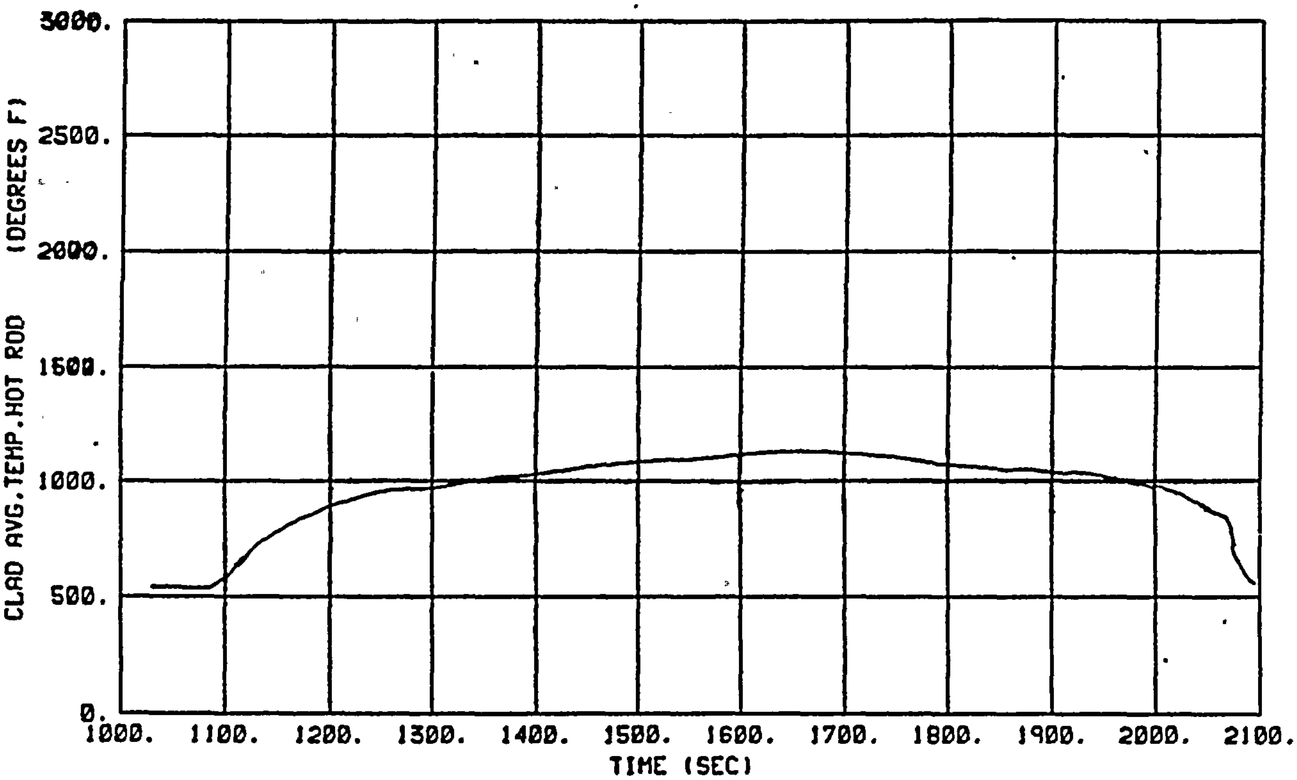


Figure C.3.2-13
HOT SPOT CLAD TEMPERATURE (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

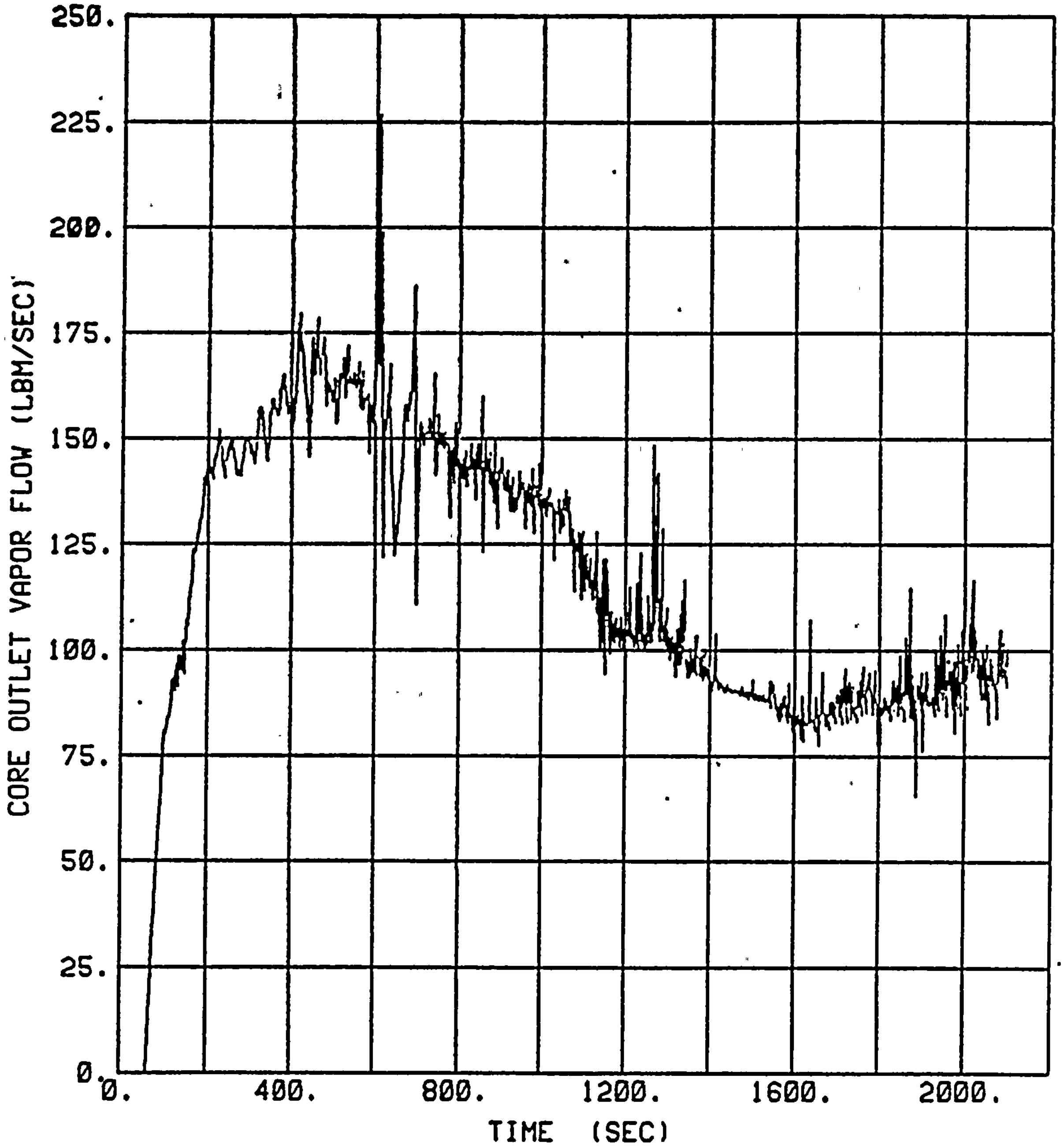


Figure C.3.2-14
CORE STEAM FLOWRATE (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

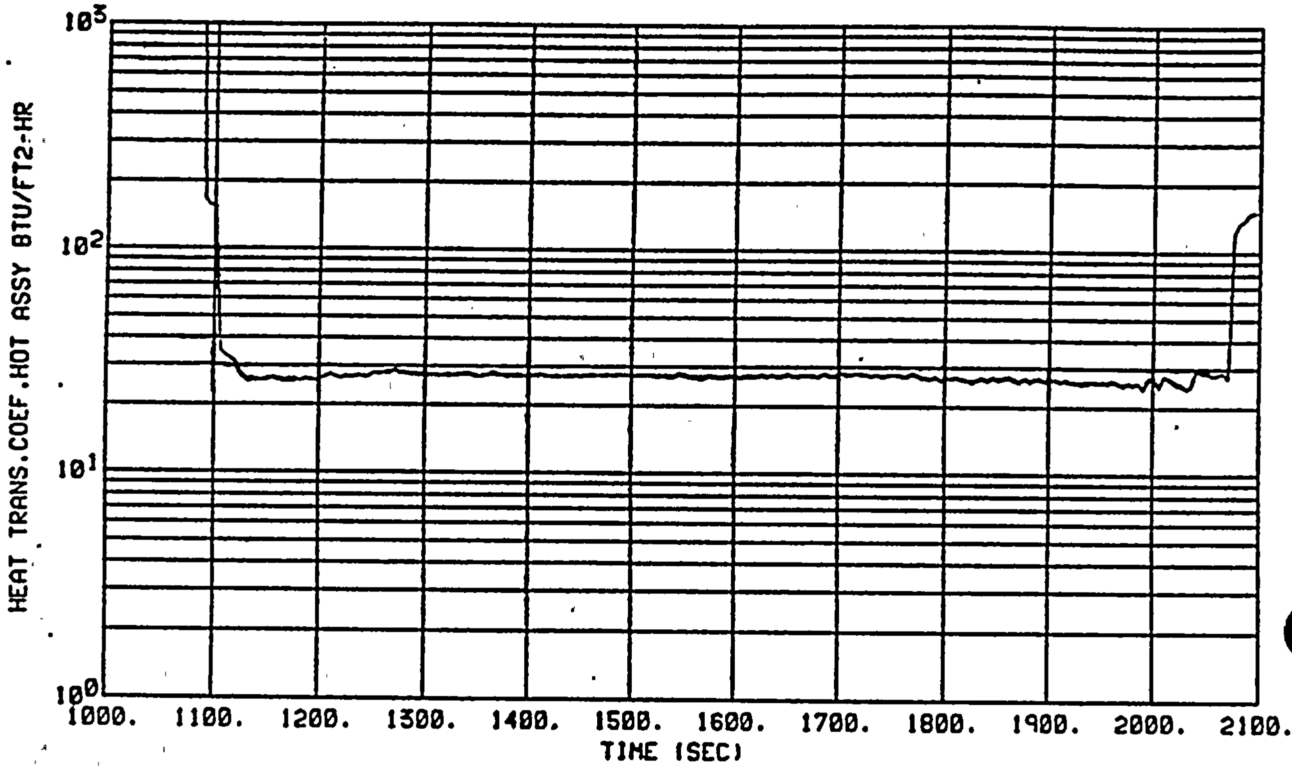


Figure C .3.2-15
HOT SPOT HEAT TRANSFER COEFFICIENT (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

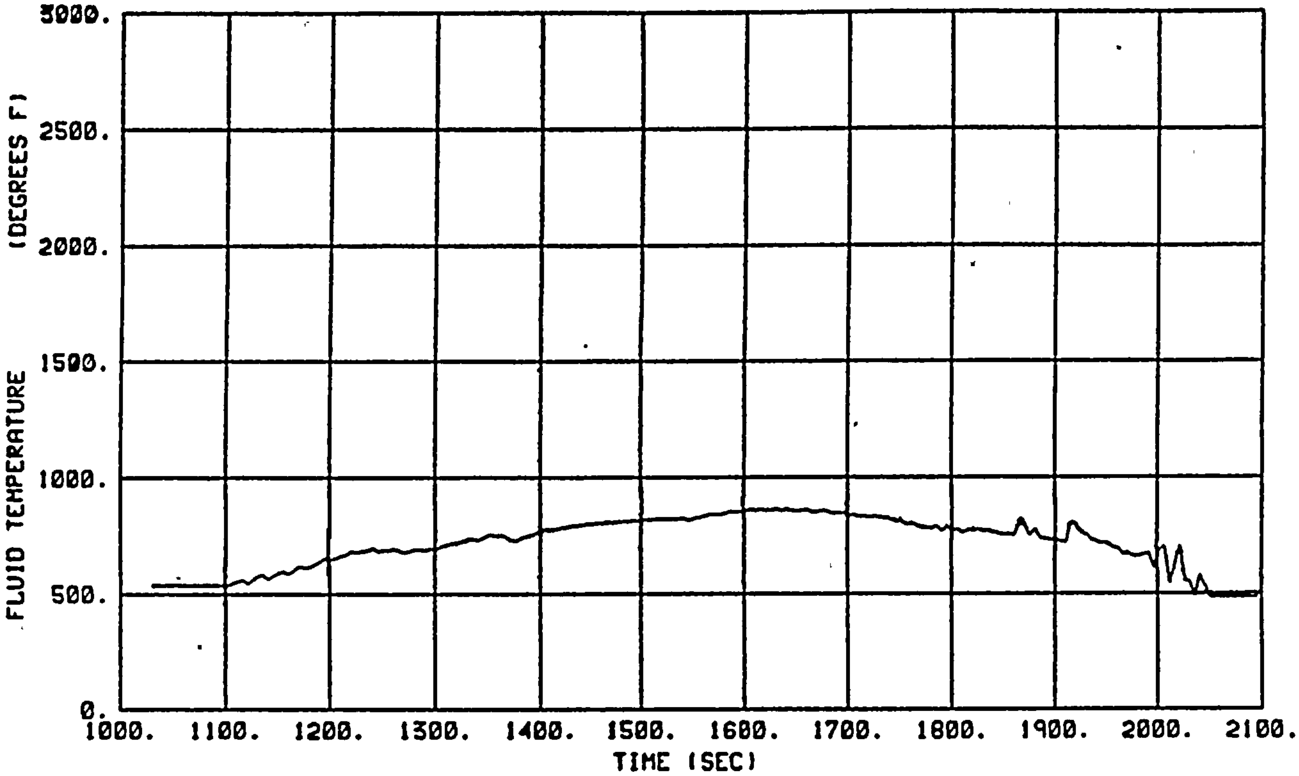


Figure C.3.2-16
HOT SPOT FLUID TEMPERATURE (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

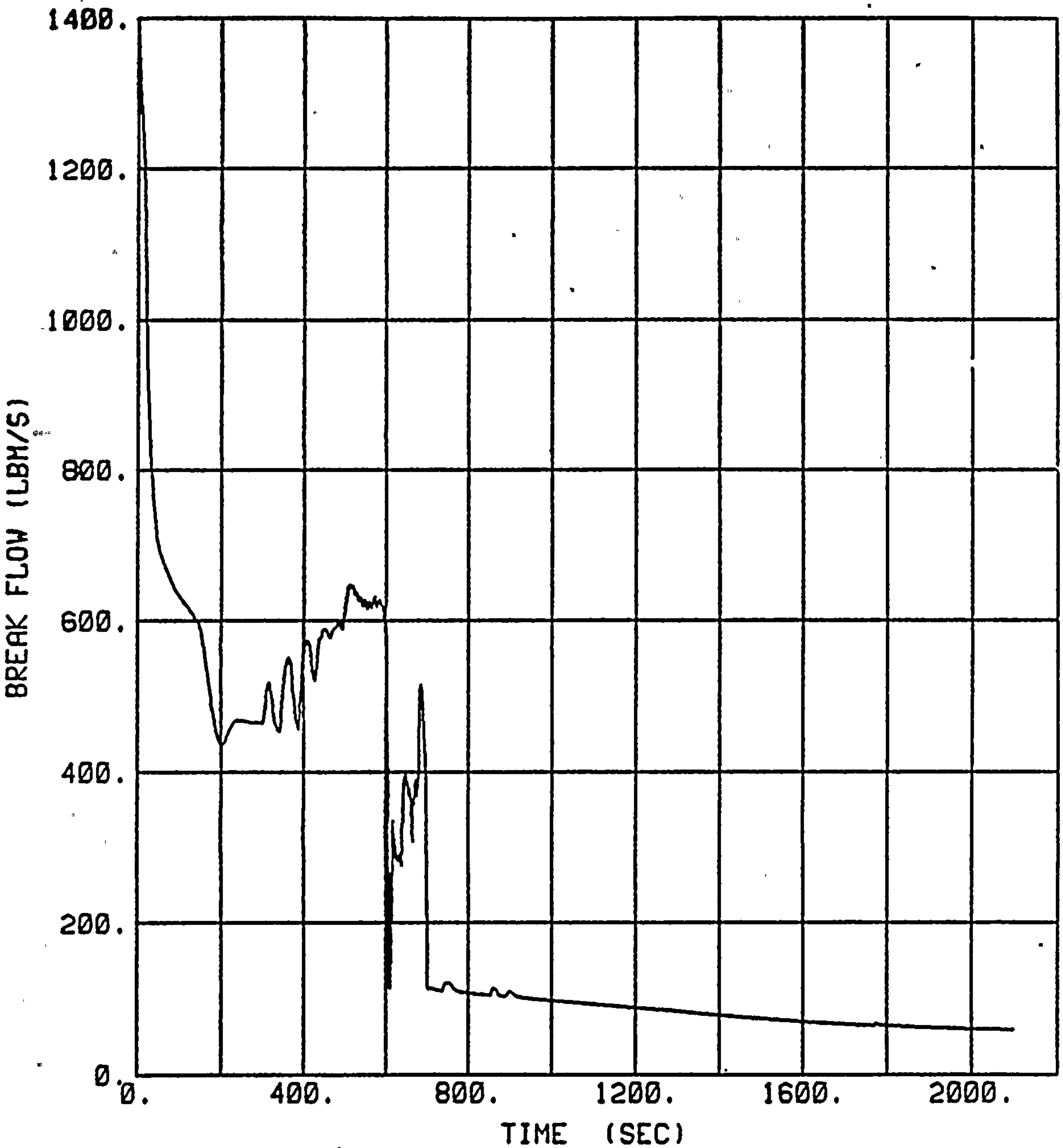


Figure C .3.2-17
TOTAL BREAK FLOW (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

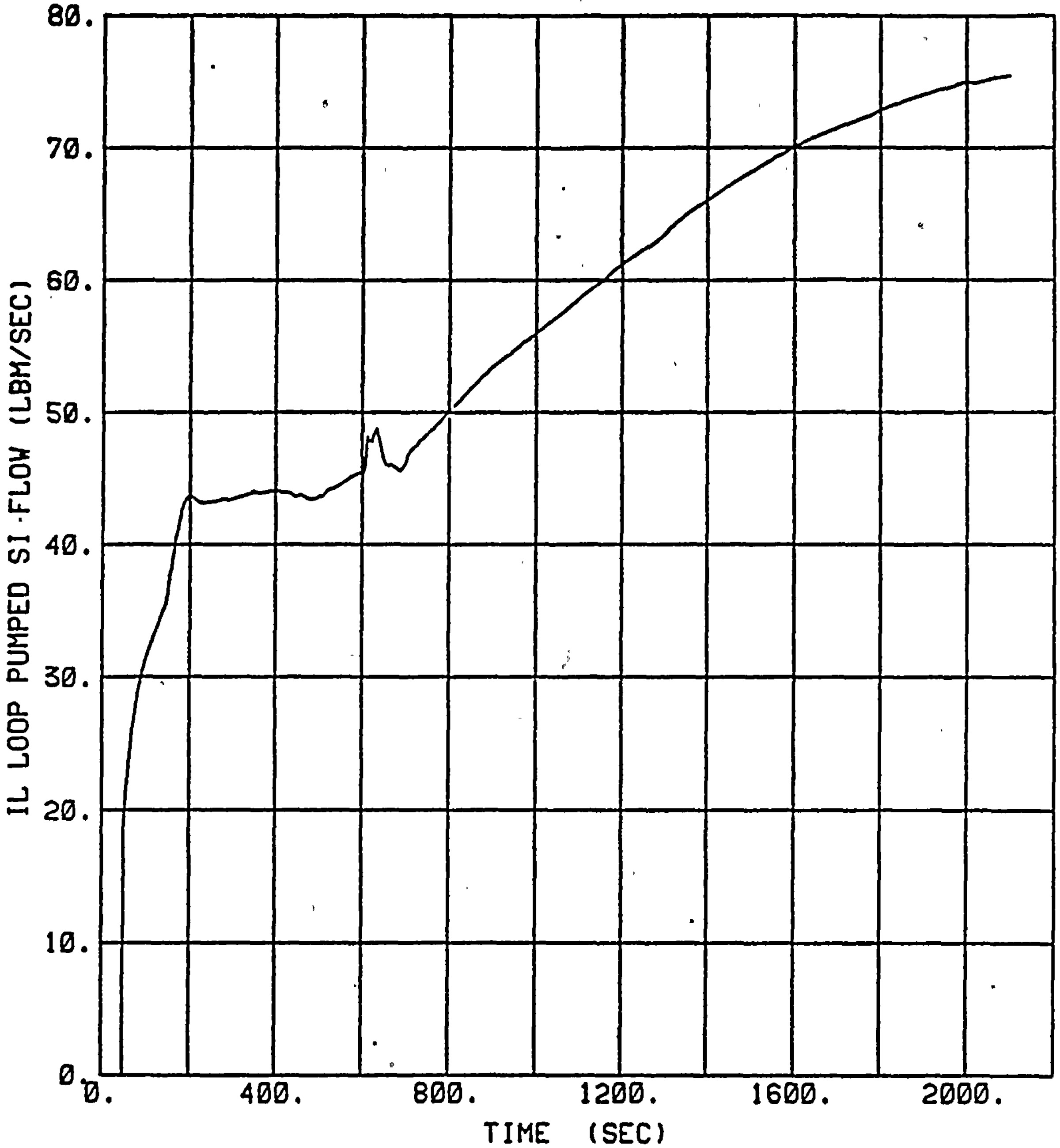


Figure C.3.2-18
INTACT LOOP PUMPED SI FLOW (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

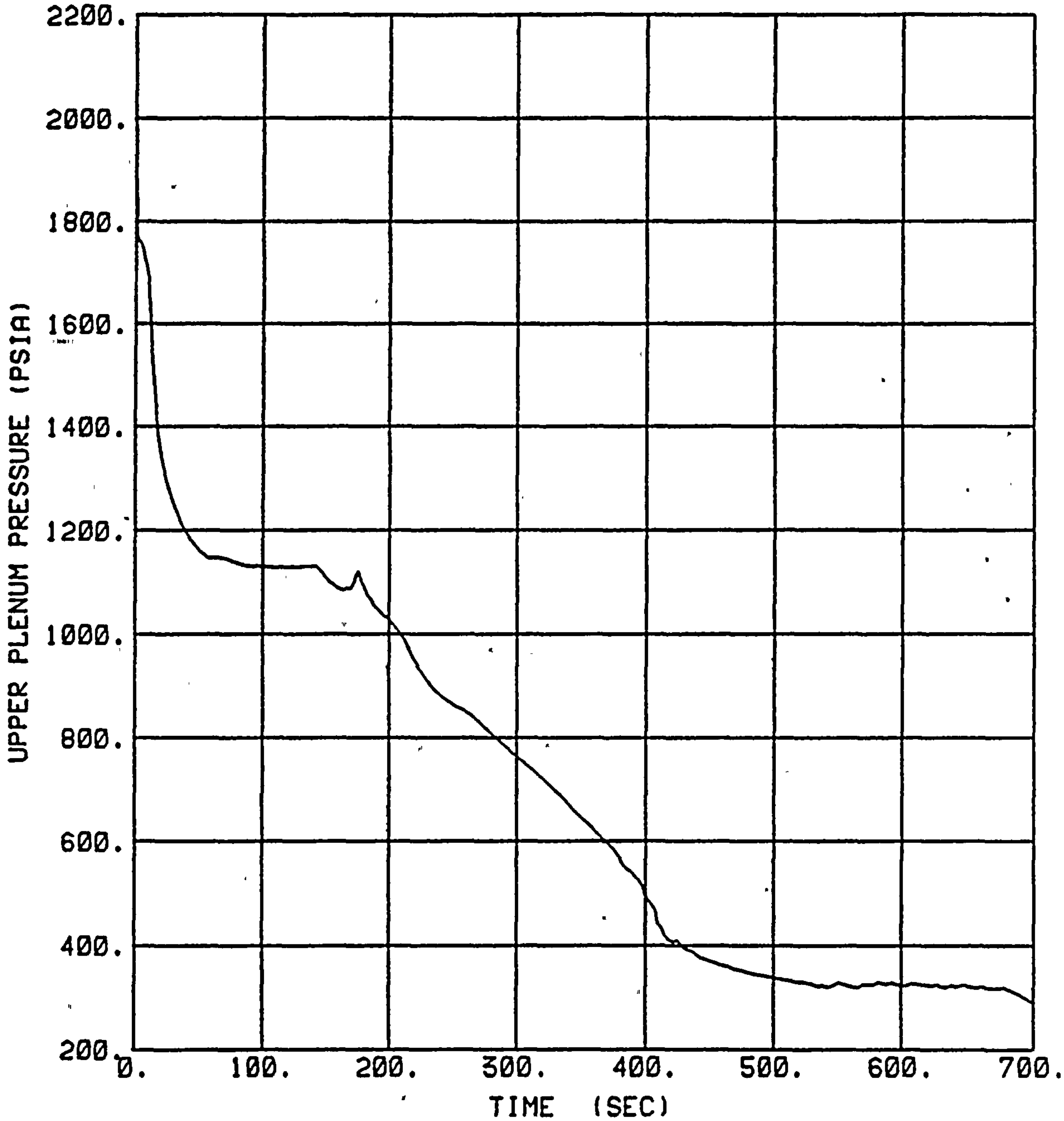


Figure C.3.2-19
RCS PRESSURE (6 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

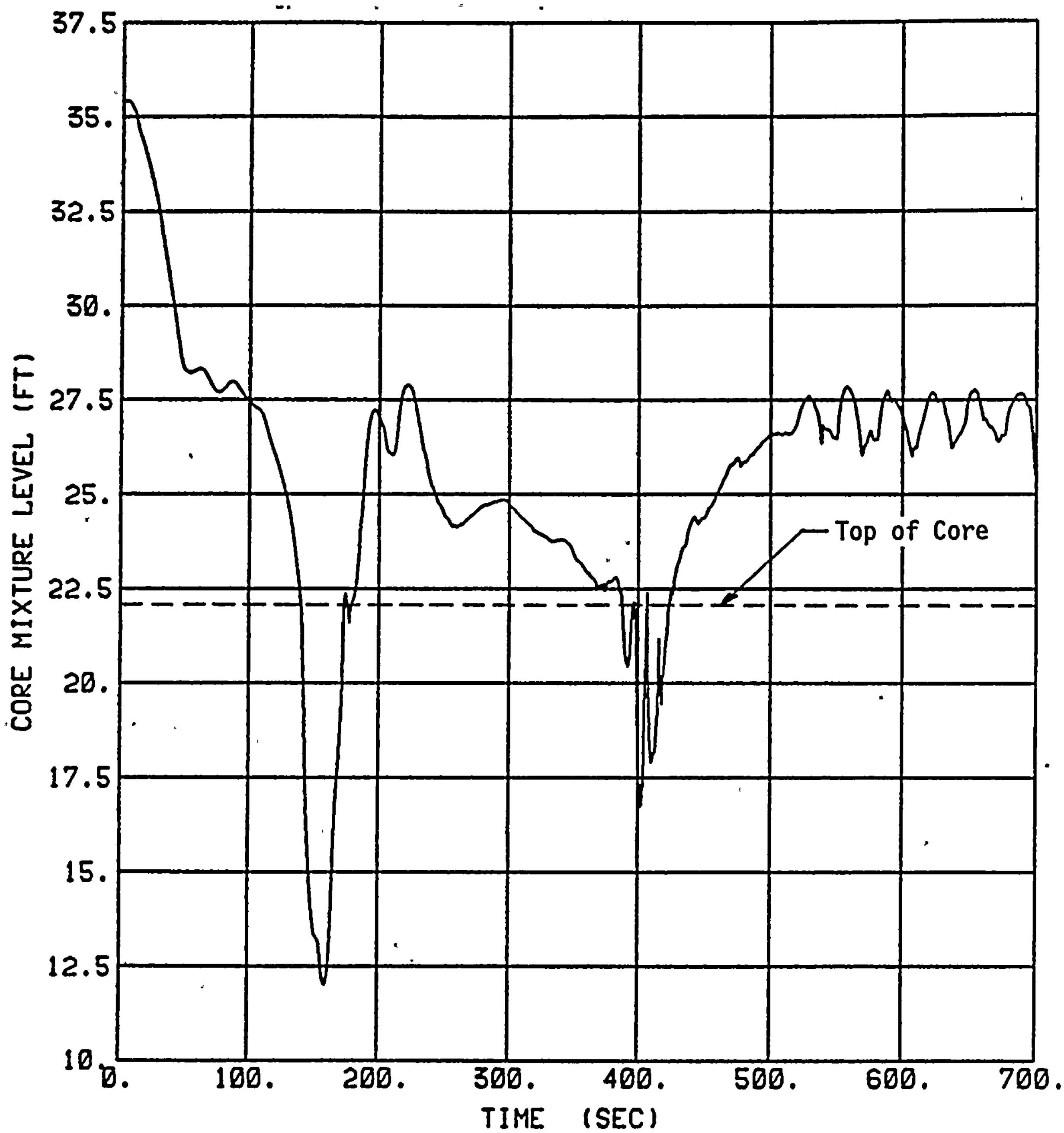


Figure C .3.2-20
CORE MIXTURE HEIGHT (6 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

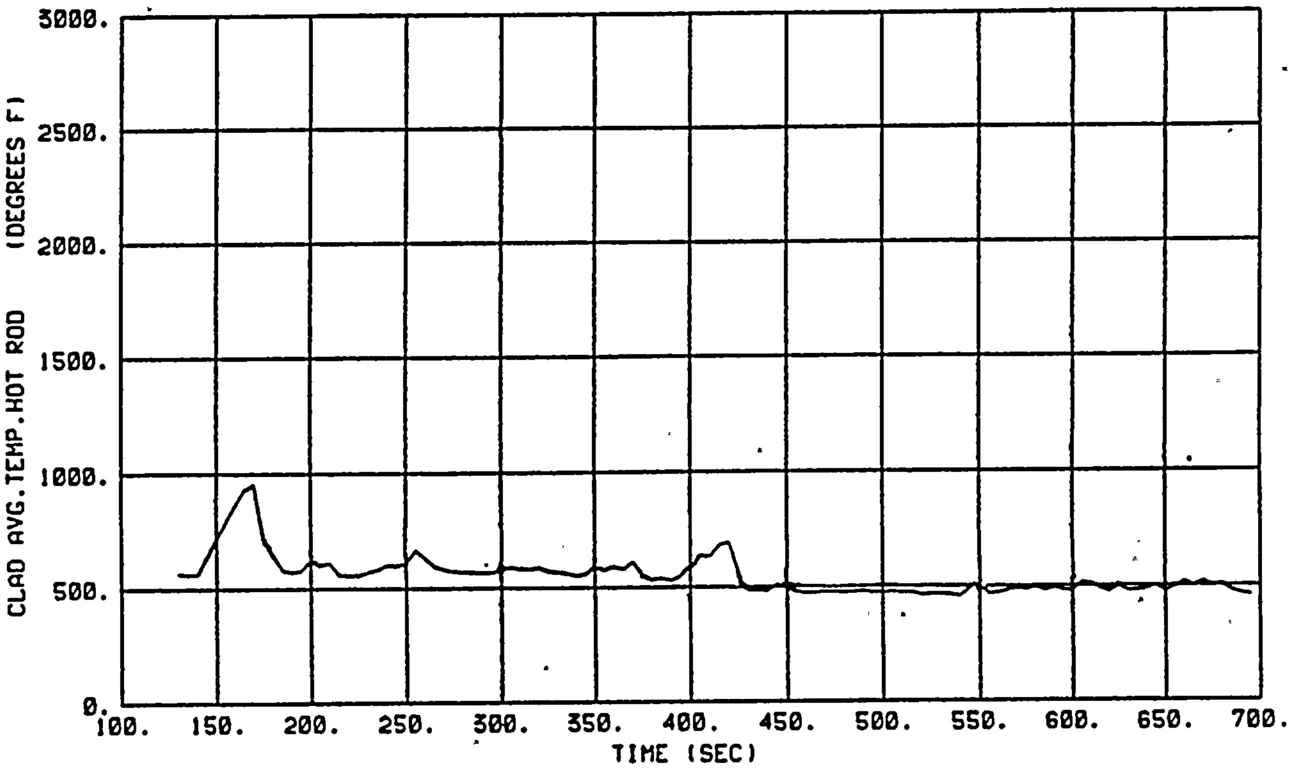


Figure C .3.2-21
HOT SPOT CLAD TEMPERATURE (6 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

