

NNECO

NORTHEAST NUCLEAR ENERGY COMPANY
A NORTHEAST UTILITIES COMPANY

P.O. BOX 270
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203-666-8911

March 3, 1978



Office of Nuclear Reactor Regulation
ATTN: Mr. William H. Regan, Jr., Chief
Environmental Projects Branch 2
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Gentlemen:

Docket Nos. 50-496
50-497

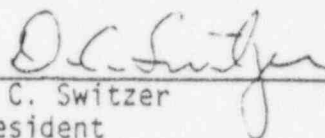
SUBJECT: Montague Nuclear Power Station
Units 1 and 2
Request for Additional Information

As requested in your letter of February 24, 1978, Northeast Nuclear Energy Company will file a supplement to its Environmental Report on or about March 31, 1978. This update will be based upon our best available estimate of the impact of a 1990 in-service date for Unit 1 on the issues identified in your letter.

Very truly yours,

NORTHEAST NUCLEAR ENERGY COMPANY

By Northeast Nuclear Energy Company
Their Agent


D. C. Switzer
President

cc: Copy List

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K. A. Matt	Met-Ed
G. F. Bierman	Met-Ed
J. G. Miller	Met-Ed
R. L. Williams	Met-Ed
W. E. Granger	Met-Ed Q.A.
K. C. Lish	Burns and Roe
J. Brodsky	Burns and Roe
P. Nardone	Burns and Roe
N. R. Barker	GAI Q.A.
C. H. Bitting	GAI
W. H. Traffas	GAI Q.A.
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H. F. Dobel	B&W
J. B. Henderson	AEC-Compliance
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B. G. Avers	GPU
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December 1, 1969

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B. G. Avers	G. P. U.	Quality Assurance
W. E. Granger	Met-Ed	Quality Control
K. Matt	Met-Ed	Administration
N. Cole	MPR	
J. Gorman	MPR	
F. S. Cantrell	A. E. C.	
Gus Lainas	A. E. C.	Div. of Reactor Licensing
Roy Gustafson	A. E. C.	Div. of Real Studies
		Consulting for compliance

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AEC AUDITBurns & Roe
Oradell, N.J.~~12-3-69~~

12/3-4/69

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METROPOLITAN EDISON COMPANY

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TELEPHONE 215 - 929-3601

March 16, 1978
GQL 0462

Director of Nuclear Reactor Regulation
Attention: Mr. S. A. Varga, Chief
Light Water Reactors Branch, No. 4
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Sir:

Three Mile Island Nuclear Station Unit 2 (TMI-2)
Docket No. 50-320
Operating License No. DPR-73
Additional Information Concerning Fire Protection

The following information is submitted at the verbal request of your Mr. T. Lee on March 3, 1978 to Mr. R. C. Cutler (GPUSC) and supplements the information provided by our letter to you dated February 17, 1978.

1. Rupture of fire service piping (Operating License Condition 2.c.(3)1.2).

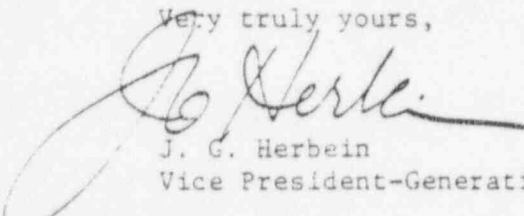
During the evaluation, the postulated fire service piping break was considered to occur anywhere along the length of the pipe, not just select locations.

2. Additional Hose Stations and Diesel Generator Basement Sprinkler Systems (Operating License Conditions 2.c(3)1.1 and G.10 of Attachment 2).

- A. A copy of the Burns and Roe, Inc. Specification 2555-146, revised to incorporate clarifications and corrections as discussed, is forwarded herewith for your information.
- B. The minimum density coverage requirement of .3 gpm per square foot of diesel generator basement applies to the overall floor square footage as shown on B&R General Arrangement Drawing 2339.

Should you have any additional questions, please contact my staff.

Very truly yours,


J. G. Herbein
Vice President-Generation

Acc. No. 4904270306
Enclosure, Burns and Roe, Inc.
Specification 2555-146, Rev.1.

