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THE CONNECTICUT LIGHT AND POWER COMPANY
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HOLYOKE WATER POWER COMPANY
NORTHEAST UTILITIES SERVICE COMPANY
NORTHEAST NUCLEAR ENERGY COMPANY

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January 25, 1980

Docket No. 50-336

Director of Nuclear Reactor Regulation
Attn: Mr. R. Reid, Chief
Operating Reactors Branch #4
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

References:
(1) D. G. Eisenhut letter to All Operating Nuclear Power Plants dated September 13, 1979.
(2) H. R. Denton letter to All Operating Nuclear Power Plants dated October 30, 1979.
(3) W. G. Counsil letter to J. Hendrie dated November 30, 1979.
(4) R. Reid letter to W. G. Counsil dated December 21, 1979.
(5) H. R. Denton letter to W. G. Counsil dated December 27, 1979.
(6) W. G. Counsil letter to R. Reid dated February 12, 1979.
(7) R. Reid letter to W. G. Counsil dated May 12, 1979.

Gentlemen:

Millstone Nuclear Power Station, Unit No. 2
Automatic Initiation of Auxiliary Feedwater

In References (1) and (2), Northeast Nuclear Energy Company (NNECO) was informed of the original Staff requirements regarding the issue of automatic initiation of auxiliary feedwater. NNECO's ongoing evaluations of this requirement were thoroughly articulated in Reference (3), which also forwarded NNECO's determination pursuant to the requirements of 10CFR50.59.

Subsequently, via Reference (4), NNECO was advised of a revision to the Staff directive of References (1) and (2), in that implementation of automatically initiated auxiliary feedwater is prohibited until the NRC completes its review and issues an approval. In accordance with the Reference (4) request, it is noted that NNECO has continued with the procurement of equipment and proceeded with the installation to the extent possible without activating the automatic-start system or adversely affecting the manual-start system. In Reference (5), the Staff accepted NNECO's determination pursuant to 10CFR50.59 and reiterated the need for an analysis of an automatically initiated system. NNECO was verbally advised that the scope of the analysis requested in Reference (5) results in no additional information requests beyond those specified in Reference (4). Therefore, the attached material is structured to respond to Reference (4) format. The Staff further advises that

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Reference (5) should not be construed as a detailed reply to each of the concerns expressed in Reference (3). Inasmuch as NNECO's position on this issue has not substantively changed since that date, we look forward to receipt of the detailed reply.

Our respective Staff's have discussed the timing of this submittal, in that it is being docketed later than the date requested in Reference (4). NNECO emphasizes that this delay is thoroughly justified given the extensive scope of analyses required. Development of the attached material has involved significant expenditure of resources by both NNECO personnel and our consultants.

With respect to the analysis results and the relevance of the Reference (3) concerns, it is noted that the analysis assumes a three-minute time delay from the start of the transient until the start of auxiliary feedwater flow. Even with incorporation of this feature, a return-to-power condition directly attributable to auxiliary feedwater flow, occurs during the transient. It is acknowledged that many conservatisms have been incorporated into the analysis, as is the case with any docketed analysis; nonetheless, it is highly unlikely that optimization of the design could have been accomplished within the time constraints originally imposed by References (1) and (2). A quantitative determination of the results of an immediately initiated system are not available at this time.

The specific analytical concerns of Reference (4) are addressed as follows. Attachment 1, Main Steam Line Break Accident Analysis - Return to Power, responds to Section A of Reference (4). The conservatisms inherent in the analysis include:

(1) Only a three-minute delay in delivery of auxiliary feedwater flow to the steam generators was assumed, rather than a more realistic longer time delay.

(2) No credit is taken for isolation of the main feedwater system, thereby resulting in a continuous flow of 772 gpm of main feedwater to the affected steam generator.

(3) A conservative representation of auxiliary pump feedwater flow, namely 2800 gpm, which is 35% higher than maximum runout flow at Millstone Unit No. 2. Thus, a total of 3572 gpm of feedwater flow is assumed in the analysis.

(4) Failure of one HPSI pump.

(5) Failure of one LPSI pump.

(6) The highest worth CEA is assumed to stick in the fully withdrawn position.

As indicated in Attachment 1, the results with respect to core performance indicate that the conclusions presented in Reference (6), which have been approved by the Staff in Reference (7), remain valid and bounding.

Attachment 2, Main Steam Line Break Analysis - Containment Pressure, responds to Section B of Reference (4). Reference (4) requests that a spectrum of postulated main steam line breaks for various reactor power levels be reanalyzed. However, only one such break was specifically reanalyzed, that

being the no load, single loop nozzle break case originally analyzed in the FSAR. NNECO's reassessment of this matter has not identified the need to extend the scope of the reanalysis effort in this regard. Again, it is conservatively assumed that the steam generator blowdown associated with auxiliary feedwater flow begins three minutes after the rupture. As requested in Reference (4), two cases were analyzed, to assure that limiting values were calculated. These cases address a limiting control valve failure in the auxiliary feedwater system, and a limiting failure regarding loss of engineered safety feature containment cooling components. Results indicate a peak containment pressure of 47 psig and a peak containment temperature of 274°F, both within original plant design bases. However, it is noted that NRC Staff acceptance of the attached analysis would not constitute a revised "licensing basis" for Millstone Unit No. 2. The Reference (4) requirement to analyze the blowdown for thirty minutes is excessively conservative and without precedent. Isolation of an affected steam generator following a massive rupture would not require thirty minutes. Details supportive of this conclusion are provided in Attachment 2.

Attachment 3, Automatic Initiation of Auxiliary Feedwater - Proposed Revisions to Technical Specifications, is also provided at this time. It is noted that these Specifications are currently undergoing internal review and are subject to further revision. Subsequent to completion of this process, a formal proposed revision will be docketed.

One additional aspect of this matter has been investigated and is noted as follows. During NNECO's review of the subject modification, it was recognized that during a postulated steam generator tube rupture event, steam generator levels will drop to the automatic initiation setpoint of the auxiliary feedwater system, which would include the terry turbine. This component exhausts directly to atmosphere. Although use of the terry turbine was previously a possibility during a steam generator tube rupture event, the modification under consideration would result in an automatic start of the terry turbine during this event. Therefore, NNECO performed a reanalysis of the radiological consequences of this event, using the methodology documented in Reference (6), and assuming a release for thirty minutes from the terry turbine exhaust. The results of this analysis are:

	Thyroid Dose (Rem)	Whole Body Dose (Rem)
(1) Results presented in Reference (6).	0.006	0.1
(2) Additional Dose From Terry Turbine	0.048	0.003
(3) Total	0.054	0.1

Pursuant to the requirements of 10CFR50.59, NNECO has concluded that the above scenario does not constitute an unreviewed safety question, but is docketing the material for informational purposes. The basis for this determination is:

(1) This scenario is not a new incident, but a refinement of a previous analysis.

(2) The conservatively calculated incremental increase in dose consequences is not significant, and the total doses remain a small fraction of 10 CFR 100 doses.

(3) The conclusions reached by the Staff and documented in Reference (7) are not substantively altered.

As stated previously, NNECO is currently finalizing its design review and the review of the proposed Technical Specifications. Therefore, NNECO has not completed all the steps necessary to reach a definitive conclusion regarding the acceptability of implementation of automatic initiation of auxiliary feedwater at Millstone Unit No. 2. Furthermore, the necessity of such a modification remains doubtful for the reasons documented in Reference (3). Additional information will be provided concurrent with the formal Technical Specification change proposal.

We trust you find the above information responsive to your request.

Very truly yours,

NORTHEAST NUCLEAR ENERGY COMPANY

W. G. Counsil

W. G. Counsil
Vice President

Attachment

DOCKET NO. 50-336

ATTACHMENT 1

MILLSTONE NUCLEAR POWER STATION, UNIT NO. 2

MAIN STEAM LINE BREAK ACCIDENT ANALYSIS - RETURN TO POWER

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JANUARY, 1980

1.0 Concern with Return to Power

The Design Basis Steam Line Break (SLB) events analyzed for Millstone Point Unit 2, Cycle 3 were reanalyzed using the same assumptions and methods and simulating automatic initiation of auxiliary feedwater flow in 3 minutes from initiation of the event.

The analysis assumed that the event is initiated by a circumferential rupture of a 34-inch (inside diameter) steam line at the steam generator main steam line nozzle. This break size is the most limiting, since it causes the greatest rate of temperature reduction in the reactor core region. The MSLB outside containment is less limiting because the blowdown rate of the steam generators is restricted by the flow venturies located in the steam lines, thus leading to a less severe reactivity insertion and a smaller potential for return-to-power than the results presented herein.

The SLB event was analyzed with the assumption of a 3 minute delay between the time of transient initiation and the time when Auxiliary Feedwater (AFW) flow is delivered to the affected steam generator. This is conservative with respect to the expected time of AFW initiation since the generation of the AFW signal actually occurs at the time of the low steam generator water level trip signal. The analysis assumes, therefore, that AFW flow is delivered to the steam generator sooner than the flow is actually available resulting in a conservative prediction of the resulting cooldown.

The analysis conservatively assumed that when the Main Steam Isolation Signal (MSIS) is actuated, no main feedwater isolation occurs. Hence, the MFW flow was assumed to be ramped down to 5% of full power feedwater flow in 60 seconds by the control system.

The 5% flow delivery to the SG was then maintained indefinitely. If credit had been taken for main feedwater isolation, the feedwater flow would have been ramped down to zero in less than 10 s from the initiation of the accident. The assumption made is conservative because it prolongs the cooldown of the RCS and thus results in a more severe reactivity transient. This is equivalent to assuming a complete failure of the MFW Isolation System, which is part of the ESF system and meets Regulatory Guides and IEEE-279 requirements.

A conservatively high value of the AFW flow was calculated assuming that all auxiliary feedwater pumps are operable and deliver water in a run-out condition due to reduced back pressure. Correspondently, the analysis used an AFW flow value equivalent to 20% of full power feedwater flow. This generic AFW flow rate is actually 35% higher than the highest run-out flow for MP2. Adding the 5% of main feedwater flow assumed by not taking credit for MFW isolation, the analysis assumed a full 60% feedwater excess over the maximum run-out AFW flow. This is equivalent to assume the combination of worst failures in the feedwater systems which will result in the most severe cooldown.

Isolation of the steam side of the intact steam generator was assumed to be accomplished by the Main Steam Isolation system, which is part of the ESF system and meets Regulatory Guides and IEEE-279 requirements. Isolation by this system occurs about 11 s following the initiating break, although the same function is performed before by the turbine stop valves.

It was also assumed that, on safety injection actuation, one of the HPSI and one of the LPSI pumps fail to start. The safety injection system is part of the ESF and meets Regulatory Guides and IEEE-279 requirements. On reactor scram, the highest worth Control Element Assembly was assumed to stick in the fully withdrawn position.

In general, single failures were considered in the design basis to the extent that a failure initiates the event and safety grade equipment is designed to accommodate single failures as described above and is consistent with the design basis presented in the FSAR. No consequential failures other than those identified above were considered. All control systems considered were assumed to function in the manner consistent with the FSAR.

Single failures concurrent with the MSLB (other than those identified above, if any), as well as loss of offsite power concurrent with MSLB, are not, and have not been part of the design basis as described in the FSAR and, therefore, were not considered.

The analysis of the Steam Line Rupture event was performed using the same procedures and methods presented in the FSAR and the Unit 2, Cycle 3 license submittal dated February 12, 1979. The two steam line rupture cases considered in conjunction with automatic initiation of auxiliary feedwater flow are:

1. 2 Loop - Full Load (2754 MWt)
2. 2 Loop - No Load (0 MWt)

1.1 <u>Two-Loop 2754 MWt</u>

The Two-Loop - 2754 MWt case was initiated at the conditions listed in Table 1. The Moderator Temperature Coefficient (MTC) of reactivity assumed in the analysis corresponds to end of life, since this MTC results in the greatest positive reactivity change during the RCS cooldown caused by the Steam Line Rupture. Since the reactivity change associated with moderator feedback varies significantly over the moderator temperatures covered in the analysis, a curve of reactivity insertion versus temperature, rather than a single value of MTC, is assumed in the analysis. The moderator cooldown curve assumed is given in Figure 1. The moderator cooldown curve given in Figure 1 was conservatively calculated assuming that on reactor scram, the highest worth Control Element Assembly is stuck in the fully withdrawn position.

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The reactivity defect associated with fuel temperature decreases is also based on end of life Doppler defect. The Doppler defect based on an end of life Fuel Temperature Coefficient (FTC), in conjunction with the decreasing fuel temperatures, causes the greatest positive reactivity insertion during the Steam Line Rupture event. The uncertainty on the FTC assumed in the analysis is given in Table 1. The β fraction assumed is the maximum absolute value including uncertainties for end of life conditions. This too is conservative since it maximizes the subcritical multiplication and thus, enhances the potential for Return-To-Power (R-T-P).

The minimum CEA worth assumed to be available for shutdown at the time of reactor trip at the maximum allowed power level is 5.3% $\Delta\rho$, assuming that the most reactive CEA is stuck in the fully withdrawn position during a scram.

The analysis conservatively assumed that on Safety Injection Actuation Signal one High Pressure Safety Injection Pump and one Low Pressure Safety Injection pump fail to start. The analysis also assumed a conservatively low value of the boron reactivity worth injected via the HPSI and LPSI pumps. A boron reactivity worth of -1.0% $\Delta\rho$ per 90 PPM was assumed in the analysis.

The conservative assumptions on feedwater flow were discussed previously. The feedwater flow and enthalpy as a function of time are presented in Figures 2 and 3 respectively.

Table 2 presents the sequence of events for the full power case initiated at the conditions given in Table 1. The reactivity insertion as a function of time is presented in Figure 4. The response of the NSSS during this event is given in Figures 5 through 13.

The results of the analysis show the affected steam generator blows dry at 68.7 seconds and thus terminates the initial cooldown of the RCS. The peak

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Return-To-Power due to subcritical multiplication attained prior to delivery of auxiliary feedwater flow is 12% at 71.9 seconds. The delivery of boron via the High Pressure Safety Injection inserts negative reactivity and the core power decreases to the decay power level. The results of the transient quoted so far are the same as previously quoted in the February 12, 1979 submittal.

The delivery of auxiliary feedwater flow starting at 180.0 seconds initiates a further cooldown of the RCS which results in a positive reactivity insertion and eventually causes the core to achieve criticality at 227.1 seconds. The return to criticality is terminated by the additional boron injected via the High and Low Pressure Safety Injection Pumps (one HPSI and one LPSI). The peak R-T-P attained due to this added cooldown is 10.8% at 345.9 seconds. This return to power is smaller than the first R-T-P quoted earlier in the transient.

The Steam Line Rupture Event initiated at HFP conditions shows that prior to delivery of auxiliary feedwater flow the results are the same as reported previously in the Unit 2, Cycle 3 license submittal. The delivery of auxiliary feedwater causes a second Return-To-Power but the additional boron injected via the safety injection pumps terminates the R-T-P and the core reactivity then continually decreases. The results of the analysis show that the additional cooldown due to the introduction of auxiliary feedwater flow does not result in a Return-To-Power which is more adverse than what was presented in the Cycle 3 license submittal. Therefore, the conclusions of the Unit 2, Cycle 3 license submittal for this transient remain valid.

1.2 Two Loop- No Load

The two loop- no load case was initiated at the conditions given in Table 3. The moderator cooldown curve is given in Figure 1. The cooldown curve corresponds to an end of life MTC. An end of life FTC was also used for the reasons previously discussed in connection with the two loop- 2754 MWt case.

The minimum CEA shutdown worth available is conservatively assumed to be the minimum required technical specification limit of 3.2% $\Delta\rho$. A maximum inverse boron worth of 85 PPM/% $\Delta\rho$ was conservatively assumed for the safety injection during the no load case. The feedwater flow and the enthalpy used in the analysis are presented in Figures 14 and 15 respectively.

Table 4 presents the sequence of events for the 2 loop- HZP case initiated from the conditions given in Table 3. The reactivity insertion as a function of time is presented in Figure 16. The NSSS response during this event is given in Figures 17 to 25.

The results of the analysis show that the affected steam generator blows dry at 111.8 seconds. The peak reactivity attained during this time period is .17% $\Delta\rho$. The addition of boron from the high pressure safety injection adds negative reactivity and thus the core reactivity becomes more negative. The results of the transient quoted so far are the same as previously quoted in the February 12, 1979 submittal except for the additional negative reactivity provided by boron in the LPSI flow.

At 180 seconds the auxiliary feedwater flow is delivered to the affected steam generator. This initiates a further cooldown of the RCS. The cooldown of the RCS inserts more positive reactivity. However, Low Pressure Safety Injection flow is initiated at 105 seconds which injects additional boron. The negative reactivity added due to boron injection via the LPSI's more than offsets the added cooldown of the RCS. The total core reactivity, therefore, does not

increase following the initial peak quoted above which occurs before auxiliary feedwater delivery.

The Steam Line Rupture event initiated at no load conditions shows that prior to delivery of auxiliary feedwater flow the results are the same as reported previously in the Unit 2, Cycle 3 license submittal. The delivery of auxiliary feedwater does not affect the peak reactivity which occurs in the transient prior to the auxiliary feedwater initiation. Hence, the results of the SLB event with automatic initiation of auxiliary feedwater are no worse than the 2 loop- no load case analyzed for Unit 2, Cycle 3 without initiation of auxiliary feedwater flow.