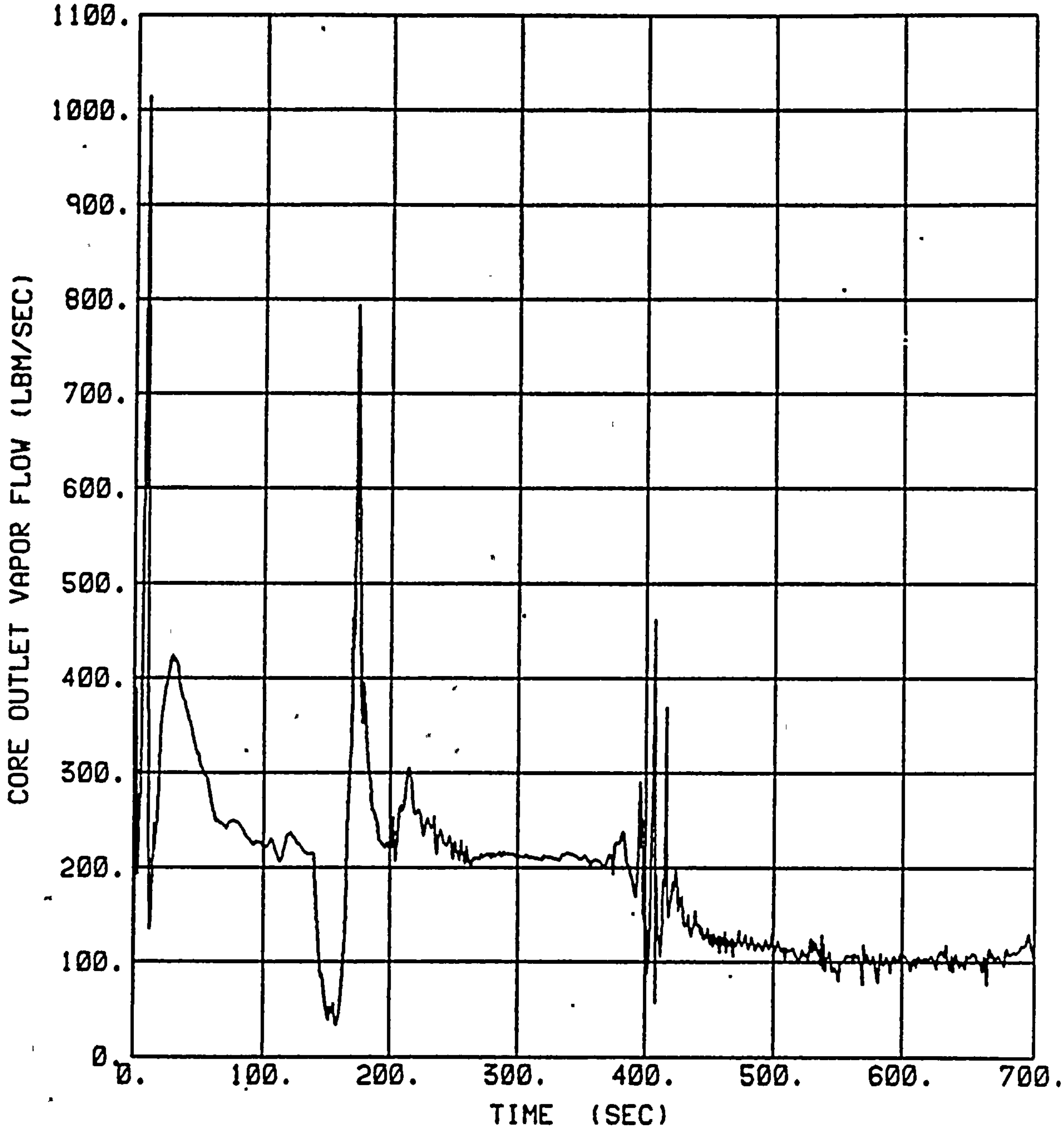


Figure C .3.2-22
CORE STEAM FLOWRATE (6 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

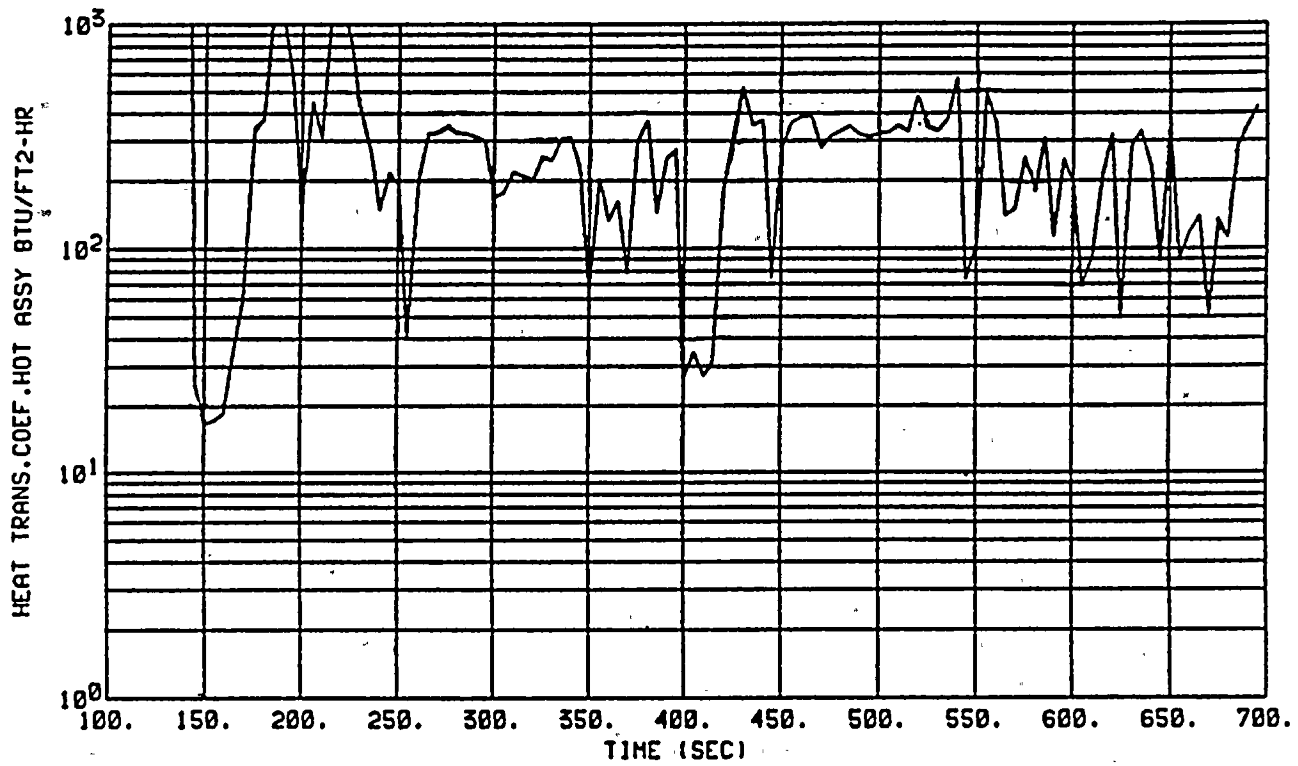


Figure C .3.2-23
HOT SPOT HEAT TRANSFER COEFFICIENT (6 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

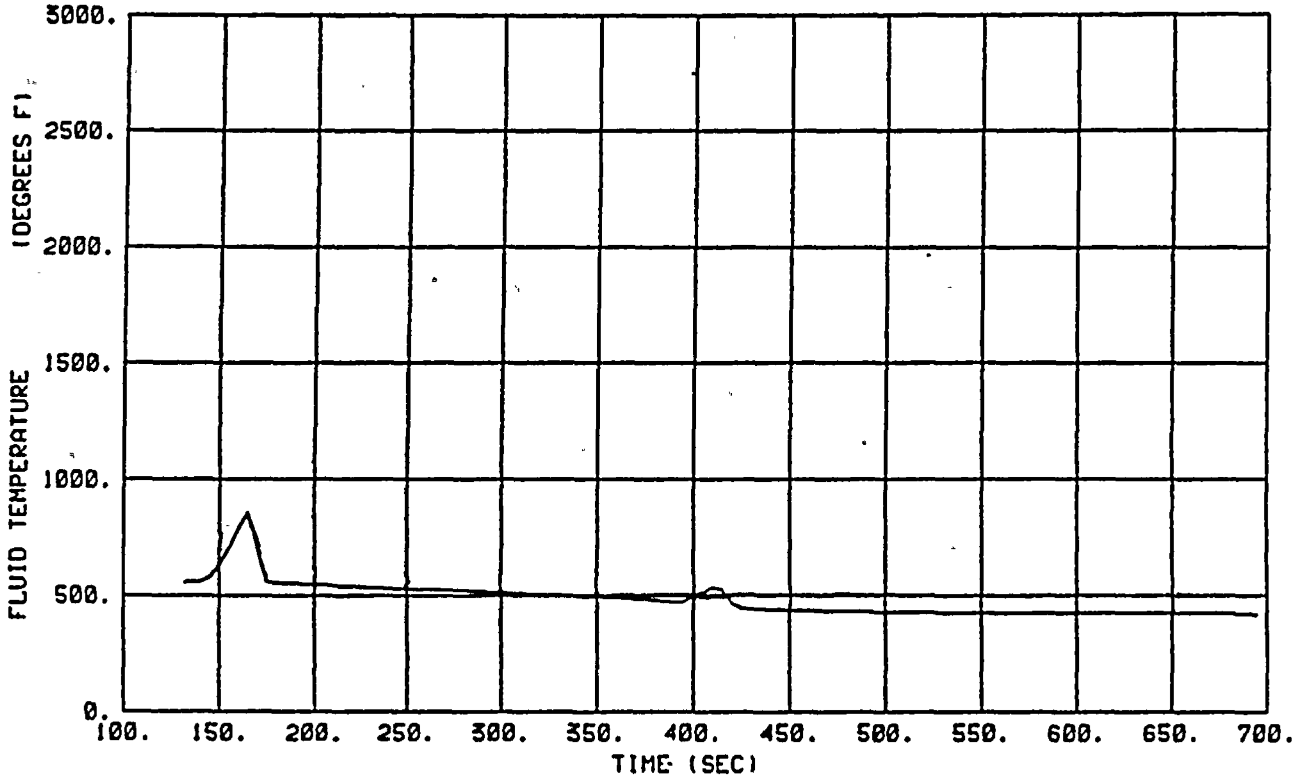


Figure C .3.2-24
HOT SPOT FLUID TEMPERATURE (6 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

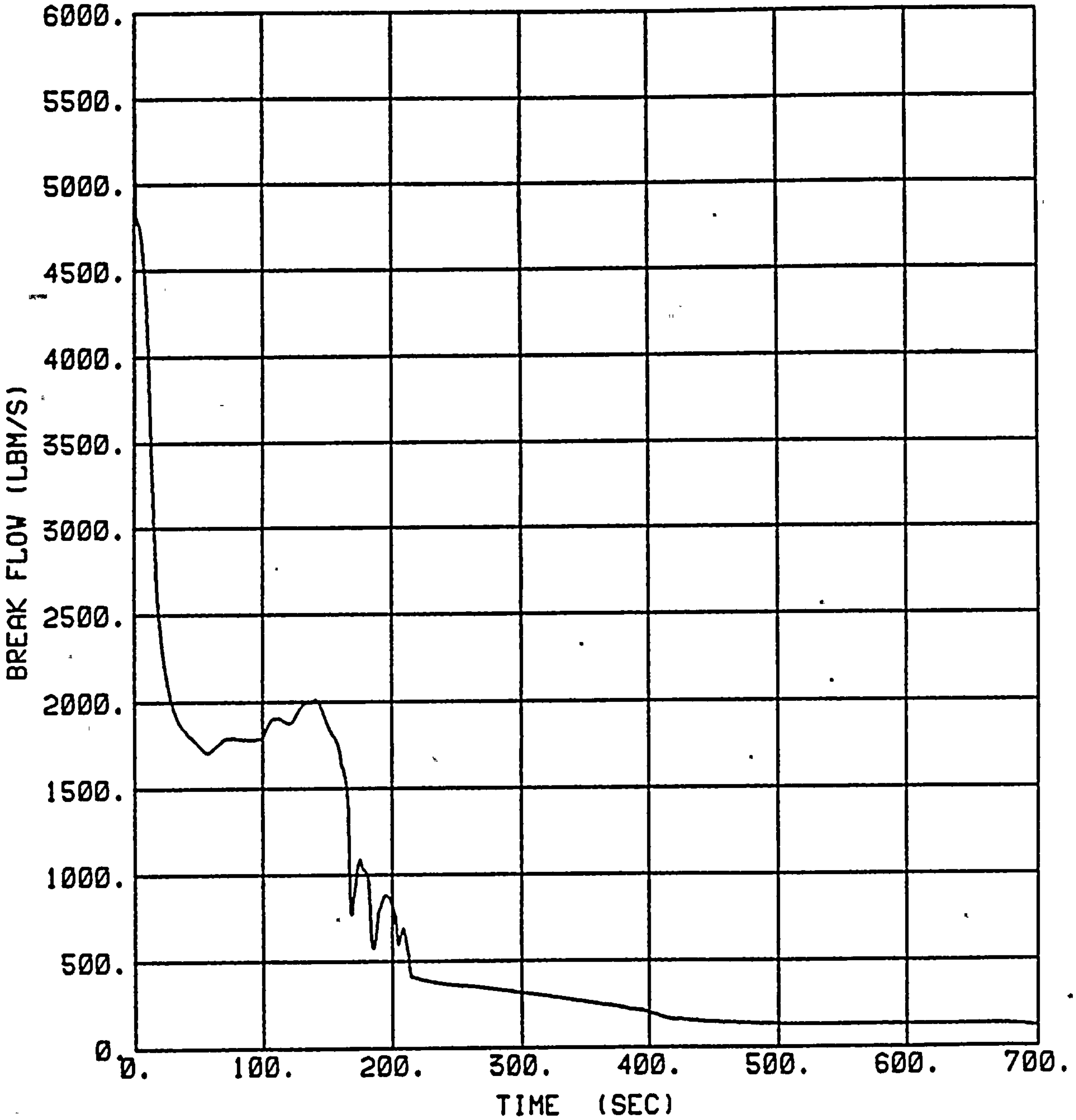


Figure C .3.2-25
TOTAL BREAK FLOW (6 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

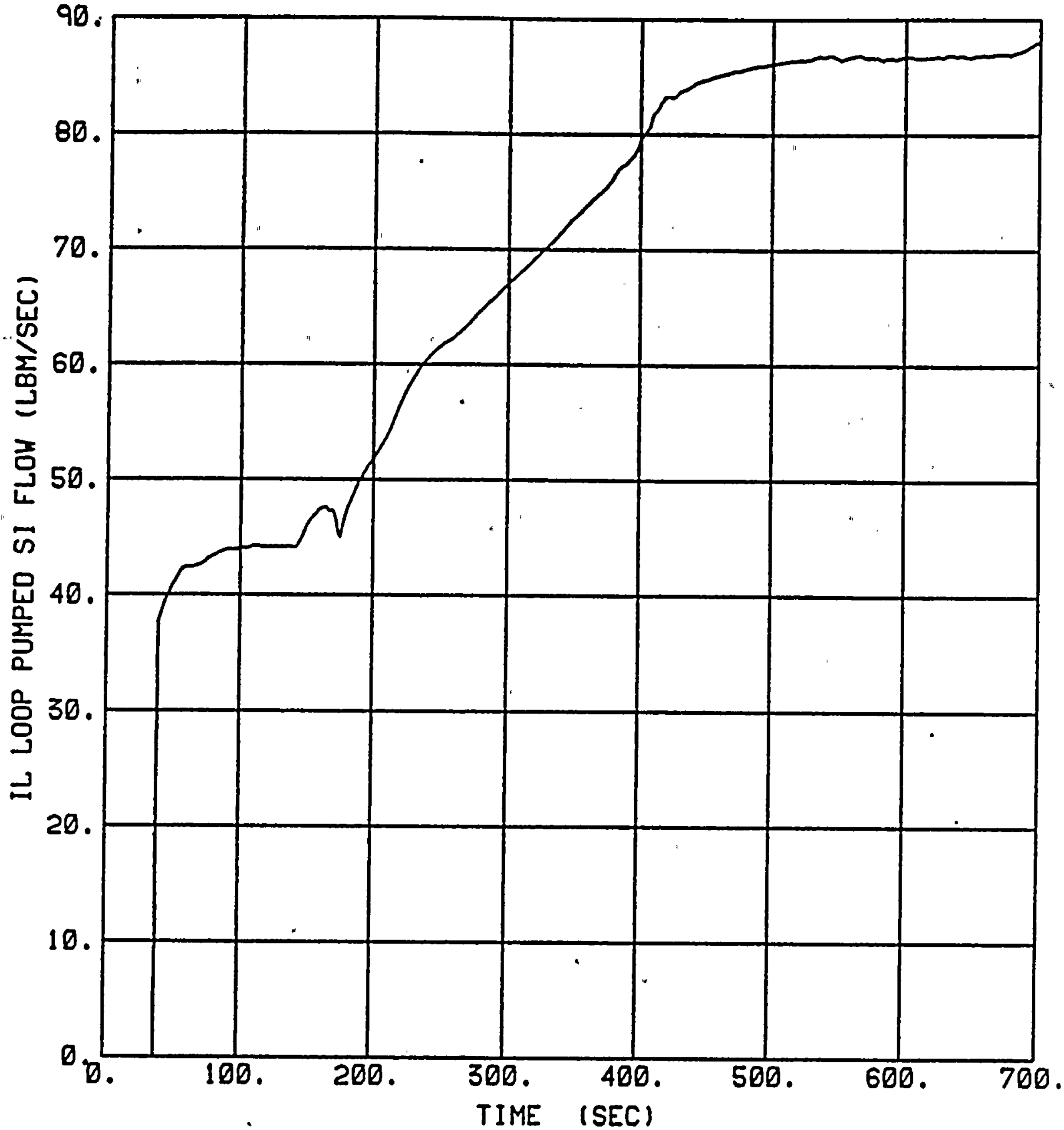


Figure C .3.2-26
INTACT LOOP PUMPED SI FLOW (6 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
Donald C. Cook Unit 2

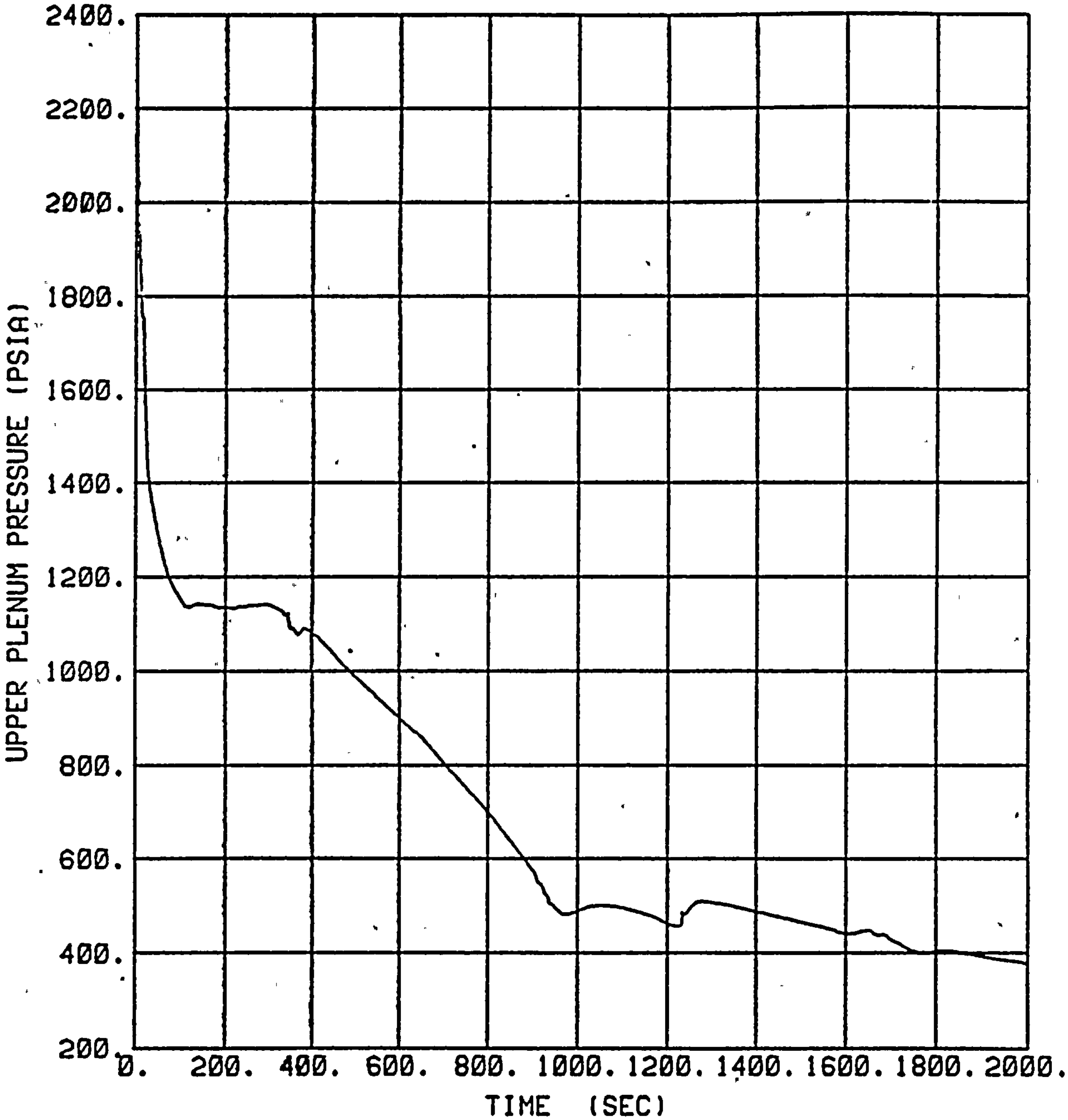


Figure C .3.2-27
RCS PRESSURE (4 Inch)
HIGH TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

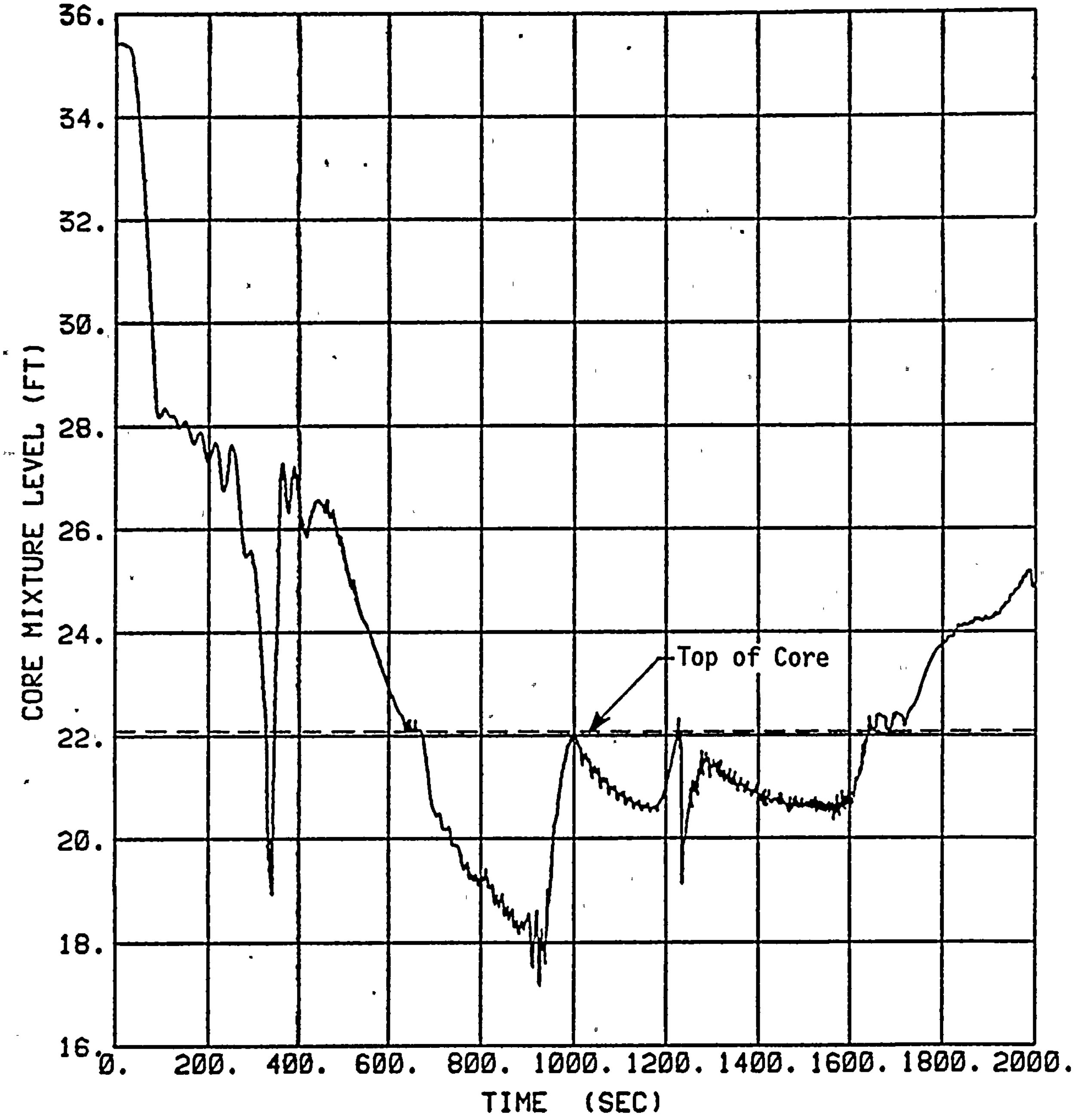


Figure C .3.2-28
CORE MIXTURE HEIGHT (4 Inch)
HIGH TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

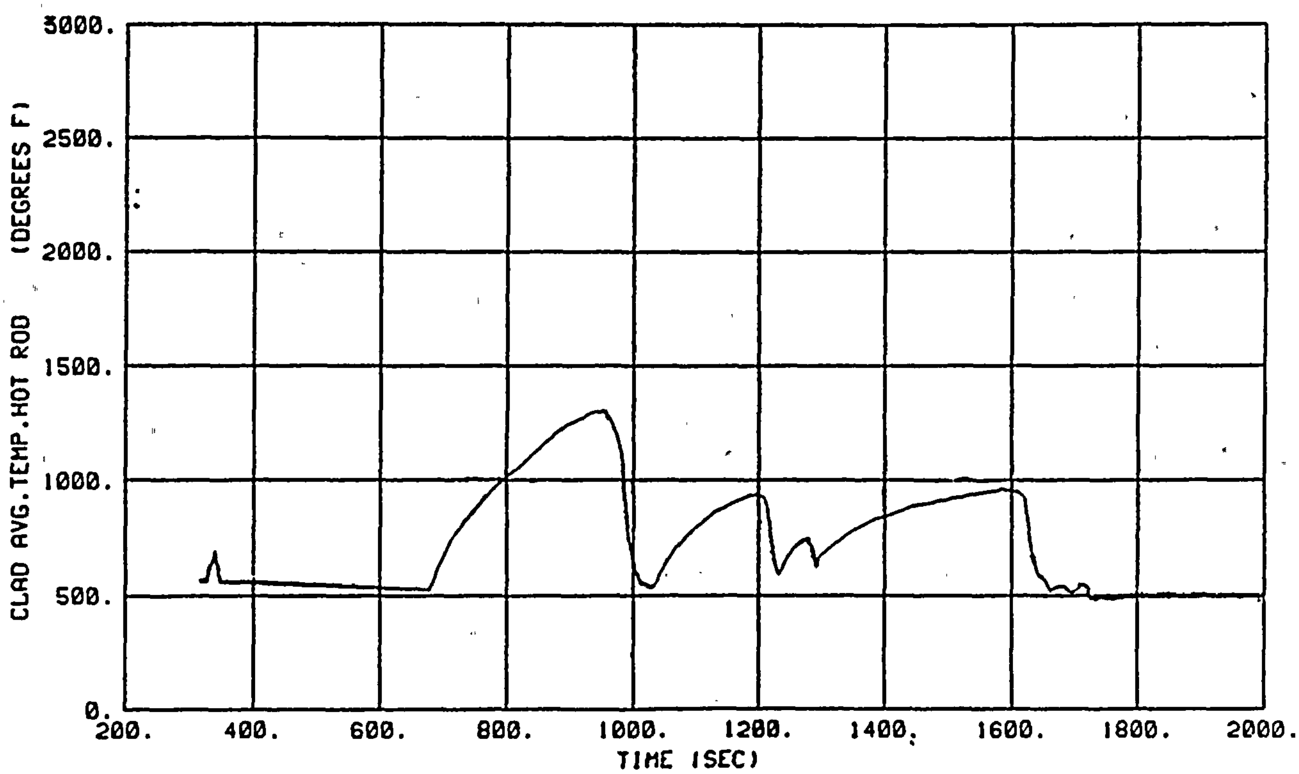


Figure C .3.2-29
HOT SPOT CLAD TEMPERATURE (4 Inch)
HIGH TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

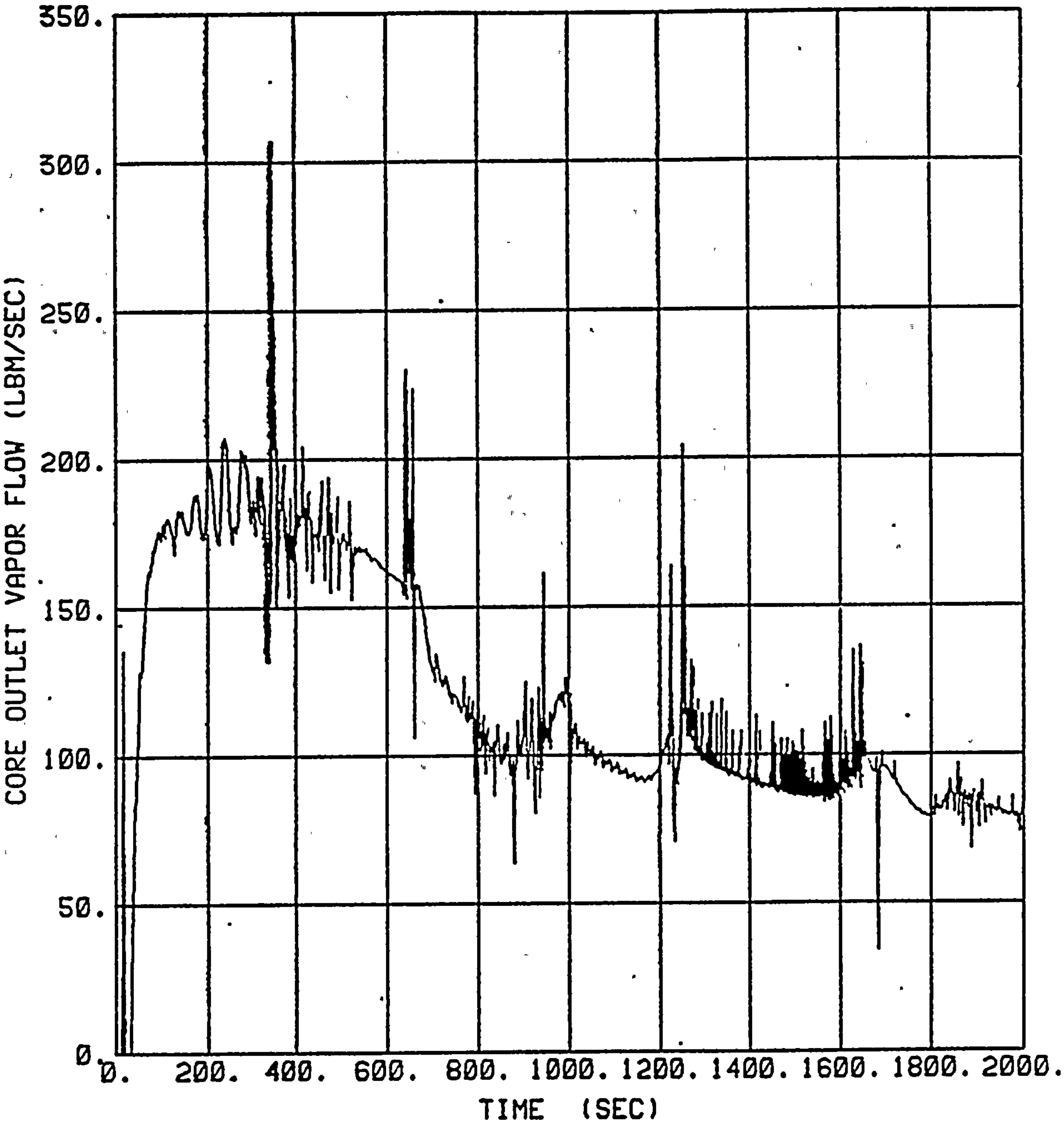


Figure C .3.2-30
CORE STEAM FLOWRATE (4 Inch)
HIGH TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