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SPECIFICATION 2555-146

SPECIFICATION DETAILS

ADDITIONAL FIRE HOSE STATIONS AND
WET PIPE SPRINKLER SYSTEMS

JERSEY CENTRAL POWER AND LIGHT COMPANY
THREE MILE ISLAND NUCLEAR STATION UNIT NO. 2

Burns and Roe, Inc.
Engineers and Constructors
29 Park Place
Paramus, New Jersey 07652

Rev. 1

~~7904270307~~ 158P

TECHNICAL SPECIFICATIONS
FOR
ADDITIONAL FIRE HOSE STATIONS AND
WET PIPE SPRINKLER SYSTEMS

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TECHNICAL SPECIFICATIONS
FOR
ADDITIONAL FIRE HOSE STATIONS AND
WET PIPE SPRINKLER SYSTEMS

1.0 SCOPE

This Specification covers the furnishing and installing of fire protection piping, valves, sprinkler nozzles, hose stations, wet pipe system alarm check valves, pressure switches and other necessary accessories to provide for the addition of fourteen (14) fire hose stations and two (2) wet pipe sprinkler systems to be added to the existing TMI Unit #2 fire protection systems. The locations of the additional hose stations are detailed in Table 1 of this Specification and are also shown on the Information Drawings attached to this Specification.

2.0 GENERAL

2.1 Work to be Provided

Contractor shall furnish and install all piping fittings and valves as required for a complete installation of all Fire Protection Systems specified herein. The work to be provided under this Specification shall include the following:

2.1.1 Furnishing and installing of fourteen (14) fire hose stations, each consisting of a wall reel, 75 feet of hose, hose angle valve, OS and Y isolation gate valve with monitor switch, and hose nozzle.

2.1.2 Furnishing and installing of two (2) wet pipe sprinkler systems for protection of the basement of both Diesel Generator buildings (El. 280'-6"). Two separate and independent systems shall be provided, one for each basement area.

2.1.3 Furnishing and installing of all hangers (temporary and permanent) for support of the fire protection piping, and valves.

2.1.4 Engineering and design of the piping and sprinkler layout for the wet pipe sprinkler systems.

2.1.5 Engineering and design of the piping layout for the hose stations.

2.1.6 Engineering and design of all hangers for support of the fire protection piping and valves.

2.1.7 Submission of Seismic analysis to qualify the hanger support system for the piping.

- 2.1.8 All drilling and welding work necessary to tap into the existing fire protection piping lines.
- 2.1.9 Delivery of all equipment, valves, piping, etc. to jobsite.
- 2.1.10 Installation of all piping and valves necessary for a complete system installation as specified herein.
- 2.1.11 All labor, supervision of labor and facilities for packaging, receiving, unloading, checking, storing and handling of the fire protection equipment.
- 2.1.12 Field testing of the equipment per NFPA Code requirements.
- 2.1.13 Shop testing of fire protection gate valves as specified herein.
- 2.1.14 Shop painting and cleaning of hangers, piping and valves.
- 2.1.15 Performing of hydraulic calculations for the piping systems.

2.2 Work by Others

The following work will be provided by others:

- 2.2.1 All wiring to the Contractor's supplied electrical equipment where required.
- 2.2.2 All field finish painting of piping and valves.
- 2.2.3 All necessary concrete core drilling to permit pipe penetrations.
- 2.2.4 Furnishing and installing of pipe sleeves for penetrations.
- 2.2.5 Hydrostatic testing of piping systems.

2.3 Codes and Standards

The codes/standards or regulations listed below are those mentioned or referenced in this Specification. The latest edition of these codes/standards or regulations in effect or promulgated at the time of award shall apply:

- 2.3.1 NFPA Code #13, Sprinkler Systems, Installation
- 2.3.2 NFPA Code #14, Standpipes and Hose Stations
- 2.3.3 Underwriters Laboratories (UL)
- 2.3.4 Factory Mutual Engineering Corporation (FM)
- 2.3.5 Manufacturer's Standardization of the Valve and Fitting Industry (MSS-SP).