TABLE 1

KEY PARAMETERS ASSUMED IN THE MAIN STEAM LINE BREAK EVENT WITH AUTOMATIC INITIATION OF AUXILIARY FEEDWATER

(2 LOOP - FULL LOAD CONDITION)

Parameters	Units	Unit 2, Cycle 3 License Submittal Values	Present Analysis Values
Initial Core Power Level	MWt	2754.0	2754.0
Initial Core Inlet Temperature	°F	551.0	551.0
Initial RCS Pressure	psia	2200.0	2200.0
Initial Steam Generator Pressure	psia	860.4	860.4
Low Steam Pressure Trip Setpoint	psia	478.0	478.0
Safety Injection Actuation Setpoint	psia	1563.0	1563.0
High Pressure Safety Injection Flow Delivery	psia	1220.0	1220.0
Low Pressure Safety Injection Flow Delivery	psia	207.1*	207.1
CEA Worth at Trip	%Δρ	-5.31	-5.31
Moderator Cooldown Curve	%Δρ vs. °F	Figure 1	Figure 1
Doppler Multiplier		1.15	1.15
Inverse Boron Worth	PPM/%Δρ	90.0	90.0
Feedwater Flow	lbm/sec vs. Sec	Figure 2	Figure 2
Feedwater Enthalpy	BTU/lbm vs. Sec	Figure 3	Figure 3

No credit for Low Pressure Safety Injection was taken in the Unit 2, Cycle 3 license submittal analysis.

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TABLE 2

Sequence of Events for the Main Steam Line Break Event
with Automatic Initiation of Auxiliary Feedwater System
(Full load, Two-Loop Condition, Nozzle Break)

Time(sec.)	Event	Safety System Initiated	Setpoint or Value
0.0	Initiation of break	----	----
3.4	Low steam Generator Pressure trip signal occurs, MSIS initiated and Main Steam Isolation Valves begin to close.	Reactor Protection System Main Steam Isolation System	478 psia
4.3	Trip breakers open	----	----
4.8	CEAs begin to drop into core	Reactor Protection System	----
10.7	Complete closure of Main Steam Isolation Valves to terminate blowdown from the intact steam generator	----	----
15.9	Pressurizer empties	----	----
16.2	Low RCS pressure, SIAS Initiated	Safety Injection System	1563 psia
22.8	High Pressure Safety Injection flow Initiated	Safety Injection System	1220 psia
64.8	Main feedwater flow completes ramp down to 5%	----	----
68.7	Affected steam generator liquid inventory depleted and beginning of blowdown of feedwater only	----	----
71.9	Peak return-to-power* occurs with a peak reactivity of -.186%Δρ		12%

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* return-to-power includes decay heat and subcritical multiplication

TABLE 2 (Continued)

Time (sec.)	Event	Safety System Initiated	Setpoint or Value
180.0	Auxiliary Feedwater flow to affected steam generator initiated	----	----
318.7	Low Pressure Safety Injection Flow Initiated	Safety Injection System	207 psia
319.9	Peak reactivity post auxiliary feedwater delivery	----	$+.13\%\Delta\rho$
345.9	Peak return to power post auxiliary feedwater delivery	----	10.8%

TABLE 3

KEY PARAMETERS ASSUMED IN THE MAIN STEAM LINE BREAK EVENT WITH AUTOMATIC INITIATION OF AUXILIARY FEEDWATER

(2 LOOP - NO LOAD CONDITION)

Parameters	Units	Unit 2, Cycle 3 Values	Present Analysis Values
Initial Core Power Level	MWt	0	0
Initial Core Inlet Temperature	°F	532.0	532.0
Initial RCS Pressure	psia	2200.0	2200.0
Initial Steam Generator Pressure	psia	895.5	895.5
Low Steam Pressure Trip Setpoint	psia	478.0	478.0
Safety Injection Actuation Setpoint	psia	1563.0	1563.0
High Pressure Safety Injection Flow Delivery	psia	1220.0	1220.0
Low Pressure Safety Injection Flow Delivery	psia	207.1*	207.1
CEA Worth at Trip	%Δρ	-3.2	-3.2
Moderator Cooldown Curve	%Δρ vs. °F	Figure 1	Figure 1
Doppler Multiplier		0.85	0.85
Inverse Boron Worth	PPM/%Δρ	85.0	85.0
Feedwater Flow	/sec vs. Sec	Figure 10	Figure 10
Feedwater Enthalpy	BTU/lbm vs. Sec	Figure 11	Figure 11

No credit for Low Pressure Safety Injection was taken in the Unit 2, Cycle 3 license submittal analysis.

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TABLE 4

Sequence of Events for the Main Steam Line Break Event
with Automatic Initiation of Auxiliary Feedwater System
(No load, Two-Loop Condition, Nozzle Break)

Time (sec.)	Event	Safety System Initiated	Setpoint or Value
0.0	Initiation of break	----	----
3.7	Low steam Generator Pressure trip signal occurs, MSIS initiated and Main Steam Isolation Valves begin to close.	Reactor Protection System Main Steam Isolation System	478 psia
4.6	Trip breakers open	----	----
5.1	CEAs begin to drop into core	Reactor Protection System	----
10.7	Complete closure of Main Steam Isolation Valves to terminate blowdown from the intact steam generator	----	----
12.4	Pressurizer empties	----	----
15.9	Low RCS pressure, SIAS Initiated	Safety Injection System	1563.0 psia
21.8	High Pressure Safety Injection flow Initiated	Safety Injection System	1220.0 psia
105.0	Low Pressure Safety Injection Flow Initiated	Safety Injection System	207.1 psia
111.8	Affected steam generator liquid inventory depleted and beginning of blowdown of feedwater only	----	----
114.4	Peak Reactivity		0.17%$\Delta\rho$

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TABLE 4 (Continued)

Time (sec.)	Event	Safety System Initiated	Setpoint or Valu
180.0	Auxiliary Feedwater flow to affected steam generator initiated	----	----

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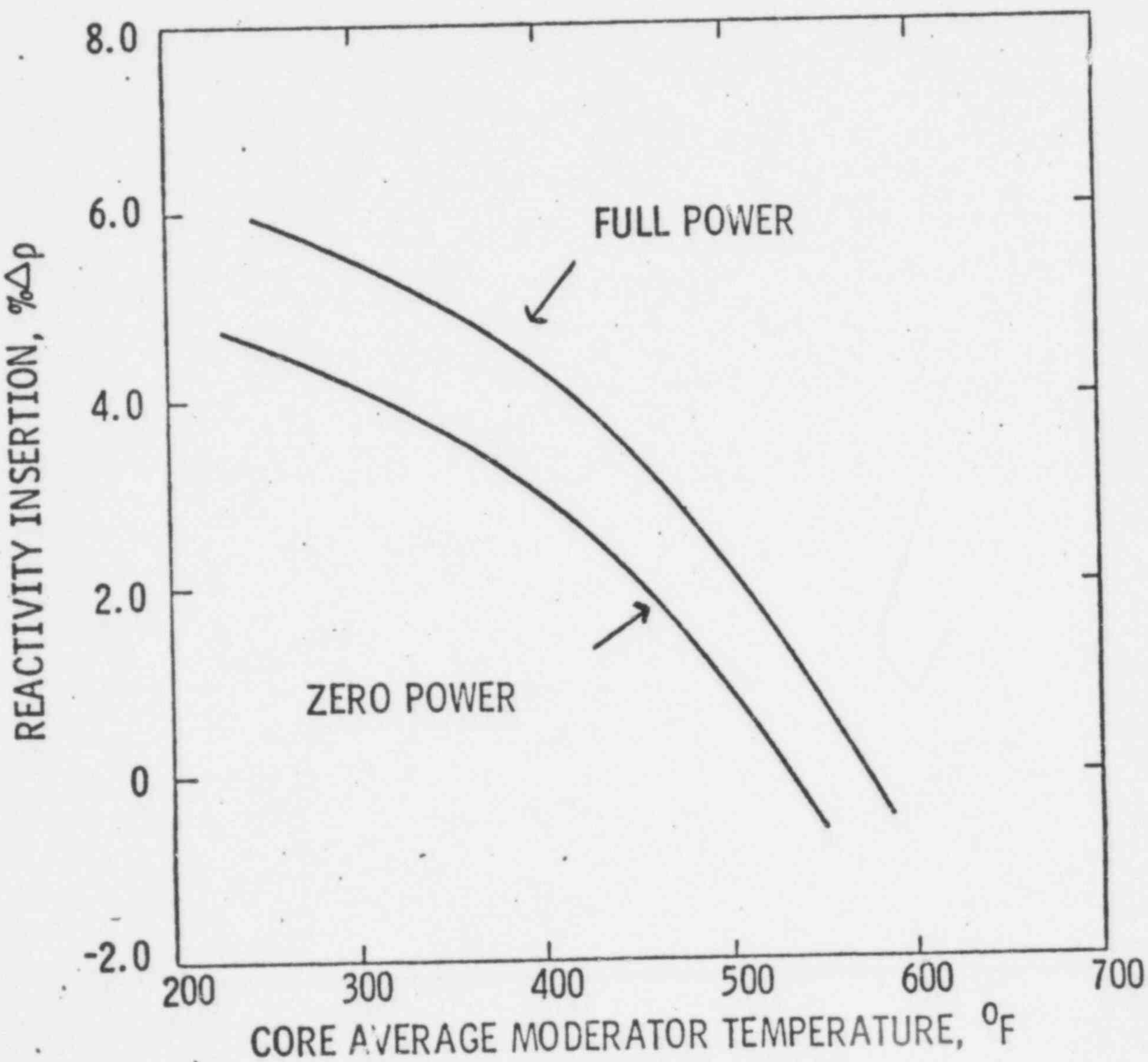

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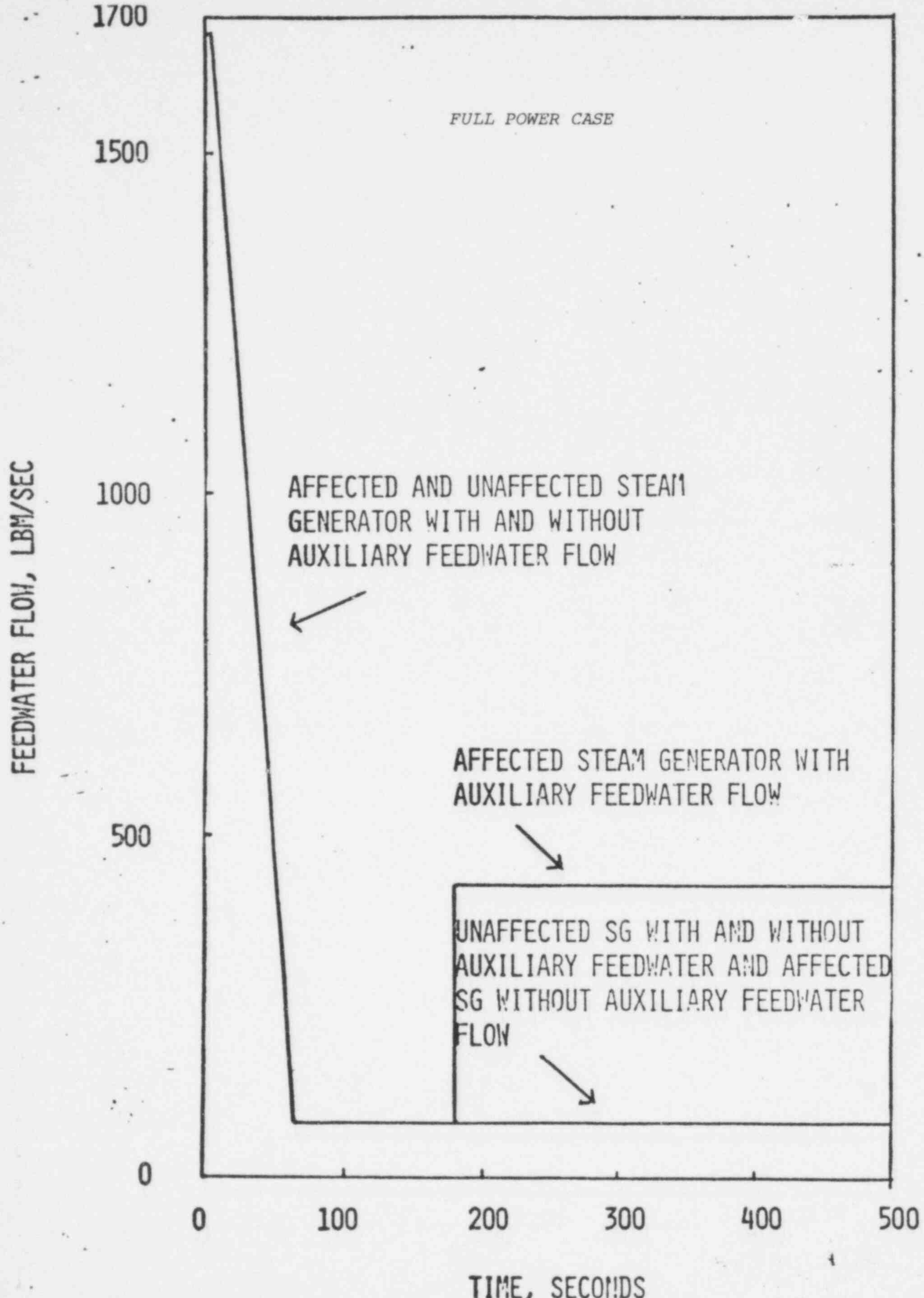
Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE REACTIVITY INSERTION VS MODERATOR TEMPERATURE	Figure 1



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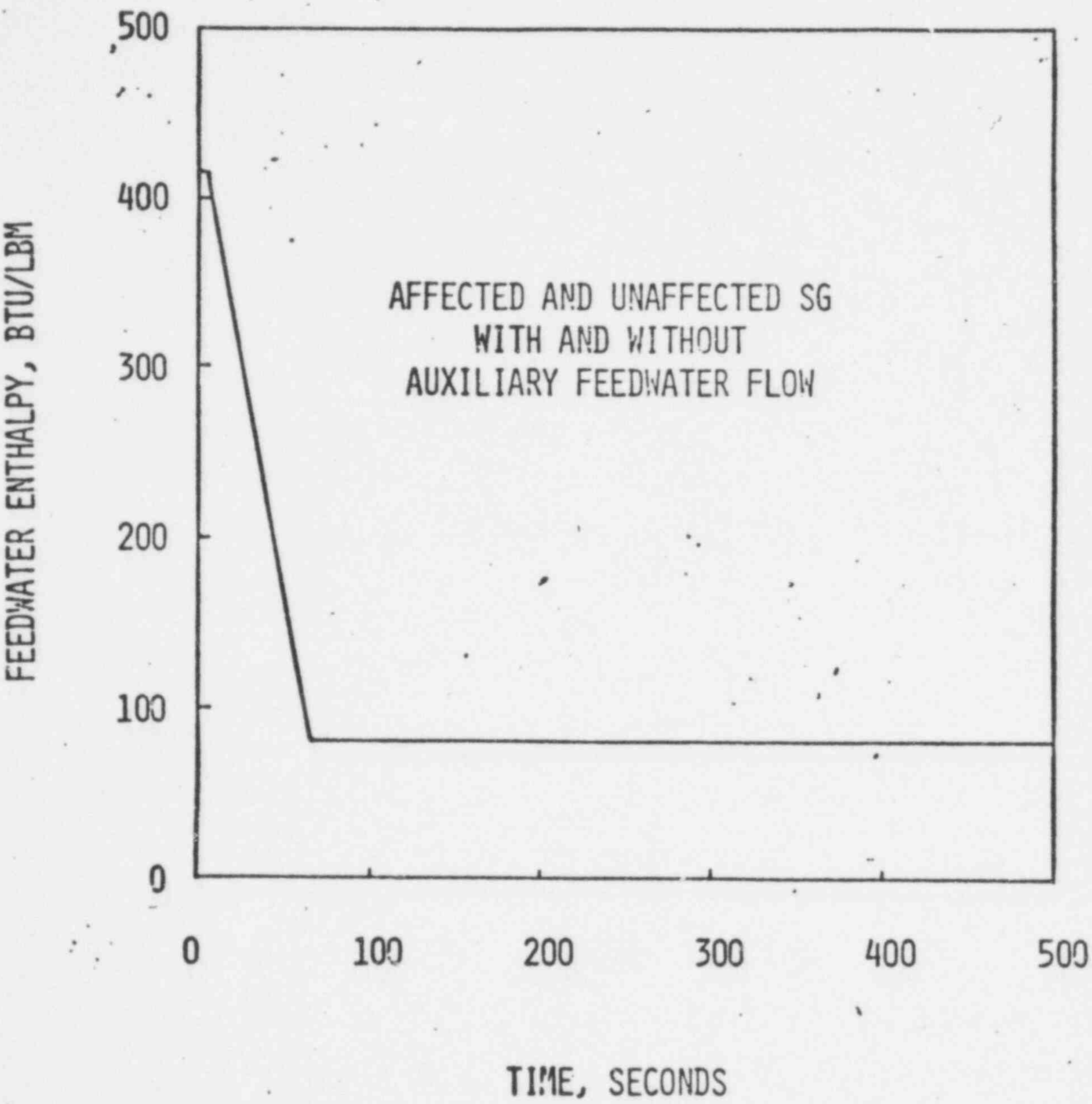
Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE EVENT FEEDWATER FLOW VS TIME	Figure 2