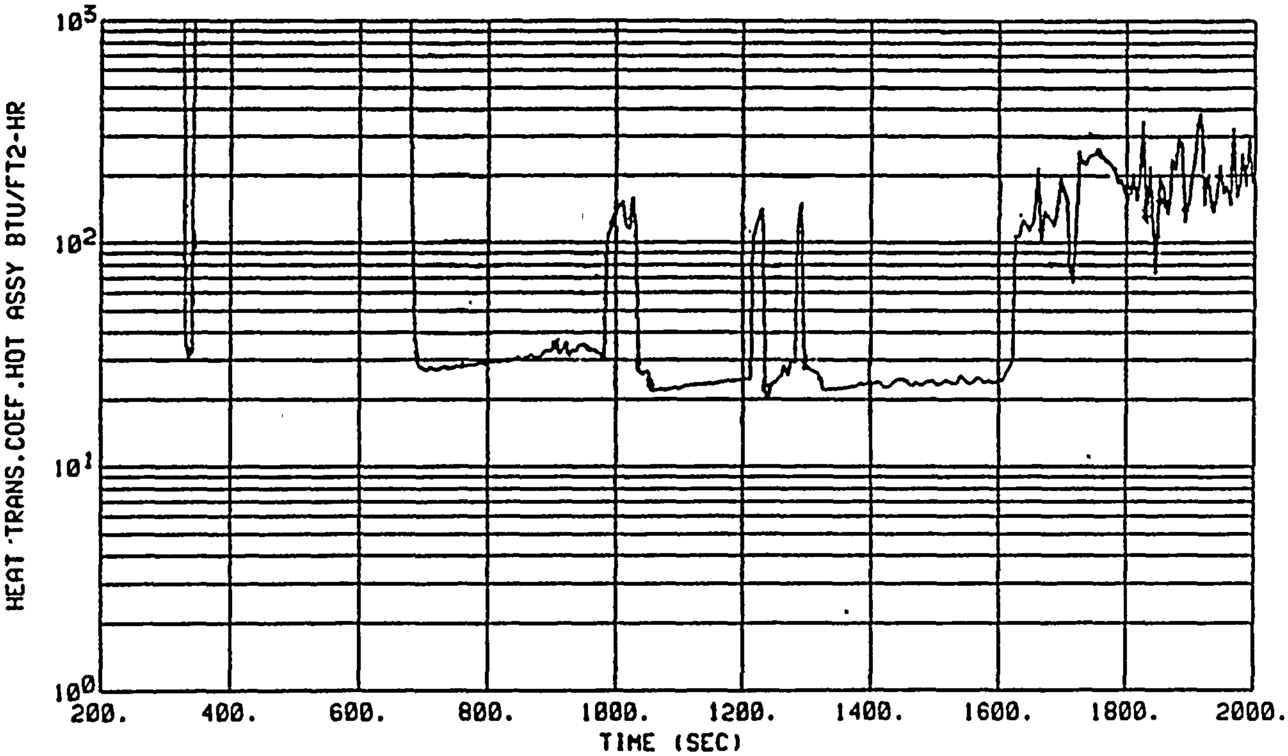


Figure C .3.2-31
HOT SPOT HEAT TRANSFER COEFFICIENT (4 Inch)
HIGH TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

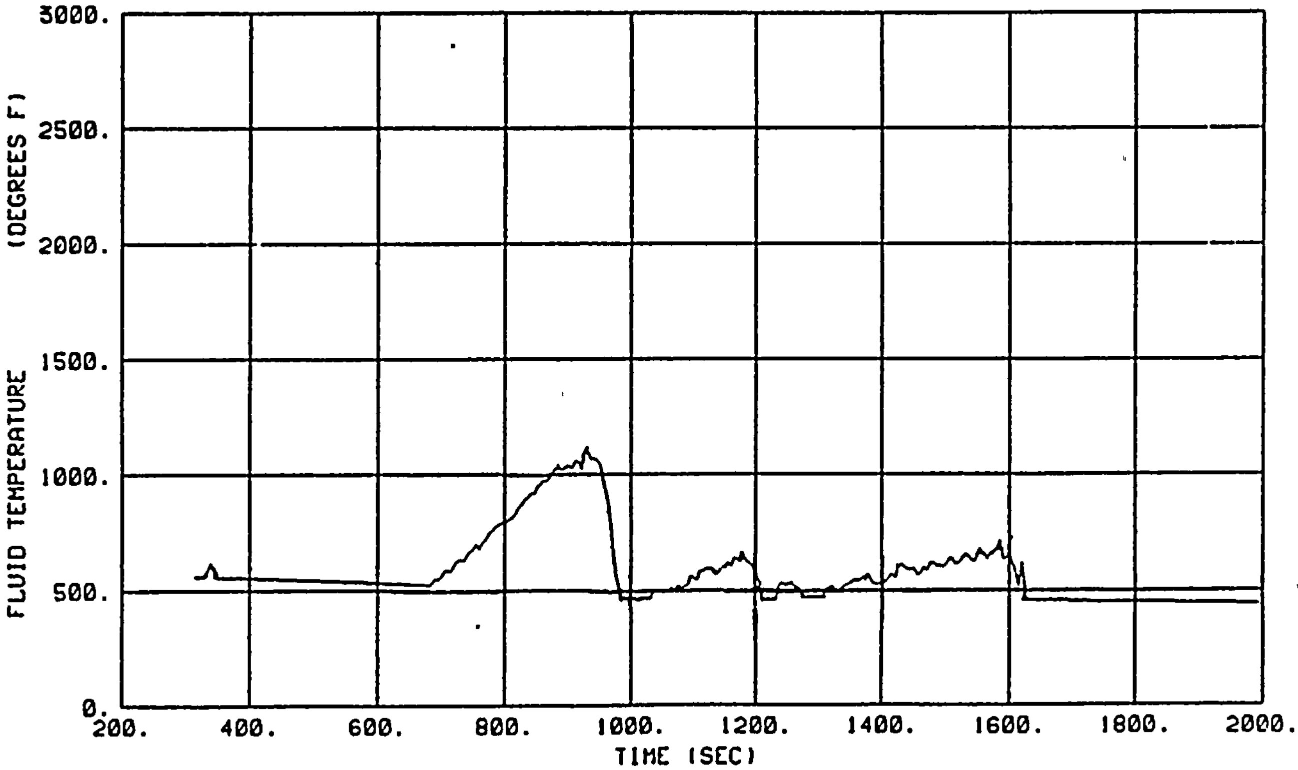


Figure C.3.2-32
HOT SPOT FLUID TEMPERATURE (4 Inch)
HIGH TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

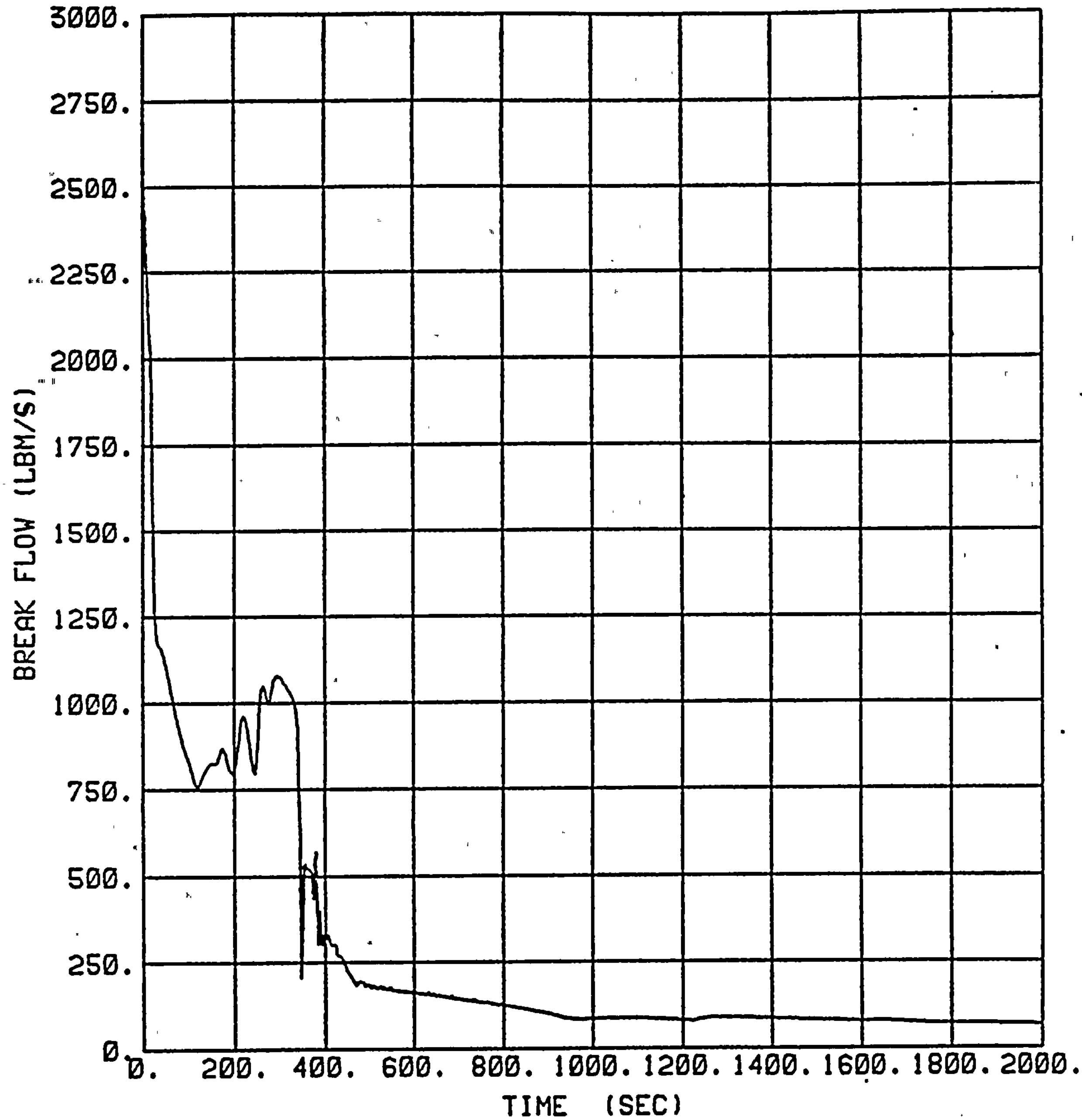


Figure C.3.2-33
TOTAL BREAK FLOW (4 Inch)
HIGH TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

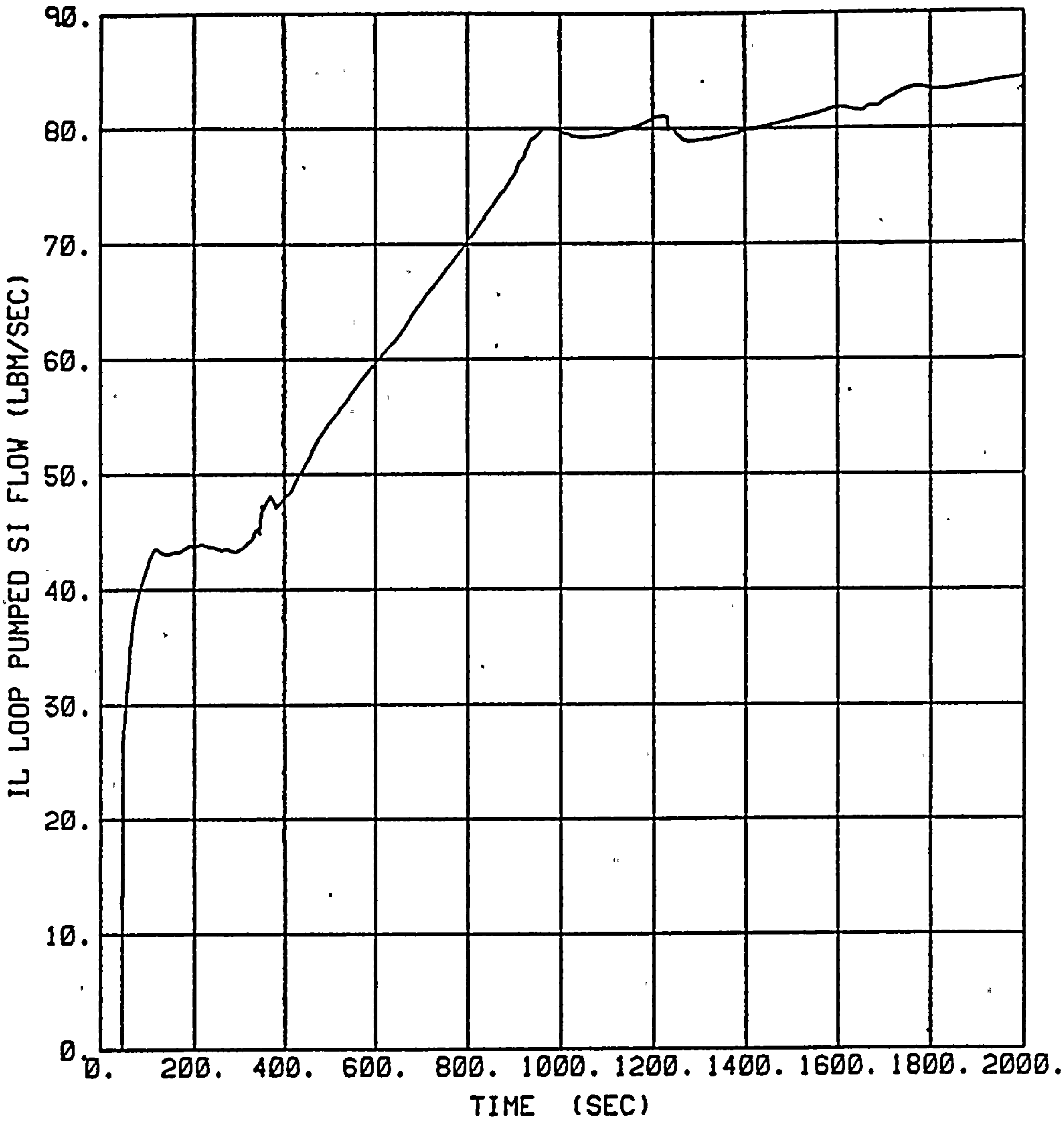


Figure C.3.2-34
INTACT LOOP PUMPED SI FLOW (4 Inch)
HIGH TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

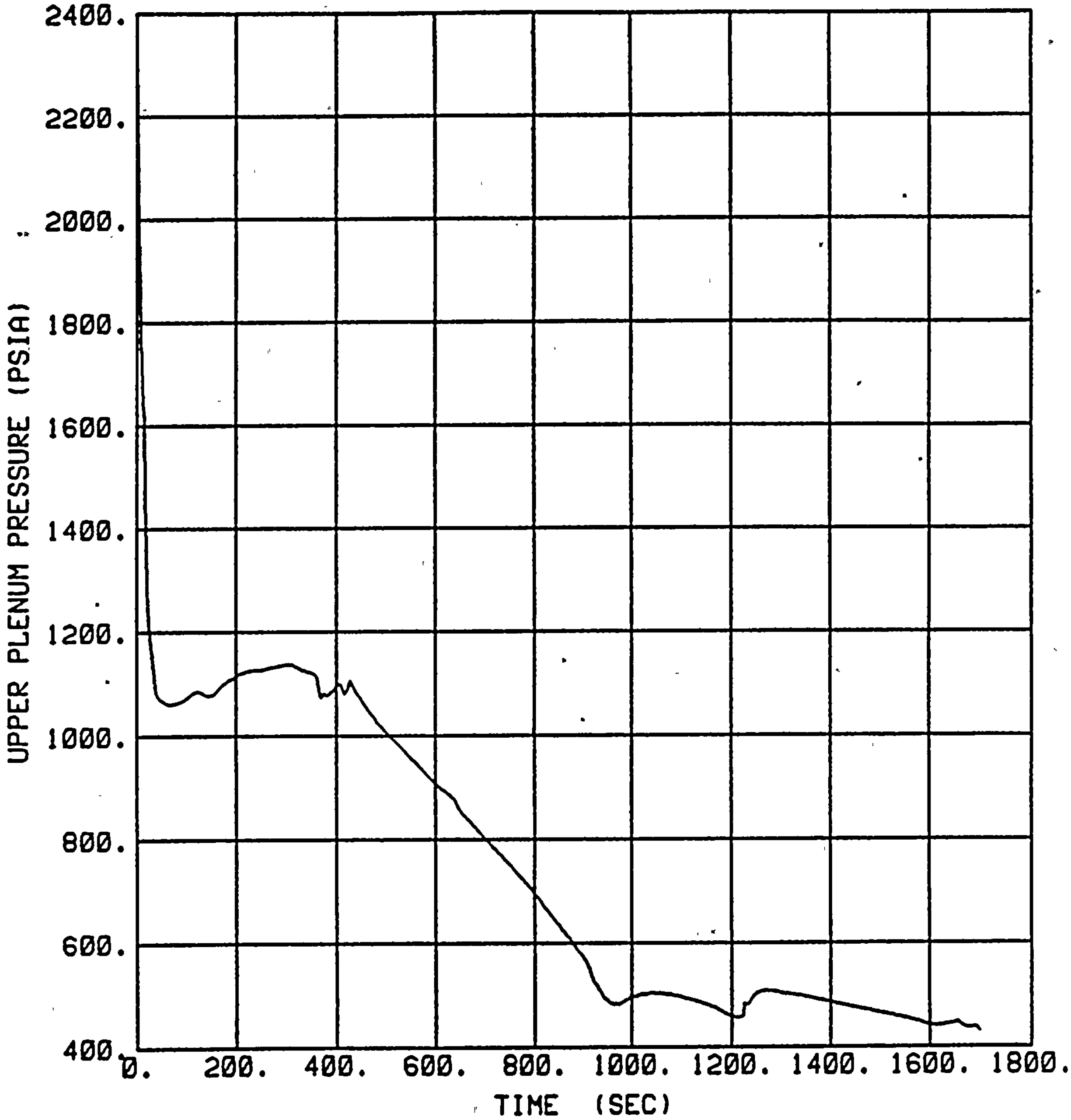


Figure C .3.2-35
RCS PRESSURE (4 Inch)
REDUCED TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

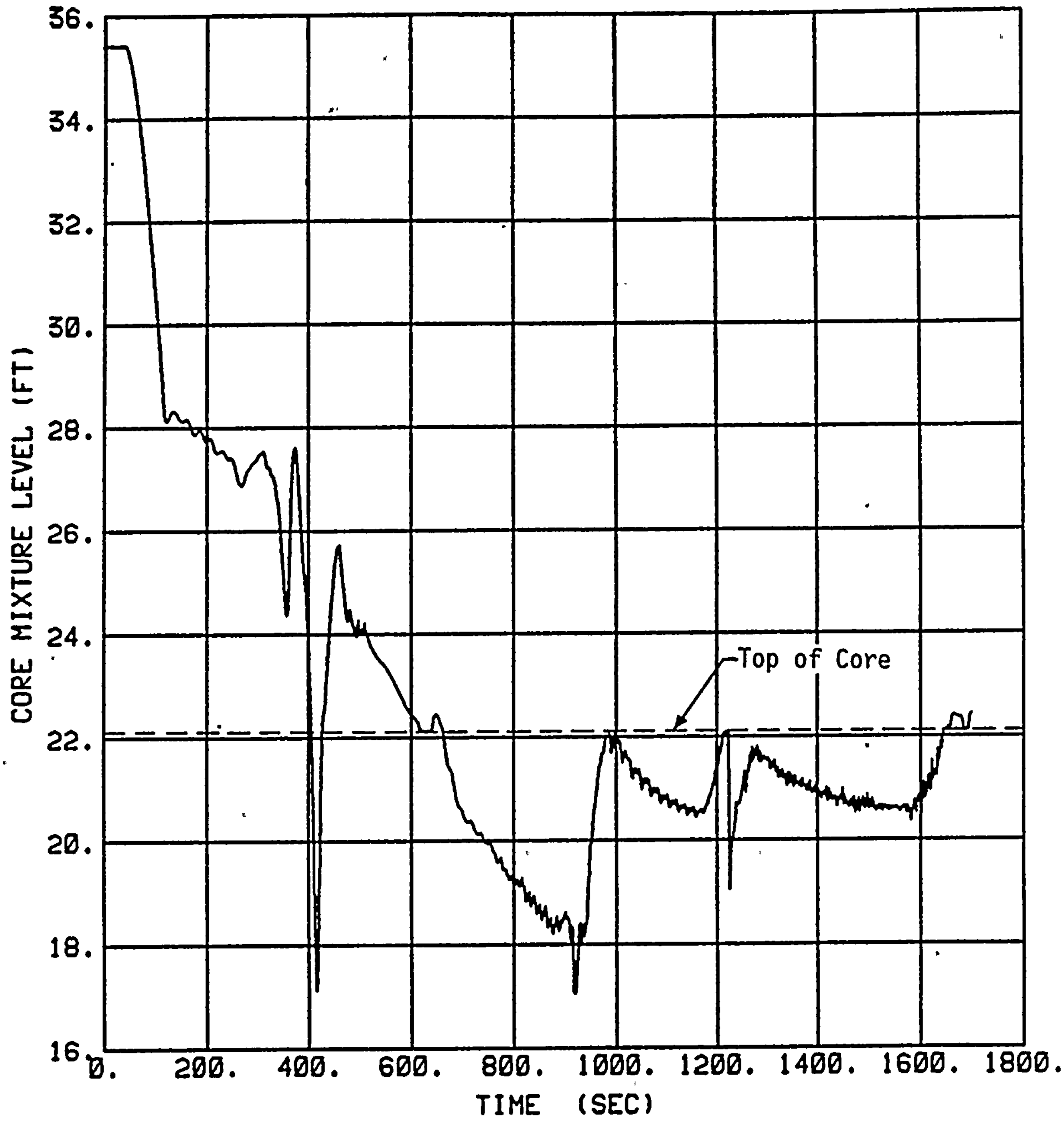


Figure C.3.2-36
CORE MIXTURE HEIGHT (4 Inch)
REDUCED TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

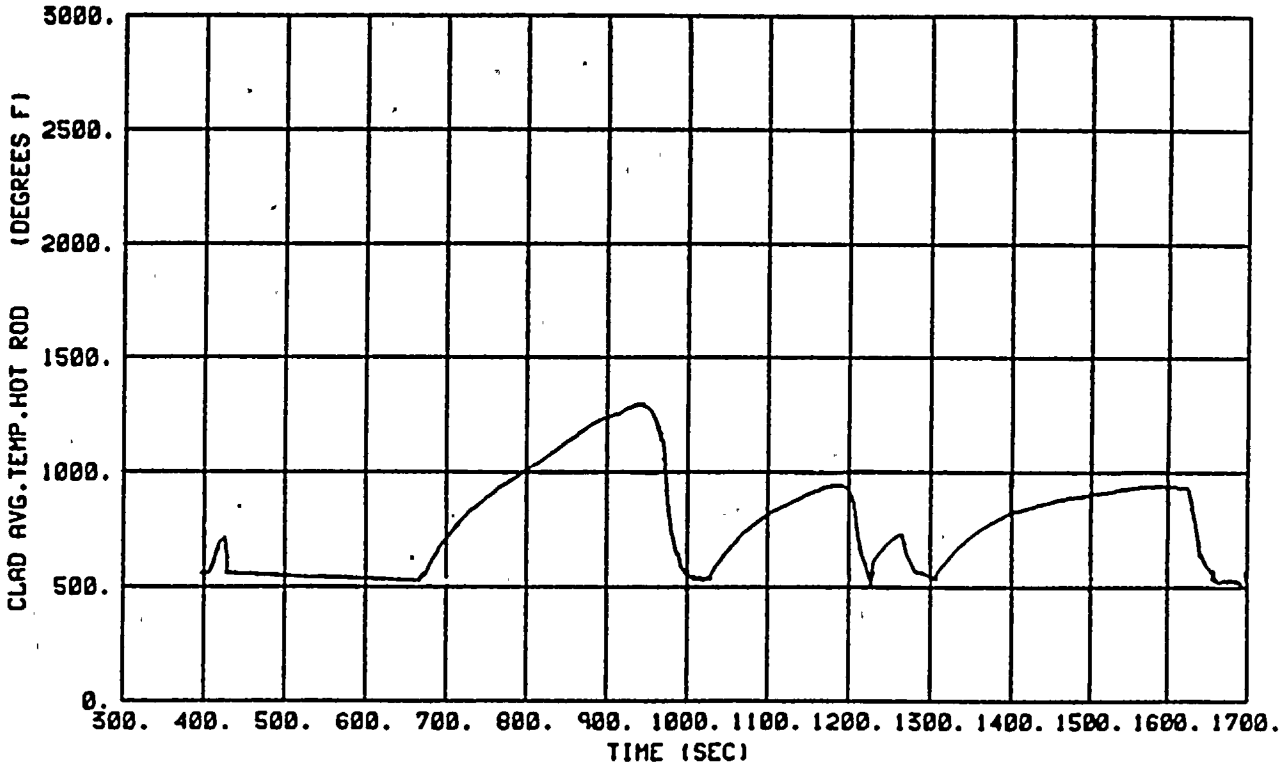


Figure C .3.2-37
HOT SPOT CLAD TEMPERATURE (4 Inch)
REDUCED TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

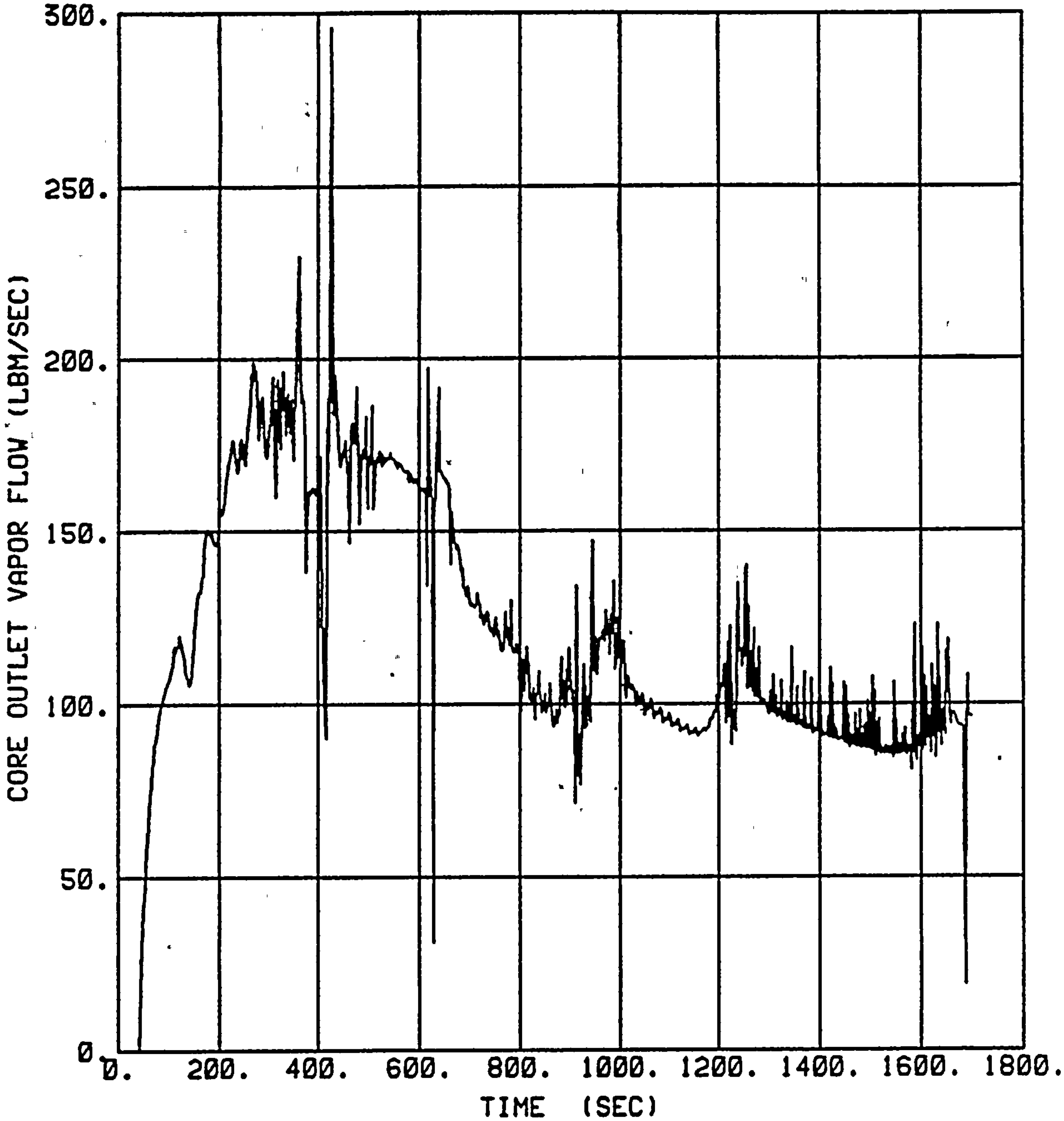


Figure C .3.2-38
CORE STEAM FLOWRATE (4 Inch)
REDUCED TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

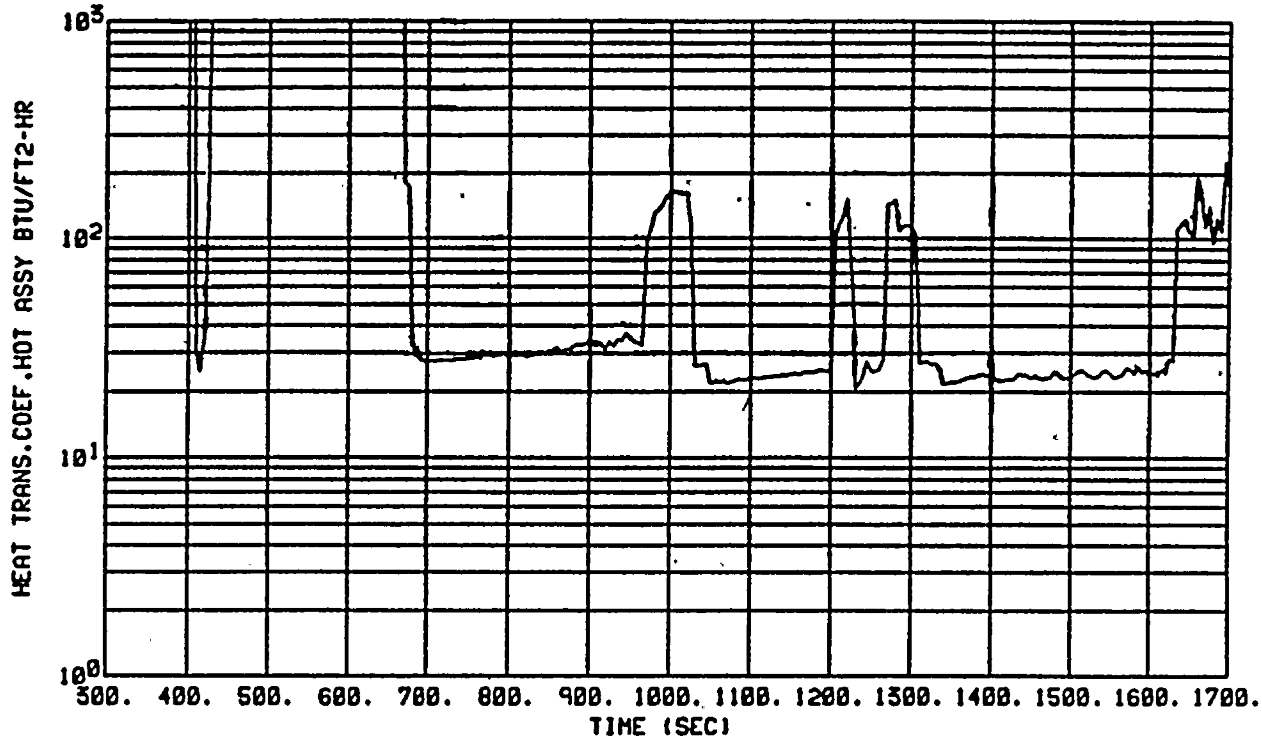


Figure C .3.2-39
HOT SPOT HEAT TRANSFER COEFFICIENT (4 Inch)
REDUCED TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