- MSS-SP-61 - Hydrostatic Testing of Steel Valves
- MSS-SP-25 - MSS Standard Marking System for Valves Fittings, Flanges and Unions
- MSS-SP-58 - Pipe Hangers and Supports - Materials and Design
- MSS-SP-69 - Pipe Hangers and Supports - Selection and Application

- 2.1.6 American National Standards Institute
 - B31.1 Power Piping
 - B16. C.I. Pipe Flanges and Flanged Fittings
- 2.1.7 American Society of Mechanical Engineers Section IX - Welding and Brazing Qualifications
- 2.1.8 Steel Structures Painting Council Specifications (SSPCS)
 - SSPC-SP-2-63 Hand Cleaning
 - SSPC-SP-3-63 Power Tool Cleaning
- 2.1.9 Uniform Building Code, International Conference of Building Officials
- 2.1.10 American Welding Society (AWS)
 - D1-0-69 Welding in Building Construction
 - A2.0 Standard Welding Symbols
 - A2.2 Nondestructive Testing Symbols
 - A3.0 Definitions - Welding and Cutting
- 2.1.11 American Society for Testing and Materials (ASTM)
 - A233 Mild Steel Arc - Welding Electrodes
 - A234 Piping Fittings of Wrought Carbon Steel and Alloy Steel for Moderate and Elevated Temperatures
 - A53 Welded and Seamless Steel Pipe
 - A120 Black and Hot Dipped Zinc Coated (Galvanized) Welded and Seamless Steel pipe for ordinary uses.

Invocation by title, name and/or number of certain specific codes/standards or regulations, under this paragraph or elsewhere in this Specification, shall in no way diminish Contractor's responsibility for compliance with any and all codes/standards or regulations which are generally recognized to be applicable to the work herein specified.

2.4 Drawings

The information drawings (Plant General Arrangement Drawings) included with this Specification show the locations of the additional hose stations to be provided by the contractor. Contractor shall prepare detailed piping layout drawings showing the location of all valves, hangers, specialties, floor penetrations, etc. Contractor shall clear all interferences in the field with respect to laying out his piping. The piping drawings generated by the Contractor shall clearly show dimensioned hanger locations and shall show where the new fire piping will tap into the existing fire protection system piping lines. In addition, all new fire piping line sizes shall be shown on the drawings and determined by the Contractor based on NFPA code requirements.

Contractor shall also prepare detailed hanger configuration drawings which shall be submitted with the piping seismic analysis.

3.0 DETAILED REQUIREMENTS

3.1 Design Conditions

3.1.1 Piping inside the following buildings shall be treated as Seismic Class I:

- Auxiliary Building
- Fuel Handling Building
- Diesel Generator Building
- Control Building
- Control Building Area
- Reactor Building

Seismic analysis shall be performed in accordance with data contained in the respective response spectra curves (See Attachment 1 to this Specification) which are based upon 0.5% damping.

Equivalent static loads shall be developed through dynamic analyses of the response of the piping and equipment to horizontal and vertical accelerations, considered acting simultaneously, using the response spectra curves indicated above and contained in Attachment I of this Specification.

Note that the value of horizontal acceleration shall be obtained by entering the applicable response spectra curve with the period of free vibration (T), to which a "tolerance" of ± 0.02 seconds shall be added. The largest acceleration value for this band of period ($T \pm 0.02$ seconds) shall be used for design. The vertical acceleration shall be considered as $2/3$ of the horizontal acceleration. Horizontal and vertical loading shall be applied simultaneously in addition to the normal design loads for idle and/or operating conditions.

Piping and equipment shall be designed using code stress values for normal design loads (ANSI B 31.1) plus the operating basis earthquake load (OBE). In addition, equipment must have "no loss of function" based upon normal design loads plus Design Basis Earthquake Load (DBE).

An equivalent vibration test using double the design earthquake load may be substituted for the above analysis.

3.1.2 Seismic design classification, Class II

Piping not included above shall be Class II and shall be designed for Zone I loads using methods and stress increase coefficients given in the latest edition of the Uniform Building Code of the International Conference of Building Officials.

3.1.3 The wet pipe sprinkler system shall be designed and installed according to the requirements of NFPA Code #13. The placement of all components associated with sprinkler systems shall be in strict accordance with NFPA Standard No. 13. The minimum density coverage for all sprinkler areas shall be .3 gpm per sq. ft. Minimum orifice size for the sprinkler nozzles shall be 1/2". Temperature ratings of the sprinkler fusible links shall be intermediate. | 1

3.1.4 All pipes, valves, fittings, joints, instruments and accessories subjected to fire pump water pressure shall be suitable for a 175 psig water working pressure unless otherwise stated.

3.1.5 All valves, spray nozzles, hoses, hose racks, control devices, and other items of equipment shall be U.L and/or F.M. approved and so labeled or certified for fire protection service.