FULL POWER CASE



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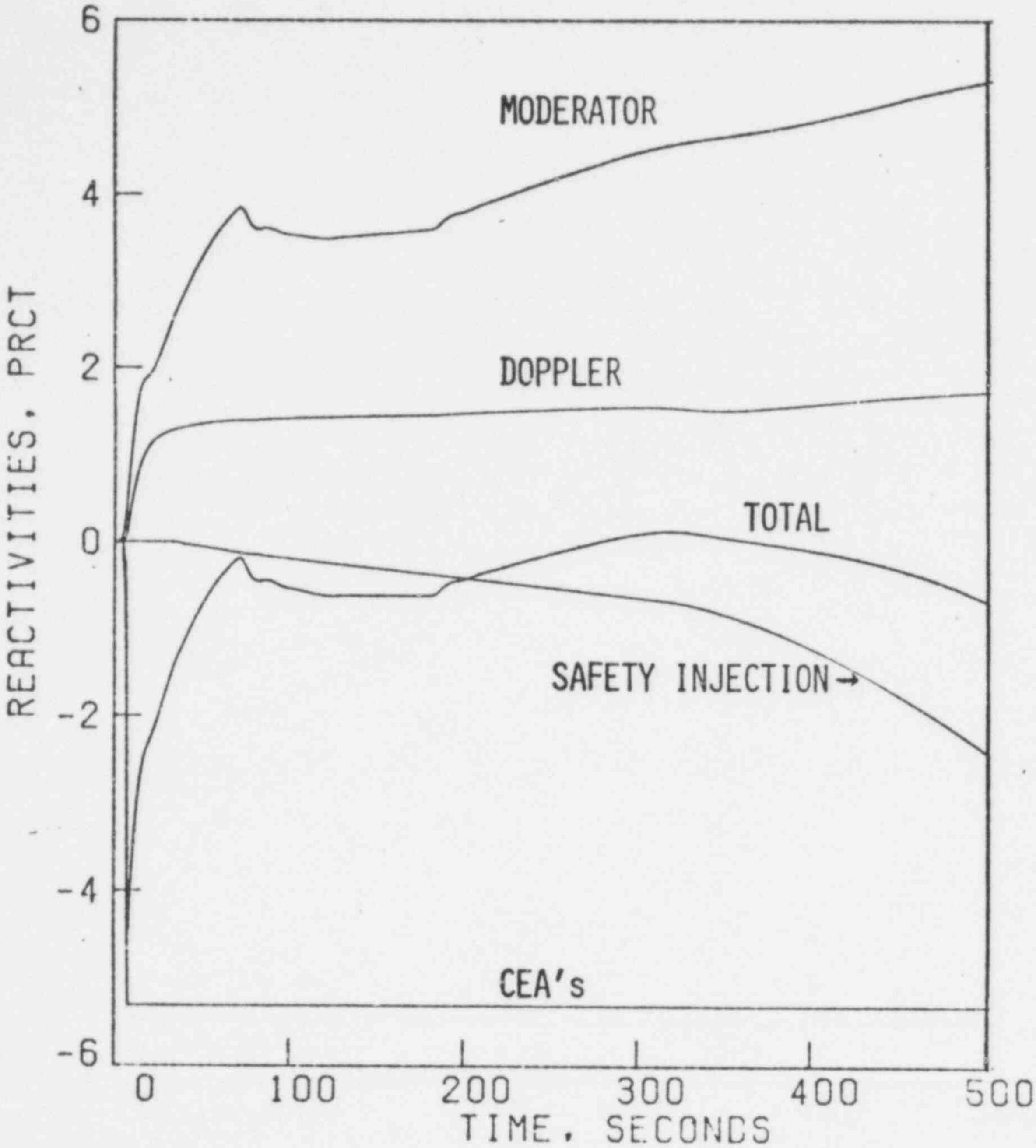
Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE EVENT FEEDWATER ENTHALPY VS TIME	Figure 3

FULL POWER CASE



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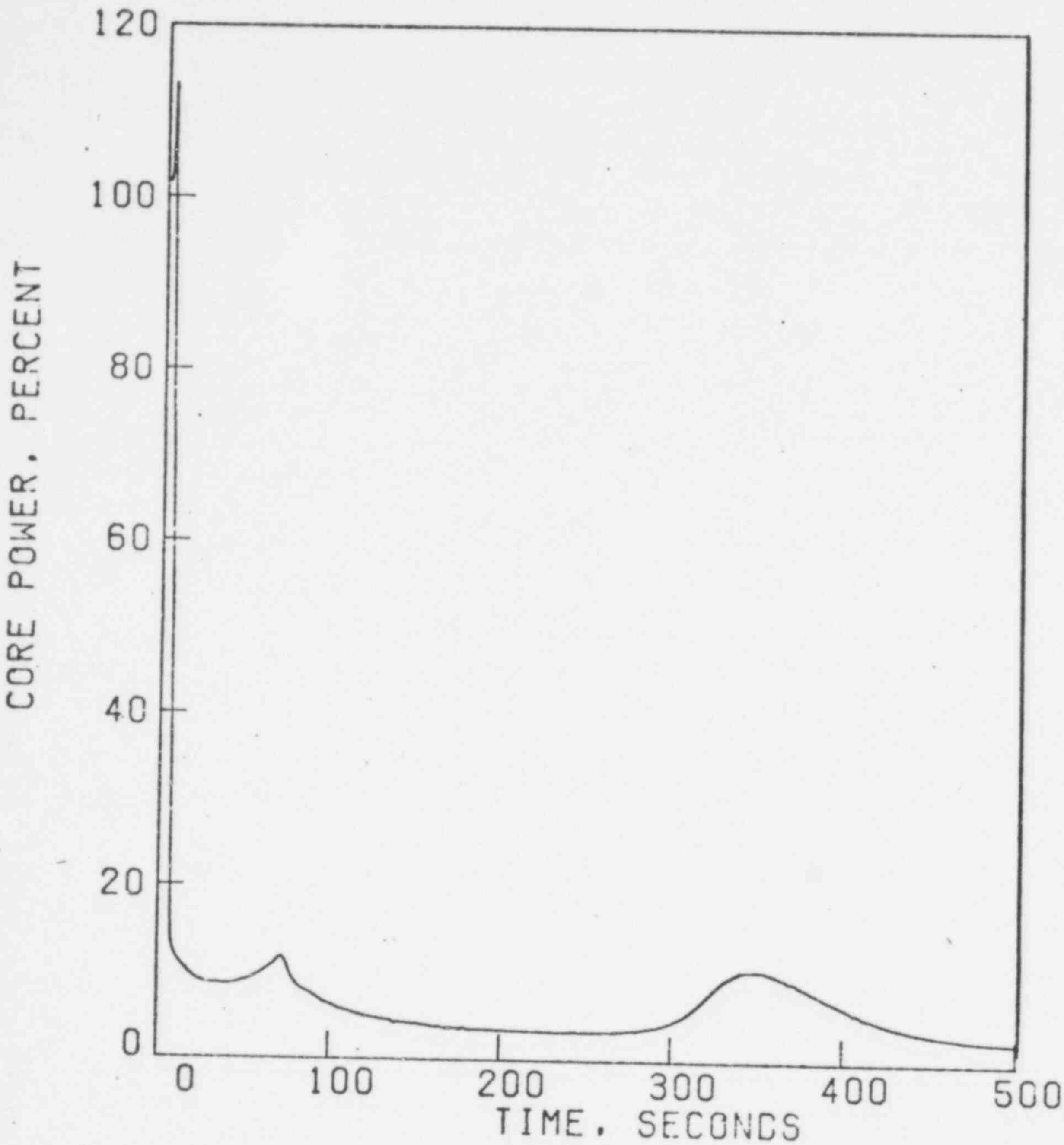
Millstone Nuclear F ver Station Unit Io. 2	STEAM LINE RUPTURE REACTIVITY CHANGES VS TIME	Figure 4

FULL POWER CASE



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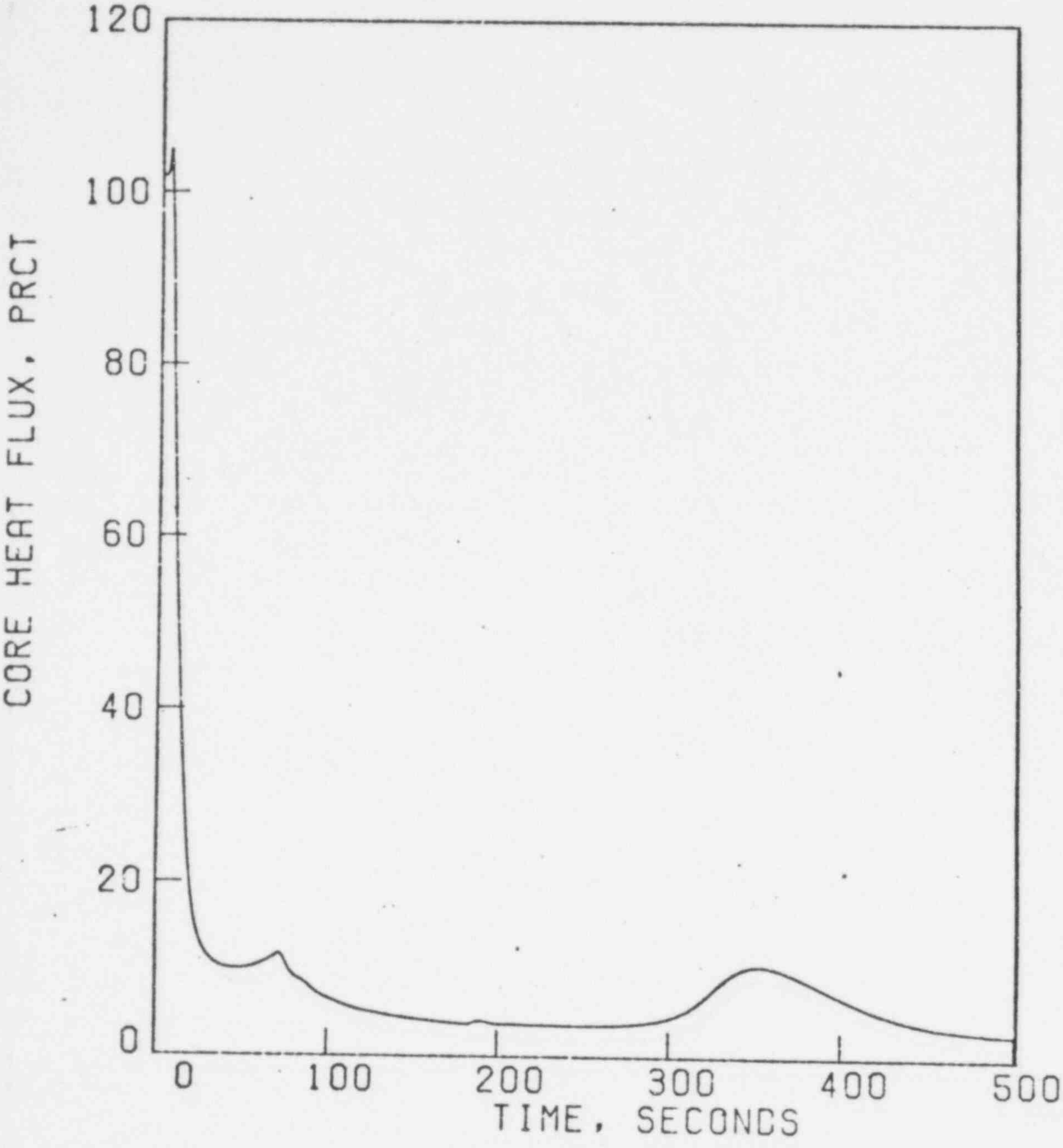
Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE CORE POWER VS TIME	Figure 5

FULL POWER CASE



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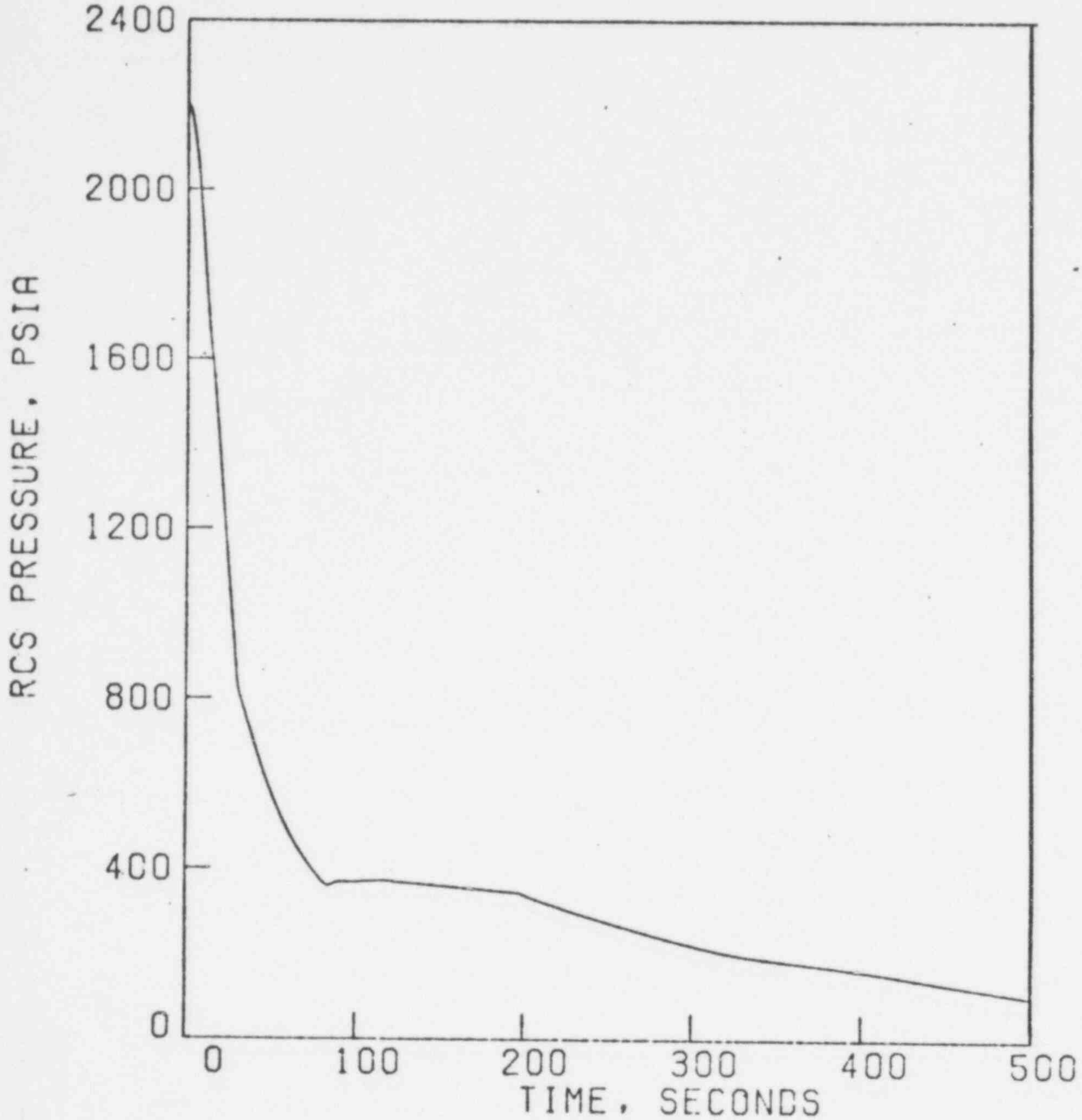
Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE CORE AVERAGE HEAT FLUX VS TIME	Figure 6

FULL POWER CASE



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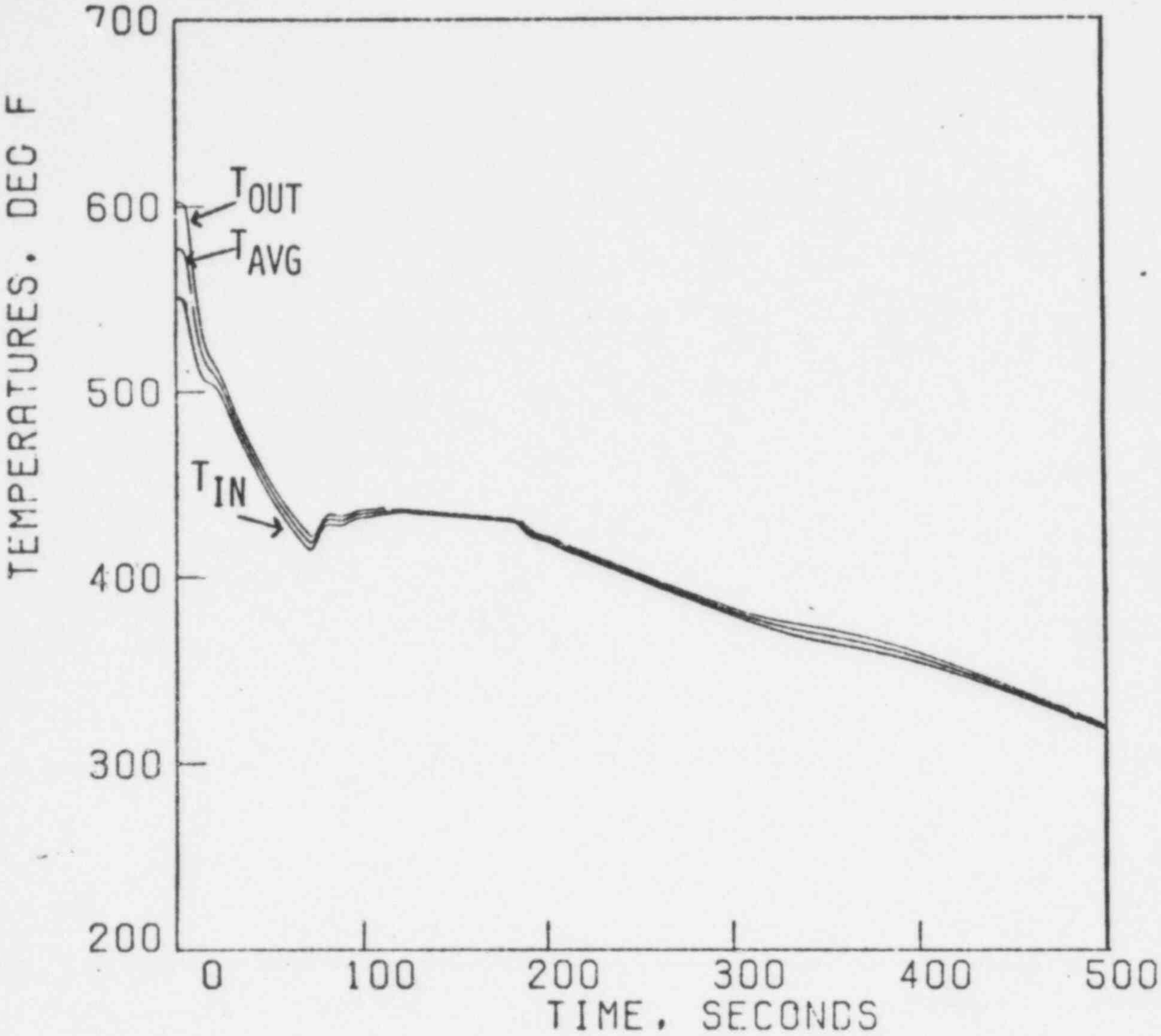
Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE REACTOR COOLANT SYSTEM PRESSURE VS TIME	Figure 7