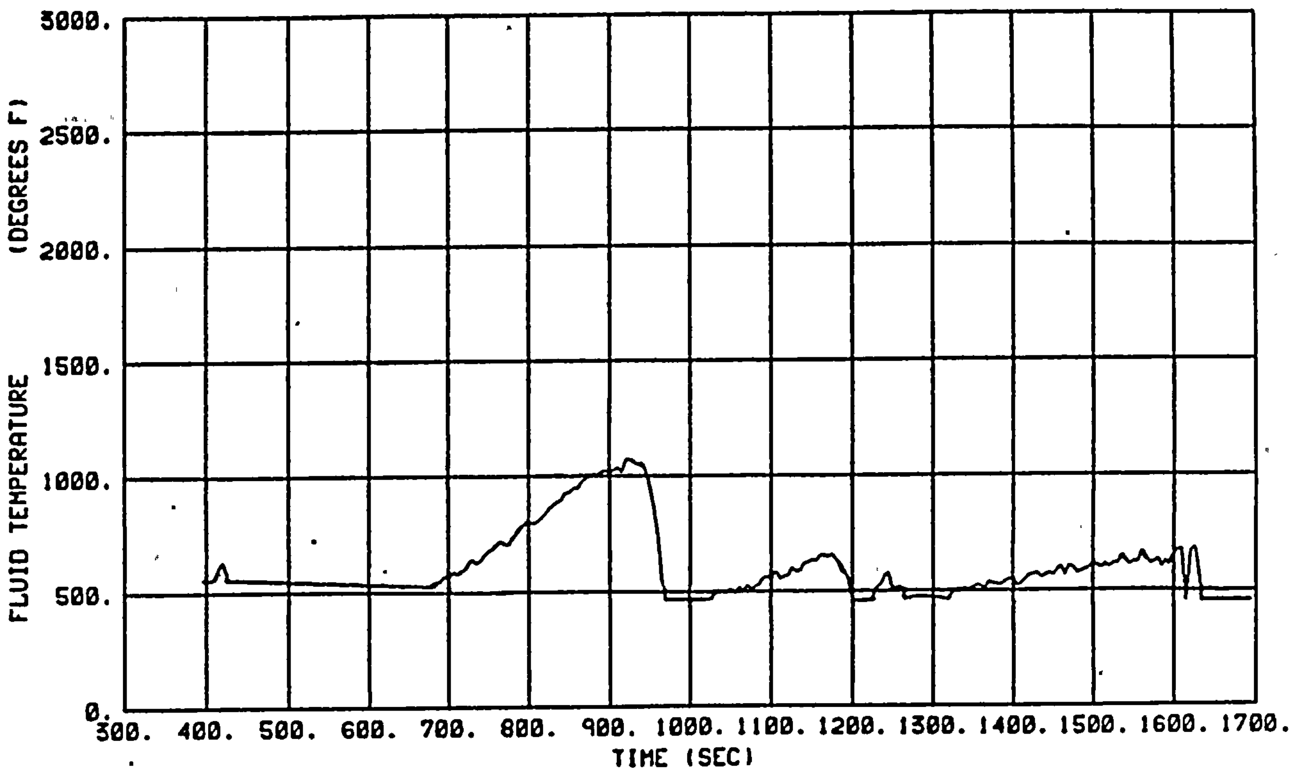


Figure C .3.2-40
HOT SPOT FLUID TEMPERATURE (4 Inch)
REDUCED TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

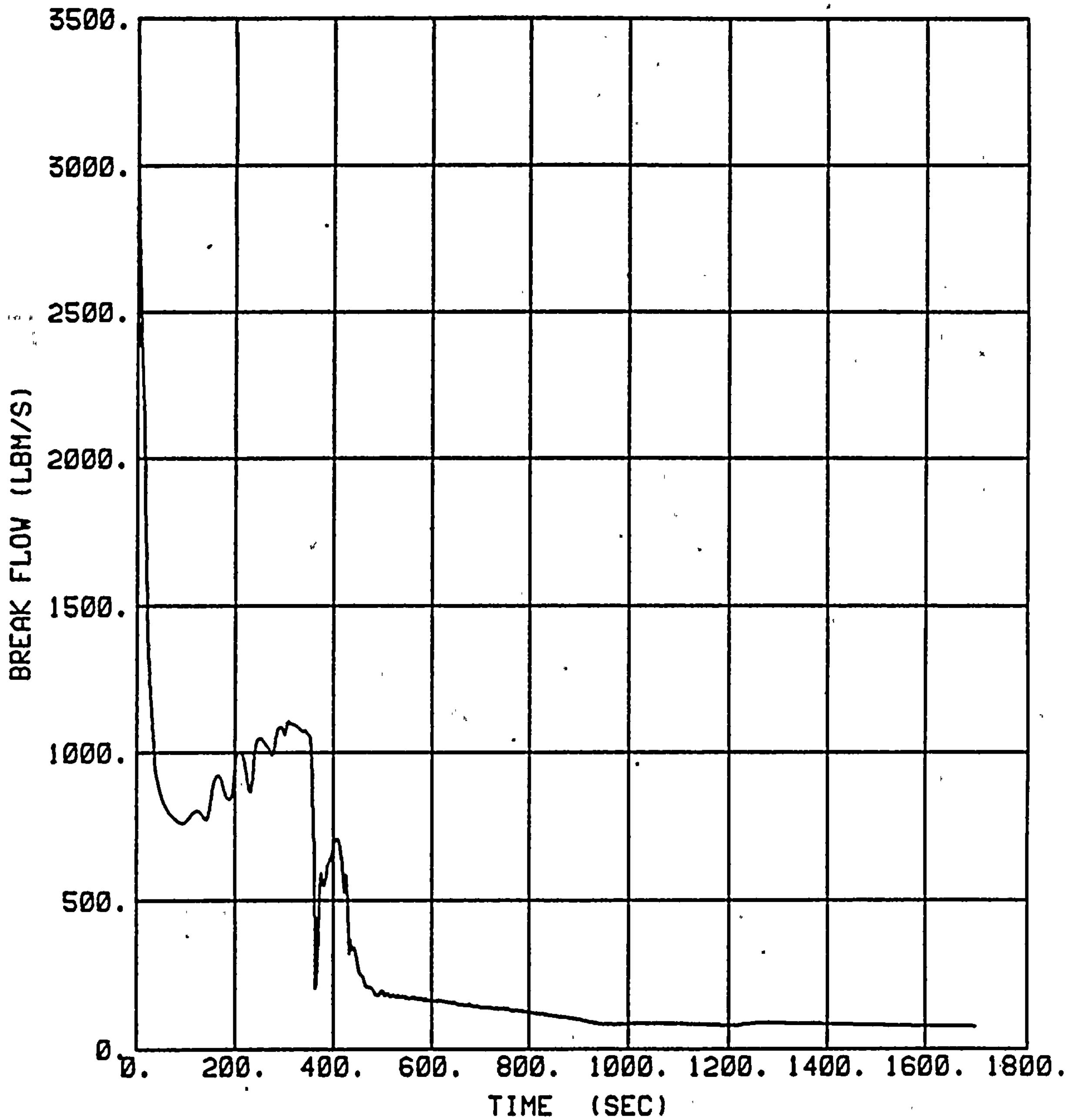


Figure C.3.2-41
TOTAL BREAK FLOW (4 Inch)
REDUCED TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

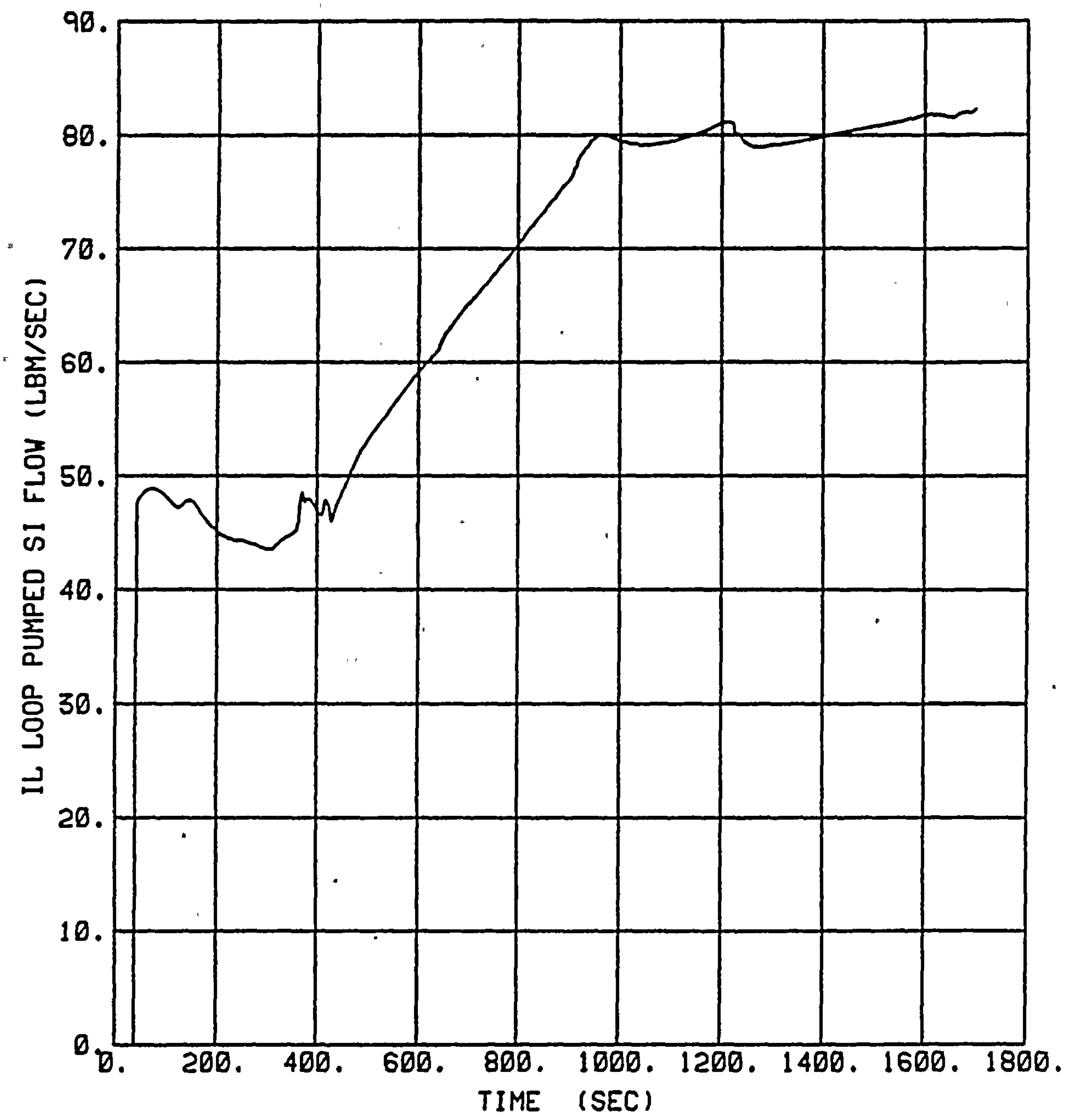


Figure C .3.2-42
INTACT LOOP PUMPED SI FLOW (4 Inch)
REDUCED TEMPERATURE, HIGH PRESSURE
Donald C. Cook Unit 2

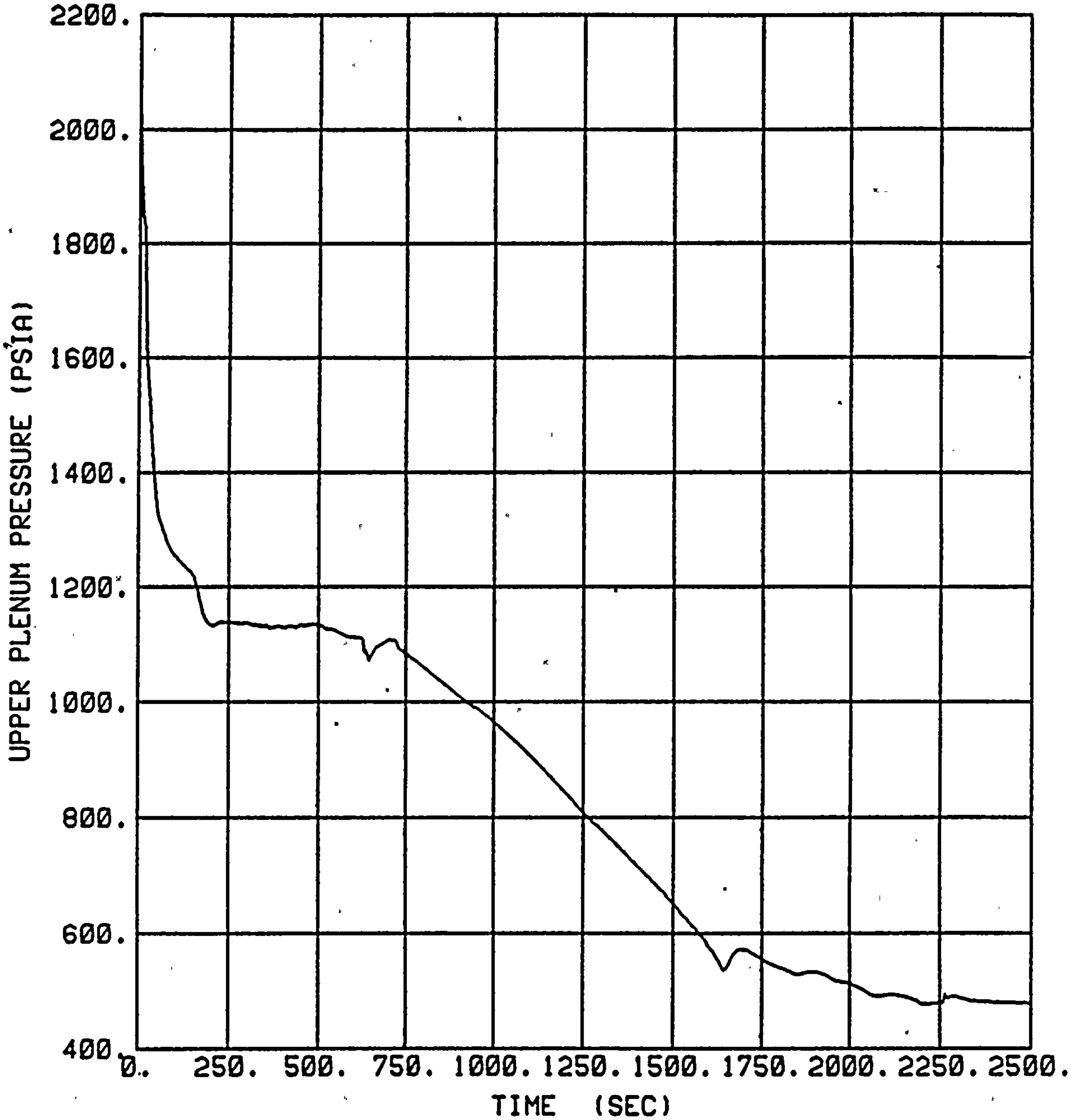


Figure C .3.2-43
RCS PRESSURE (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

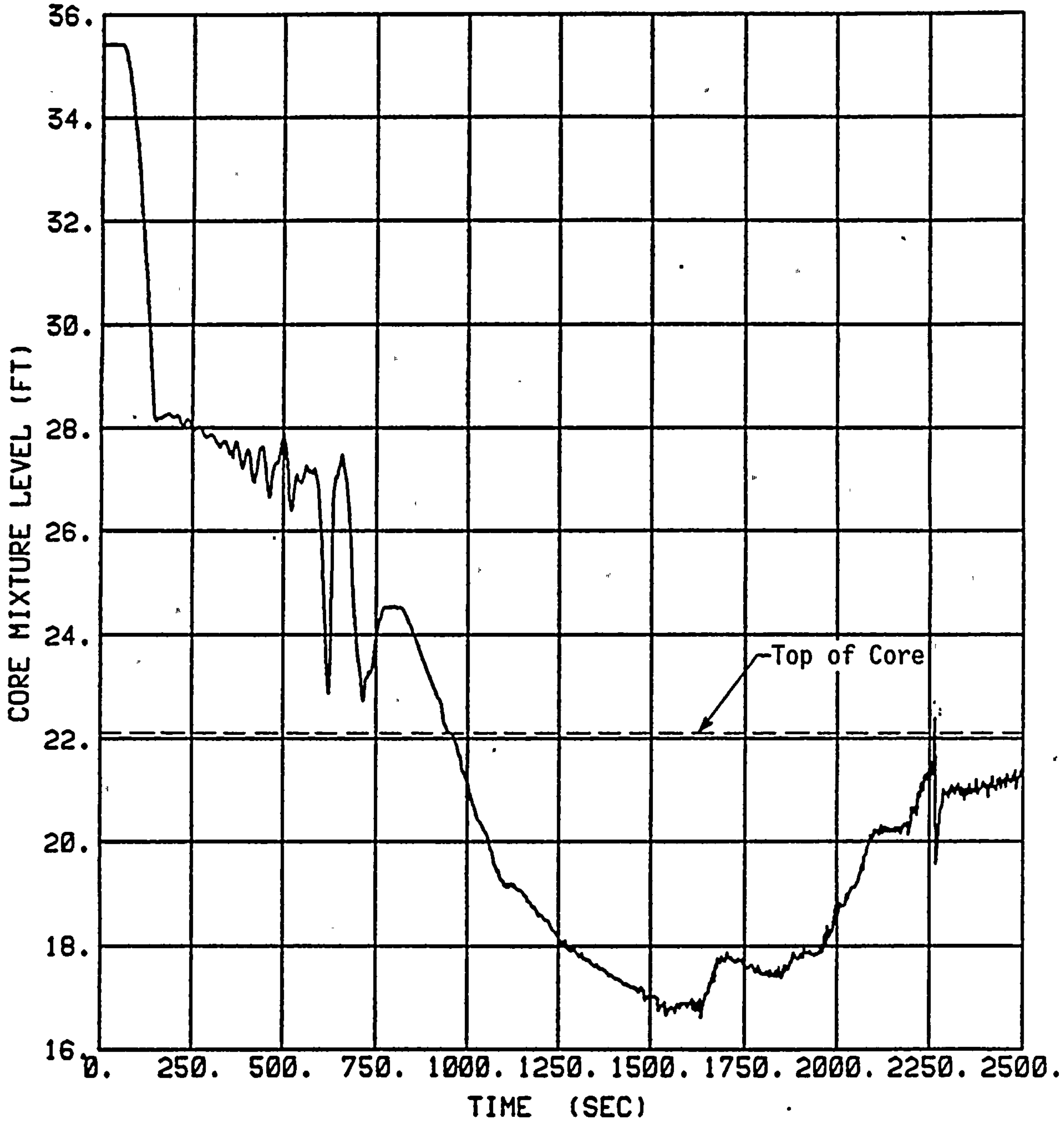


Figure C.3.2-44
CORE MIXTURE HEIGHT (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

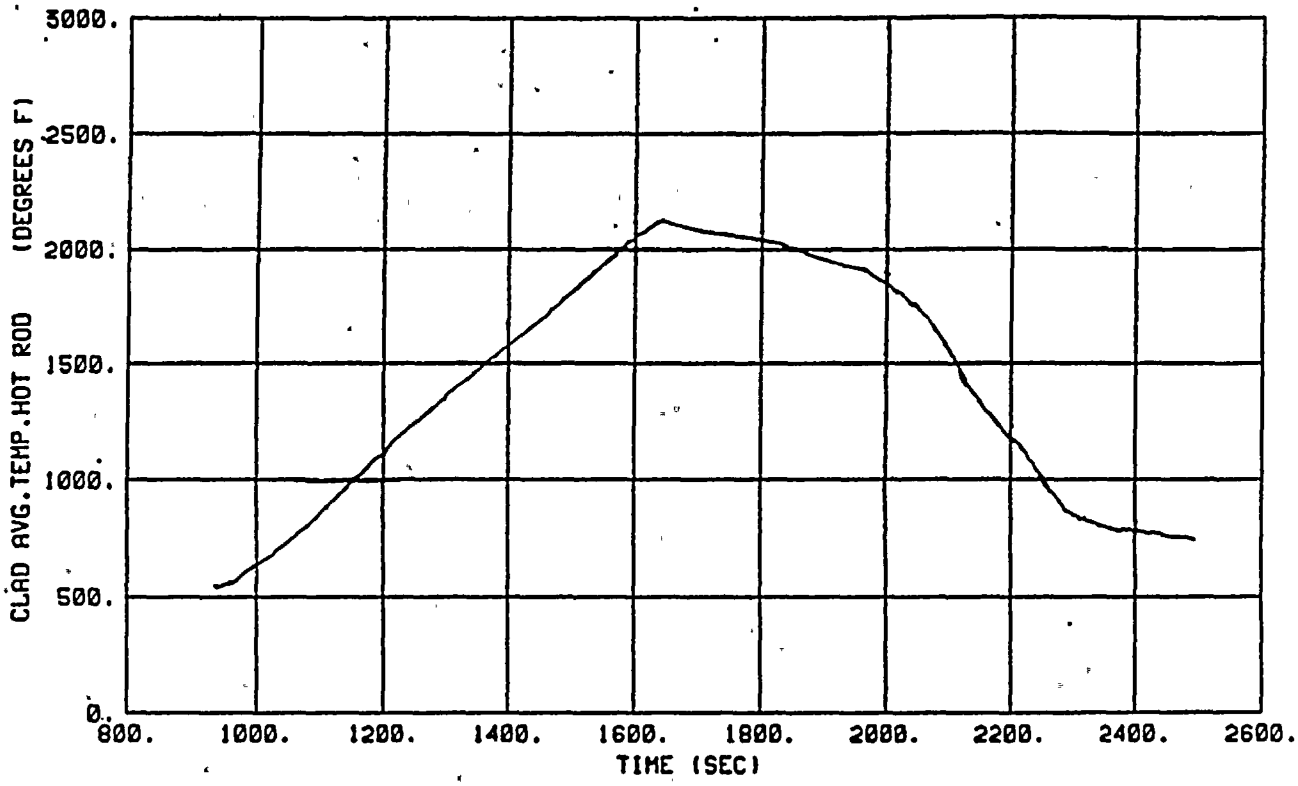


Figure C.3.2-45
HOT SPOT CLAD TEMPERATURE (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

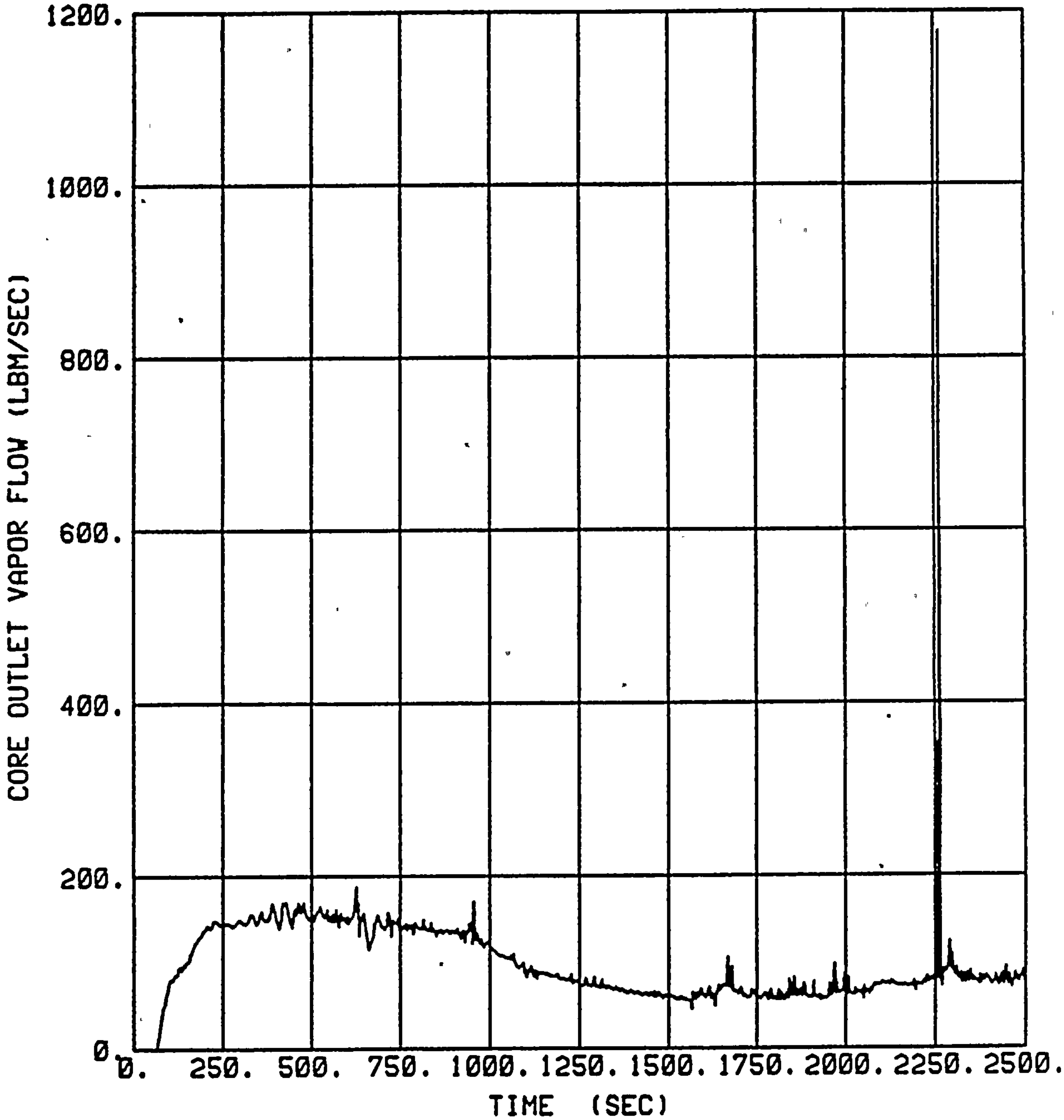


Figure C.3.2-46
CORE STEAM FLOWRATE (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

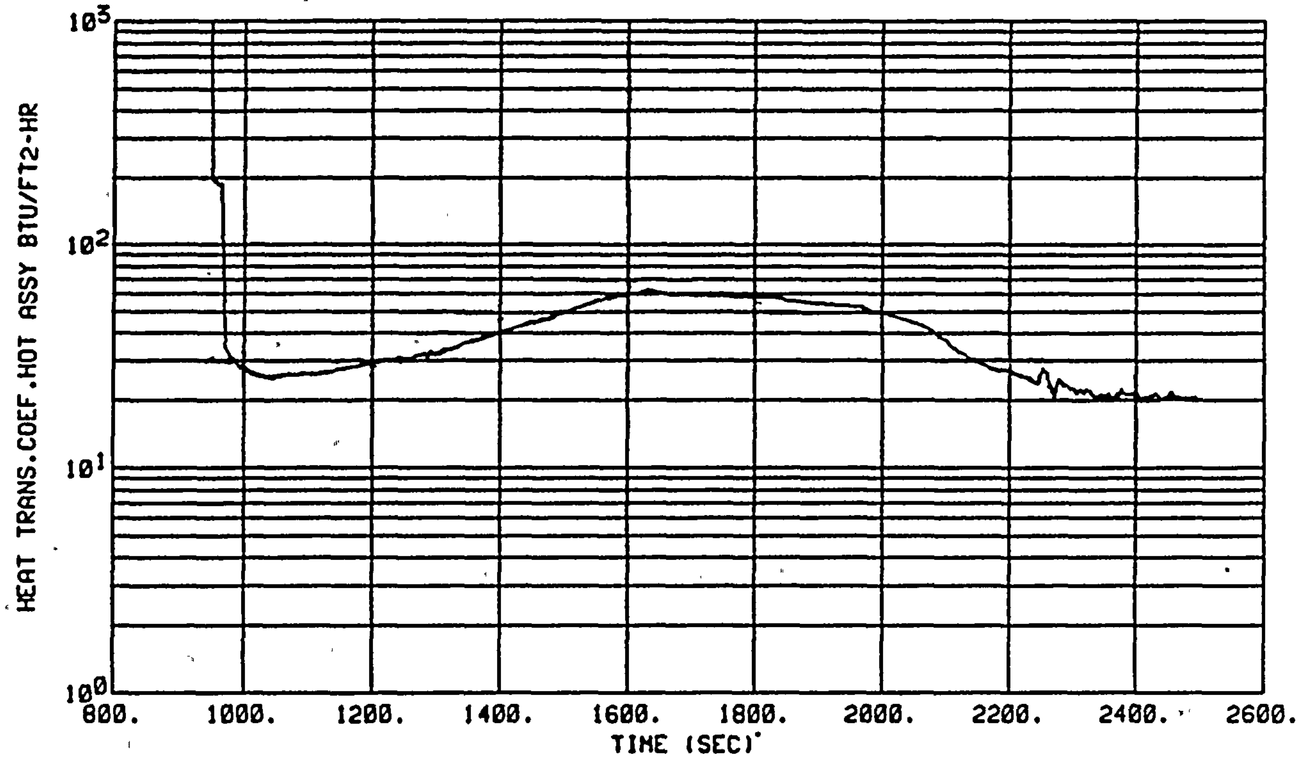


Figure C.3.2-47
HOT SPOT HEAT TRANSFER COEFFICIENT (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

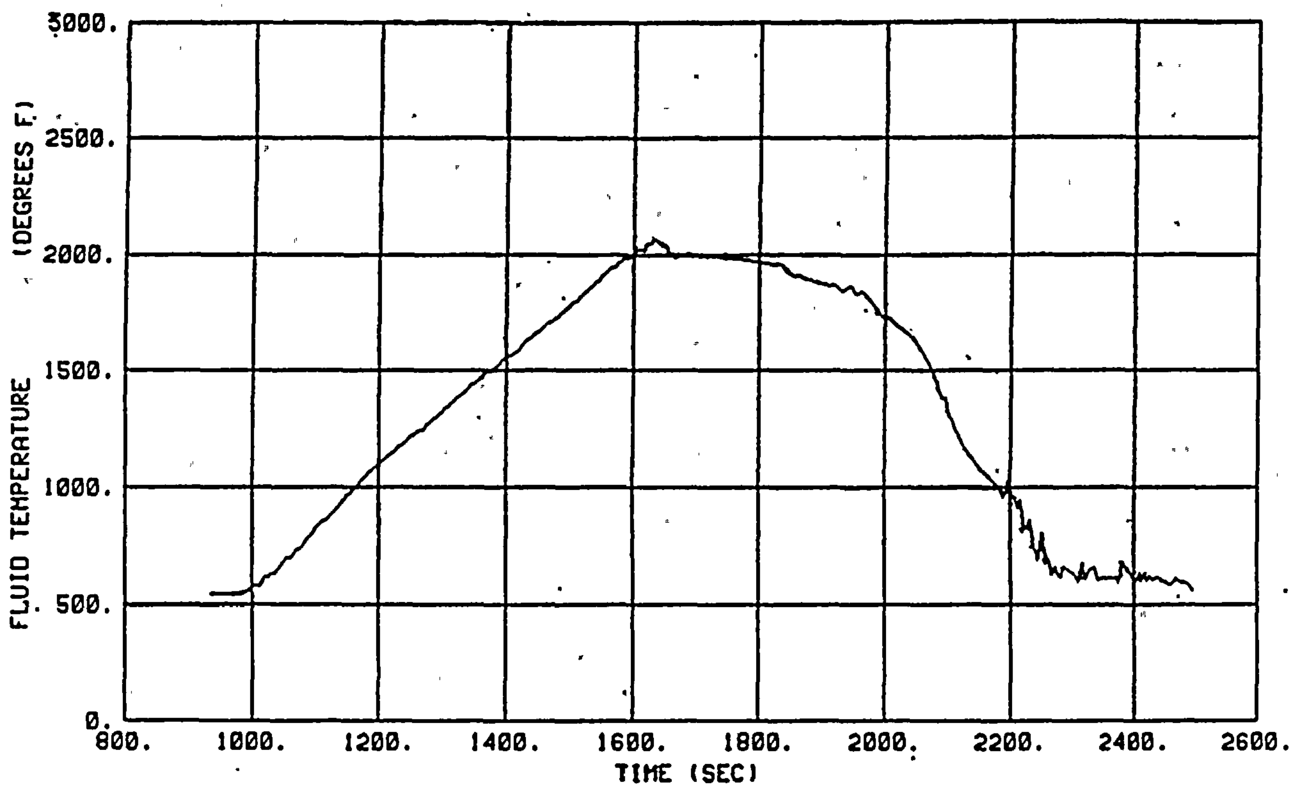


Figure C.3.2-48
HOT SPOT FLUID TEMPERATURE (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