3.1.6 Hose Stations shall be designed for Class II services in accordance with the requirements of NFPA Code #14. The piping line sizes to hose stations shall be consistent with the requirements stated in NFPA Code #14. Piping line sizes shall be clearly shown on the Contractor's piping drawings and shall require Engineer approval prior to installation.

3.2 Materials of Construction

3.2.1 All piping up to and including 4 inches nominal sizes on the system side of the wet pipe sprinkler valves shall be threaded schedule 40 ASTM A120 black steel pipe. Fittings shall be standard 150 lb. malleable iron fittings. | 1

3.2.2 All 6 inch piping on the system side of the wet pipe sprinkler alarm valves shall be threaded schedule 40 ASTM A53 black steel pipe. Fittings shall be standard 150 lb. malleable iron fittings. | 1

3.2.3 All piping up to and including 4 inches nominal size on the supply side of the wet pipe sprinkler system valves shall be schedule 40 ASTM A120 black steel pipe. This pipe shall be welded in accordance with paragraph 3.3 of this Specification. Welded fittings shall be standard ASTM A234, WPB forged steel.

3.2.4 All 6 inch piping on the supply side of the wet pipe sprinkler system valves shall be schedule 40 ASTM A53 black steel pipe. This pipe shall be butt welded in accordance with paragraph 3.3 of this Specification. Welded fittings shall be standard ASTM A234 WPB forged steel.

3.2.5 All piping to hose stations up to and including 4 inches nominal sizes shall be schedule 40 ASTM A120 black steel pipe. All 6 inch piping to hose stations shall be schedule 40 ASTM A53 black steel pipe. Piping 2½ inch nominal sizes and above to hose stations shall be butt welded in accordance with paragraph 3.3 of this Specification. Welded fittings shall be standard ASTM A234 WPB forged steel. Piping 2 inches nominal sizes and under to hose stations shall be threaded. Fittings shall be standard 150 lb. malleable iron fittings.

3.2.6 Flanged connections shall be provided where required in accordance with NFPA 13 requirements.

3.2.7 Gate Valves (2 1/2" and Larger)

Material & Specification	Cast Iron Body Bronze Mounted ASTM A-126 Class B
Type	Bolted Bonnet, O.S. & Y.
Rating	175 lb. ANSI Standard
Seating Surface, Including Back Seat	Bronze
Ends	Flanged 125 lb. ANSI Standard (B16.1)

3.2.8 Piping Support Hangers - all hangers shall be fabricated from A-36 steel.

3.3 Welding Requirements

The Welding Requirements applied for this Specification shall be the same as those specified in Specification 2555-72, Section 15-H, paragraph 3.3 entitled "FABRICATION".

3.4 Hose Stations

Fire hose stations shall consist of a continuous flow wall reel, Wirt & Knox Style FD47 or Engineer approved equal. Hose reels shall be suitable for working pressure up to 300 lbs. and shall be sized to accomodate 75 feet of 1 1/2 inch all service hose. Hose shall be Wirt and Knox Servall non-collapsible hose, 23-0222-2 braid, oil resistant with neoprene tube and cover, or Engineer approved equal. Hose stations shall also include 1 1/2 inch Seco type 76U angle valve or engineer approved equal. Valve shall incorporate standard tapered iron pipe thread on both ends. Hose nozzle shall be Powhattan 02-349 "All Fog" Nozzle, cast brass with satin brass finish, for use with 1 1/2 inch hose or Engineer approved equal.

Each hose station shall be provided with an OS&Y isolation gate valve (minimum size - 2 1/2") with a Grinnel model #F640 (or Engineer approved equal) monitor switch. Monitor switch shall be rated 125 volts AC, 10 amps.

3.5 Wet Pipe Sprinkler Systems

Wet Pipe Sprinkler Systems shall be furnished for the areas specified in Table 1 of this Specification.

Each wet pipe sprinkler system shall incorporate an alarm check valve, an OS&Y isolation gate valve (with monitor switch) located upstream of the check valve, pressure switch to indicate system water flow, local water motor gong, pressure gauge for local readout of system pressure, test pipes, drain and vent lines and other necessary accessories which are required by NFPA Code #13. Minimum size of gate valves and alarm check valves shall be 4".

The monitor switch furnished for the gate valve shall be the same as that specified in 3.4 above for the hose stations. The pressure switch shall be Grinnell model number B-2 or Engineer approved equal. Pressure switch shall be rated 10 amps for 115/230 volts AC and shall be provided with one open and one closed circuit.