FULL POWER CASE



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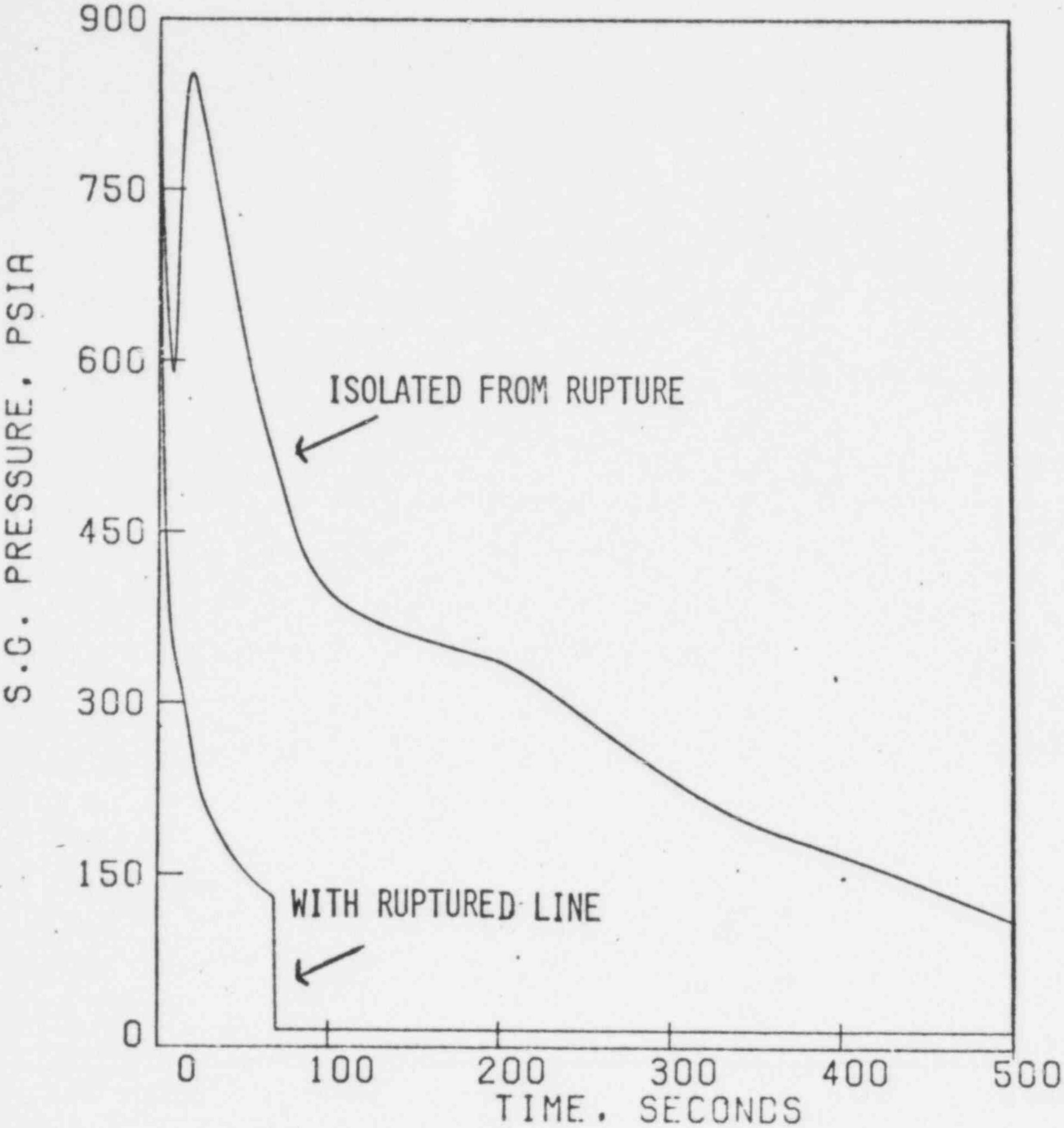
Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE REACTOR COOLANT TEMPERATURE VS TIME	Figure 8

FULL POWER CASE



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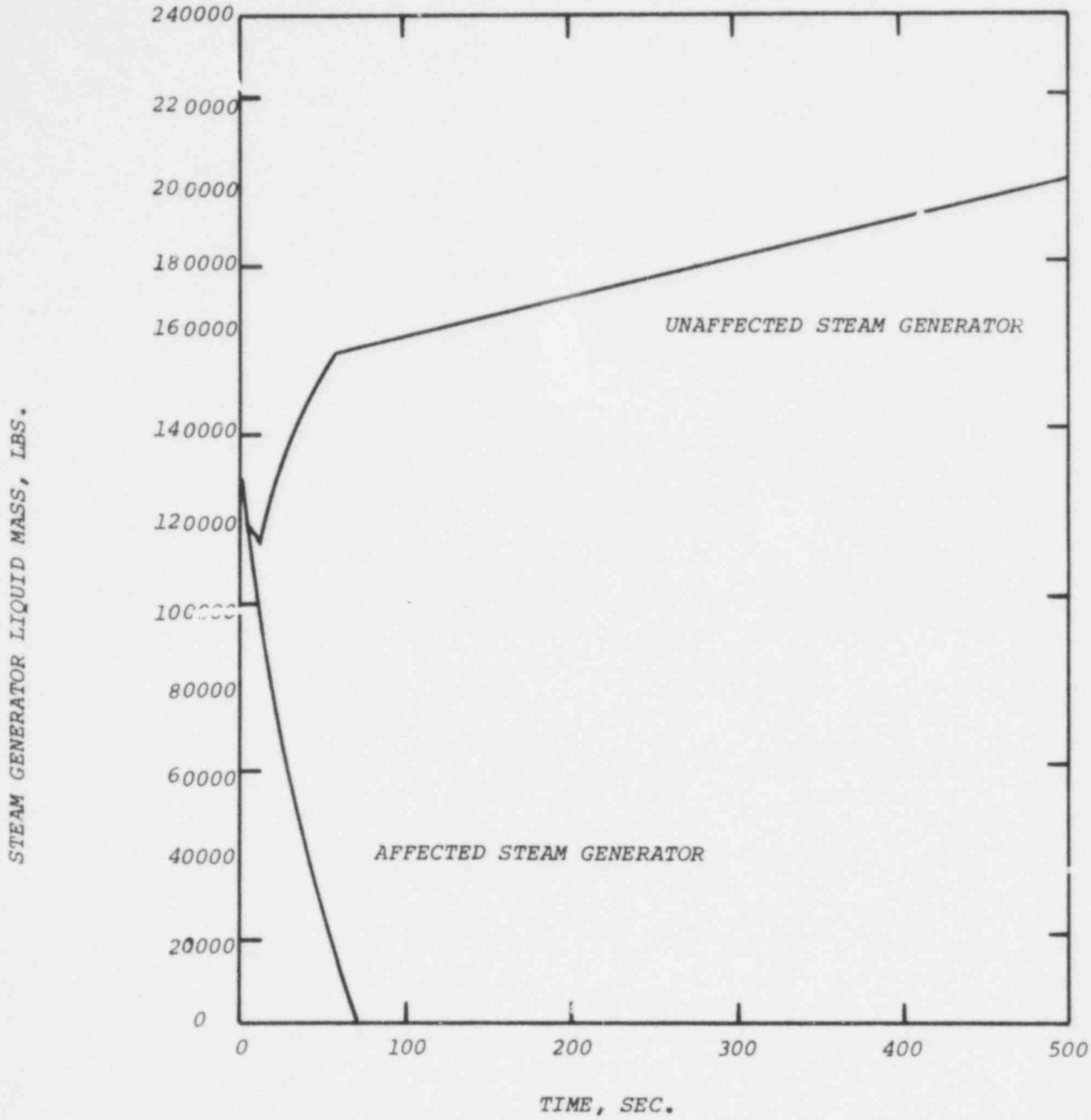
Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE STEAM GENERATOR PRESSURE VS TIME	Figure 9

FULL POWER CASE



STEAM LINE RUPTURE EVENT

STEAM GENERATOR LIQUID MASS

VS TIME

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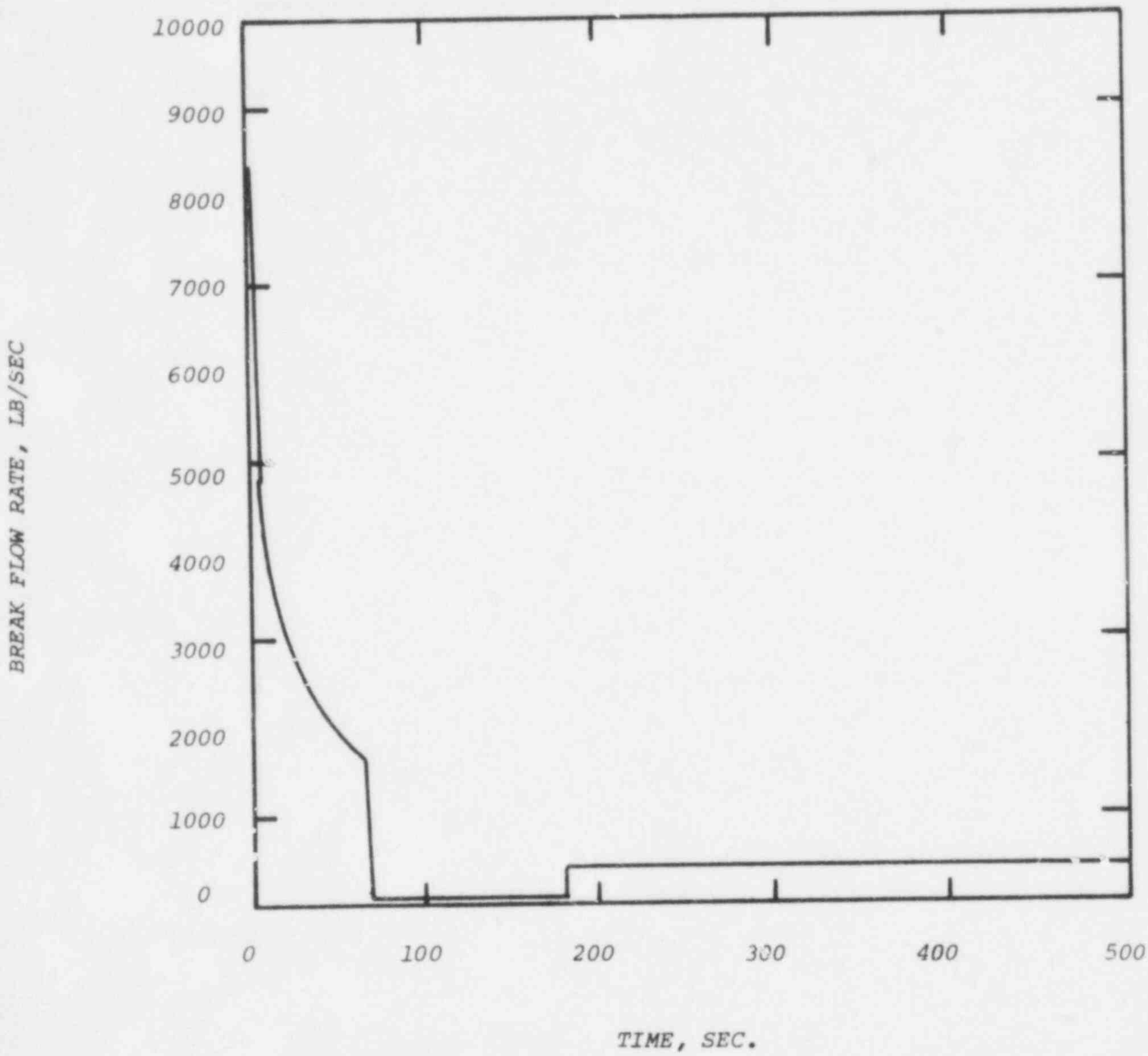
FIGURE 10

FULL POWER CASE



STEAM LINE RUPTURE EVENT

BREAK FLOW RATE VS. TIME

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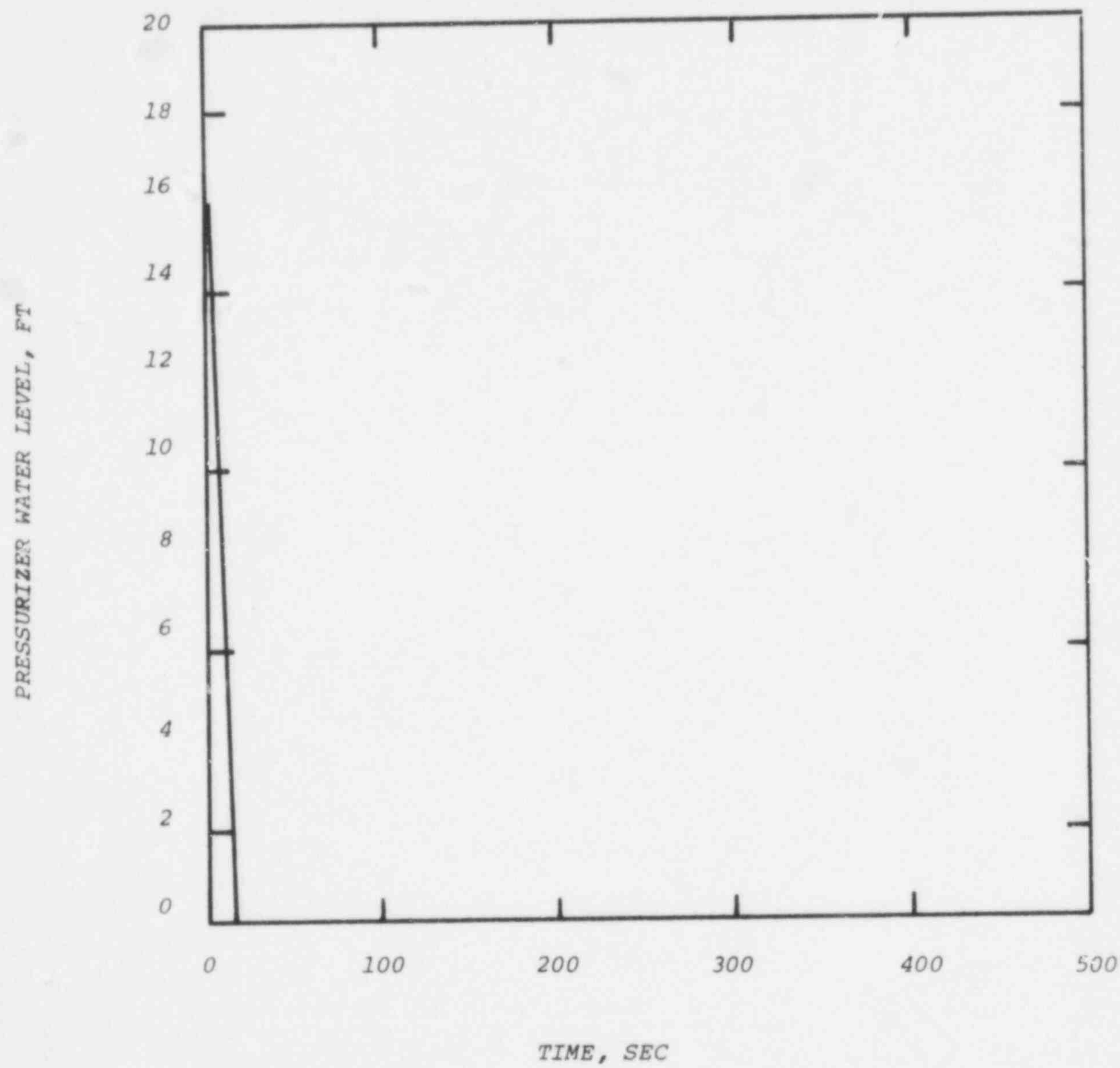
FIGURE 11