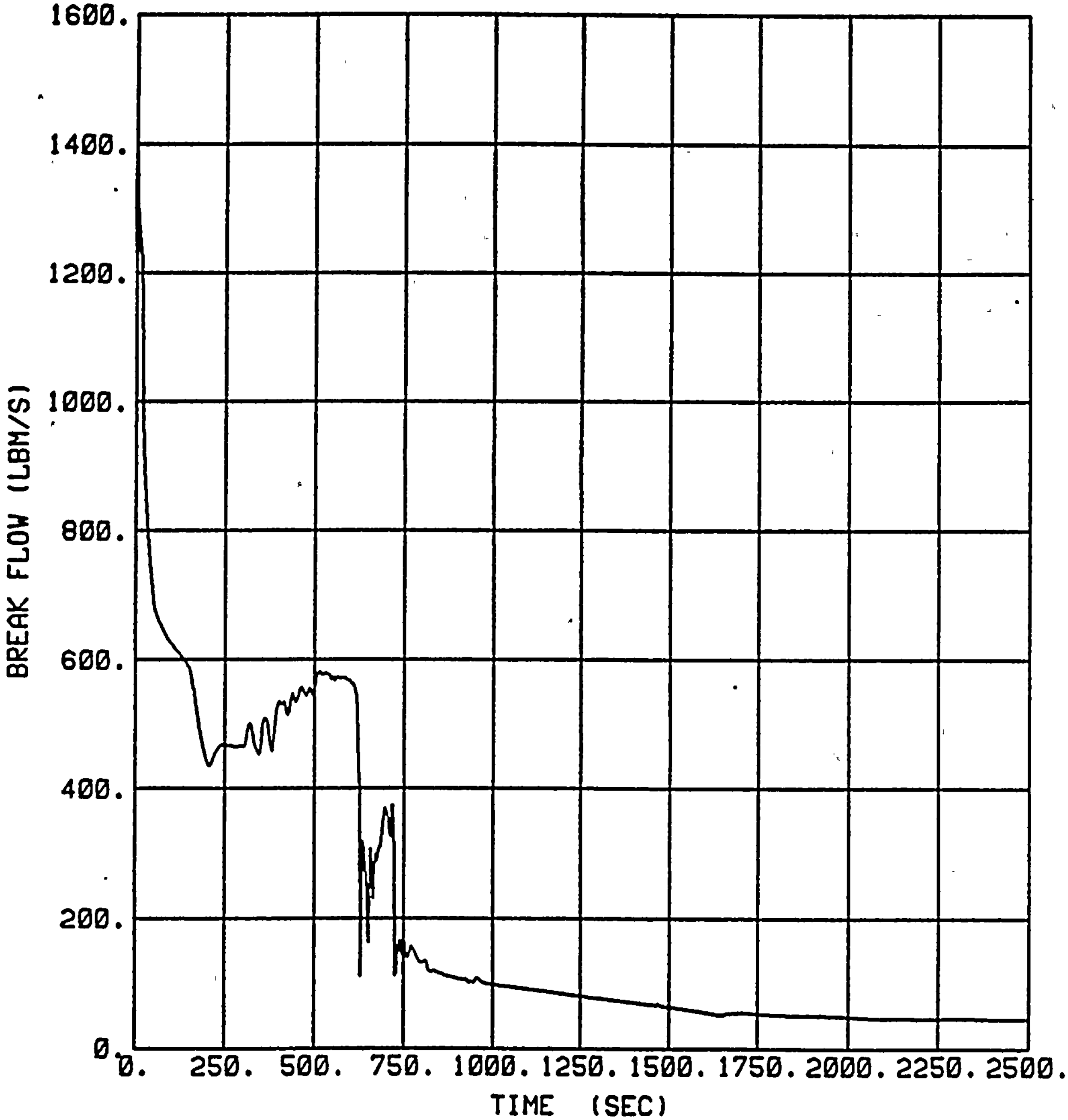


Figure C.3.2-49
TOTAL BREAK FLOW (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

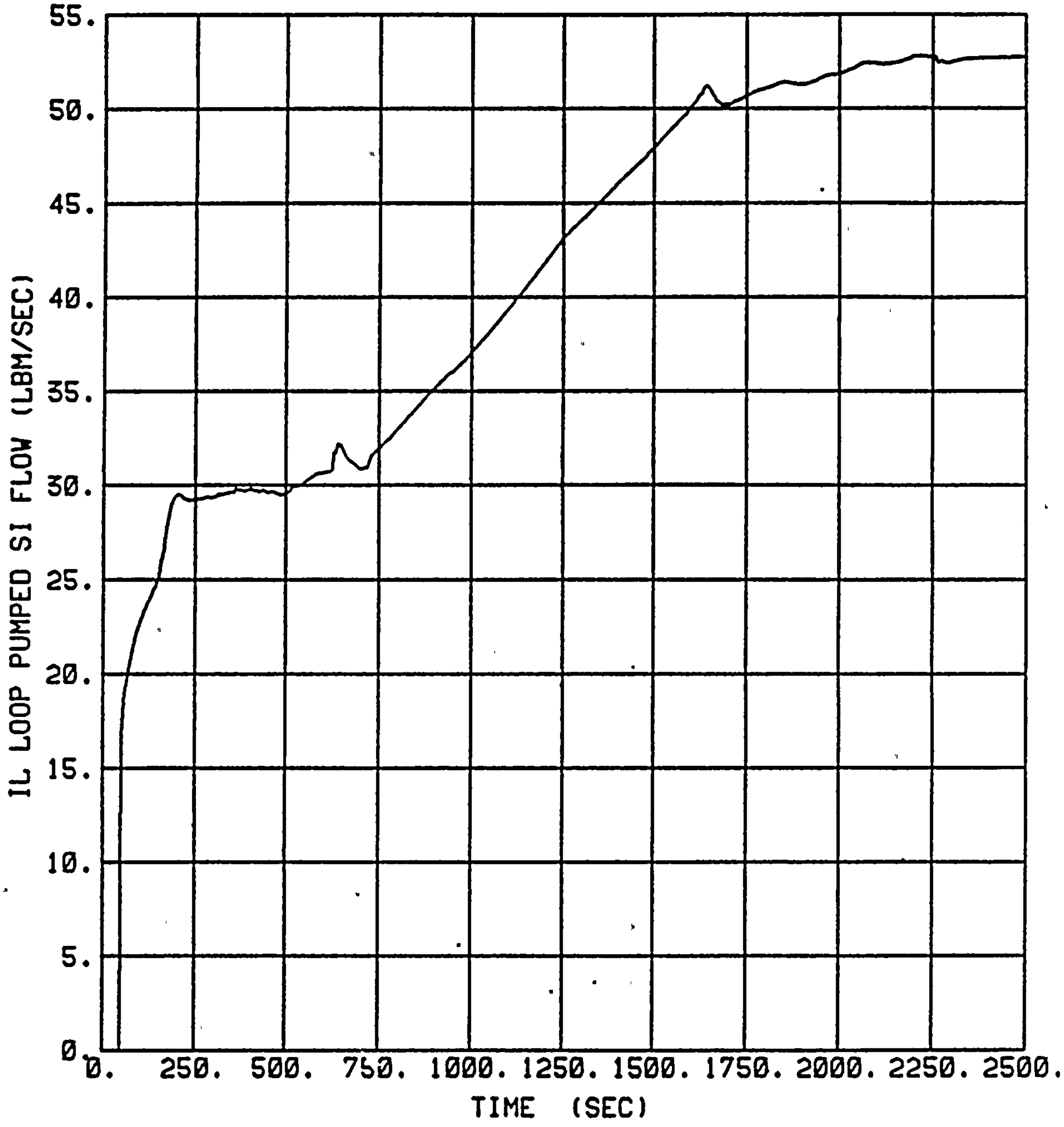


Figure C.3.2-50
INTACT LOOP PUMPED SI FLOW (3 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

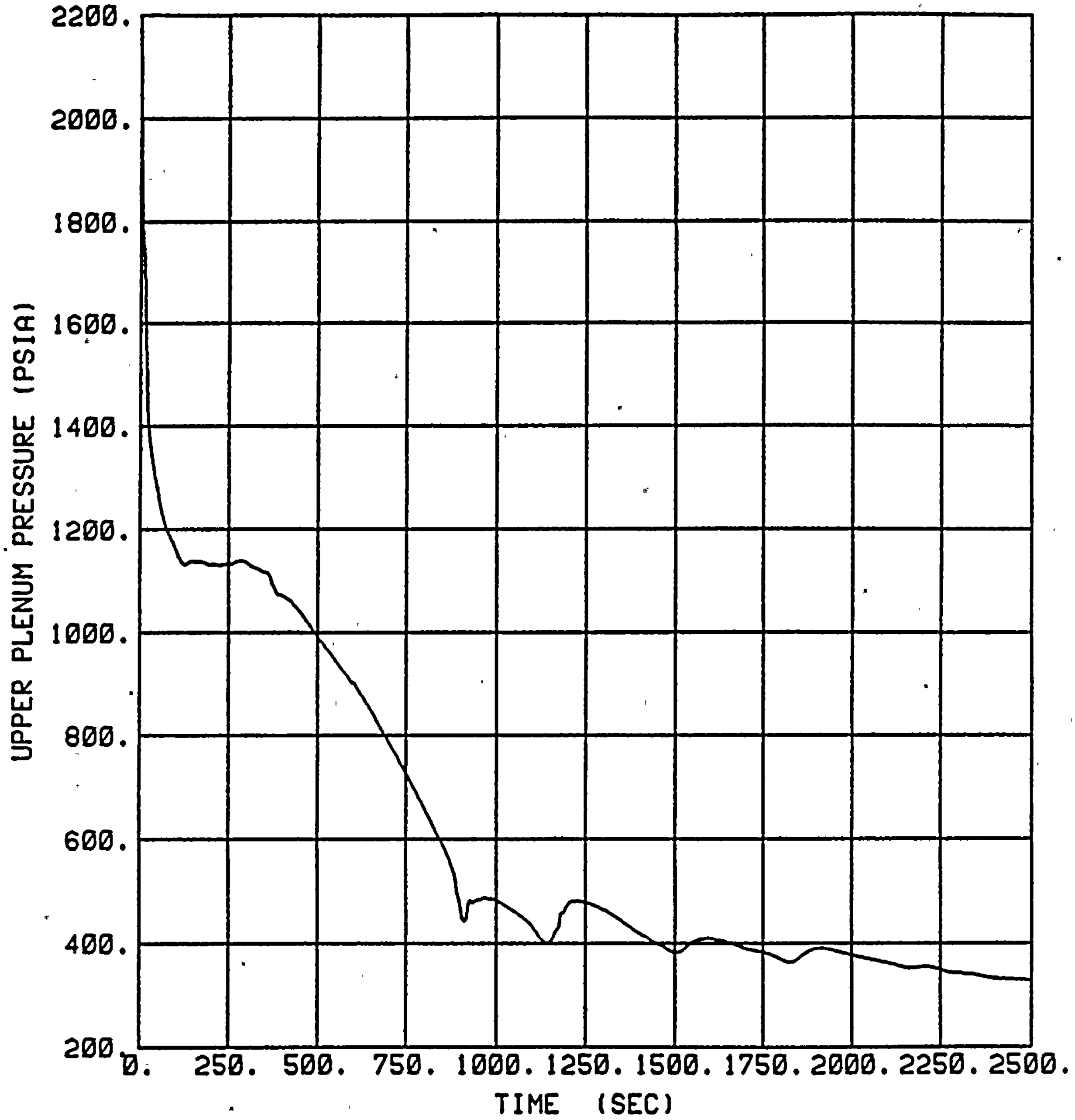


Figure C.3.2-51
RCS PRESSURE (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

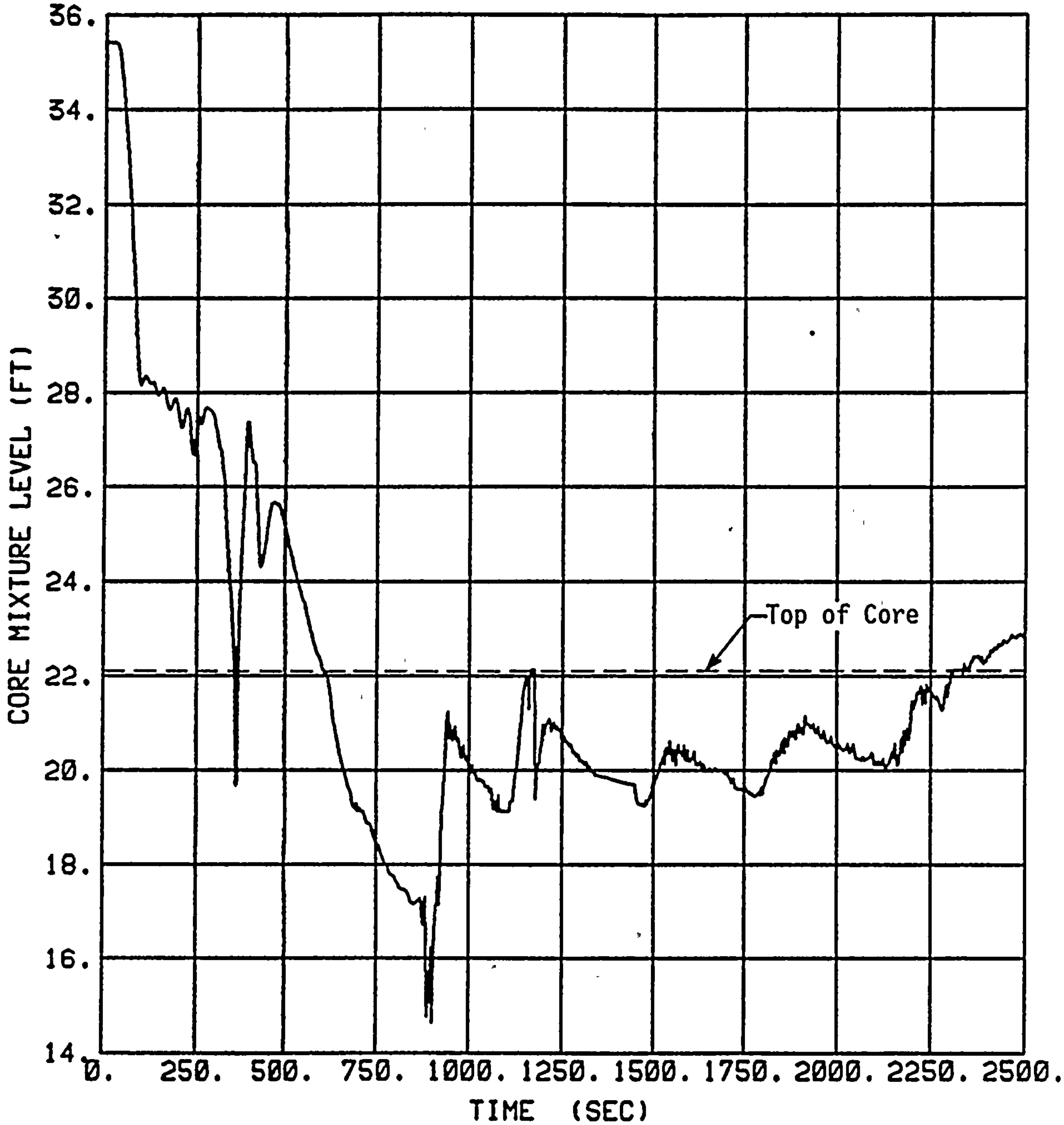


Figure C.3.2-52
CORE MIXTURE HEIGHT (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

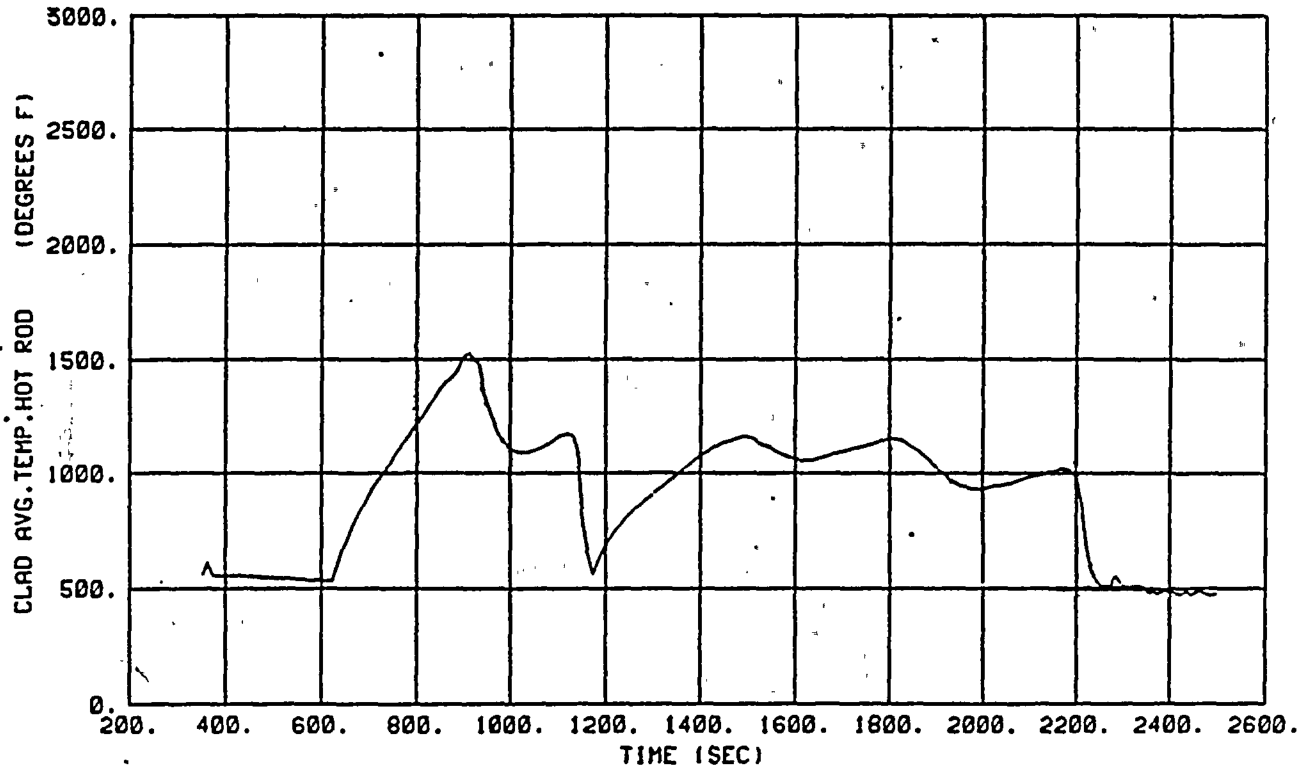


Figure C.3.2-53
HOT SPOT CLAD TEMPERATURE (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

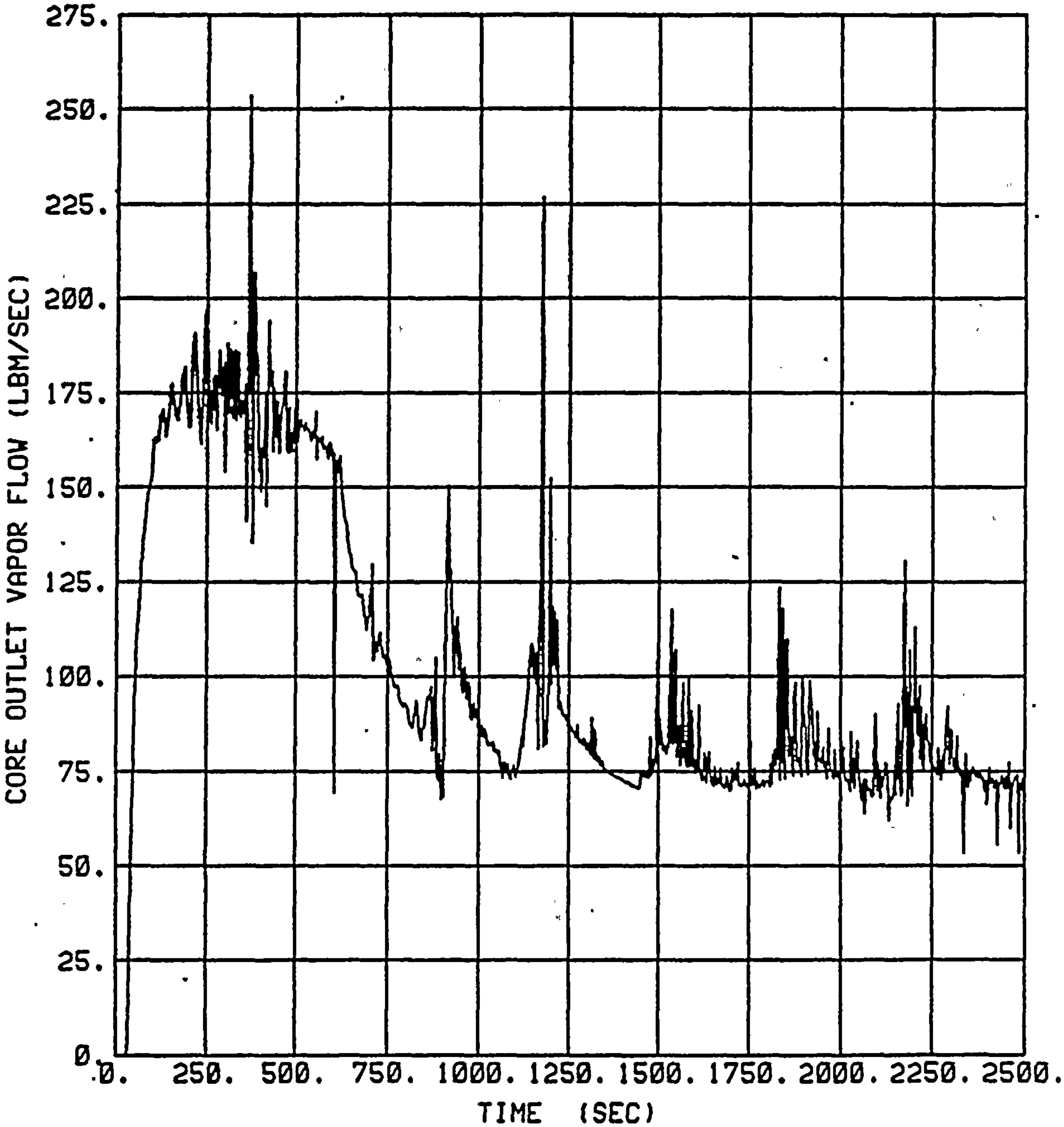


Figure C.3.2-54
CORE STEAM FLOWRATE (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

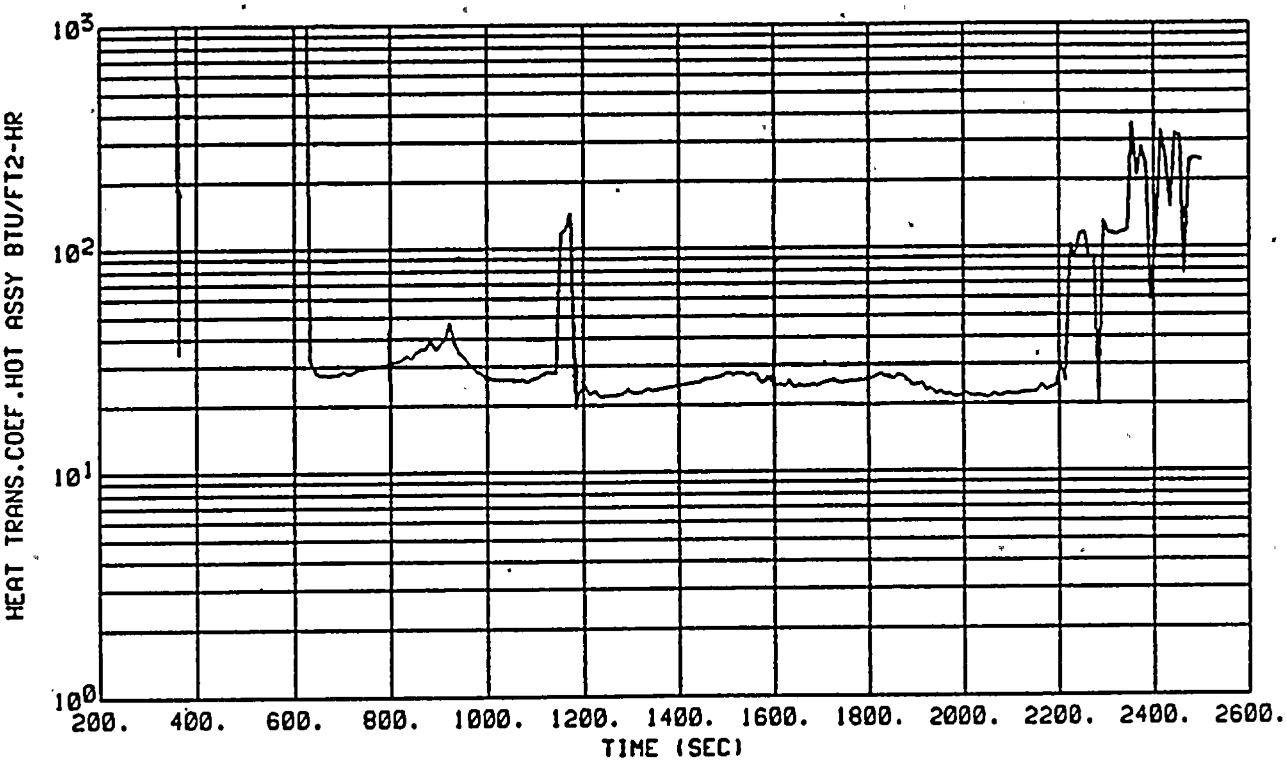


Figure C .3.2-55
HOT SPOT HEAT TRANSFER COEFFICIENT (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

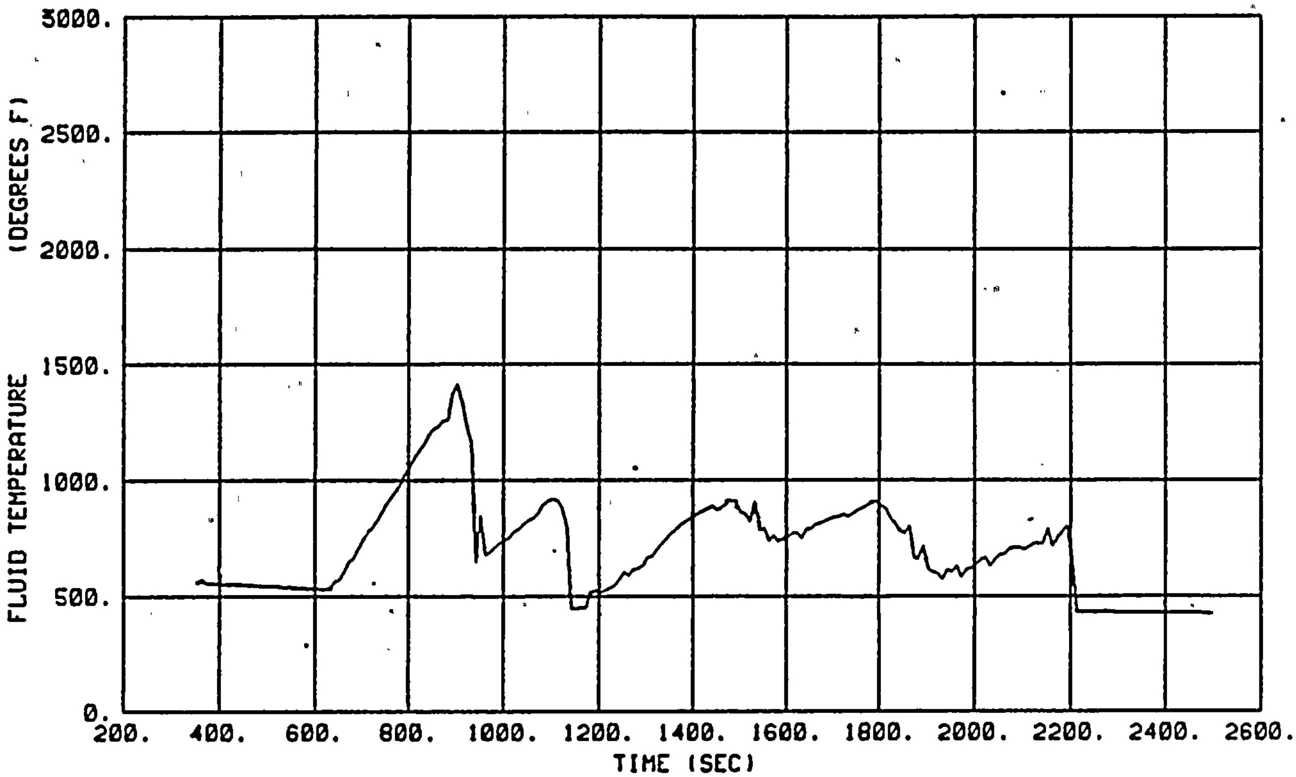


Figure C.3.2-56
HOT SPOT FLUID TEMPERATURE (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

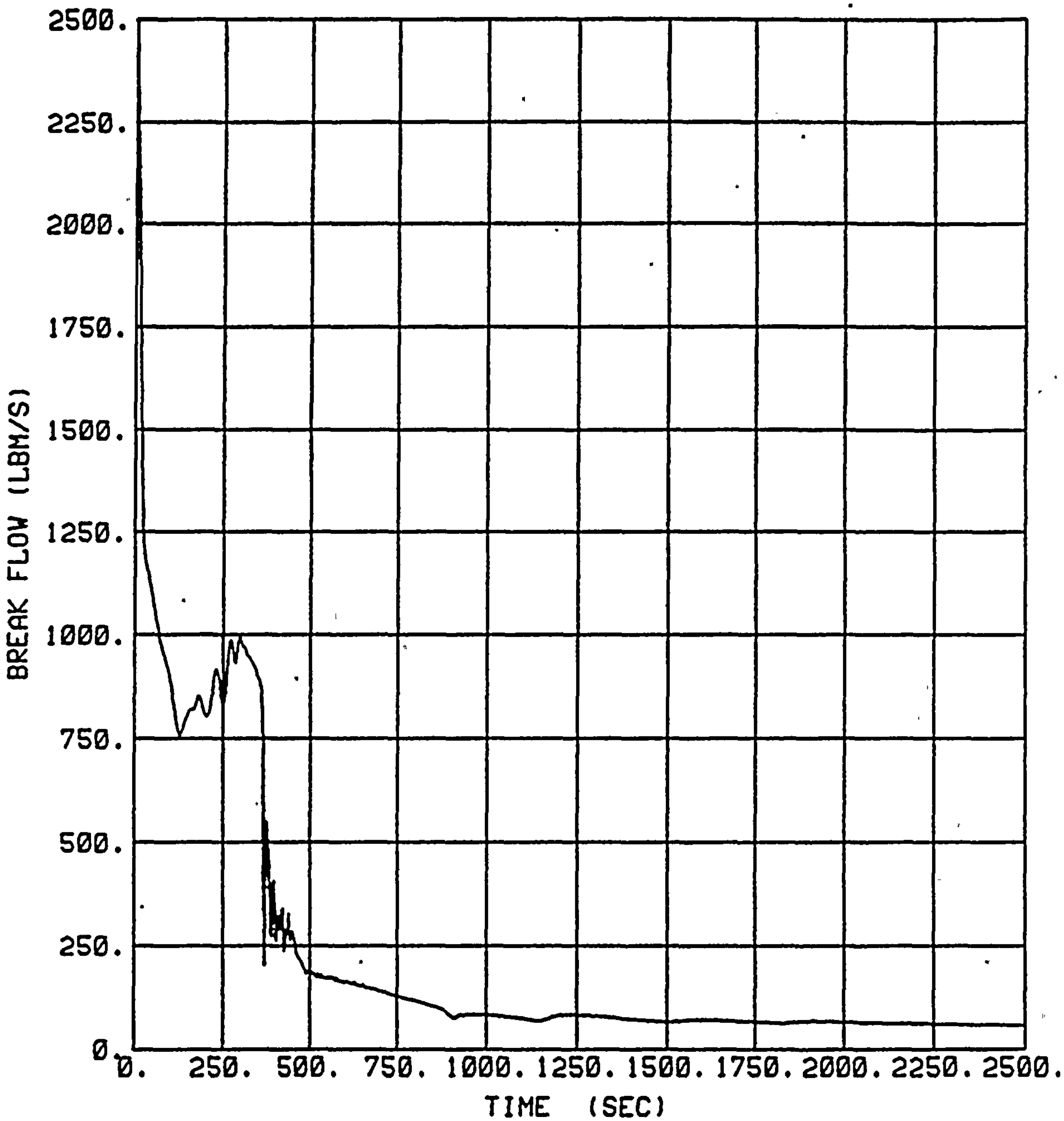


Figure C.3.2-57
TOTAL BREAK FLOW (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