3.6 OS and Y Gate Valves

The OS and Y gate valves shall be constructed to meet the following requirements in addition to the valve material requirements specified in paragraph 3.2 of this Specification:

Identification plates shall be provided and permanently attached to each valve. Identification plates shall be carbon steel and have black identification figures stamped hereon. Marking on plates shall be in accordance with MSS-SP-25 and shall also state name of system of which they are a component and the tag number of the valve (see Table 1 of this Specification).

Accessories, if not mounted on the valve, shall be similarly identified with the valve mark number. Rotation arrows for open and close shall be marked on all handwheels.

Valve flange end connections shall be in accordance with ANSI B16.1.

Valves shall be designed for repacking at full rated pressure with valve open.

Valves shall be provided with back seat arrangement to prevent leakage into the gland chamber.

The latest revision of UL 262 shall apply to the gate valves to be furnished under this Specification.

3.7 Hangers for Support of the Piping Systems

Contractor shall furnish and install all the necessary hangers, supports, anchors, guides, braces, concrete inserts, supplementary steel, and accessory equipment to independently hold and support the fire protection systems in their proper locations for the designed coverage. Where required to do so because of location, Contractor shall furnish necessary seismic analysis for the proposed hanger configurations and designs and for the proposed locations of the hangers.

Unless otherwise specified, all pipe hangers and support assemblies shall comply with ANSI B31.1, Power and Piping Code, the current issue of the Manufacturer's Standardization Society Standard Practice SP-58 and SP-69 concerning "Pipe Hangers and Supports", and the applicable portions of NFPA Code #13.

3.8 Painting and Cleaning

- .1 All unfinished miscellaneous steel furnished under this Specification for support of piping shall be thoroughly cleaned of dirt, or mill scale in accordance with Steel Structures Painting Council Specifications SSPC-SP-2-63, "Hand Cleaning" or SSPC-SP-2-63, "Power Tool Cleaning" as required. All of the aforesaid miscellaneous steel shall receive one shop coat of Keeler & Long, Inc., Tri-Polor White Primer 6040 with a dry film thickness as recommended by the paint manufacturer.
- .2 Outside surface of all pipe shall receive one (1) shop coat of lead-free primer. Shop paint shall be applied to a minimum thickness of 2 mils.
- .3 Paint shall be omitted at all areas of field welding for a minimum of one (1) inch on each side of the weld preparation. A water-soluble rust-inhibitor shall, instead, be used. All contact surfaces of field bolted connections may be painted.

3.9 Nameplates

All pressure switches, valves and monitor switches shall be labeled with individual nameplates which shall contain the following information:

- a. Unit tag numbers as designed by the Engineer. Unit tag numbers are specified in Table 1 of this Specification.
- b. Manufacturer's name.
- c. Manufacturer's serial number.

These nameplates shall be made of suitably inscribed metal or plastic and affixed by screws or attached by stainless steel or copper wire.

4.0 INSTALLATION

Installation work shall include all reerating, moving from storage, rigging, setting, assembly, alignment, grouting, cleaning, testing and all other necessary work to prepare each system of equipment and its integral parts for normal service.

Contractor shall furnish all labor, materials and equipment necessary to complete the mechanical installation of all fire protection systems and piping specified herein. All field electrical work, that is, all external electrical wiring between the Contractor's supplied equipment, will be provided by others.

The interior of all pipe and fittings shall be thoroughly cleaned of all foreign matter before being installed and shall be kept clean until the work has been accepted.

Every precaution shall be taken to prevent foreign material from entering the pipe while it is being installed. It is essential that no foreign matter be permitted to enter the pipelines at any time.

Contractor shall be responsible for laying out and installing his piping systems clear of all service piping, ductwork, equipment, cable trays, lighting fixtures and structures. It shall be the Contractor's responsibility to field check his piping layout to avoid interferences. Contractor shall be responsible for making all required corrections resulting from faulty layout and installation work at no additional cost to the Owner.

5.0 TESTING

- .1 The wet pipe sprinkler systems shall be tested per NFPA Code #13 requirements.
- .2 Fire Protection gate valves shall be given a hydrostatic test on the body and seat in accordance with MSS-SP-61.