FULL POWER CASE



STEAM LINE RUPTURE EVENT

PRESSURIZER LEVEL VS. TIME

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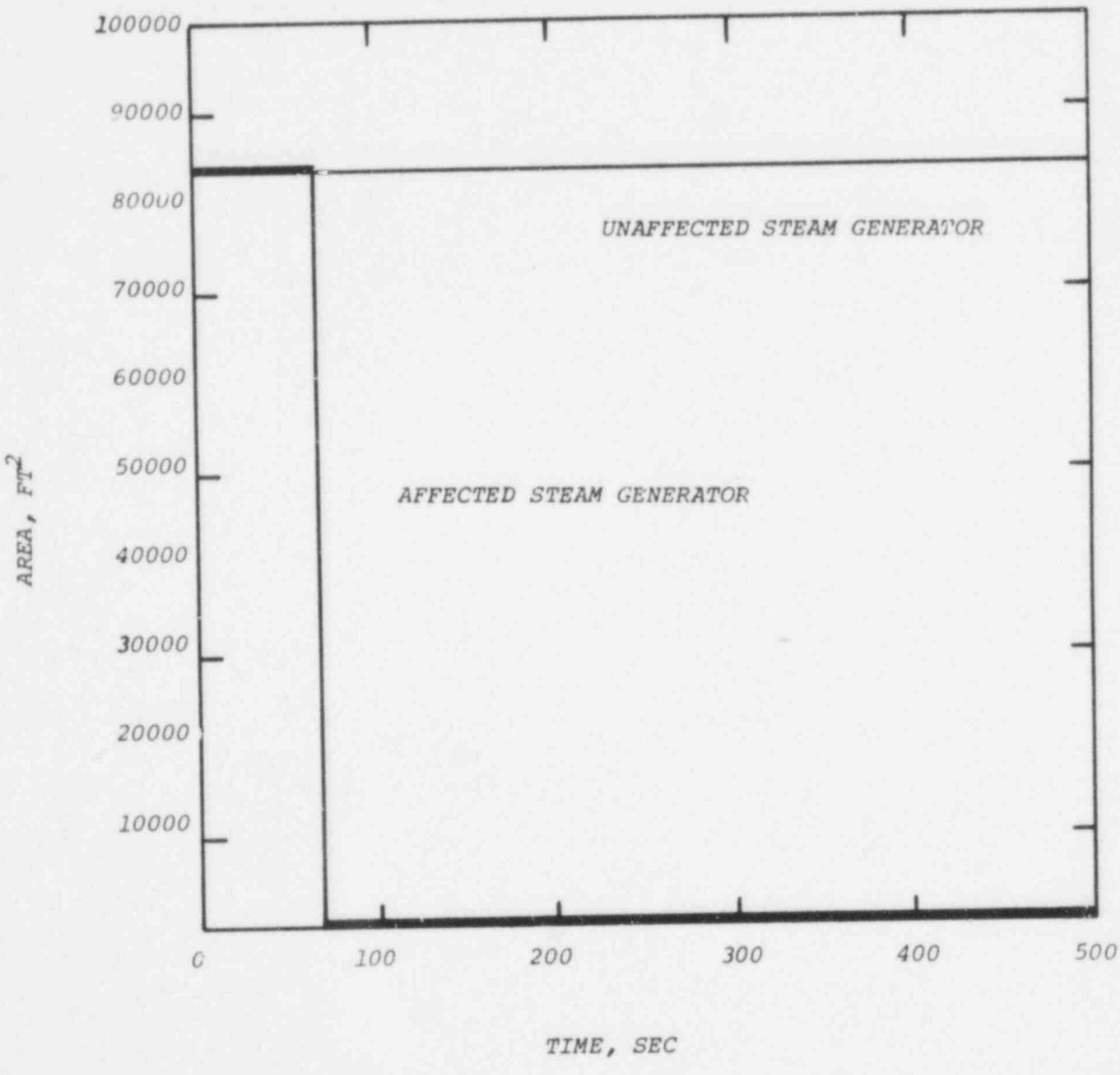
FIGURE 12

FULL POWER CASE



STEAM LINE RUPTURE EVENT

STEAM GENERATOR HEAT TRANSFER AREA

COVERED VS. TIME

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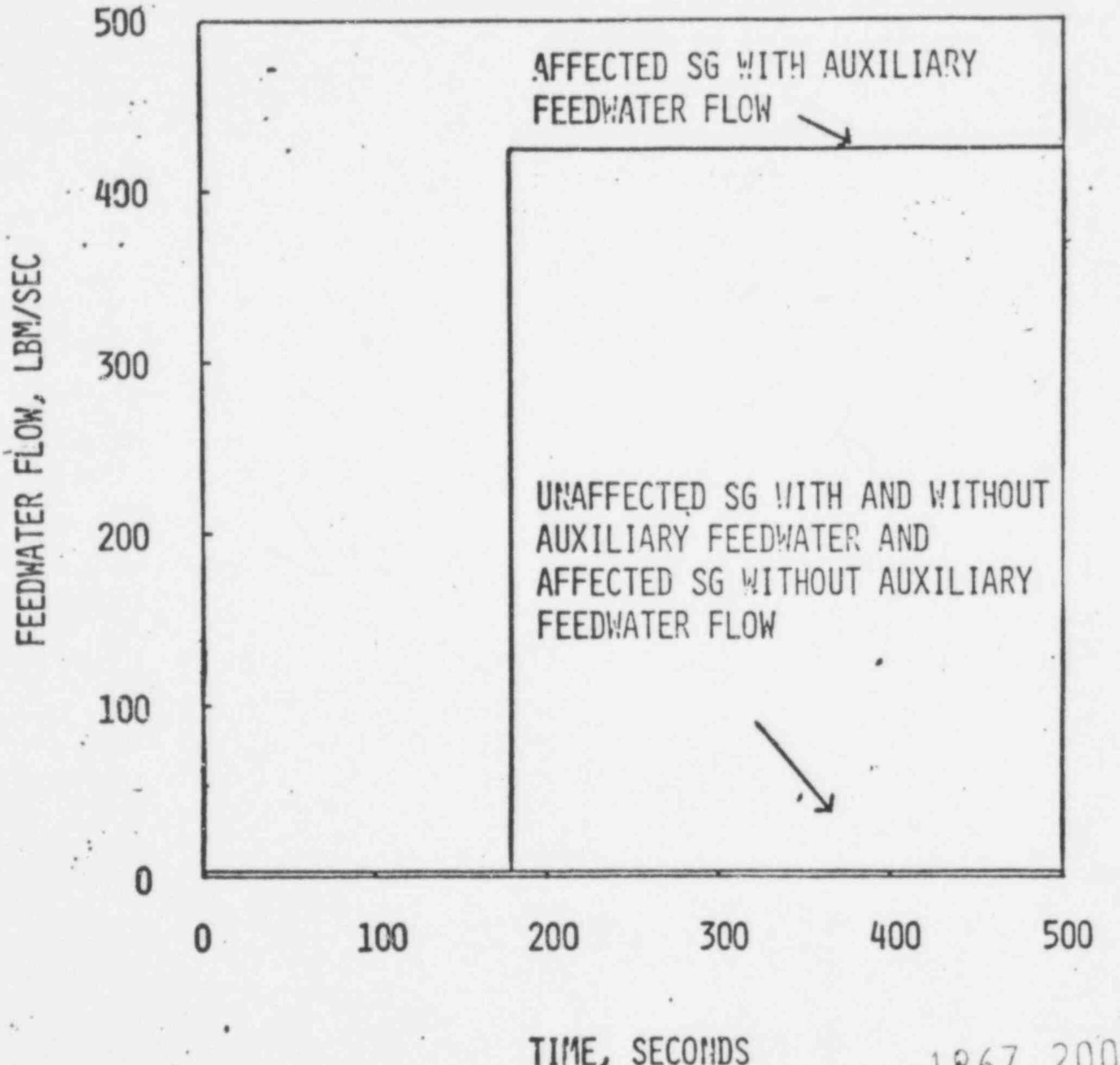
FIGURE 13

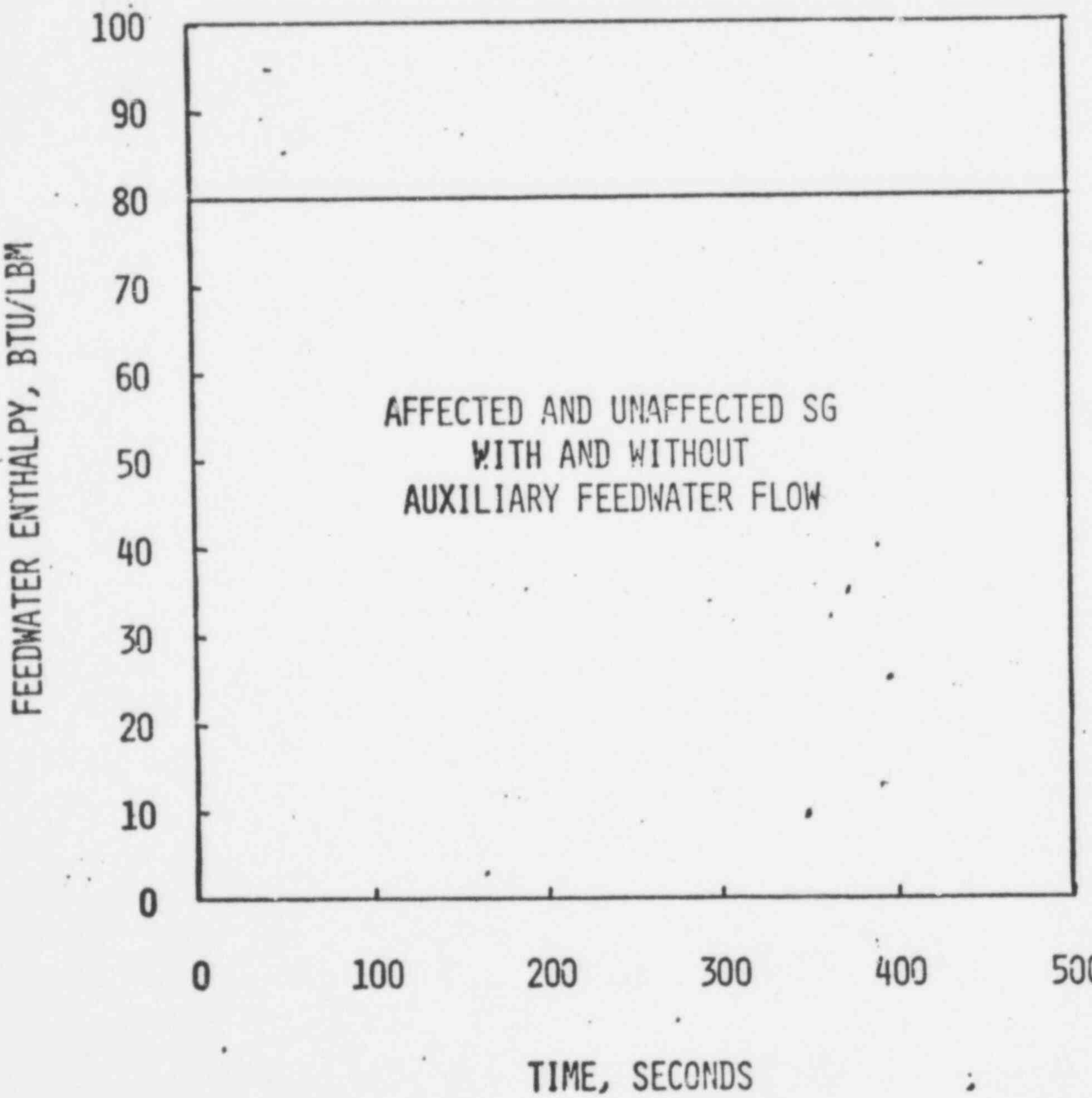
ZERO POWER CASE



1867 200

Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE EVENT FEEDWATER FLOW VS TIME	Figure 14

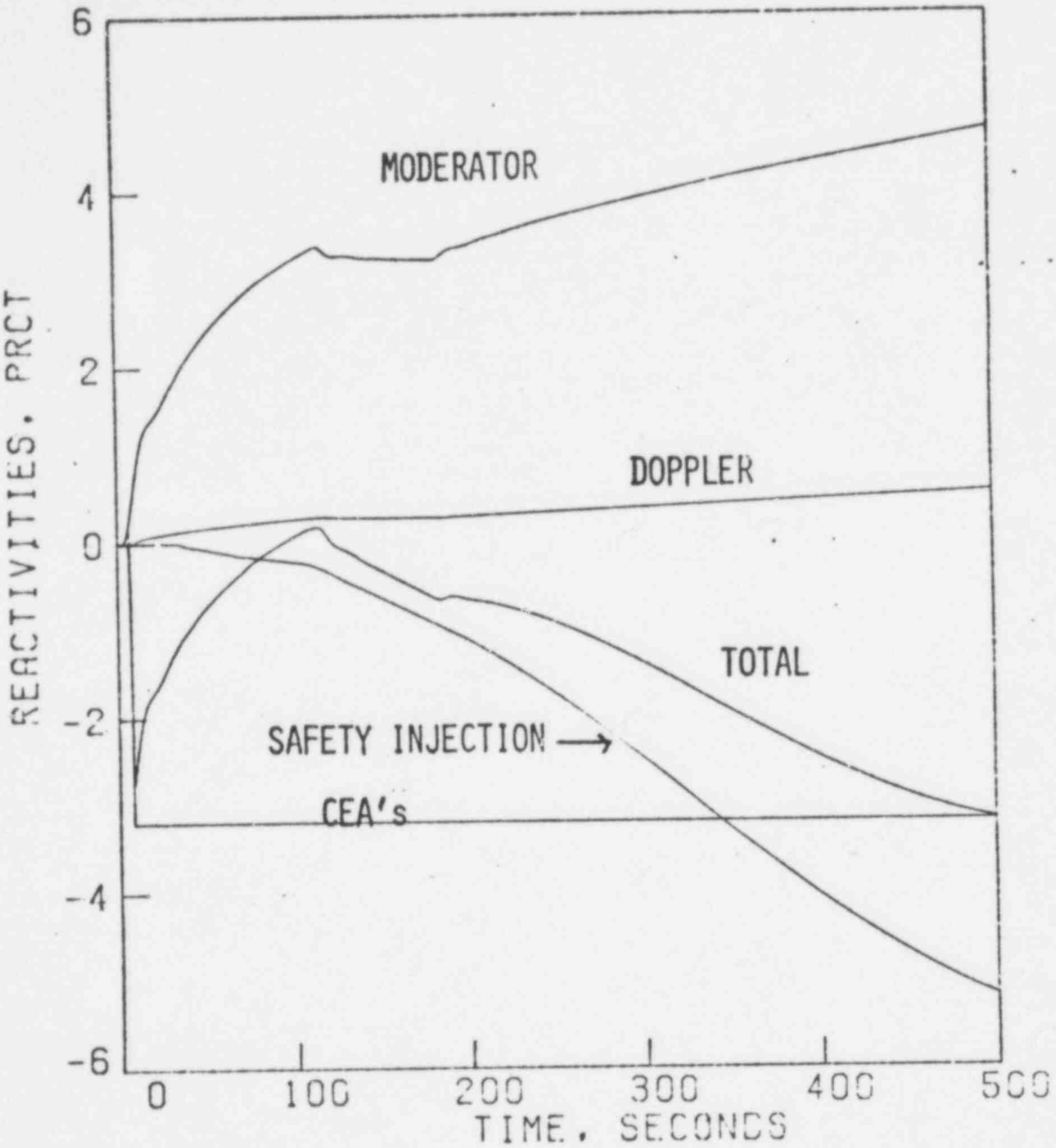
ZERO POWER CASE



1867 201

Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE EVENT FEEDWATER ENTHALPY VS TIME	Figure 15

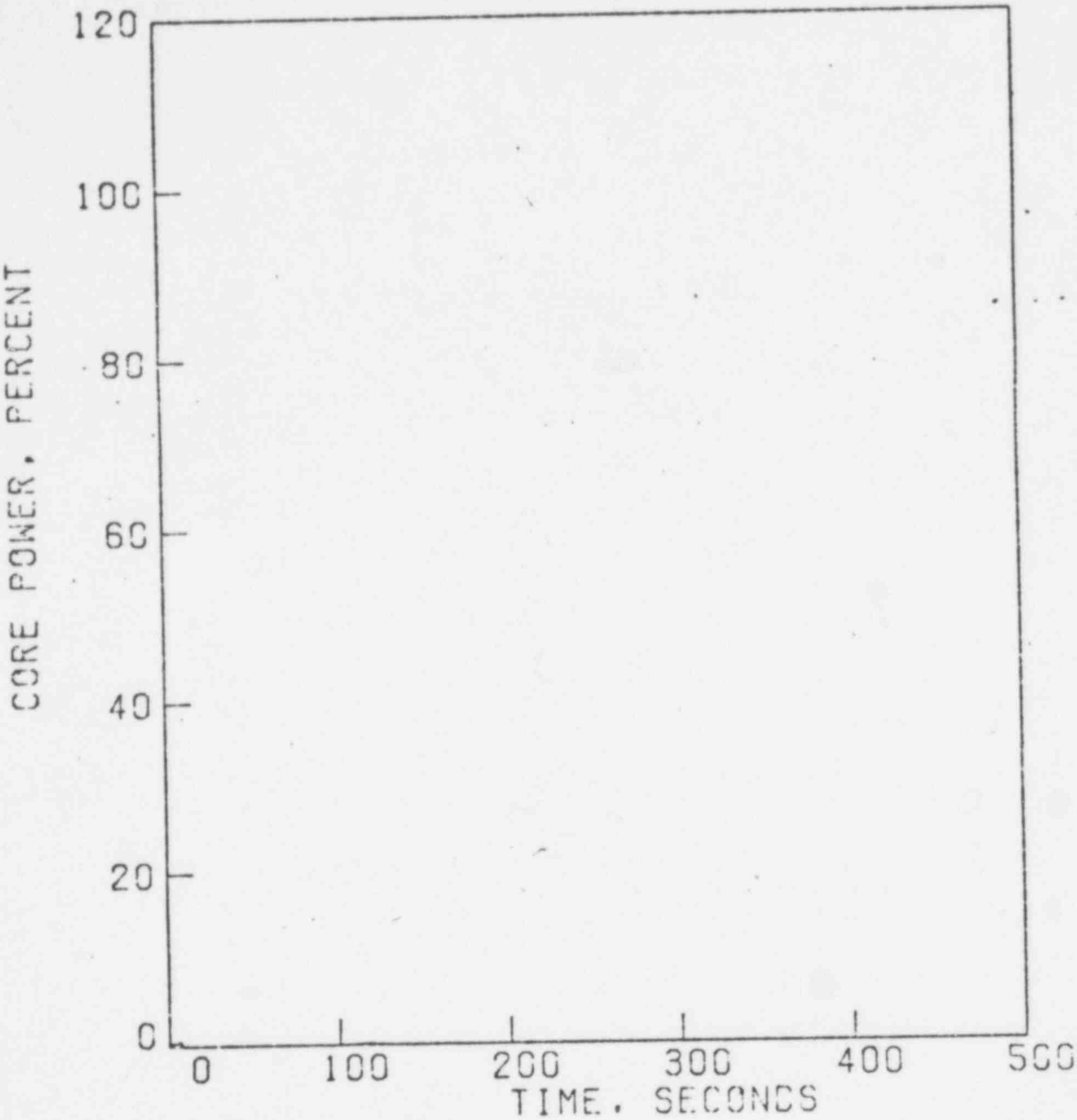
ZERO POWER CASE



1867 202

Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE REACTIVITY CHANGES VS TIME	Figure 16