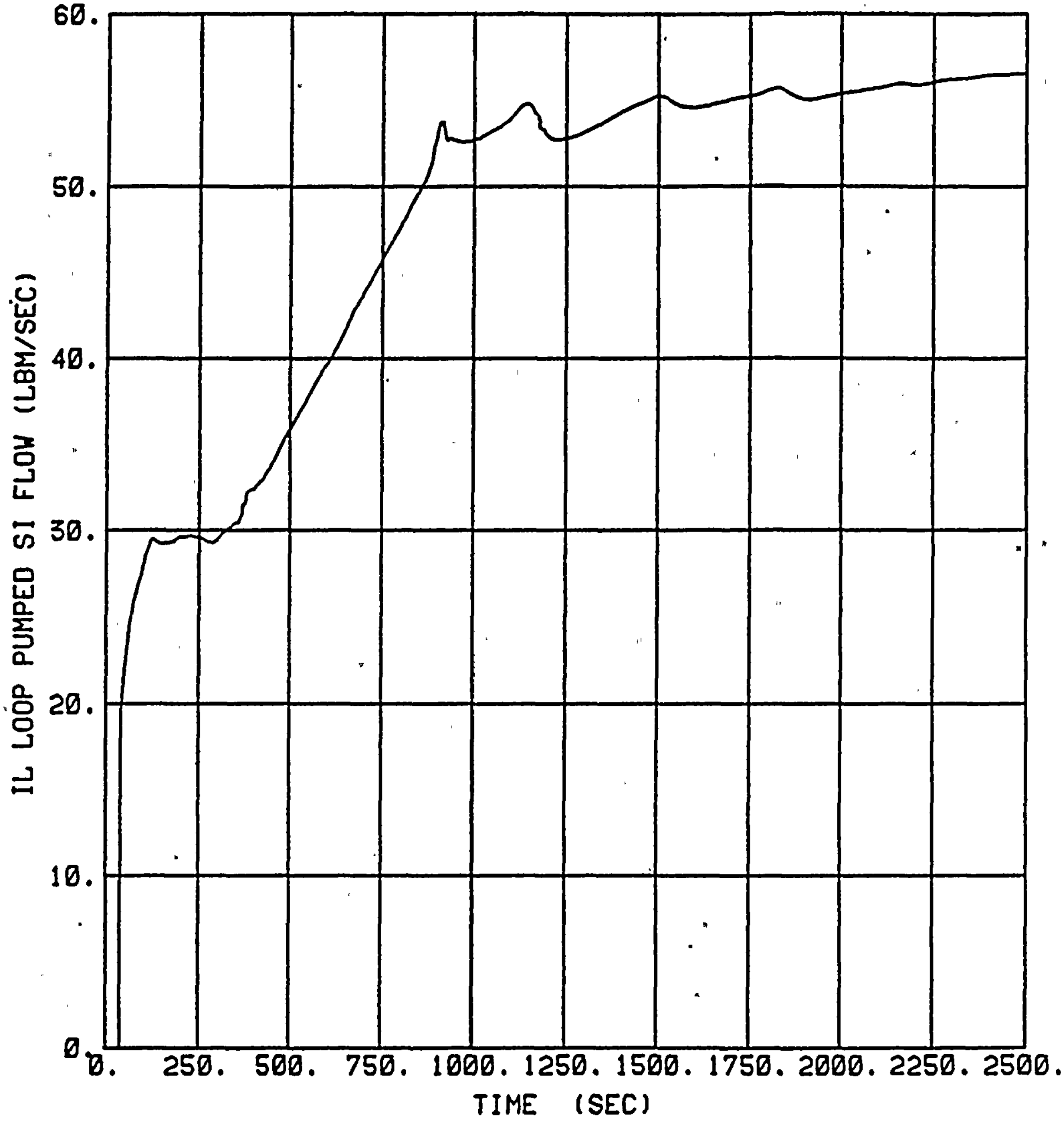


Figure C.3.2-58
INTACT LOOP PUMPED SI FLOW (4 Inch)
HIGH TEMPERATURE, REDUCED PRESSURE
CROSS TIES CLOSED
Donald C. Cook Unit 2

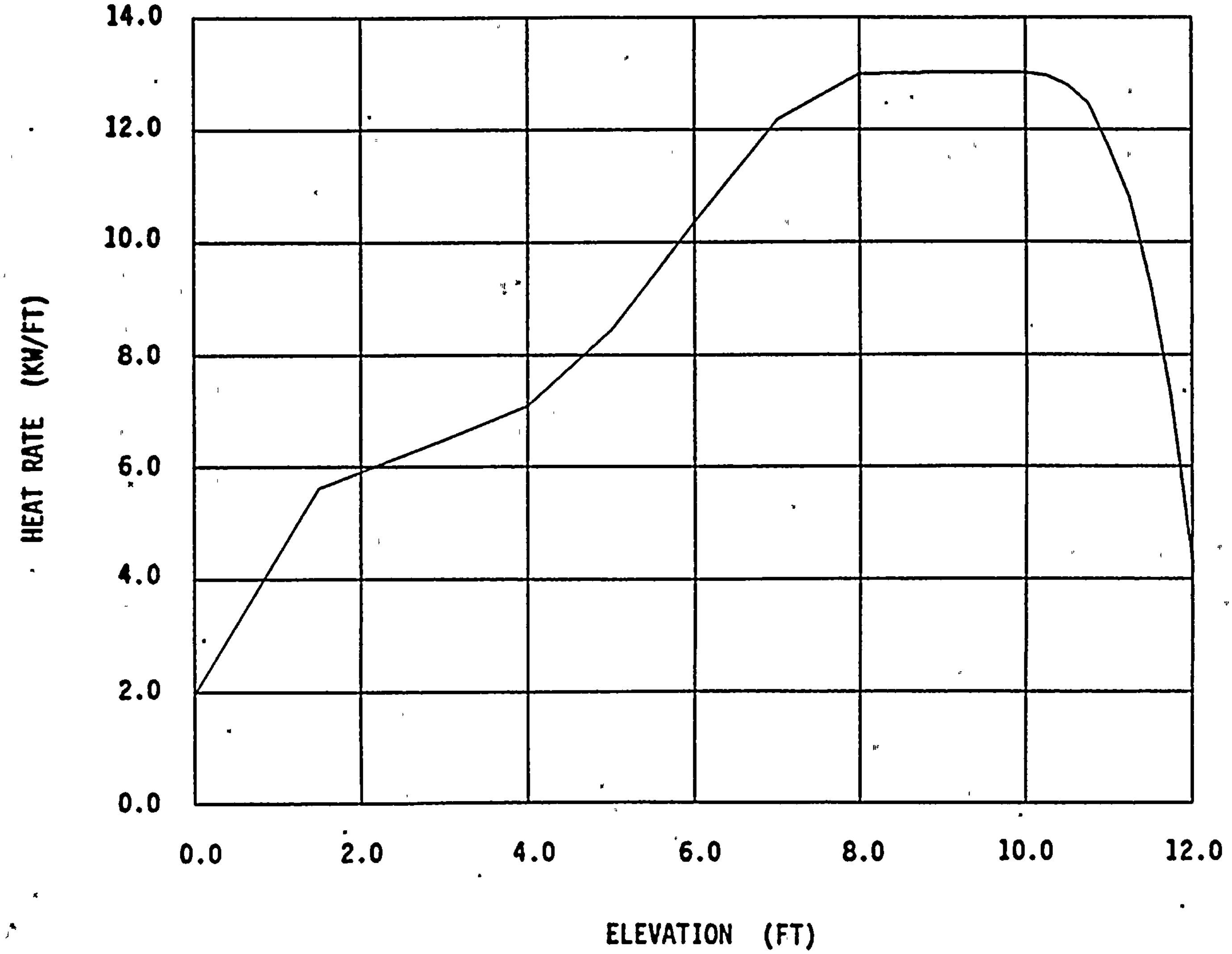


Figure C.3.2-59
HOT ROD POWER DISTRIBUTION
3413 MWT SI CROSS TIES CLOSED
Donald C. Cook Unit 2

ATTACHMENT 5 TO AEP:NRC:1071E

PORTIONS OF WCAP 11902, SUPPLEMENT 1

STEAMLINE BREAK MASS/ENERGY RELEASES
DESCRIPTION AND SUPPORTING MATERIAL

TABLE S-3.13-2, UNIT 1 SAFETY INJECTION
AND RESIDUAL HEAT REMOVAL PUMP
DIFFERENTIAL PRESSURES

WCAP-11902
Supplement 1

RERATED POWER AND REVISED TEMPERATURE AND PRESSURE OPERATION FOR DONALD C. COOK NUCLEAR PLANT UNITS 1 & 2 LICENSING REPORT

September 1989

WESTINGHOUSE ELECTRIC CORPORATION
Energy Systems Business Unit
P.O. BOX 355
Pittsburgh, Pennsylvania 15230

TABLE S-2.1-1

COOK NUCLEAR PLANT UNITS 1 AND 2
DESIGN POWER CAPABILITY PARAMETERS FOR RERATING PROGRAM

Parameter	(Unit 1, Original) Case 1	(Unit 2, Current) Case 2
NSSS Power, MWt	3250	3423
Core Power, MWt	3250	3411
RCS Flow,(gpm/loop)*	88,500	-***
Minimum Measured Flow, (total gpm)**	366,400	364,960
RCS Temperatures, °F		
Core Outlet	602.0	-
Vessel Outlet	599.3	-
Core Average	570.5	575.5
Vessel Average	567.8	574.1
Vessel/Core Inlet	536.3	-
Steam Generator Outlet	536.3	-
Zero Load	547.0	547.0
RCS Pressure, psia	2250	2250
Steam Pressure, psia	758	794.4
Steam Flow, (10^6 lb/hr.tot.)	14.12	14.6
Feedwater Temperature, °F	434.8	423.4
% SG Tube Plugging	0	10% avg./ 15% peak

Flow Definitions:

*RCS Flow (Thermal Design Flow) - The conservatively low flow used for thermal/hydraulic design. The design parameters listed above are based on this flow.

**Minimum Measured Flow - The flow specified in the Tech. Specs. which must be confirmed or exceeded by the flow measurements obtained during plant startup and is the flow used in reactor core DNB analyses for plants applying the Improved Thermal Design Procedure.

***Flow values supplied in FSAR for Unit 2 are 141.3 x 10^6 lb/hr for vessel coolant flow, and 134.9 x 10^6 lb/hr for active core flow.

Note: Dashes in Case 2 indicate information which was not contained in the FSAR, and is therefore information which is unavailable to Westinghouse.

TABLE S-2.1-1 (Cont'd)

COOK NUCLEAR PLANT UNITS 1 AND 2
DESIGN POWER CAPABILITY PARAMETERS FOR RERATING PROGRAM

Parameter	(Revised) Case 3	(Revised) Case 4	(Revised) Case 5	(Revised) Case 6
NSSS Power, MWt	3262	3425	3425	3425
Core Power, MWt	3250	3413	3413	3413
RCS Flow, (gpm/loop)*	88,500	88,500	88,500	88,500
Minimum Measured Flow, (total gpm)**	366,400	366,400	366,400	366,400
RCS Temperatures, °F				
Core Outlet	610.1	583.6	614.0	613.9
Vessel Outlet	607.5	580.7	611.2	611.2
Core Average	579.2	549.7	581.8	581.8
Vessel Average	576.3	547.0	578.7	578.7
Vessel/Core Inlet	545.2	513.3	546.2	546.2
Steam Generator Outlet	545.0	513.1	546.0	546.0
Zero Load	547.0	547.0	547.0	547.0
RCS Pressure, psia	2250 or 2100	2250 or 2100	2250 or 2100	2250 or 2100
Steam Pressure, psia	807	603	820	806
Steam Flow, (10^6 lb/hr.tot.)	14.20	14.98	15.07	15.06
Feedwater Temperature, °F	434.8	442.0	442.0	442.0
% SG Tube Plugging (average)	15	10	10	15

Flow Definitions:

*RCS Flow (Thermal Design Flow) - The conservatively low flow used for thermal/hydraulic design. The design parameters listed above are based on this flow.

**Minimum Measured Flow - The flow specified in the Tech. Specs. which must be confirmed or exceeded by the flow measurements obtained during plant startup and is the flow used in reactor core DNB analyses for plants applying the Improved Thermal Design Procedure.

TABLE S-2.1-1 (Cont'd)

COOK NUCLEAR PLANT UNITS 1 AND 2
DESIGN POWER CAPABILITY PARAMETERS FOR RERATING PROGRAM

Parameter	(Revised) Case 7	(Revised) Case 8	(Revised) Case 9	(Revised) Case 10
Power, MWt	3600	3600	3600	3600
Core Power, MWt	3588	3588	3588	3588
RCS Flow, (gpm/loop)*	88,500	88,500	88,500	88,500
Minimum Measured Flow, (total gpm)**	366,400	366,400	366,400	366,400
RCS Temperatures, °F				
Core Outlet	585.4	618.0	585.4	618.1
Vessel Outlet	582.3	615.2	582.3	615.2
Core Average	549.9	584.6	549.9	584.7
Vessel Average	547.0	581.3	547.0	581.3
Vessel/Core Inlet	511.7	547.3	511.7	547.4
Steam Generator Outlet	511.4	547.1	511.4	547.2
Zero Load	547.0	547.0	547.0	547.0
RCS Pressure, psia	2250 or 2100	2250 or 2100	2250 or 2100	2250 or 2100
Steam Pressure, psia	587	820	576	806
Steam Flow, (10^6 lb/hr.tot.)	15.90	16.00	15.89	15.99
Feedwater Temperature, °F	449.0	449.0	449.0	449.0
% SG Tube Plugging (average)	10	10	15	15

Flow Definitions:

*RCS Flow (Thermal Design Flow) - The conservatively low flow used for thermal/hydraulic design. The design parameters listed above are based on this flow.

**Minimum Measured Flow - The flow specified in the Tech. Specs. which must be confirmed or exceeded by the flow measurements obtained during plant startup and is the flow used in reactor core DNB analyses for plants applying the Improved Thermal Design Procedure.

S-3.3 NON-LOCA SAFETY EVALUATION

S-3.3.1 Introduction

This section evaluates the effects of the Cook Nuclear Plant Rerating Program on the non-LOCA transients. The non-LOCA safety evaluation provided within is applicable only for Unit 1, with the exception of the steamline break mass/energy releases (inside and outside containment). The effort performed is to support Unit 1 operation with an uprated core power of 3413 MWt in the range of reactor vessel average temperatures between 547°F and 578.7°F at primary pressure values of 2100 psia <u>or</u> 2250 psia. Table S-2.1-1 (Cases 4 and 5) presents the range of conditions possible for the rerating of Unit 1. The steamline break mass/energy release analyses are performed to support the potential future Unit 1 rerating as well as to bound a potential rerating of Unit 2. Table S-2.1-1 (Cases 7 and 8) presents the range of conditions possible for the future rerating of Unit 2. In addition, the evaluation performed is to support a maximum average steam generator tube plugging level of 10%, with a peak steam generator tube plugging level of 15%.

The following non-LOCA safety evaluation also supports the change and/or relaxation of certain plant parameters to provide Unit 1 with increased operating margin and flexibility. Included in the non-LOCA safety evaluation are:

Increased Most Negative Moderator Temperature Coefficient (MTC) (Tech Spec 3.1.1.4b)
Degraded ECCS Charging Pump Flow (Tech Spec 4.5.2f)
Increased Main Steamline Isolation Valve (MSIV) Closure Time (Tech Spec 4.7.1.5b and Tech Spec Table 3.3-5 items 5h, 6h, & 7c)

The evaluation conservatively assumes 0 ppm boron concentration in the Boron Injection Tank (BIT).

The evaluation also supports a change to the steam generator water level program. The existing level program is a ramp function from 33% narrow range span (NRS) to 44% NRS from 0% power to 20% power and a constant level at 44% NRS between 20% power and 100% power. The proposed steam generator water level program is a constant level at 44% NRS between 0% power and 100% power.

S-3.3.4.1 Steamline Break Mass/Energy Releases

This section will discuss the analyses of the steamline break event to determine the mass and energy releases inside containment and the superheated mass and energy releases outside containment for the Cook Rerating Program. The analyses were performed to support the range of conditions possible for the rerating of Unit 1 as well as to position Unit 2 for a potential rerating. The analyses also consider the relaxation of certain plant parameters (Section S-3.3-1).

Steamline Break Mass/Energy Releases Inside Containment

The current mass/energy releases for the inside containment analysis is based on work performed for Unit 2, which is applicable for Unit 1. The calculation of the mass/energy release following a steamline break is described in the Cook Unit 2 FSAR Section 14.1.5. The steamline break mass/energy releases were recalculated to address the rerating of both Units and the relaxation of the plant parameters described in Section S-3.3.1.

Steamline ruptures occurring inside a reactor containment structure may result in significant releases of high energy fluid to the containment environment, possibly resulting in high containment temperatures and pressures. The quantitative nature of the releases following a steamline rupture is dependent upon the many possible configurations of the plant steam system and containment designs as well as the plant operating conditions and the size of the rupture. These variations make it difficult to reasonably determine the single "worst case" for both containment pressure and temperature evaluations following a steambreak. The FSAR analysis determined that the limiting scenario of the steambreak cases analyzed for the containment response evaluation were a break size of 0.942 ft^2 occurring at 30% power for the split rupture scenario and a break size of 4.6 ft^2 occurring at full power for the double-ended rupture scenario. (The 30% power split break case was slightly more limiting.) However, it is difficult to conclude if these FSAR cases remain bounding for the range of conditions possible for the reratings of both Units.

Adding to the difficulty in determining the effect of the rerating conditions are the plant parameters changes incorporated into the Cook Rerating Program. The potential changes of certain plant parameters (i.e, relaxed most negative MTC limit, degraded ECCS performance, increased MSIV closure time, and 0 ppm BIT boron concentration requirement) are penalties in the calculation of mass/energy releases. It is not readily apparent as to the total impact of the combination of these changes. As such, a series of steamline breaks, consistent with the cases presented in the FSAR, were analyzed to determine the containment response to a variety of postulated pipe breaks encompassing wide variations in plant operation, safety system performance, and break sizes.

Method of Analysis

The LOFTRAN computer code (Reference 2) was used to calculate the break flows and enthalpies of the release through the steambreak. Blowdown mass/energy releases determined using LOFTRAN include the effects of core power generation, main and auxiliary feedwater additions, engineered safeguards systems, reactor coolant thick metal heat storage, and reverse steam generator heat transfer.

A bounding analysis was performed to address the range of conditions possible for the potential Unit 1 rerating and the potential Unit 2 rerating. The assumptions on the initial conditions are taken to maximize the mass and total energy released. The higher primary temperatures along with the higher uprated power level associated with the Unit 2 rerating parameters are conservative for the mass/energy release calculations. The upper bound temperature of Table S-2.1-1, Case 8 was used. Since the mass blowdown rate is dependent on steam pressure and the steam pressure is less for the lower bound temperature case, the steam pressure of the upper bound temperature case is limiting for the range of operating conditions possible for the reratings of Unit 1 and Unit 2.

The functions which actuate safety injection and steamline isolation during a steamline rupture event are commonly referred to as the Steamline Break Protection System. A plant's steamline break protection system design can have a large effect on steamline break results. The steamline break protection system designs for Unit 1 and Unit 2 are different. Unit 1's design is referred to as an "OLD" steamline break protection system design. Unit 2's design is referred to as a "HYBRID" steamline break protection system design. The two systems have the following characteristics:

Unit 1 - "OLD" Steamline Break Protection

Safety Injection Signals

1. High-high steam flow coincident with low steamline pressure (two out of four lines)

2. High-high steam flow coincident with low-low Tavg (two out of four lines)

3. Two out of three differential pressure signals between a steam line and the remaining steam lines

4. Two out of three low pressurizer pressure signals

5. Two out of three hi containment pressure signals

Steamline Isolation Signals

1. High-high steam flow coincident with low steamline pressure (two out of four lines)

2. High-high steam flow coincident with low-low Tavg (two out of four lines)

3. Two out of four hi-hi containment pressure signals

Unit 2 - "HYBRID" Steamline Break Protection

Safety Injection Signals

1. Low steamline pressure (two out of four lines)

2. Two out of three differential pressure signals between a steam line and the remaining steam lines

3. Two out of three low pressurizer pressure signals

4. Two out of three hi containment pressure signals

Steamline Isolation Signals

1. Low steamline pressure (two out of four lines)

2. High-high steam flow coincident with low-low Tavg (two out of four lines)

3. Two out of four hi-hi containment pressure signals

The only differences between the Unit 1 and Unit 2 designs is the actuations from a high-high steam flow and low-low Tavg signal and the logic associated with the low steamline pressure signal required to actuate safety injection and steamline isolation. For Unit 1, a high-high steam flow coincident with low-low Tavg signal actuates both safety injection and steamline isolation. For Unit 2, a high-high steam flow coincident with low-low Tavg signal actuates only steamline isolation. However, the difference is not significant for the calculation of the mass/energy releases since the analysis does not take credit for any ESF actuations on a high-high steam flow coincident with low-low Tavg signal.

Unit 1's design requires a coincidence between the low steamline pressure and high-high steam flow for protection actuation. Unit 2's design only requires the low steamline pressure signal for protection actuation; no coincidence with steam flow is required.

The coincidence logic required for safety injection initiation and steamline isolation on high-high steam flow and low steam pressure for Unit 1 is more limiting for the calculation of mass/energy releases inside containment than Unit 2's design. Actuation of safety injection and steamline isolation will limit the mass/energy released to the containment. Delaying the safeguards initiation will result in a conservative calculation of the mass/energy

releases for the containment pressure and temperature evaluation. The coincidence requirement for high-high steam flow with low steam pressure of the Unit 1 design increases the likelihood that safeguards initiation might be delayed compared to Unit 2's design where only a low steam pressure signal is required. In the case where the coincidence logic prohibits safety injection and steamline isolation on high-high steam flow with low steam pressure, one of the other signals must be received before the safeguards are initiated. As such, the Unit 1 steamline break protection system design was assumed in this bounding analysis for the calculation of the mass/energy releases inside containment.

Assumptions

A series of steamline breaks were analyzed to determine the most severe break condition for the containment temperature and pressure response. The following assumptions were used in the analysis:

a. Double-ended pipe breaks were assumed to occur at the nozzle of one steam generator and also downstream of the flow restrictor. Split ruptures were assumed to occur at the nozzle of one steam generator.

b. The blowdown is assumed to be dry saturated steam.

c. As discussed above, the Unit 1 steamline break protection system design is assumed. However, credit was not taken for safeguards actuation on high steam line differential pressure or high-high steam flow coincident with low-low Tavg.

d. Steamline isolation is assumed complete 11 seconds after the setpoint is reached for either high-high steam flow coincident with low steam pressure or hi-hi containment pressure. The isolation time allows 8 seconds for valve closure plus 3 seconds for electronic delays and signal processing. The total delay time for steamline isolation of 11 seconds is assumed to support the relaxation of the main steam isolation valve (MSIV) closure time.

e. 4.6 ft^2 and 1.4 ft^2 double-ended pipe breaks were evaluated at 102, 70, 30, and zero percent power levels.

f. Split pipe ruptures were evaluated at 0.86 ft^2, 102% power; 0.908 ft^2, 70% power; 0.942 ft^2, 30% power; and 0.4 ft^2, hot shutdown.

These split break sizes for each power level were modeled because they reflect the largest breaks for which ESF actuations (i.e., steamline isolation, feedwater isolation, and safety injection) must be generated by high containment pressure trips. The high-high steam flow coincident with low steam pressure is not reached for these break sizes or smaller break sizes. (Reference 5)

g. Failure of a main steam isolation valve, failure of a feedwater isolation valve or main feed pump trip, and failure of auxiliary feedwater runout control were considered. Two cases for each break size and power level scenario were evaluated with one case modeling the MSIV failure and the other case modeling the AFW runout control failure. Each case assumed conservative main feedwater addition to bound the feedwater isolation valve or main feed pump trip failure.

h. The auxiliary feedwater system is manually re-aligned by the operator after 10 minutes.

i. A shutdown margin of 1.3% $\Delta k/k$ is assumed. This assumption includes added conservatism with respect to the Unit 1 end-of-life shutdown margin requirement of 1.6% $\Delta k/k$ at no load, equilibrium xenon conditions, and the most reactive RCCA stuck in its fully withdrawn position. The Unit 1 end-of-life shutdown margin requirement was used as the basis for this assumption since it is more limiting than the existing Unit 2 shutdown margin requirement.

j. A moderator density coefficient of 0.54 $\Delta k/gm/cc$ is assumed to support the relaxation of the most negative moderator temperature coefficient limit.

k. Minimum capability for injection of boric acid (2400 ppm) solution corresponding to the most restrictive single failure in the safety injection system. The Emergency Core Cooling System (ECCS) consists of the following systems: 1) the passive accumulators, 2) the low head safety injection (residual heat removal) system, 3) the high head (intermediate head) safety injection system, and 4) the charging safety injection system. Only the charging safety injection system and the passive accumulators are modeled for the steam line break accident analysis.

The modeling of the safety injection system in LOFTRAN is described in Reference 2. Figure 3.3-52 of WCAP-11902 presents the safety injection flow rates as a function of RCS pressure assumed in the analysis. The flow corresponds to that delivered by one charging pump delivering its full flow to the cold legs. The safety injection flows assumed in this analysis take into account the degradation of the ECCS charging pump performance. No credit has been taken for any borated water that might exists in the injection lines, which must be swept from the lines downstream of the boron injection tank isolation valves prior to the delivery of boric acid to the reactor coolant loops. For this analysis, a boron concentration of 0 ppm for the boron injection tank is assumed.

After the generation of the safety injection signal (appropriate delays for instrumentation, logic, and signal transport included), the appropriate valves begin to operate and the safety injection charging pump starts. In 27 seconds, the valves are assumed to be in their final position (VCT charging pump suction valve has closed following opening of RWST charging pump suction valve) and the pump is assumed to be at full speed and to draw suction from the RWST. The volume containing the low concentration borated water is swept into the core before the 2400 ppm borated water reaches the core. This delay, described above, is inherently included in the modeling.

l. For the at-power cases, reactor trip is available by safety injection signal, overpower protection signal (high neutron flux reactor trip or OPΔT reactor trip), and low pressurizer pressure reactor trip signal.

m. For reactor coolant pump (RCP) operation, offsite power is assumed available. Continued operation of the reactor coolant pumps maximizes the energy transferred from the reactor coolant system to the steam generators.

n. No steam generator tube plugging is assumed to maximize the heat transfer characteristics.

Single Failure Effects

a. Failure of a main steam isolation valve (MSIV) increases the volume of steam piping which is not isolated from the break. When all valves operate, the piping volume capable of blowing down is located between the steam generator and the first isolation valve. If this valve fails, the volume between the break and the isolation valves in the other steamlines, including safety and relief valve headers and other connecting lines, will feed the break. For the cases which modeled a failure of a MSIV, the steamline volumes associated with Unit 2 were assumed since the volume available for blowdown for this scenario is greater than Unit 1. For the cases which did not model a failure of a MSIV, the steamline volumes associated with Unit 1 were assumed since the volume available for blowdown for this scenario is greater than Unit 2.

b. Failure of a diesel generator would result in the loss of one containment safeguards train resulting in minimum heat removal capability.

c. Failure of a feedwater isolation valve would result in additional inventory in the feedwater line which would not be isolated from the steam generator. The mass in this volume can flash into steam and exit through the break. For consistency with the FSAR steamline break mass/energy release analysis, all cases conservatively assumed failure of the feedwater isolation valve, which resulted in the additional inventory available for release through the steambreak and in higher than normal main feedwater flows.

d. Failure of the auxiliary feedwater runout control equipment would result in higher auxiliary feedwater flows entering the steam generator prior to re-alignment of the AFW system. For cases where the runout control operates properly, a bounding constant AFW flow of 670 gpm to the faulted steam generator was assumed. This value was increased to 1325 gpm to simulate a failure of the runout control.

Results

The steamline break mass/energy releases inside containment were calculated to account for the range of conditions possible for the potential reratings of Unit 1 and Unit 2 and for the relaxation of certain plant parameters. One set of mass/energy releases were calculated to bound the reratings for both Units incorporating the limiting steamline break protection design of Unit 1. The analysis assumptions support relaxation of the most negative moderator temperature coefficient limit, degradation of the charging pump performance of the Emergency Core Cooling System, extension of the main steam isolation valve closure time, and relaxation of the minimum BIT boron concentration requirement.

Section S-3.4.2.1 presents the containment integrity evaluation for a main steamline break using the mass/energy releases calculated here. As discussed in Section S-3.4.2.1, the limiting scenarios of the steambreak cases analyzed for the containment response evaluation were a break size of 4.6 ft^2 occurring at 102% power with a main steamline isolation failure for the double-ended rupture scenario and a break size of 0.86 ft^2 occurring at 102% power with an auxiliary feedwater runout protection failure for the split rupture scenario. Table S-3.3-4 presents the mass/energy releases for these limiting steambreak cases of the containment response evaluation.

S-3.3.6 REFERENCES

1. Augustine, D. B., and Cecchett, D. L., "Reduced Temperature and Pressure Operation for Donald C. Cook Nuclear Plant Unit 1 Licensing Report," WCAP-11902, October 1988.

2. Burnett, T, W., T., et al., "LOFTRAN Code Description," WCAP-7907-A, April 1, 1984.

3. Butler, J. C., and Love, D. S, "Steamline Break Mass/Energy Releases for Equipment Qualification Outside Containment," WCAP-10961, Rev. 1 (proprietary) and WCAP-11184 (nonproprietary), October, 1985.

4. Hollingsworth, S. D., and Wood, D. C., "Reactor Core Response To Excessive Secondary Steam Releases," WCAP-9227, January 1978.

5. Land, R. E., "Mass and Energy Releases Following a Steam Line Rupture;" WCAP-8860, September 1976.

6. "American Electric Power Service Corporation Donald C. Cook Nuclear Plant Unit 1: Safety Evaluation for Including Uncertainty Due to Operator Readability of Pressurizer Pressure Instrumentation," AEP-89-216, Letter from J. C. Hoebel (W) to R. B. Bennett (AEPSC), September 1989.