6.0 INFORMATION TO BE SUBMITTED

- .1 Detailed piping layout drawings showing the physical location of all valves, hangers and floor penetrations and the sizes of all fire piping lines.
- .2 Seismic analysis and hanger designs for the Seismic I piping system.
- .3 Specification data sheets (including materials of construction) for all fire equipment to be furnished under this Specification.
- .4 Test Data sheets shall be furnished to insure testing compliance with NFPA Code #13.
- .5 Submission of hydraulic calculations substantiating pipe line sizes and orifice nozzle sizes for the water systems.

1

Table 1

HOSE STATIONS

1. Control Building Mechanical Equipment Room, Elevation 351'-6"; C47-CA (South wall); Locate hose station 12 feet from inside of wall. (Tag numbers: Isolation gate valve - FS-V-654, Hose angle valve - FS-V-655, Monitor switch - FS-KS-6700)
2. Control Building Mechanical Equipment Room, Elevation 351'-6"; Between C49-C50 & CD, (North wall); Locate hose station 10 feet from Panel 709AG (edge of panel) (Tag numbers: Isolation gate valve - FS-V-656, Hose angle valve - FS-V-657, Monitor switch - FS-KS-6701)
3. Control Building Battery & DC Switchgear Room, Elevation 280'-6", C-49-CA (South wall). (Tag numbers: Isolation gate valve - FS-V-656, Hose angle valve - FS-V-657, Monitor switch - FS-KS-6701)
4. Control Building Battery & DC Switchgear Room, Elevation 280'-6", C48-CD (North wall). (Tag numbers: Isolation gate valve - FS-V-660, Hose angle valve - FS-V-661, monitor switch - FS-KS-6703)
5. Auxiliary Building, Elevation 328'-0", Between AJ-AL, A62; Locate hose station next to 40 B:C fire extinguisher (wall directly north of Unit Substation 2-45). (Tag numbers: Isolation gate valve - FS-V-662, Hose angle valve - FS-V-663, monitor switch - FS-KS-6704)
6. Auxiliary Building, Elevation 305'-0"; Between AE-AG, A60 (East wall); Locate hose station seven feet from end of wall of Unit Substation Room 2-21E. (Tag numbers: Isolation gate valve - FS-V-664, hose angle valve - FS-V-665, monitor switch - FS-KS-6705)
7. Auxiliary Building, Elevation 305'-0"; Between A60-A61, at (North wall); Locate hose station 15 feet from end of east wall. (Tag numbers: Isolation gate valve - FS-V-666, hose angle wall - FS-V-667, monitor switch - FS-KS-6706)
8. Auxiliary Building, Elevation 280'-6"; Between AE-AG & A62-A63; Locate hose station between doors to rooms containing WDL-K-2A and WDL-K-2B. Do not locate hose station on block wall. (Tag numbers: Isolation gate valve - FS-V-668, hose angle valve - FS-V-669, monitor switch - FS-KS-6707)

Table 1 - (Continued)

HOSE STATIONS

9. Control Building Area (West side), Elevation 282'-6", CAa-C57; Locate hose station on west side of column. (Tag numbers: Isolation gate valve - FS-V-670, hose angle valve - FS-V-671, monitor switch - FS-KS-6708)
10. Diesel Generator Building (West); Between DD and DE, D70, 10 feet south of edge of double door. (Tag numbers: Isolation gate valve - FS-V-672, hose angle valve - FS-V-673, monitor switch - FS-KS-6709)
11. Diesel Generator Building (East); Between DD and DE, D69, 10 feet south of edge of double door. (Tag numbers: Isolation gate valve - FS-V-674, hose angle valve - FS-V-675, monitor switch - FS-KS-6710)
12. River Water Pump Hose; Locate hose station six feet south of double doors of Switchgear Room 2-3E. (Tag numbers: Isolation gate valve - FS-V-676, hose angle valve - FS-V-677, monitor switch - FS-KS-6711)
13. River Water Pump House; Locate station near emergency exit fire door, locate station 5 feet west of edge of door. (Tag numbers: Isolation gate valve - FS-V-678, hose angle valve - FS-V-679, monitor switch - FS-KS-6712)
14. Control Building, Elevation 305'-0". Cable Room C46-47 & CA; Locate hose station four feet west of edge of door. (Tag numbers: Isolation gate valve - FS-V-680, hose angle valve - FS-V-681, monitor switch - FS-KS-6713)