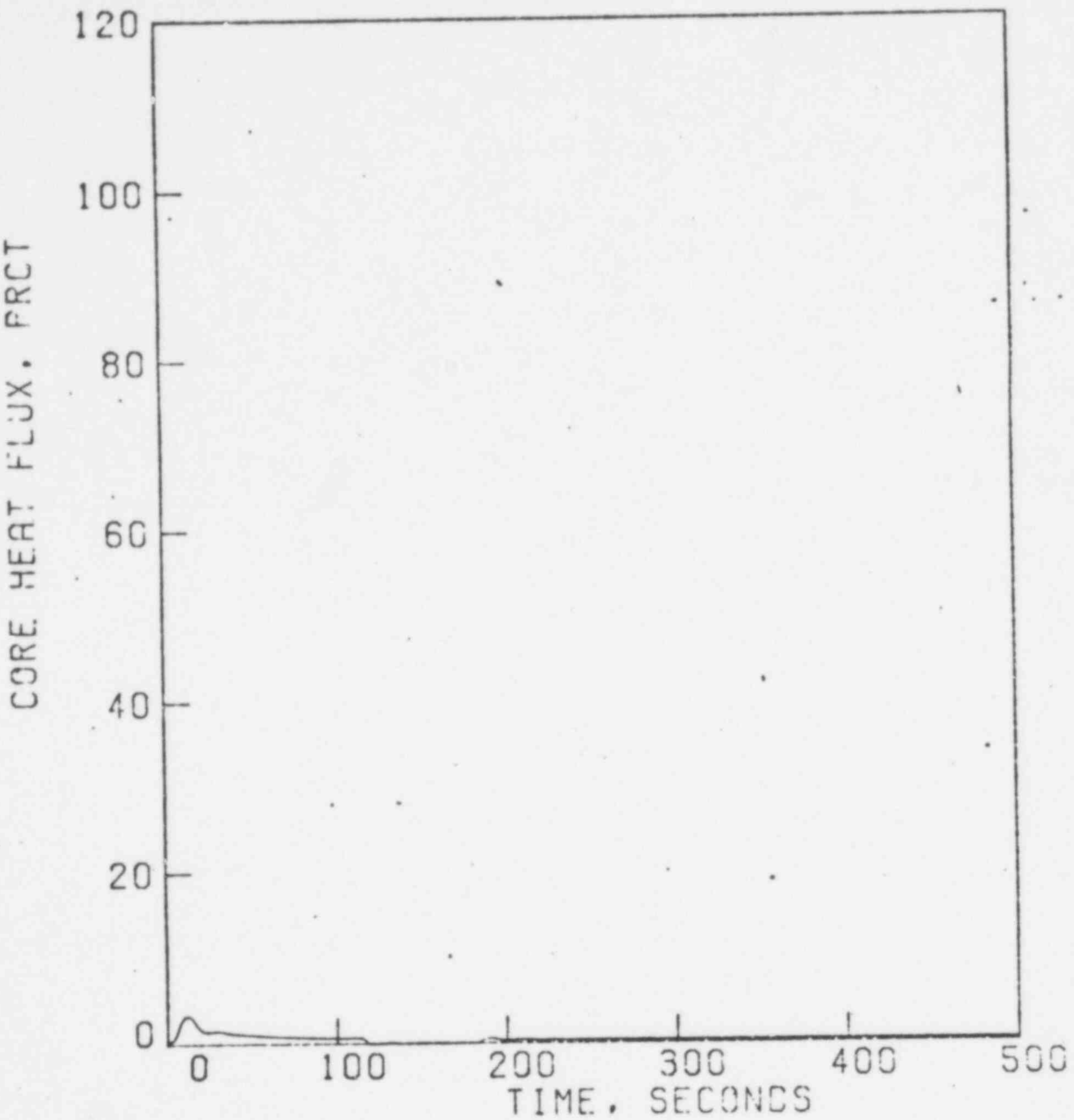
ZERO POWER CASE



1867 203

Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE CORE POWER VS TIME	Figure 17

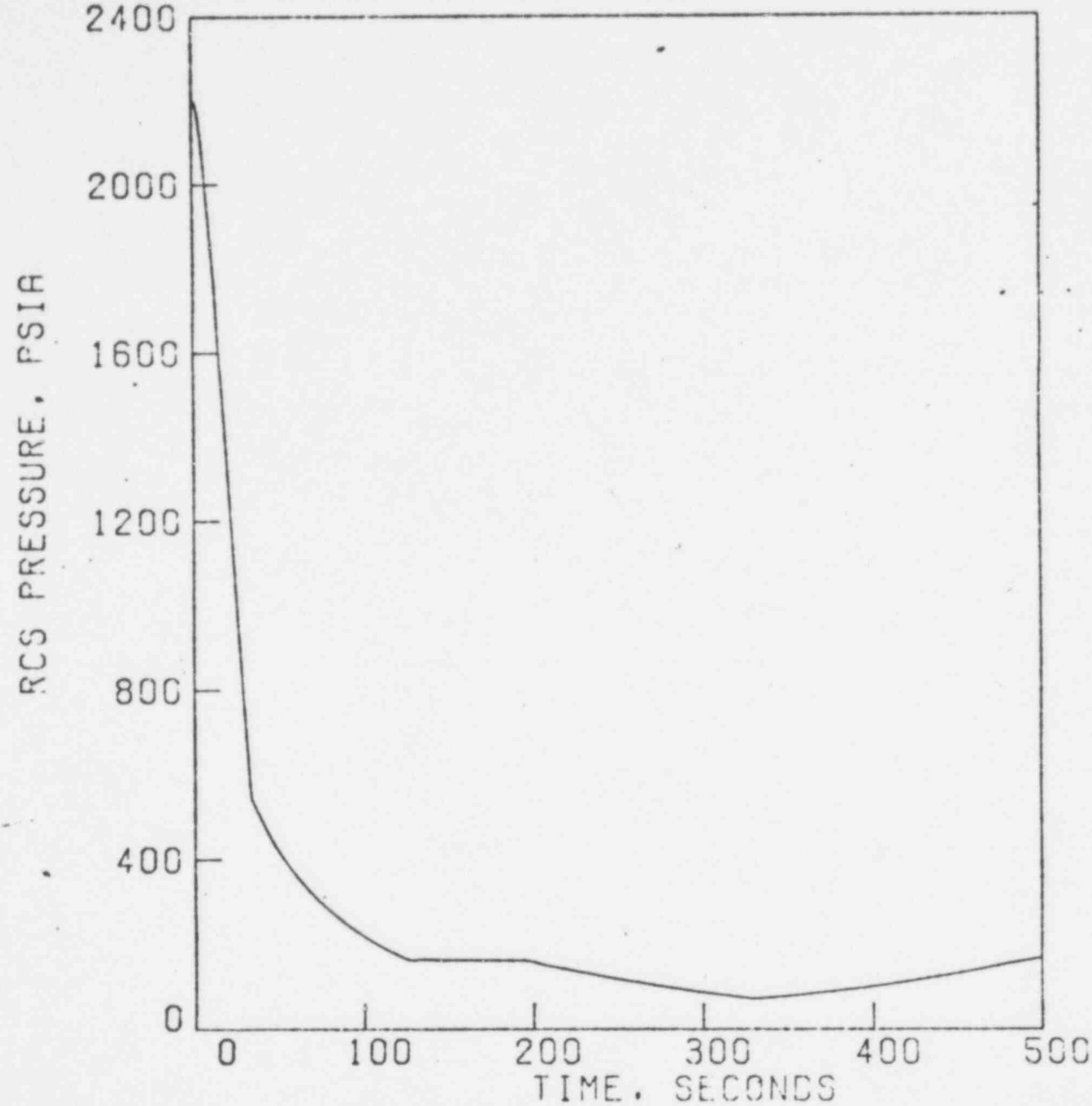
ZERO POWER CASE



1867 204

Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE CORE AVERAGE HEAT FLUX VS TIME	Figure 18

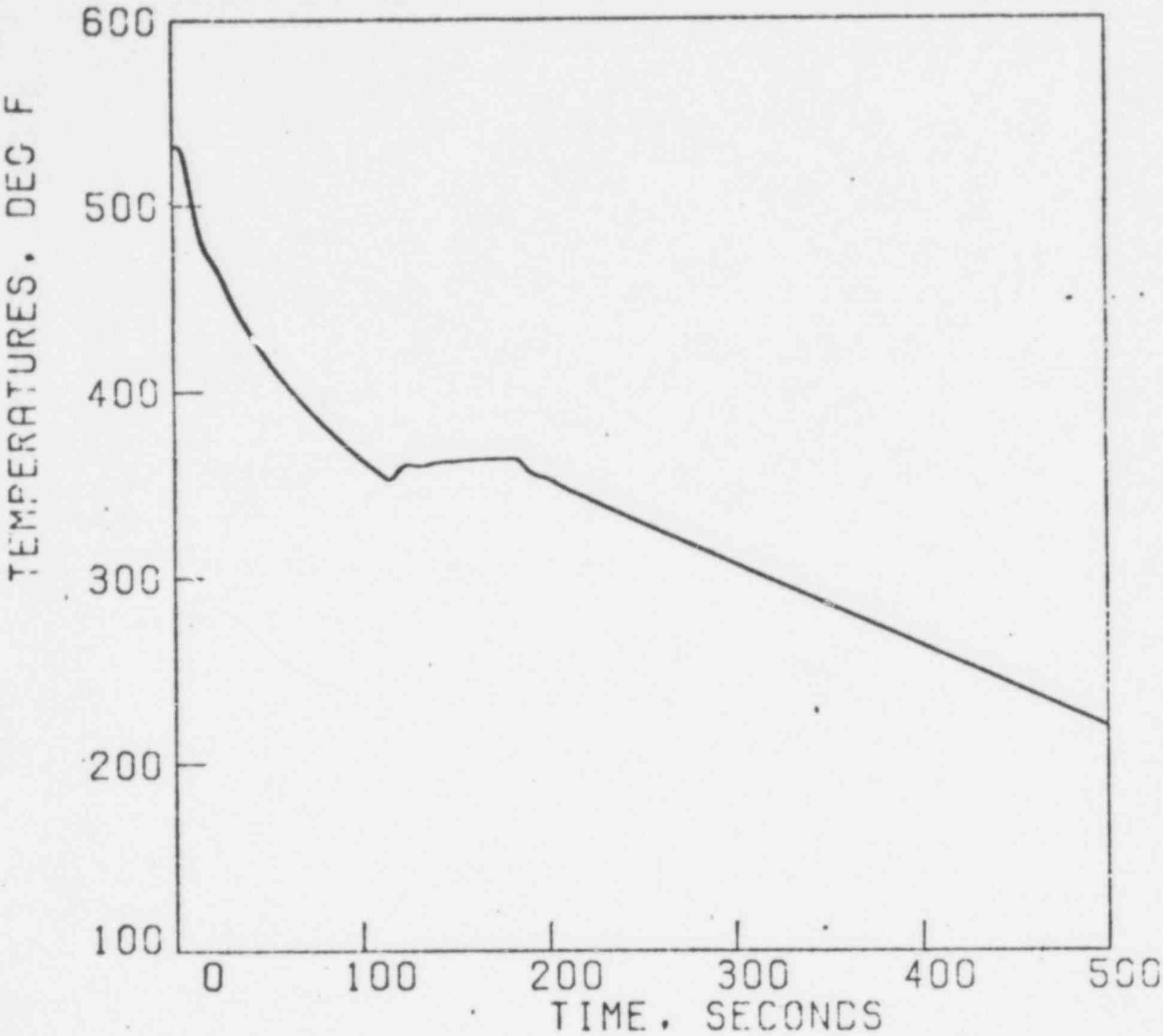
ZERO POWER CASE



1867 205

Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE REACTOR COOLANT SYSTEM PRESSURE VS TIME	Figure 19

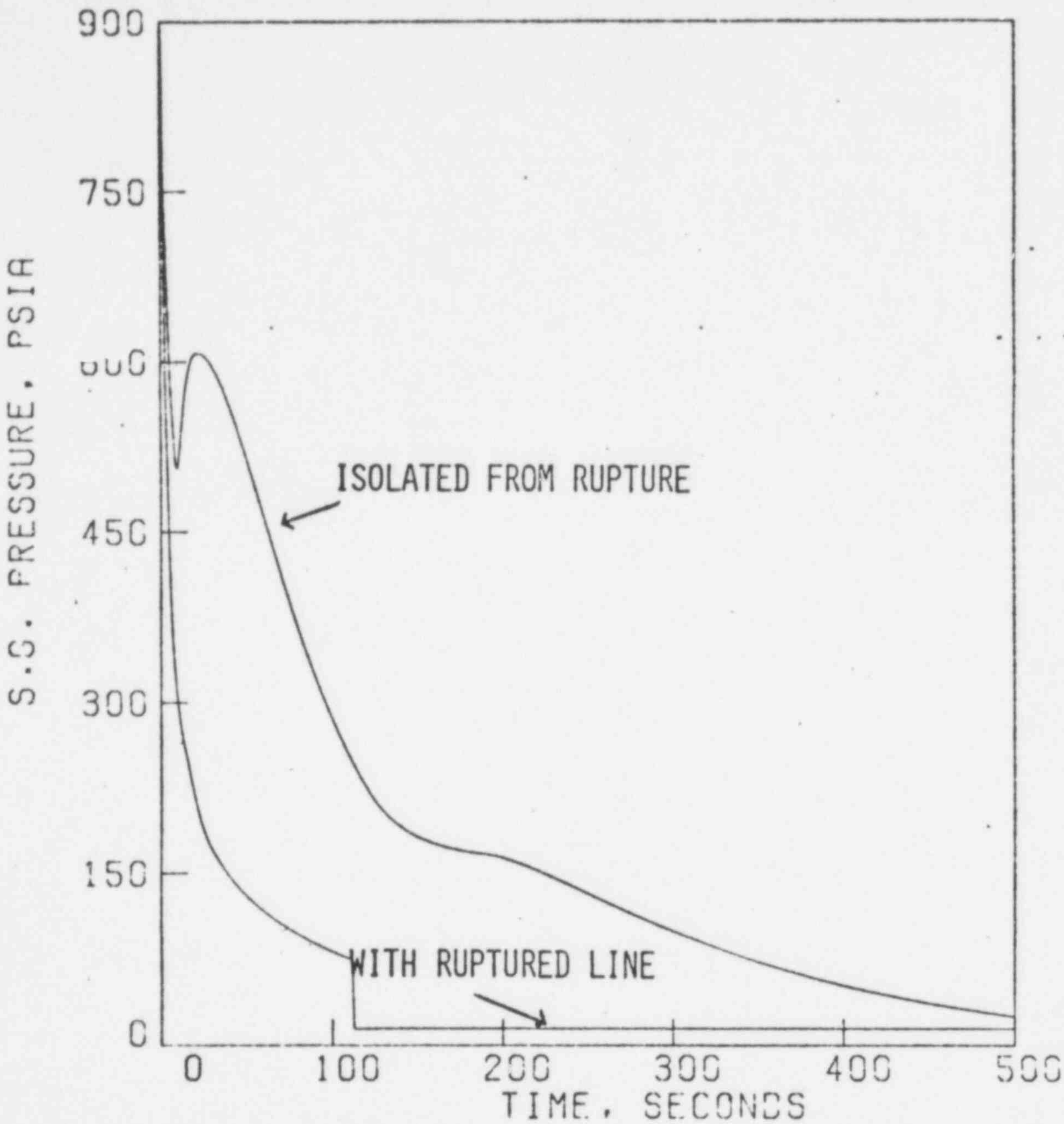
ZERO POWER CASE



1867 206

Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE REACTOR COOLANT TEMPERATURES VS TIME	Figure 20