TABLE S-3.3-4

.STEAMLINE BREAK
MASS/ENERGY RELEASES INSIDE CONTAINMENT
102% POWER DER (4.6 FT^2) BREAK
FAILURE - MSIV

TIME (SEC)	MASS (LBM/SEC)	ENERGY (BTU x 10^6/SEC)
0.00	0.00	0.0
0.20	10430.00	1.250
3.60	6552.00	7.883
6.60	5612.00	6.748
12.80	4978.00	5.974
13.00	4913.00	5.895
13.20	4847.00	5.816
13.40	4781.00	5.737
13.60	4716.00	5.660
14.00	4587.00	5.504
14.40	4458.00	5.350
14.80	4332.00	5.198
15.00	4269.00	5.123
15.20	4206.00	5.047
15.60	4083.00	4.899
15.80	4022.00	4.826
16.00	3961.00	4.753
16.60	3782.00	4.538
17.20	3606.00	4.328
17.60	3492.00	4.190
17.80	3435.00	4.122
18.40	3268.00	3.921
18.60	3213.00	3.856
18.80	3158.00	3.790
19.20	3050.00	3.660
23.80	1876.00	2.251
28.80	1623.00	1.421
30.40	1575.00	1.883
36.40	1461.00	1.746
39.20	1431.00	1.708
50.70	1369.00	1.634
57.20	1356.00	1.618
106.20	1331.00	1.588
109.20	1331.00	1.587
111.20	1184.00	1.409
118.20	308.70	0.358
125.20	188.10	0.217
136.20	98.97	0.114
602.70	93.24	0.107

TABLE S-3.3-4 (Cont'd)

STEAMLINE BREAK
MASS/ENERGY RELEASES INSIDE CONTAINMENT
102% POWER SPLIT (0.86 FT^2) BREAK
FAILURE - AUXILIARY FEEDWATER RUNOUT PROTECTION

TIME (SEC)	MASS (LBM/SEC)	ENERGY (BTU x 10^6/SEC)
0.00	0.00	0.0000
0.20	1394.00	1.6690
1.60	1366.00	1.6370
2.00	1358.00	1.6270
2.40	1350.00	1.6170
2.80	1342.00	1.6080
4.20	1316.00	1.5770
4.40	1312.00	1.5730
8.60	1550.00	1.8540
9.40	1575.00	1.8840
12.00	1632.00	1.9500
12.60	1638.00	1.9570
15.80	1635.00	1.9530
18.00	1618.00	1.9340
21.40	1458.00	1.7460
22.60	1400.00	1.6790
23.60	1357.00	1.6280
23.80	1349.00	1.6180
25.00	1302.00	1.5630
32.00	1103.00	1.3260
32.20	1098.00	1.3210
33.80	1064.00	1.2810
42.00	928.70	1.1180
42.60	920.80	1.1090
43.20	913.10	1.1000
43.80	905.70	1.0910
44.40	898.40	1.0820
55.20	799.10	0.9625
67.20	732.60	0.8823
80.20	691.30	0.8325
82.20	686.60	0.8269
96.20	662.50	0.7977
98.70	659.50	0.7941
118.20	645.70	0.7775
124.20	643.60	0.7749
282.70	633.20	0.7623
285.20	633.10	0.7622
290.20	615.00	0.7402
292.70	579.70	0.6977
297.70	556.60	0.6695
302.70	490.40	0.5896
320.20	304.70	0.3643

TABLE S-3.3-4 (Cont'd)

STEAMLINE BREAK
MASS/ENERGY RELEASES INSIDE CONTAINMENT
102% POWER SPLIT (0.86 FT^2) BREAK
FAILURE - AUXILIARY FEEDWATER RUNOUT PROTECTION

TIME (SEC)	MASS (LBM/SEC)	ENERGY (BTU x 10^6/SEC)
330.20	238.70	0.2845
340.20	206.50	0.2456
352.70	190.20	0.2259
525.20	181.90	0.2160
535.20	182.00	0.2160
600.20	182.10	0.2162
605.20	190.70	0.2258

S-3.4.2.1 Main Steamline Break (MSLB) Containment Integrity

Introduction and Background

An evaluation was performed to determine the impact of reduced temperature and pressure operation on the Donald C. Cook Nuclear Plant Unit 1 Long-Term Main Steamline Break Containment Integrity analysis. This evaluation is documented

in Section 3.4.2 of WCAP-11902, "REDUCED TEMPERATURE AND PRESSURE OPERATION FOR DONALD C. COOK NUCLEAR PLANT UNIT 1 LICENSING REPORT," and it was concluded that reduced temperature and pressure operation did not have an adverse impact on the analysis results and conclusions. This Section documents the analysis performed for both Donald C. Cook Nuclear Plant Units 1 & 2 to determine the impact of the rerated conditions described in Section S-2.1 on Containment Integrity following a Main Steamline Break.

A series of main steamline split and double-ended breaks were analyzed as a part of the original licensing basis for Donald C. Cook Nuclear Plant Unit 2 to determine the most severe break condition for containment temperature and pressure response for this design basis event. The analysis and evaluation are discussed in Reference 1. These results documented in the FSAR show that the most limiting double-ended break was the 4.6 square foot break, occurring at 102% power with main steam isolation valve failure. The most limiting split break was the 0.942 square foot break, occurring at 30% power with the failure of auxiliary feedwater runout protection. The calculated peak temperatures for these cases were 319.1°F and 328.1°F respectively. Additional generic sensitivities discussed in Reference 2, illustrate that other smaller breaks were not limiting.

Purpose

The purpose of the analysis documented in the following paragraphs is to demonstrate that the peak containment temperature resulting from a design basis main steamline break will not exceed the equipment qualification temperature criterion for Donald C. Cook Nuclear Plants Units 1 and 2, at the rerated conditions. The containment pressure response generated for the LOCA Containment Integrity analysis for the double-ended pump suction RCS break case (Reference 3) bounds the Main Steamline Break containment pressure response, and therefore is not a concern here. This analysis assumes reduced safety injection flow, due to degradation of ECCS performance, closure of the RHR crosstie valves and the current containment heat sink information.

Analytical Assumptions

The analysis performed for the Rerating Program is consistent with the Reference 1 analysis except for assumptions directly related to the rerating parameters. The analytical effort provides bounding system calculations for both Units 1 & 2 at the rerated plant conditions described in Section S-2.1.

A spectrum of split breaks is analyzed at 0.86 ft^2, 102% power; 0.908 ft^2, 70% power; 0.942 ft^2, 30% power and 0.4 ft^2, hot shutdown. Double-ended breaks of 1.4 ft^2 and 4.6 ft^2 are analyzed at power levels of 102%, 70%, 30% and zero power levels.

The break sizes analyzed in the present analysis are based on the current FSAR analysis. As in the FSAR analysis, loss of one containment safeguards train was also assumed for all the cases in addition to the single failure assumed in the mass and energy release calculations.

The following cases were analyzed for containment response:

A. Split break cases

1) 0.86 ft^2, 102% power, MSIV failure
2) 0.86 ft^2, 102% power, AFRP failure
3) 0.908 ft^2, 70% power, MSIV failure
4) 0.908 ft^2, 70% power, AFRP failure
5) 0.942 ft^2, 30% power, MSIV failure
6) 0.942 ft^2, 30% power, AFRP failure
7) 0.40 ft^2, hot shutdown, MSIV failure
8) 0.40 ft^2, hot shutdown, AFRP failure

Note: MSIV - Main Steam Isolation Valve
AFRP - Auxiliary Feedwater Runout Protection

B. Double-ended rupture cases*

1) 4.6 ft^2, 102% power, MSIV failure
2) 4.6 ft^2, 102% power, AFRP failure
3) 4.6 ft^2, 70% power, MSIV failure
4) 4.6 ft^2, 70% power, AFRP failure
5) 4.6 ft^2, 30% power, MSIV failure
6) 4.6 ft^2, hot shutdown, MSIV failure
7) 1.4 ft^2, 102% power, MSIV failure
8) 1.4 ft^2, 102% power, AFRP failure
9) 1.4 ft^2, 70% power, MSIV failure
10) 1.4 ft^2, 30% power, MSIV failure
11) 1.4 ft^2, hot shutdown, MSIV failure

Note: *The limiting 4.6 ft^2 double-ended failure cases (102% and 70% power), with MSIV failure were analyzed with AFRP failure and found to be less limiting than the corresponding MSIV failure cases. Therefore only the most limiting 1.4 ft^2 (102% power) was analyzed with AFRP failure.

The mass and energy releases to the containment as a result of the postulated accident are calculated using the LOFTRAN computer code (Reference 4). The mass and energy releases are calculated using two different failures for each case namely, 1) failure of the auxiliary feedwater runout protection and 2) failure of the main steam isolation valve. As in Reference 1, no credit is taken for entrainment. Section S-3.3.4.1 presents additional details regarding the calculation of the inside containment steamline break mass and energy releases.

The LOTIC-III computer code (Reference 5) is used to calculate the consequence of these releases, in particular the peak containment temperature.

The main steam line break containment integrity calculations are performed with an additional failure of one of the containment safeguards trains, which results in minimum spray flow (this includes a 10% degradation in the spray pump flow). Where applicable, input data consistent with that of the LOCA containment integrity analysis (Reference 3) is used.

The total initial ice mass assumed is 2.11×10^6 lbs.

The initial conditions in the containment are a temperature of 120°F in the lower and dead ended compartments, a temperature of 27°F in the ice condenser, and a temperature of 57°F in the upper compartment. All volumes are at a pressure of 0.3 psig and a relative humidity of 15%.

The refueling water storage tank (RWST) temperature is assumed to be 100°F.

A spray pump flow of 1900 gpm to the upper compartment and 900 gpm to the lower compartment is assumed, at a temperature of 100°F.

The spray flow is initiated 45.0 seconds after the containment reaches the hi-hi pressure signal of 3.5 psig. This setpoint includes instrument uncertainties.

Results

The results of the analysis show that the maximum calculated containment temperature is 324.9°F for the 4.6 ft^2 double ended rupture at 102% of the full power. The mass and energy calculations for this case are based on the main steam isolation valve failure.

The maximum containment temperature calculated for the limiting small split break (0.86 ft^2 at 102% of full power) is 324.4°F. The auxiliary feedwater runout protection failure is assumed for this case. Table S-3.4-1 and Figures S-3.4-1 through S-3.4-4 show the results for the two limiting cases.

Comparison of these results to the current FSAR results with respect to the peak containment temperature indicates that the FSAR result was more limiting. This is due to the lower mass and energy releases inside containment, calculated for the present analysis. The peak temperature shown in the FSAR for the limiting split break case (0.86 ft^2 at 102% of full power, with auxiliary feedwater runout protection failure) is higher than the

present case. However, the FSAR results for the limiting double-ended rupture case (4.6 ft^2 at 102% power, with main steam isolation valve failure) is lower than the present double-ended results. A detailed study of the results shows that even though the mass and energy releases within containment are lower in both the present cases, the double-ended break results in a higher temperature due to reduced flows from the lower compartment into the ice-condenser.

The peak occurs very early in the transient (within the first ten seconds). At this early time the only heat removal systems that exist are the containment wall heat sinks and the heat flow between the compartments. In the present case, heat removal by the walls is better (due to more detailed modeling of the walls), but the heat flow from the lower compartment into the ice-condenser is lower (due to the lower initial temperature assumed in the ice-condenser and the upper compartment, which affects the driving force through the ice-condenser).

Conclusions

The main steamline break containment integrity analysis has been performed consistent with the current licensing basis analysis and Donald C. Cook Nuclear Plant Units 1 & 2 rerating program, considering the present plant operating conditions. The results of this analysis are bounded by the current FSAR results. This analysis therefore demonstrates that the containment heat removal systems function to rapidly reduce the containment pressure and temperature in the event of a main steamline break accident.

S-3.4.3 References

1. Westinghouse letter # NS-TMA-1946, 9/20/78, " American Electric Power Projects Donald C. Cook Unit 2 (Docket 50-316) Response to Question 022.9".

2. Westinghouse letter #AEP-80-525, 3/10/80, "Response to NRC Question 022.17 - AMP's steamline break analysis".

3. WCAP-11908," Containment Integrity Analysis for Donald C. Cook Nuclear Plant Units 1 and 2", July 1988.

4. WCAP-7907-P-A (Proprietary), "LOFTRAN Code Description", April 1984.

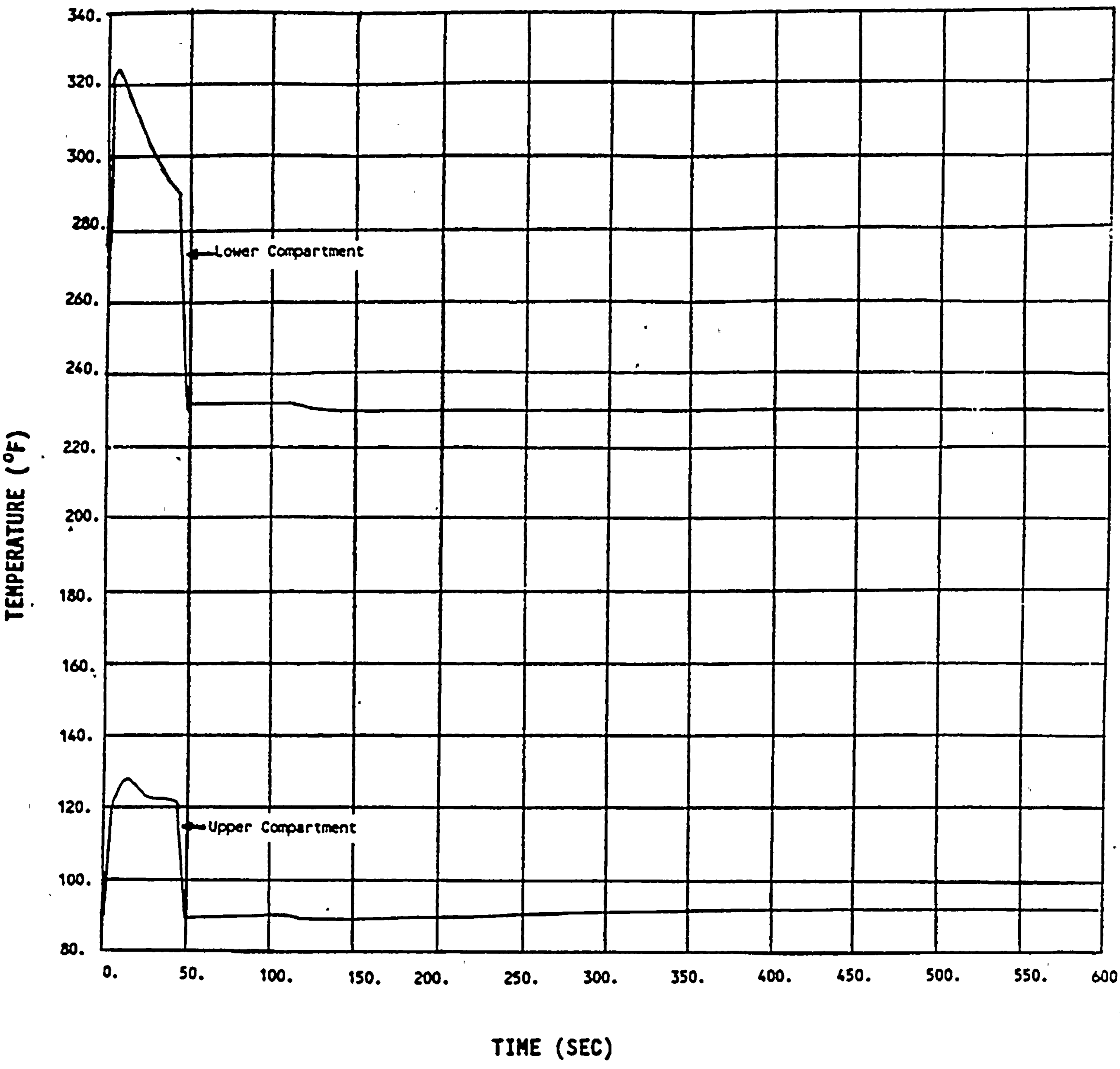
5. WCAP-8354-P-A (Proprietary), Supplement 2, "Long Term Ice Condenser Containment Code - LOTIC-3 Code", February 1979.

TABLE S-3.4-1

MAIN STEAMLINE BREAKS

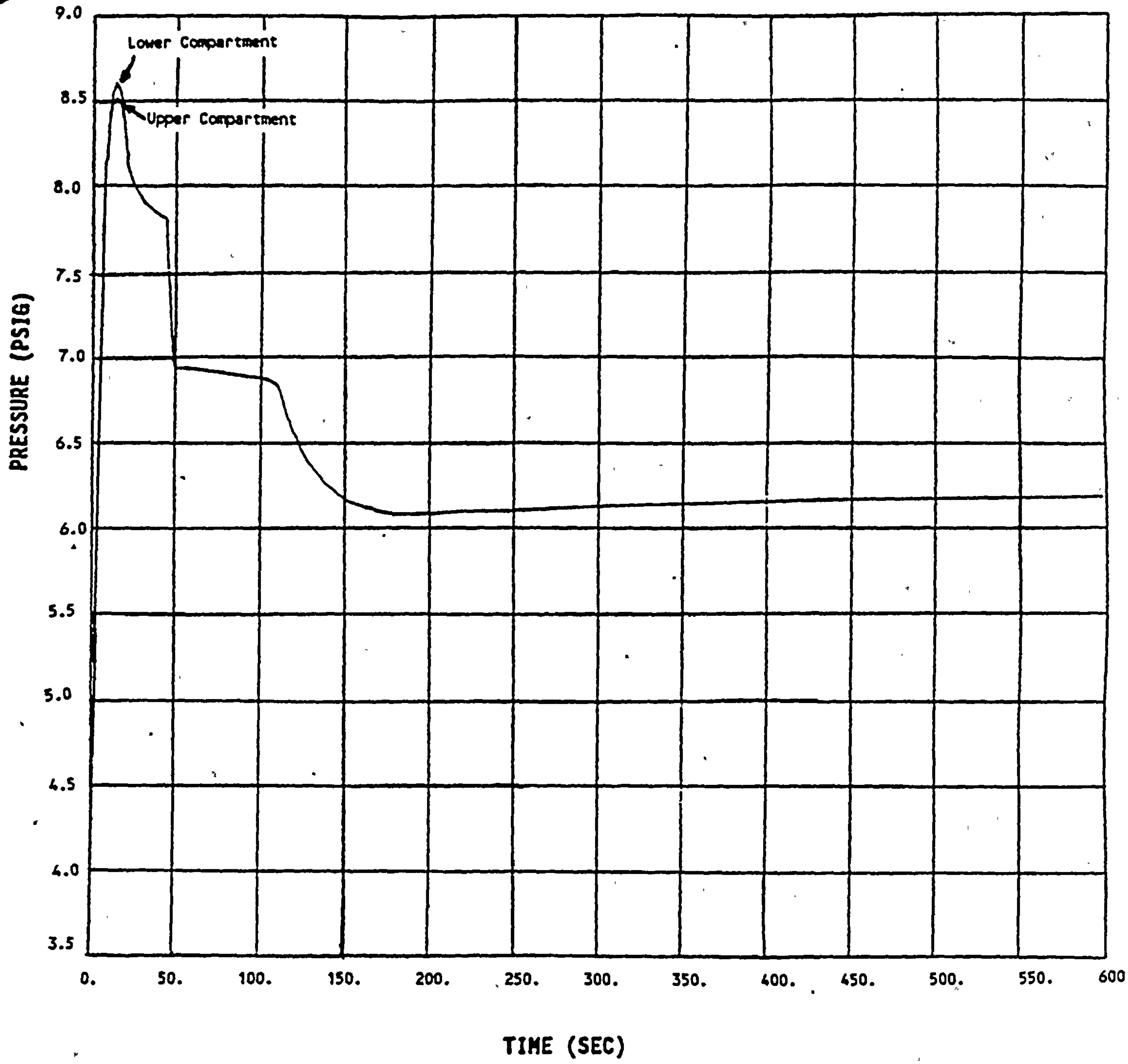
Type of Break	Double-Ended Rupture	Split Break
Break Size (FT^2)	4.6	0.86
Type of Failure	MSIV	AFRP
T_{max} (°F)	324.9	324.4
Time of T_{max} (sec)	6.39	50.72
P_{max} (psig)	8.62	7.24
Time of P_{max} (sec)	14.01	50.72

Note: MSIV - Main Steam Isolation Valve
AFRP - Auxiliary Feedwater Runout Protection



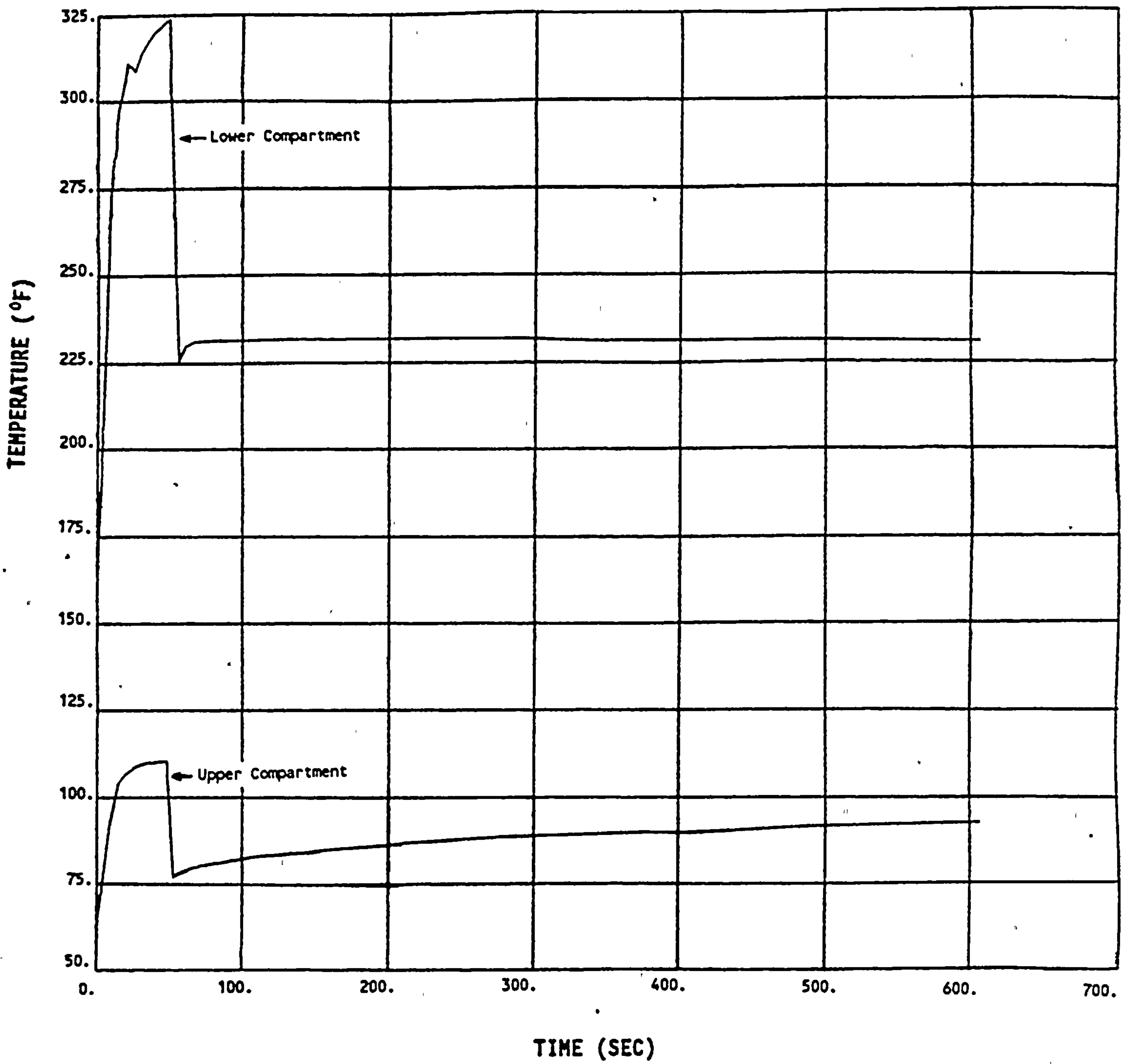
COMPARTMENT TEMPERATURE

Figure S-3.4-1 - 4.6 ft^2 Double-Ended Rupture, 102% Power, MSIV Failure



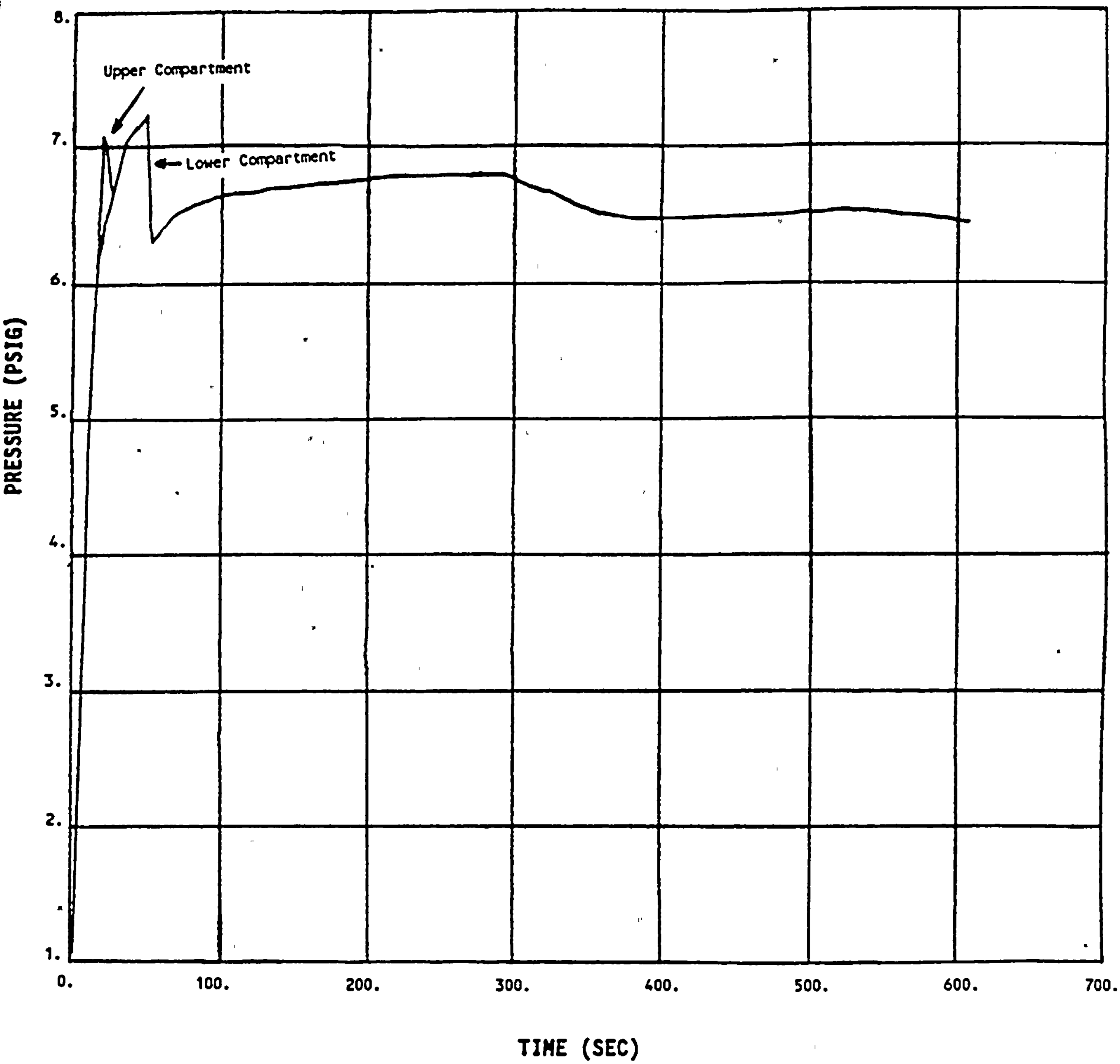
COMPARTMENT PRESSURE

Figure S-3.4-2 - 4.6 ft^2 Double-Ended Rupture, 102% Power, MSIV Failure



COMPARTMENT TEMPERATURE

Figure S-3.4-3 - 0.86 ft^2 Split Break, 102% Power, AFRP Failure



COMPARTMENT PRESSURE

Figure S-3.4-4 - 0.86 ft^2 Split Break, 102% Power, AFRP Failure

TABLE S-3.13-2 (Continued)

OTHER TECHNICAL SPECIFICATION CHANGES

Tech. Spec. Item/ Page	Description of Change	Basis for Change
9. Emergency Core Cooling System Section 3.5.2 page 3/4 5-5	RHR : 160 psid SI : 1385 psid Charging: 2290 psid	These values represent 10% pump degradation and are consistent with the Westinghouse analyses. These values supersede those presented in WCAP-11902.

ATTACHMENT 6 TO AEP:NRC:1071E

PORTIONS OF WCAP 11902

JUSTIFICATION FOR PRESSURIZER LEVEL

FIGURE 3.3-52, SAFETY INJECTION FLOW
SUPPLIED BY ONE PUMP

WCAP-11902

REDUCED TEMPERATURE AND PRESSURE OPERATION FOR DONALD C. COOK NUCLEAR PLANT UNIT 1 LICENSING REPORT

D. L. Cecchett
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October 1988

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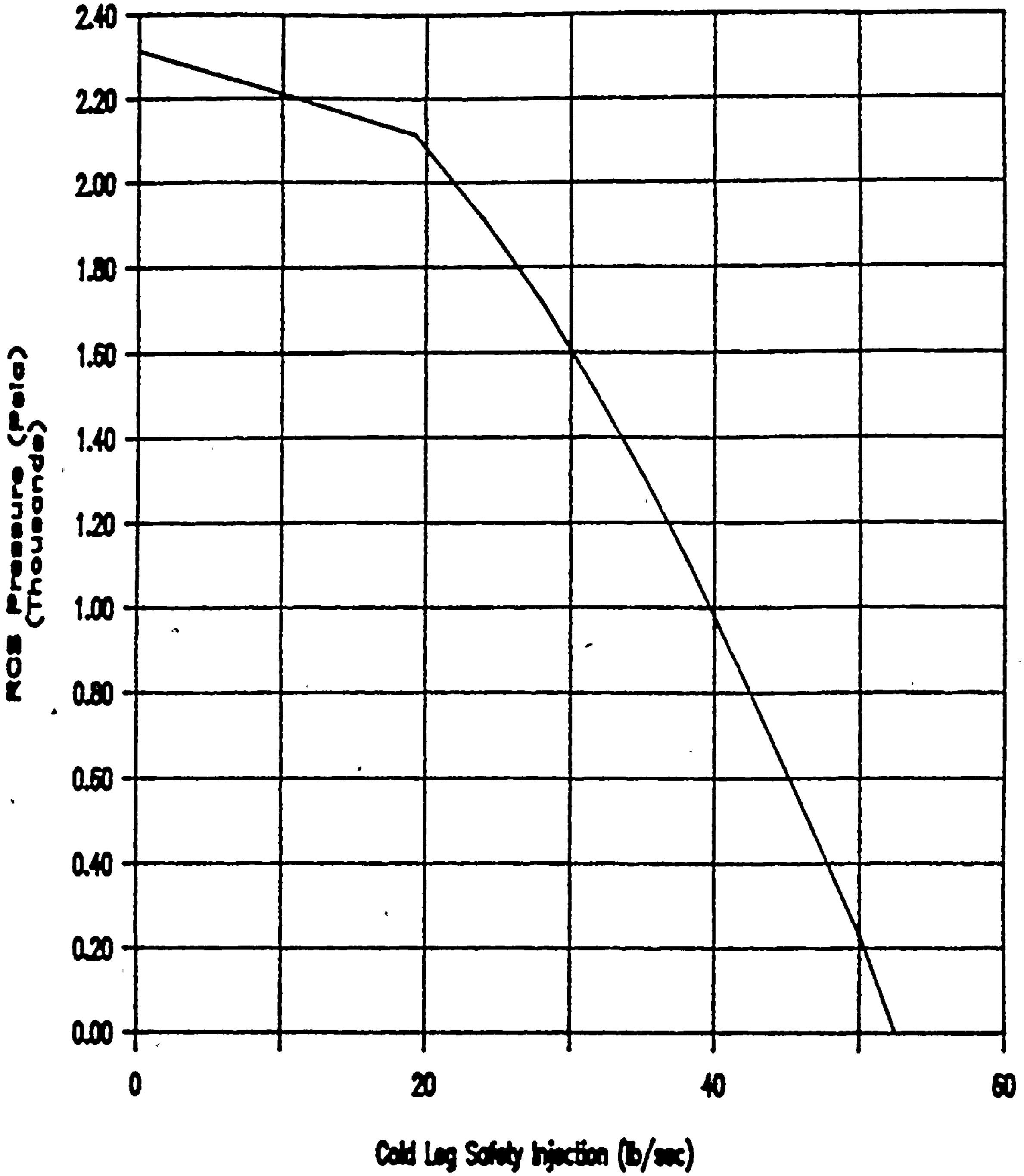


Figure 3.3-52 Safety Injection Flow Supplied by One Charging Pump

3.13 JUSTIFICATION FOR PRESSURIZER LEVEL

3.13.1 Introduction

As part of the Cook Nuclear Plant Unit 1 Reduced Temperature and Pressure Program, the Pressurizer High Level limit in the Technical Specifications (currently set at 62%) was reviewed to determine whether or not it could be increased to allow for additional margin to that limit. The following description supports the increase of that limit from 62% to 92% (see Technical Specification Section 3.4.4).

3.13.2 Discussion

The Pressurizer High Level limit is to provide that a steam bubble is present in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients and the possibility of passing water through the relief and safety valves. Requiring the presence of a steam bubble is consistent with analytical assumptions. The maximum initial pressurizer volume was used in the loss of normal feedwater analysis where one of the criteria is that loss of water from the reactor core shall not occur. This maximum volume, which corresponds to approximately 65% indicated level, is based on maintaining nominal pressurizer level with the pressurizer level control system (assuming uncertainties). The safety analysis is based on the assumption that the plant will be maintained at nominal conditions.

The use of 92% for the Pressurizer High Level limit is recommended. This value corresponds to the high pressurizer level trip and does insure the presence of a bubble. Levels greater than this would be abnormal and would require action. It is expected that normally the pressurizer level will be maintained at the nominal level.

The initial conditions in the accident analyses in Chapter 14 of the FSAR are based on the nominal programmed values of temperature, pressurizer pressure and level, and steam generator level. To these nominal values are added appropriate measurement uncertainties which are added in the conservative direction (positive or negative) as appropriate to the accident in question.

The Technical Specifications are based upon the assumptions and results of the safety analyses which are consistent with the assumptions of nominal initial conditions plus or minus uncertainties.

The system parameters of RCS temperature, pressurizer pressure, pressurizer level, and steam generator level are maintained by automatic control systems. Temperature is controlled by the rod control system and pressure by the heaters and sprays. The pressurizer and steam generator levels are programmed as a function of power level and use various input parameters to maintain the program level. All of these systems may be operated manually, in which case the operator strives to duplicate the automatic system.

The correct maintenance of these plant variables is consistent with the Technical Specifications for two reasons. First, although malfunctions in these systems could cause deviations from the programmed values, these malfunctions would be detected by the resulting plant transient and subsequently addressed. These transients cause and are already bounded by the Condition II event and analyses presented in the FSAR. Second, these programmed values are displayed in the control room for each channel and these parameters are also monitored by the operator in accordance with plant operating procedures. In addition, deviation alarms sound in the control room if any of these four control parameters fall outside the program value. Thus, if a malfunction in the control system did not cause a transient or if the plant were operating under manual control, the operator would detect the malfunctions as a result of the alarms or according to the surveillance requirements in the procedures and/or correct and maintain them as well.

The operating procedures used by the plant provide that the plant is operated in accordance with the design of these control systems regardless of whether they are operated automatically or in manual control. All control system parameters are specified in the Precautions, Limitations, and Setpoints (PLS) document. The PLS document parameters are developed to optimize plant operation and are consistent with the assumptions made in the safety analysis as to initial conditions and the programming of all control system variables. Furthermore, those control system variables, which are important to the safety analysis, are specifically noted in the PLS, usually by footnote.

Note that the maintenance of operating procedures is required by the Technical Specifications. Since these operating procedures prevent abnormal combinations of plant parameters and since failures of the control systems are detectable, the Technical Specifications, as written, are consistent with the safety analysis and no further specifications on controlled parameters is required. The control systems are not required to operate once the accident has started. The safety analysis does not assume operation of the control system during the course of an accident unless operation of the control systems makes the results more limiting with respect to the acceptance criteria. Finally, the control systems, although not safety grade, are highly reliable systems. There is no indication based on plant operating experience that the revised Technical Specifications will not be adequate.

It should be noted that the normal operational transients (Condition I events) do not cause these parameters to significantly deviate from their nominal values. This is because these Condition I events are the design basis transients of the control systems. The control system is designed to maintain the plant parameters within the specified programs and to return them to the program values if they deviate. The system response to these transients is provided in the setpoint study for each plant. The results presented show that the control system can indeed function as designed and maintain the plant parameters as desired. Since normal operation does not cause large changes in these parameters, one is forced to conclude that it requires an abnormal transient (Condition II, III, or IV) to generate these adverse or odd initial conditions.

Thus, in order for an accident to occur in which the initial conditions are significantly outside the normal operating range, the plant must first undergo a transient which would generate the abnormal initial condition for the accident. This is, in effect, the consideration of two transients at once, which is outside the scope of the licensing basis accident analyses for the plant. In particular, if the plant were operating under automatic control of these parameters, the accident would have to occur very shortly after the first transient, since the control system would be acting to restore the

parameters to their normal values. The occurrence of such a "smart" accident is highly unlikely, and it is inappropriate to apply ANS classification and acceptance criteria. Since the ANS classification and acceptance criteria are based on the anticipated frequency of occurrence of a postulated accident, this "smart" accident would have a different classification than the accident based on normal conditions and would have more relaxed acceptance criteria.

Independent of the above considerations, there are extreme limits on temperature, pressurizer pressure, pressurizer level, and steam generator level provided in the Technical Specifications. The pressurizer level (high) limits are provided in terms of the trip setpoints. Pressure is monitored with respect to reactor trip by the overpower/overtemperature delta-T trips. Should any transient cause one of the trip setpoints to be reached, protective action will then be initiated. Thus the protection system setpoints serve to provide an envelope of initial conditions which prevent operation of the plant in extreme configurations.

3.13.3 Conclusions

Based on the above, there are no safety issues due to the Pressurizer High Level limit being set at 92%. This conclusion is reached as a result of the stated assumptions for the FSAR Chapter 14 Accident Analysis, normal operating practices and control limitations such as interlocks and limiters. For all these parameters, there are adequate annunciators to alert the operator to excessive deviation from the nominal parameters and allow timely restoration.

ATTACHMENT 7 TO AEP:NRC:1071E

DONALD C. COOK NUCLEAR PLANT UNIT 2 CYCLE 8
DRAFT CORE OPERATING LIMITS REPORT

1.0 CORE OPERATING LIMITS REPORT

This Core Operating Limits Report for Donald C. Cook Nuclear Plant Unit 2 Cycle 8 has been prepared in accordance with the requirements of Technical Specification 6.9.1.11.

The Technical Specifications affected by this report are listed below:

3/4.1.1.4	Moderator Temperature Coefficient
3/4.1.3.1	Movable Control Assemblies Group Height
3/4.1.3.4	Rod Drop Time
3/4.1.3.5	Shutdown Rod Insertion Limits
3/4.1.3.6	Control Rods Limits
3/4.2.1	Axial Flux Difference
3/4.2.2	Heat Flux Hot Channel Factor
3/4.2.3	Nuclear Enthalpy Rise Hot Channel Factor
3/4.2.6	Allowable Power Level

2.0 OPERATING LIMITS

The cyle-specific parameter limits for the specifications listed in Section 1.0 are presented in the following subsections. These limits have been developed using the NRC-approved methodologies specified in Technical Specification 6.9.1.11.

2.1 Moderator Temperature Coefficient (Specification 3/4.1.1.4)

2.1.1 The Moderator Temperature Coefficient EOL Limit is:

The EOL/ARO/RTP-MTC shall be less negative than the value given in Figure 1.

where: ARO stands for All Rods Out
EOL stands for End of Cycle Life
RTP stands for Rated Thermal Power
HZP stands for Hot Zero Thermal Power

2.1.2 The MTC Surveillance limit is:

The 300 ppm/ARO/RTP-MTC should be less negative than or equal to -3.3E-4 $\Delta k/k/°F$.

2.2 Rod Drop Time Drop Height (Specification 3/4.1.3.4)

2.2.1 All rods shall be dropped from at least 228 steps.

2.3 Shutdown Rod Insertion Limit (Specification 3/4.1.3.5)

2.3.1 The shutdown rods shall be withdrawn to at least 228 steps.

2.4 Control Rod Insertion Limits (Specification 3/4.1.3.6, and 3/4.1.3.1)

2.4.1 The control banks shall be limited in physical insertion as shown in Figure 2.

2.4.2 Successive Control Banks shall overlap by 100 steps. The sequence for Control Bank withdrawal shall be Control Bank A, Control Bank B, Control Bank C, and Control Bank D.

2.5 Axial Flux Difference (Specification 3/4.2.1)

2.5.1 The Allowable Operation Limits are provided in Figure 3.

2.5.2 The AXIAL FLUX DIFFERENCE (AFD) target band during base load operations is +3%, -3% for core average burnup < 0.0 MWD/MTU.

2.5.3 The AFD target band is +5%, -5% for core average accumulated burnup ≥ 0.0 MWD/MTU

2.5 <u>Heat Flux Hot Channel Factor</u> - $F_Q(Z)$ (Specification 3.2.2)

$$F_Q(Z) \leq \frac{CFQ}{P} * K(Z) \qquad \text{for } P > 0.5$$

$$F_Q(Z) \leq 2 * CFQ * K(Z) \qquad \text{for } P \leq 0.5$$

$$\text{where: } P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$$

2.5.1 CFQ= 2.33 for Westinghouse fuel
2.10 for ANF fuel

2.5.2 K(Z) is provided in Figures 4 and 5 for the respective fuel type

2.5.3 V(Z) is provided in Figure 6

2.6 <u>Nuclear Enthalpy Rise Hot Channel Factor</u> - $F^N_{\Delta H}$ (Specification 3/4.2.3)

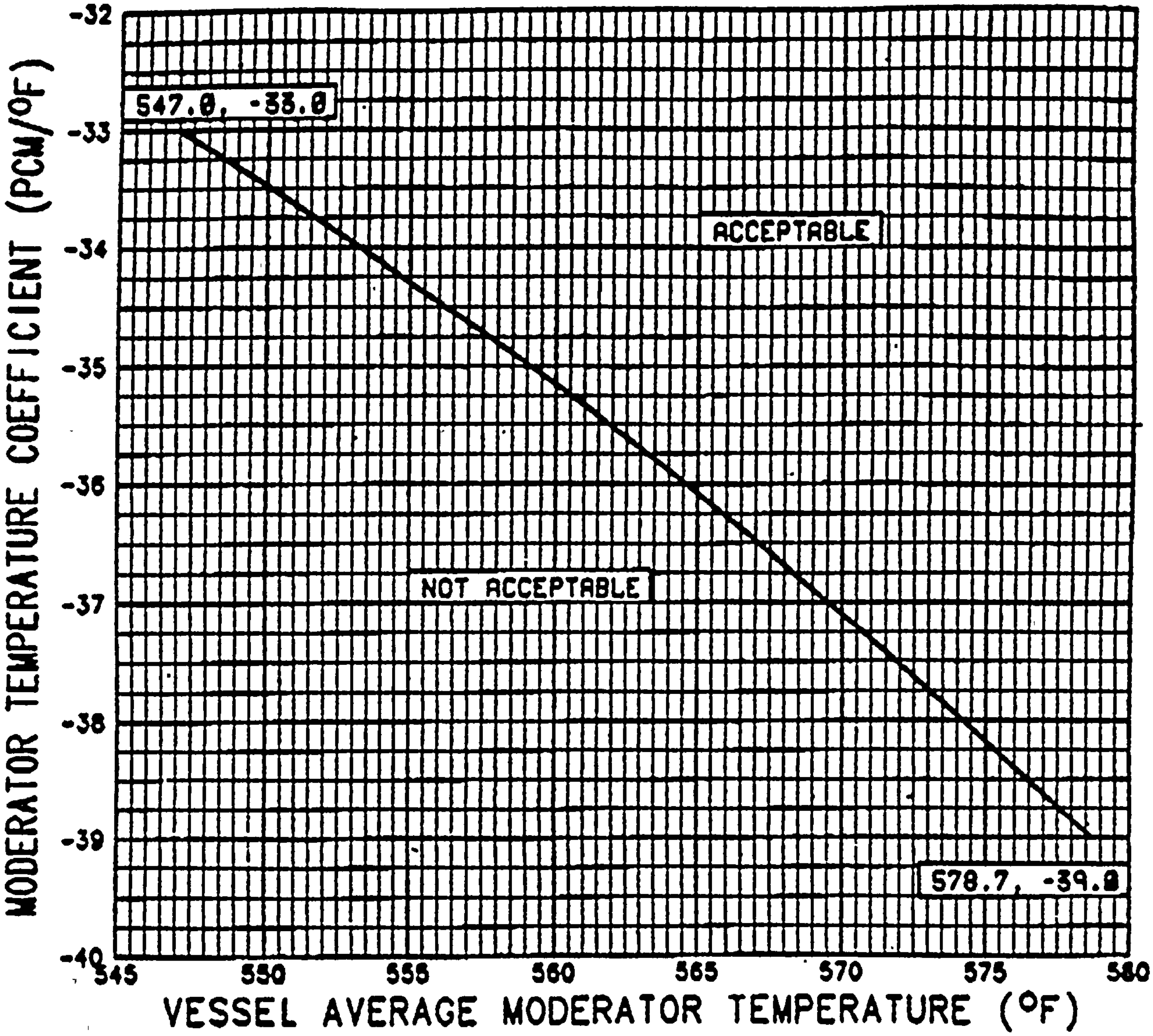
$F^N_{\Delta H} \leq$ CFDH * (1 + PFDH * (1-P))

$$\text{where: } P = \frac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$$

2.6.1 CFDH = 1.56 for Westinghouse fuel
= 1.49 for ANF fuel

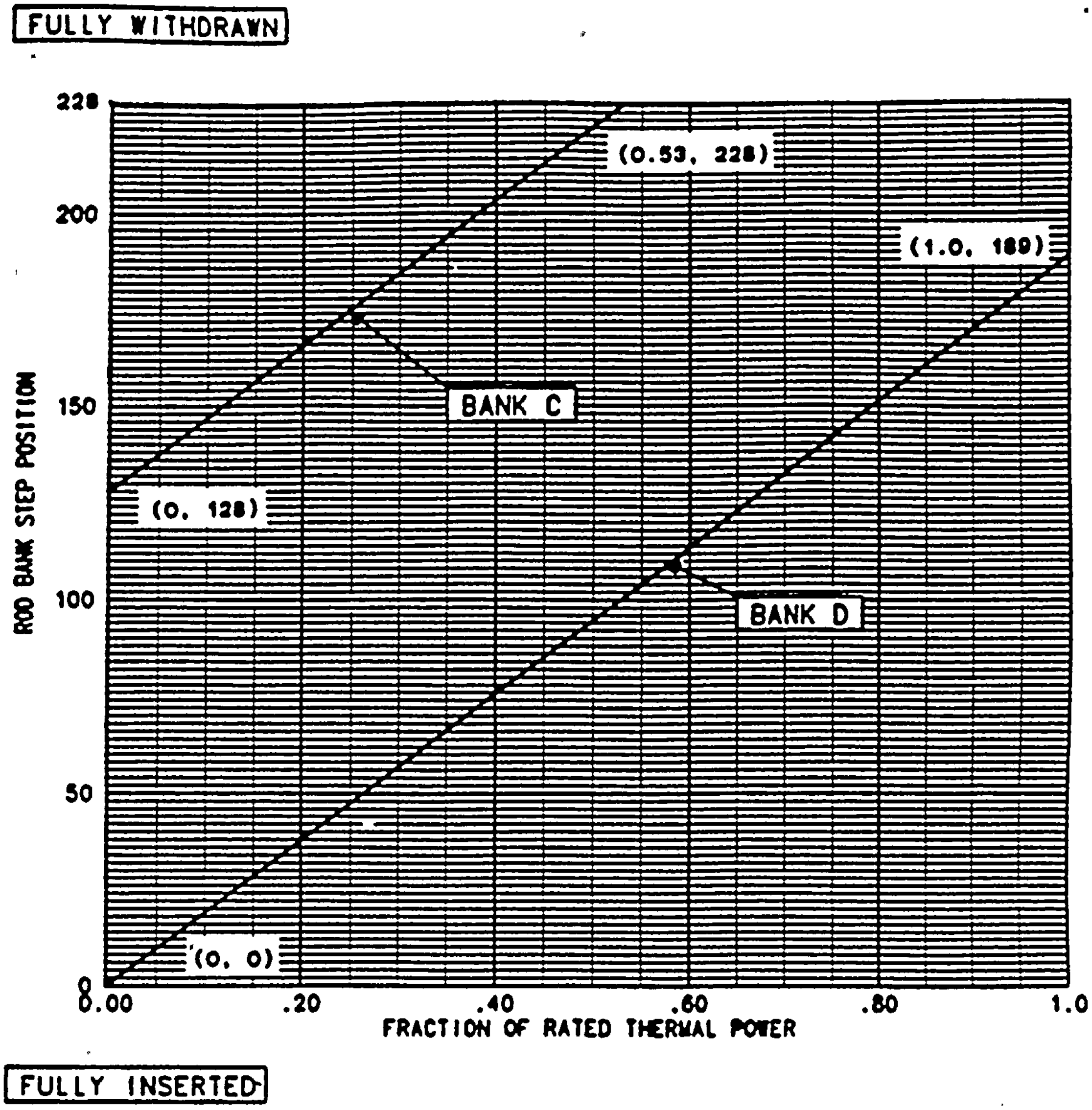
2.6.2 PFDH = 0.3 for Westinghouse fuel
= 0.2 for ANF fuel

FIGURE 1



MOST NEGATIVE MODERATOR TEMPERATURE COEFFICIENT LIMIT

FIGURE 2



ROD BANK INSERTION LIMITS VERSUS THERMAL POWER

FOUR LOOP OPERATION

FIGURE 3
AXIAL FLUX DIFFERENCE LIMITS
AS A FUNCTION OF RATED THERMAL POWER

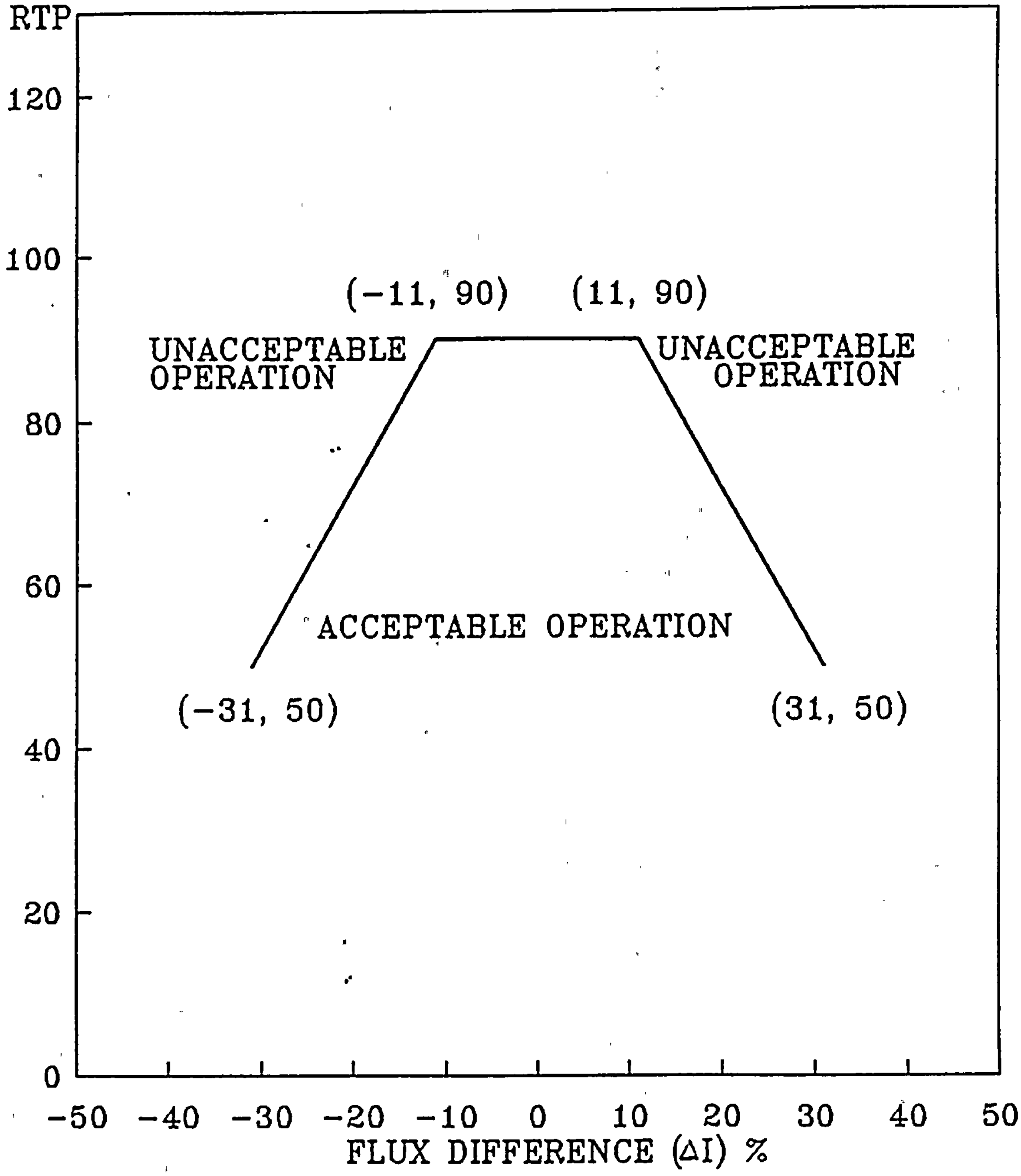


FIGURE 4

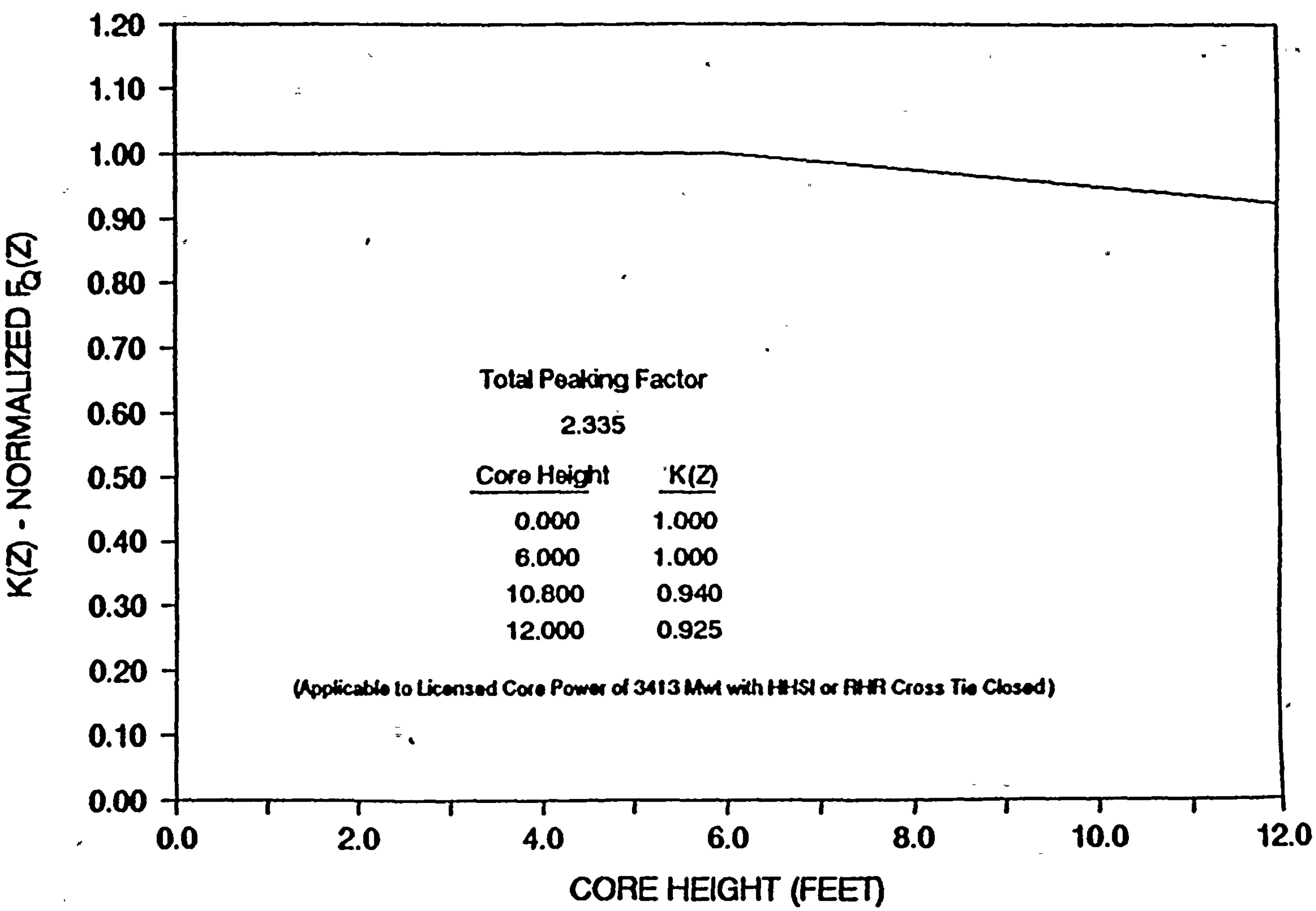

K(Z) - NORMALIZED $F_Q(Z)$
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.0
2.0
4.0
6.0
8.0
10.0
12.0
CORE HEIGHT (FEET)
Total Peaking Factor
2.335
Core Height K(Z)
0.000 1.000
6.000 1.000
10.800 0.940
12.000 0.925
(Applicable to Licensed Core Power of 3413 Mwt with HHSI or RHR Cross Tie Closed)

FIGURE 5

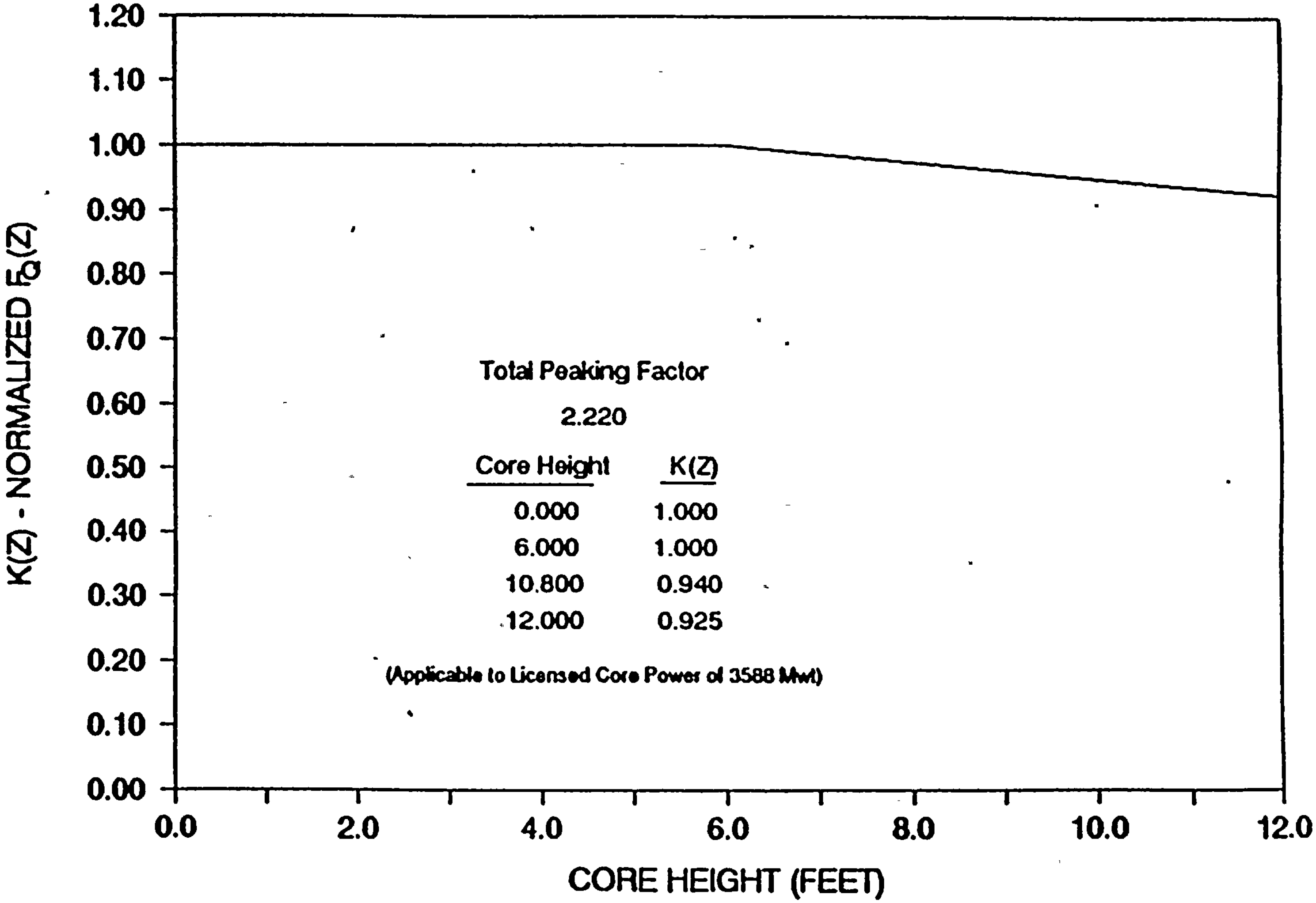

K(Z) - NORMALIZED F_Q(Z)
1.20
1.10
1.00
0.90
0.80
0.70
0.60
0.50
0.40
0.30
0.20
0.10
0.00
0.0
2.0
4.0
6.0
8.0
10.0
12.0
CORE HEIGHT (FEET)
Total Peaking Factor
2.220
Core Height K(Z)
0.000 1.000
6.000 1.000
10.800 0.940
12.000 0.925
(Applicable to Licensed Core Power of 3588 Mwt)

FIGURE 6

V(Z) AS A FUNCTION OF CORE HEIGHT

NOT YET CALCULATED

ATTACHMENT 8 TO AEP:NRC:1071E

JUSTIFICATION FOR DELETION OF ANALYSES FOR
COOK NUCLEAR PLANT UNIT 2
RELOAD TRANSITION SAFETY REPORT (RTSR)

Introduction

On August 3, 1989, the NRC wrote a letter to AEPSC (J. Giitter to M. P. Alexich, found in Attachment 9) in response to a request that AEPSC had made concerning the need to continue to evaluate seven transients for Cook Nuclear Plant Unit 2 which had been addressed by Advanced Nuclear Fuels Corporation (ANF, formerly Exxon) starting in Cycle 6. AEPSC will be placing Westinghouse manufactured fuel into Unit 2 starting with Cycle 8 (Westinghouse is the NSSS vendor and fuel supplier for Cycles 1, 2 and 3). Westinghouse has also performed the associated safety analyses and evaluations. Since ANF will not provide the fuel and supporting analysis for Cycles 8 and 9, AEPSC requested that the NRC determine the need for continued assessment of the seven transients.

As indicated in the NRC letter, the NRC staff has determined that the seven additional events analyzed for Cycle 6 and currently discussed in Section 14 of the Updated Final Safety Analysis Report (UFSAR) are not part of the licensing basis and, therefore, are not required to be analyzed for Cycle 8. However, the NRC staff expected, the letter said, "that the license amendment application provided in support of the Cycle 8 reload will sufficiently address why exclusion of these seven events does not involve a significant hazards consideration, by applying the standards in 10 CFR 50.92." The significant hazards consideration analysis of the removal of these seven events is provided below.

Significant Hazards Consideration Analysis

Seven events not in the Donald C. Cook Nuclear Plant Unit 2 licensing basis were addressed for Cycle 6. This was not done as a result of changes in fuel assembly type from Westinghouse Standard 17 x 17 fuel to ANF 17 x 17 fuel. Rather, this was done as a result of changes to the ANF methodology for pressurizer water reactors which was undergoing revision and NRC review at the time preparatory to formal NRC approval. An important aspect of the changes to the ANF methodology was to base the reload analyses on the Standard Review Plan Chapter 15 events rather than on the plant original FSAR. Therefore, the seven transients in question were analyzed or evaluated consistent with the revised ANF methodology to provide the NRC assurance that all appropriate safety limits were satisfied, even though these seven events were not in the Donald C. Cook Nuclear Plant Unit 2 licensing basis.

Based on use of the approved Westinghouse methodology, AEPSC concludes that the removal of the seven transients identified in our

request to the NRC from the list of events addressed in Chapter 14 of Cook Nuclear Plant Unit 2 UFSAR:

1) Does not involve a significant increase in the probability or consequences of an accident previously evaluated.

   There will not be a significant increase in the probability of an accident because there will be no change in plant operation or equipment as a result of not addressing the events in question. The seven events when addressed for Cycle 6 resulted in no operational restrictions, changes in operation procedures, or changes to the plant. EOPs exist to address events such as inadvertent operation of the ECCS or CVCS that result in increased RCS inventory and for the inadvertent opening of a pressurizer PORV which will not change if the events are not addressed. Thus, there will not be a significant increase in consequences. Therefore, we conclude criteria 1 is satisfied. The statement that "there will be no change in plant operation or equipment as a result of not addressing the events in question," is based on a review of the Unit 2 Cycle 6 Reload Licensing Plant Impact List.

2) Does not create the possibility of a new or different kind of accident from any accident previously evaluated.

   Again, there will be no change in plant operation or equipment as a result of not addressing the events in question. Therefore, AEPSC believes new or different kinds of accidents cannot result.

3) Does not involve a significant reduction in a margin of safety.

   Since addressing the events in question resulted in no operating restrictions, procedural changes or plant changes there can be no reduction in the margin of safety.

AEPSC therefore concludes that the license amendment requested does not involve a significant hazards consideration as defined in 10 CFR 50.92.

Conclusion

In summary, given that the codes and methods used by Westinghouse for reload safety analyses have already been determined to be acceptable by the NRC for the analysis of Westinghouse NSSSs, there is no need to do additional analyses to confirm this. Thus, the requirements of 10 CFR 50.92 are satisfied for the return to Westinghouse codes/methods for Cook Nuclear Plant Unit 2.

ATTACHMENT 9 TO AEP:NRC:1071E

LETTER FROM JOSEPH G. GIITTER, NRC STAFF,
TO MILTON P. ALEXICH, AEPSC, DATED AUGUST 3, 1989