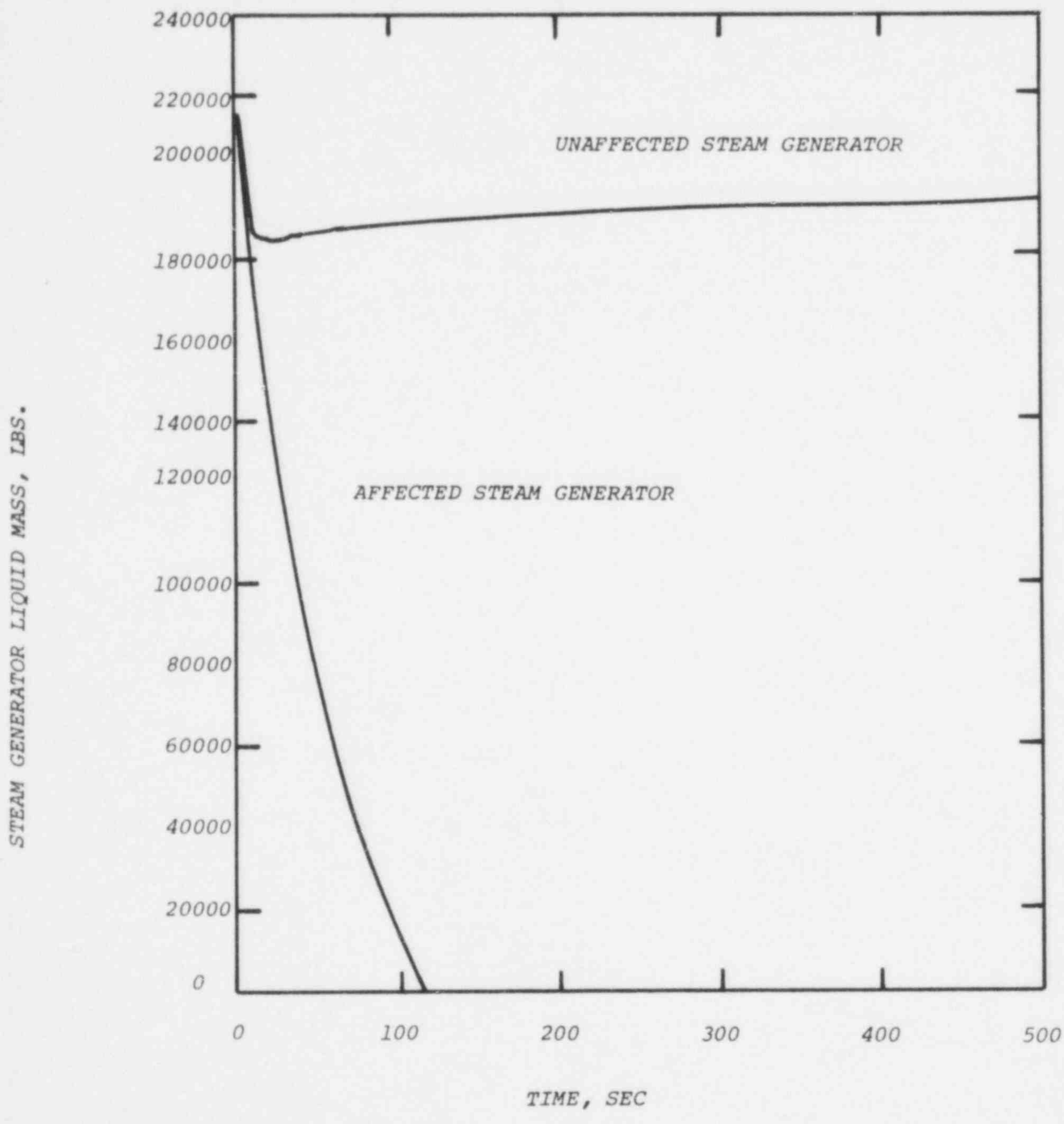
ZERO POWER CASE



1867 207

Millstone Nuclear Power Station Unit No. 2	STEAM LINE RUPTURE STEAM GENERATOR PRESSURE VS TIME	Figure 21

ZERO POWER CASE



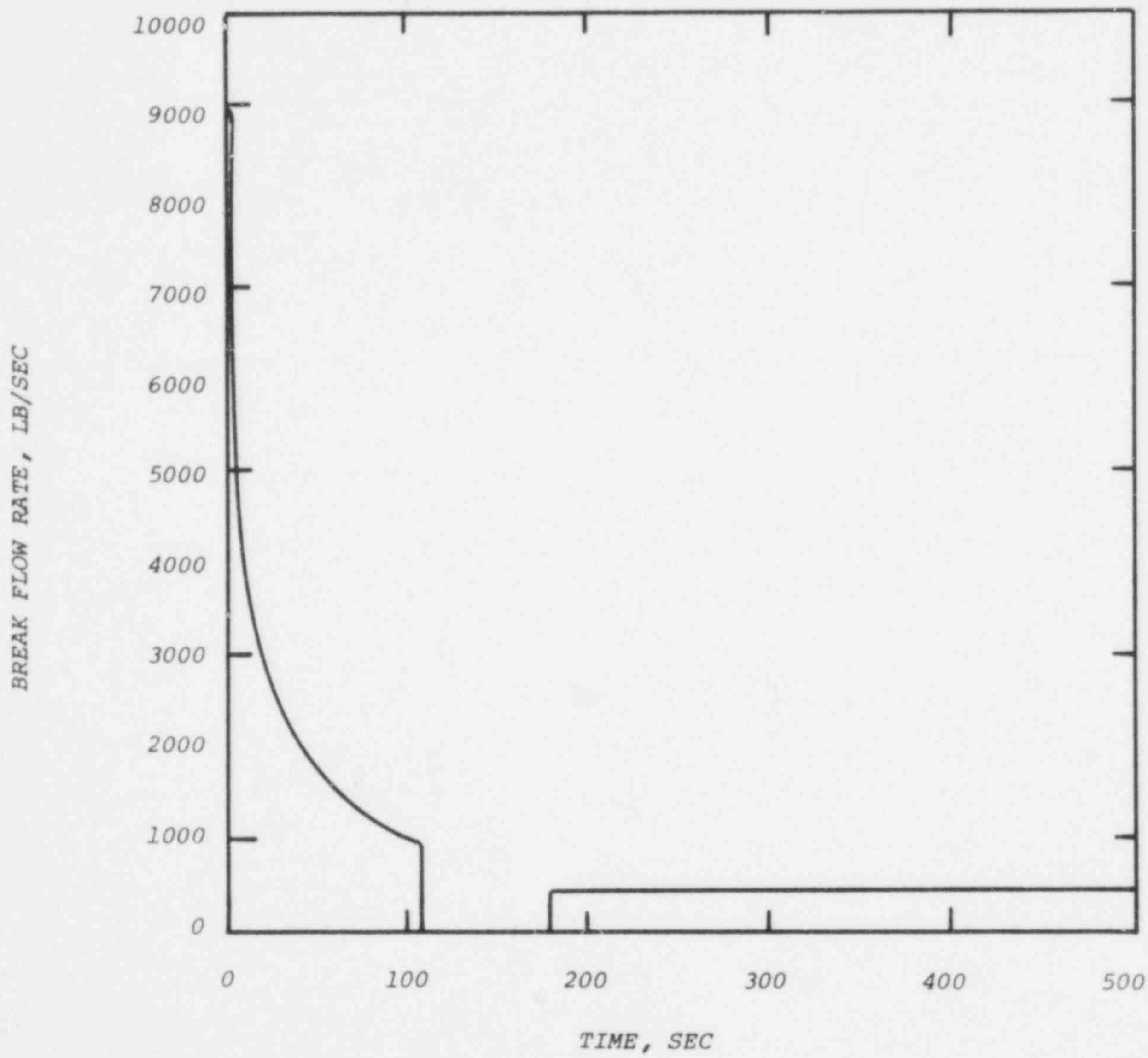
STEAM LINE RUPTURE EVENT

STEAM GENERATOR LIQUID MASS VS. TIME

1867 208

FIGURE 22

ZERO POWER CASE

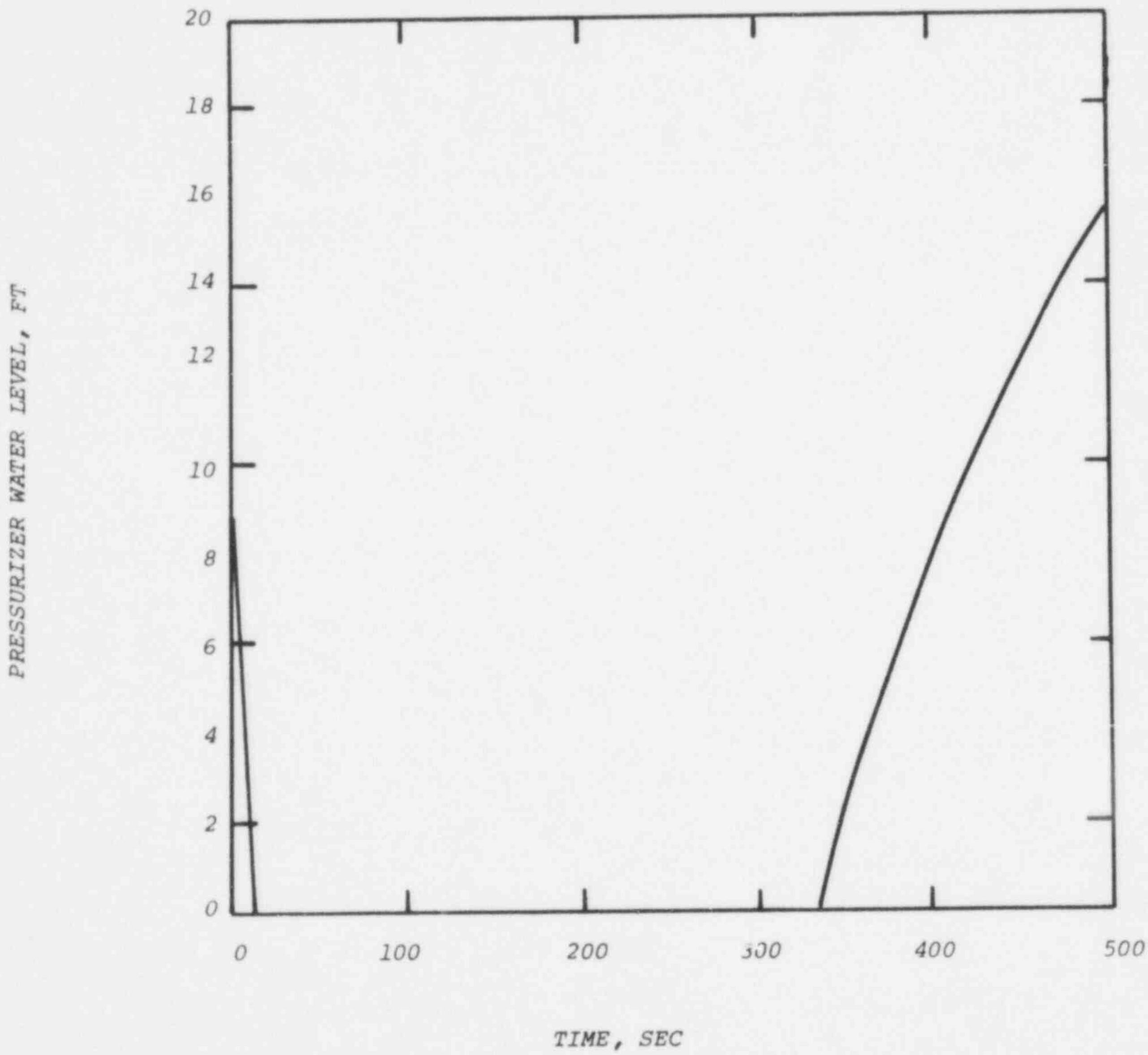


STEAM LINE RUPTURE EVENT

BREAK FLOW RATE VS. TIME

1867 209

ZERO POWER CASE



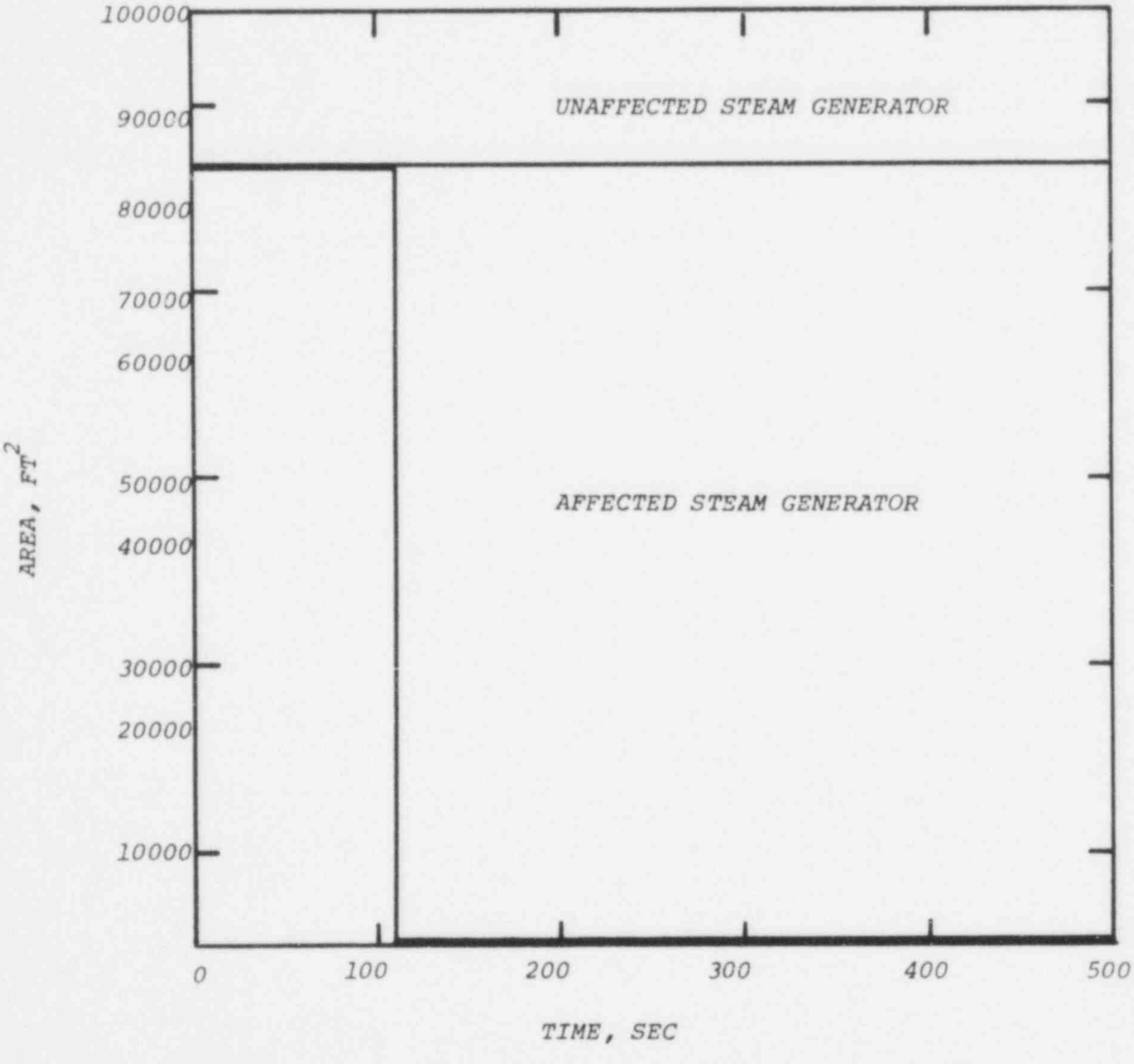
STEAM LINE RUPTURE EVENT

PRESSURIZER LEVEL VS. TIME

1867 210

FIGURE 24

ZERO POWER CASE



STEAM LINE RUPTURE EVENT

STEAM GENERATOR HEAT TRANSFER

AREA COVERED VS. TIME

1867 211

FIGURE 25

DOCKET NO. 50-336

ATTACHMENT 2

MILLSTONE NUCLEAR POWER STATION, UNIT NO. 2

MAIN STEAM LINE BREAK ANALYSIS - CONTAINMENT PRESSURE

1867 212

JANUARY, 1980

B. Containment Pressure

Question 1

Review your current analysis of this event, and provide NRC with the assumptions used during this analysis. Particular emphasis should be placed on describing how AFS flow was accounted for in your original analysis. (Reference to previously submitted information is acceptable if identified as to page number and date.) Any changes in your design which would impact the conclusions of your original analysis should be discussed. We are particularly concerned with design changes that could lead to an underestimation of the containment pressure following a MSLB inside containment.

Response

The current containment pressure analysis for a steam line rupture within containment is presented within the Millstone 2 FSAR. The analysis was performed in response to question 14.10 and is contained within Amendment 15, dated February 16, 1973.

The analysis performed was based on the no load, single loop nozzle break case with a 20% moisture content in the blowdown. The primary results of the analysis were a peak containment pressure of 46.9 psig and a peak temperature of 279.0 degrees F. Both results are within respective design conditions of 54 psig and 289 degrees F. The effects of auxiliary feedwater flow to the affected steam generator were not addressed, due to operating procedures which require isolation of the affected steam generator prior to initiation of auxiliary feedwater.

1867 213

Analyses have been performed to evaluate the effects of implementing automatic initiation of auxiliary feedwater on the previously docketed MSLB containment pressure analysis. The revised analyses do not change the pertinent conclusions of the original anlysis. (Peak pressure and temperature well within design parameters.)

2. Provide the following information for the reanalyses performed to determine the maximum containment pressure for a spectrum of postulated main steam line breaks for various reactor power levels for the proposed AFS design.

Question

a. Specify the AFS Flow rate that was used in your original containment pressurization analyses. Provide the basis for this assumed flow rate.

Response

AFS flow was not evaluated in the original analysis based on operating procedures which require isolation of the affected steam generator prior to auxiliary feedwater initiation.

Question

b. Provide the rated flow rate, the run out flow rate, and the pump head capacity curve for your AFS design.

Response

Millstone Unit No. 2 has one Steam Turbine Auxiliary Feedwater pump with a rated flow rate of 600 gpm plus 2 Electric Auxiliary Feedwater

pumps with rated flow rates of 300 gpm each. The total run out flow for all three pumps is 2050 gpm. Pump head capacity curves are are also attached.

Question

c. Provide the time span over which it was assumed in your original analysis that AFS was added to the affected steam generator following an MSLB inside containment.

Response

Auxiliary feedwater flow to the affected steam generator was not addressed due to the factors previously presented.

Question

d. Discuss the design provisions in the AFS used to terminate the AFS flow to the affected steam generator. If operator action is required to perform this function, discuss the information that will be available to the operator to alert him of the need to isolate the auxiliary feedwater to the affected steam generator, the time when this information would become available, and the time it would take the operator to complete this action. Define credit for operator action. If termination of AFS flow is dependent on automatic action, describe the basic operation of the auto-isolation system. Describe the failure modes of the system. Describe any annunciation devices associated with the system.

Response

The design of the system to automatically initiate auxiliary feedwater incorporates a three minute delay following actuation based on low steam generator level. The key parameter available to the operator following an MSLB would be low steam generator pressure in the affected steam generator. The MSLB analysis indicates MSIV closure initiated at approximately 3 seconds after the break and a secondary side pressure of 500 psia in the affected steam generator versus approximately 695 psia in the intact steam generator. The mismatch becomes greater, approximately 98 psia in the affected steam generator versus 547 psia in the intact steam generator at 80 seconds after the break. The plant operating procedures are written to enable a quick determination of the steam line rupture and affected steam generator. Once the determination is completed approximately 5 seconds are required to manually isolate the affected steam generator. A copy of Procedure 2509, Steam Line Rupture, is provided for your information.

Manual isolation of the affected steam generator would therefore occur prior to initiation of auxiliary feedwater with or without implementation of an automatic initiation system.

1867 216

Question

e. Provide the single active failure analysis which specifically identifies those safety grade systems and components relied upon to limit the mass and energy release and the containment pressure response. The single failure analysis should include, but not necessarily be limited to: partial loss of containment cooling systems and failure of the AFS isolation valve to close.

Response

Two containment pressure calculations were performed to envelope effects of single active failures upon containment pressure response. Case 1 evaluated the effects of a control valve failure in the auxiliary feedwater system, resulting in greater than design flow to the affected steam generator. No isolation of the affected steam generator was assumed. Case 1 also included the effects of the loss of offsite power. The pump run-out flow assumed was 2050 gpm.

Case 2 was performed based on failure of a diesel generator and the resultant loss of one-half of the emergency safeguards features which reduce containment pressure (1 containment spray and 2 containment air recirculation fans). This assumption is the most limiting single failure with respect to containment pressure response. No isolation of the affected steam generator was assumed.

Question

f. For the single active failure case which results in the maximum containment atmosphere pressure, provide a chronology of events. Graphically, show the containment atmosphere pressure as a function of time for at least 30 minutes following the accident. For this case, assume the AFS flow to the broken loop steam generator to be at the pump run out flow (if a run out control system is not part of the current design) for the entire transient if no automatic isolation to auxiliary feedwater is part of the current design.

Response

A chronology of events is shown in Table 1 for the limiting case, which is Case 1 described above.

The containment atmosphere pressure is plotted versus time in Figure 1.

Question

g. For the case identified in (f) above, provide the mass and energy release data in tabular form. Discuss and justify the assumptions made regarding the time at which active containment heat removal systems become effective.

Response

Mass and energy releases are given in Table 2. The assumptions made regarding the time at which active containment heat removal systems become effective are given in References (1) and (2).

Reference 1: Millstone Nuclear Power Station Unit No. 2 - Proposed Revision to Technical Specifications dated December 13, 1977.

Reference 2: Millstone Nuclear Power Station Unit No. 2 - "Diesel Start Times" - Letter dated October 11, 1978, W. G. Counsil to R. Reid.

Table 1

Chronology of Events

Time (seconds)	Event
0	Main Steam Line Rupture at Steam Generator Nozzle
1	SIAS - Diesel Generator Initiation Signal
10.5	Main Steam Isolation Valves Closed. Blowdown from Intact Steam Generator Stops
18	High-High Containment Pressure Signal
28.2	Containment Air Recirculation Fans Performing Design Function
55.9	Containment Spray Flow Starts
70.0	Steam Generator Blowdown Due to Original Mass Stops
180.0	Steam Generator Blowdown Due to Auxiliary Feedwater Flow Starts
1800.0	Affected Steam Generator Isolated; Blowdown Stops

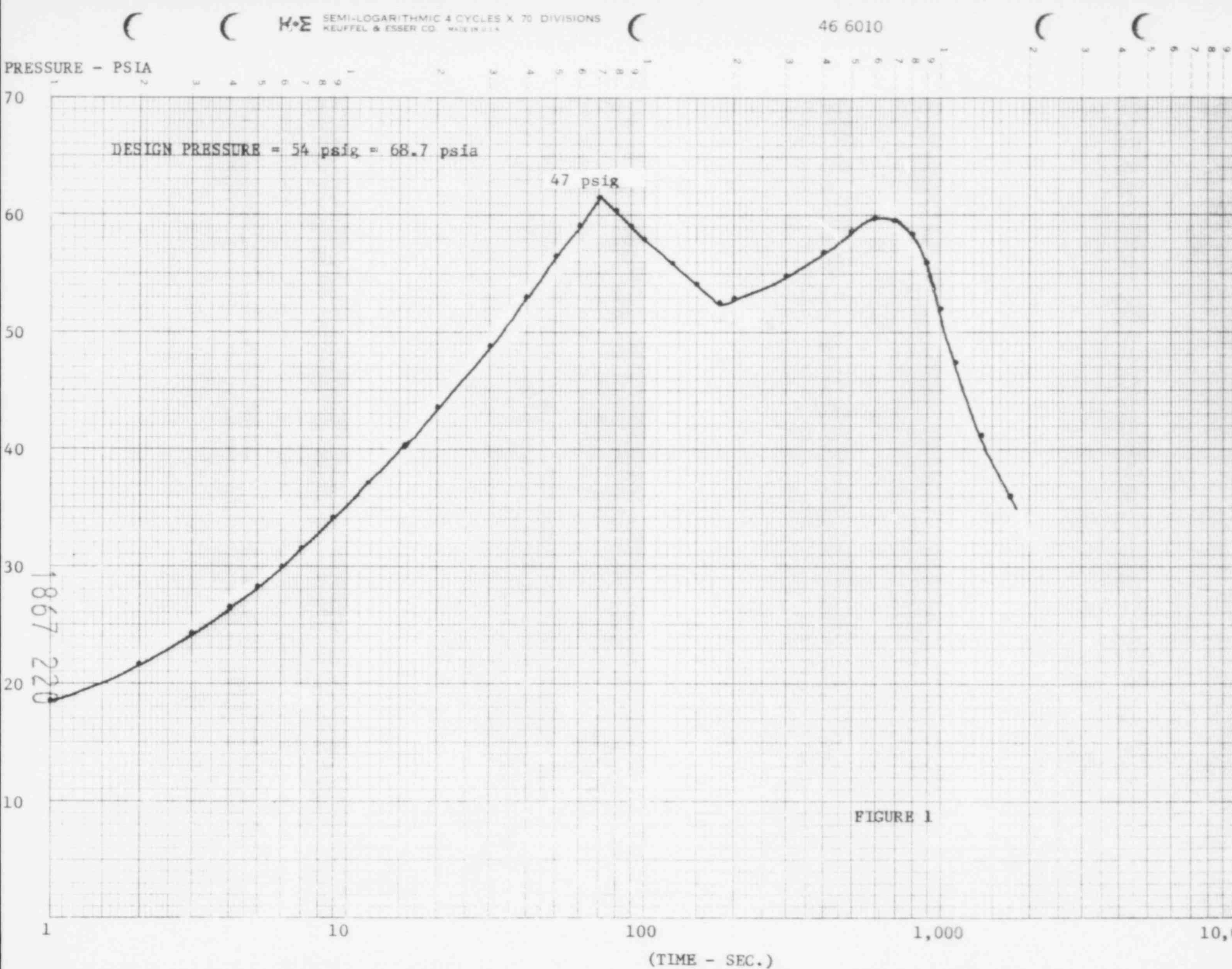

K•E SEMI-LOGARITHMIC 4 CYCLES X 70 DIVISIONS
KEUFFEL & ESSER CO.
46 6010
PRESSURE - PSIA
DESIGN PRESSURE = 54 psig = 68.7 psia
47 psig
(TIME - SEC.)
1867 220

FIGURE 1

MILLSTONE UNIT NO. 2

CONTAINMENT RESPONSE CALCULATION
MAIN STEAM LINE BREAK
WITH AUXILIARY FEEDWATER FLOW

CASE 1

TABLE 2

MASS/ENERGY RELEASES

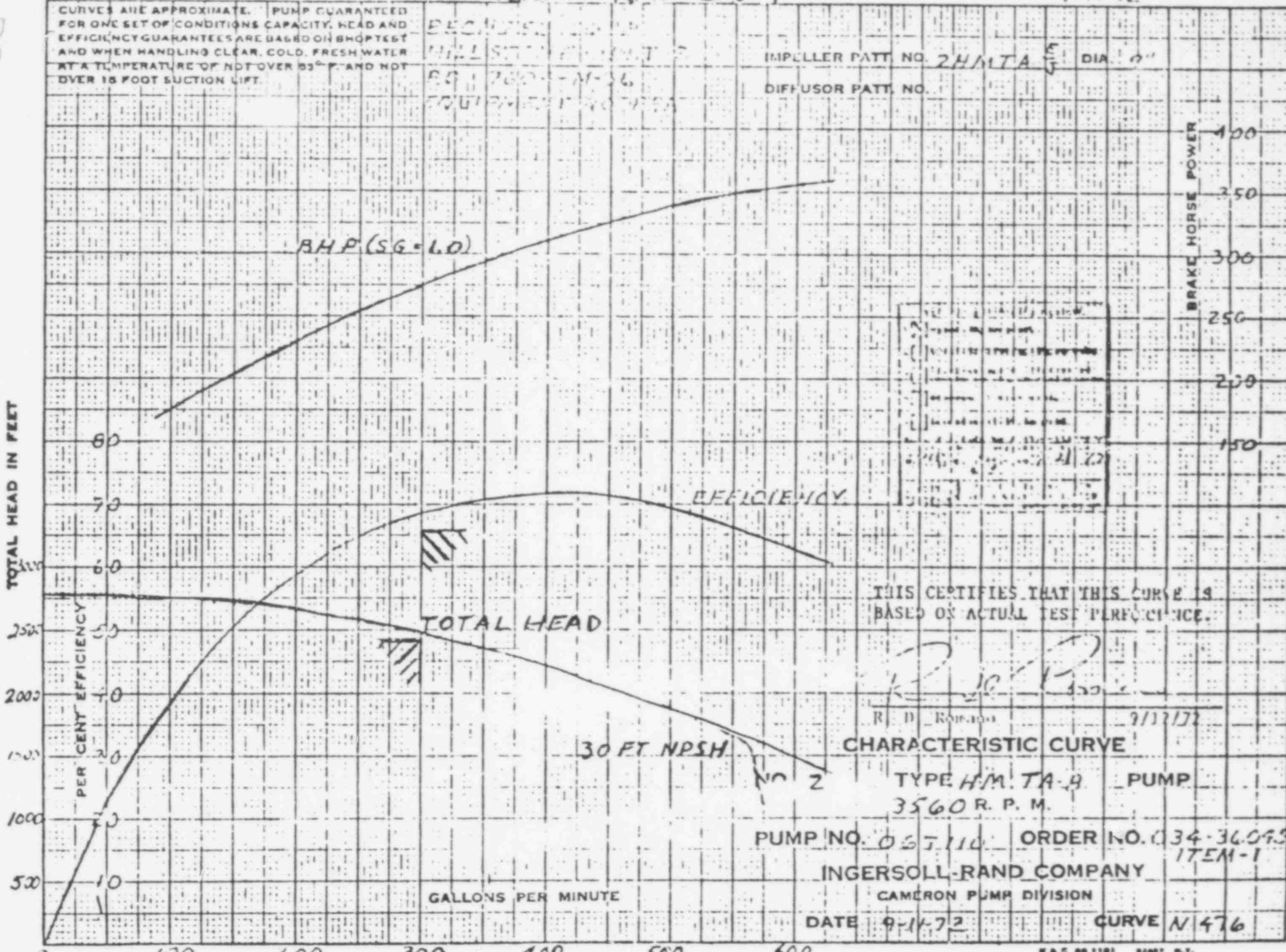
Time (Sec.)	$\dot{m}$ (lbm/sec)	h (Btu/lbm)
0.0	0.0	0.0
0.00001	1.776 + 4	1,063.4
1.0	1.475 + 4	1,060.8
2.0	1.263 + 4	1,058.6
3.0	1.1067 + 4	1,056.0
4.0	9.860 + 3	1,053.7
5.0	8.908 + 3	1,051.4
6.0	8.167 + 3	1,049.5
7.0	7.575 + 3	1,047.9
8.0	6.698 + 3	1,047.0
9.0	5.372 + 3	1,042.9
10.0	4.231 + 3	1,040.0
20.0	3.794 + 3	1,037.1
30.0	2.983 + 3	1,029.5
40.0	2.431 + 3	1,024.1
50.0	2.094 + 3	1,019.5
60.0	1.817 + 3	1,015.4
70.0	1.610 + 3	1,011.7
71.0	0.0	0.0
179.9	0.0	0.0
180.0	281.0	1,198.4
200.0	281.0	1,171.2
250.0	281.0	1,171.4
300.0	281.0	1,169.6
350.0	281.0	1,171.3
400.0	281.0	1,175.7
450.0	281.0	1,172.4
475.0	281.0	1,172.4
480.0	265.0	1,171.6
490.0	260.0	1,172.1
500.0	256.0	1,171.4
550.0	243.0	1,171.4
600.0	224.0	1,170.8
650.0	200.0	1,170.6
700.0	170.0	1,170.1
750.0	137.0	1,170.0
800.0	104.0	1,168.9
850.0	75.0	1,167.8
900.0	54.0	1,166.9
950.0	38.0	1,167.7
1,000.0	28.0	1,168.1
1,800.0	28.0	1,168.1
1,801.0	0.0	0.0

1867 221

7604-1 6-38-1

CURVE NO. N 47
DATE 9-11-72

MILLSTONE UNIT NO. 2



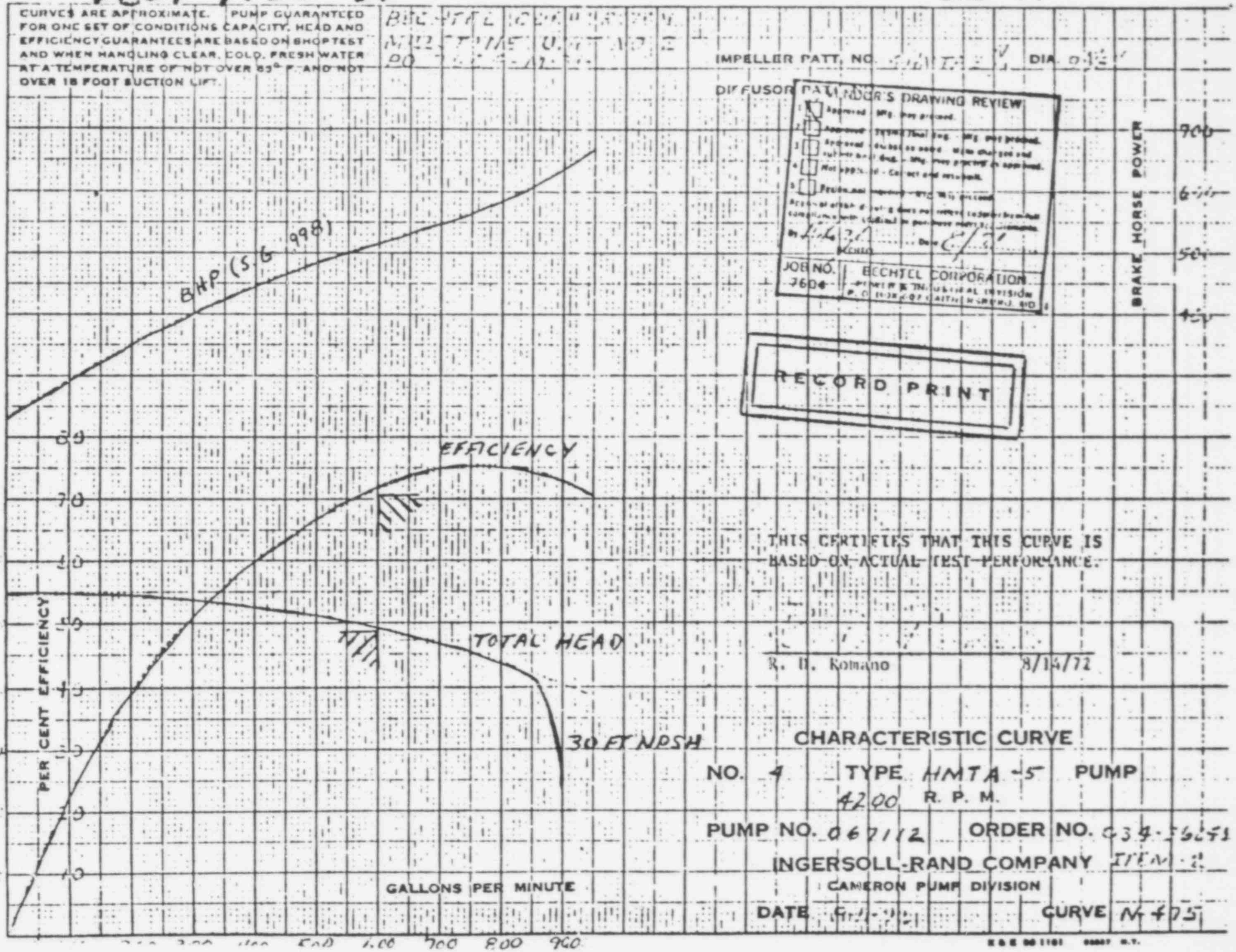
POOR ORIGINAL

9-11

1867 222

7604-M36-37-1

CURVE NO.
DATE



POOR ORIGINAL

1867 223