WET PIPE SPRINKLER SYSTEM

1. East Diesel Generator Building, Elevation 280'-6", complete coverage (one system). (Tag numbers: Isolation gate valve - FS-V-682, alarm check valve - FS-V-683, monitor switch - FS-KS-6714, pressure switch - FS-KS-6715)
2. West Diesel Generator Building, Elevation 280'-6", complete coverage (one system). (Tag numbers: Isolation gate valve - FS-V-684, alarm check valve - FS-KS-6715, monitor switch - FS-KS-6716, pressure switch - FS-KS-6717)



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

APR 18 1978

Docket No: 50-320

MEMORANDUM FOR: Milton J. Grossman, Hearing Division Director and
Chief Counsel, OELD

FROM: D. B. Vassallo, Assistant Director for Light Water
Reactors, Division of Project Management, NRR

SUBJECT: BOARD NOTIFICATION - THREE MILE ISLAND-2

I recommend that the enclosed document related to the B&W revised small break Loss-of-Coolant Accident be provided to the Three Mile Island-2 Board.

It appears that the interim corrective measure will require procedures for operator action in addition to a power limitation. The plant status is such that the proposed limiting power level of 93% has not yet been achieved. The staff will take the necessary action to provide for implementation of the interim corrective action in a timely manner. Long-term solutions to the problem have not been specifically addressed at this time.

D. B. Vassallo, Assistant Director
for Light Water Reactors
Division of Project Management

Enclosure:
As stated

cc w/enclosure:

E. Case
E. Volgenau
R. Boyd
R. Mattson
H. Denton
R. DeYoung
V. Stello
D. Eisenhut
T. Engelhardt
B. Grimes
J. Stolz
K. Kniel
O. Parr
S. Varga
I&E (7)
R. Reid
H. Silver

Acc. No. 502090541 1P

C/27 3

METROPOLITAN EDISON COMPANY SUBSIDIARY OF GENERAL PUBLIC UTILITIES CORPORATION

POST OFFICE BOX 842 READING, PENNSYLVANIA 19603

TELEPHONE 215 - 829 2001

April 17, 1978

CQL 0714

Director of Nuclear Reactor Regulation
Attn: R. W. Heid, Chief
Operating Reactors Branch No. 4
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Director of Nuclear Reactor Regulation
Attn: Mr. S. A. Varga, Chief
Light Water Reactors Branch No. 4
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Gentlemen:

Three Mile Island Nuclear Station

TMI-1 DFR-50, Docket 50-289

TMI-2 DFR-73, Docket 50-320

In accordance with your oral request of April 14, 1978, please be advised that B&W has evaluated the revised small break LOCA as originally reported on April 12, 1978 pursuant to 10 CFR 21. The evaluation results, assuming loss of offsite power and the most damaging single failure, are as follows:

1. Assuming no operator action, the core will remain covered and there is no cladding temperature excursion provided that thermal power is limited to less than:

TMI-1 < 69% of 2535 Mw

TMI-2 < 63% of 2772 Mw

2. Assuming operator action in 20 minutes to cross connect the HPI discharge and (assuming failure of a diesel) open the HPI ETAS discharge valves to a predetermined throttle setting (which prevents HPI pump runout) the core would remain covered and there would be no cladding temperature excursion for thermal powers of:

7904210325 2PP

R. W. Reid, Chief
S. A. Varga, Chief

-2-

Ingr

TMI-1 100% of 2535 MWt

TMI-2 93% of 2772 MWt

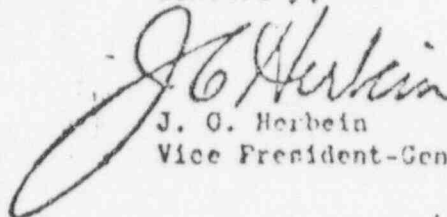
* More detailed analysis may support a higher power level.

3. When no single failure is assumed or when operator action is taken when accident conditions do not exist (or other LOCA conditions exist) no adverse situation exists or is created and former LOCA accident analyses are bounding.

With respect to Item 2, above the necessary operator action can be completed under adverse circumstances within 11 minutes thus allowing 9 minutes for operator reaction. We are in the process of preparing procedures to accomplish these operator actions.

We are reviewing other possible long term solutions for this situation and will advise you of our selected alternative. In the interim the above mentioned operator action is appropriate and acceptable.

Sincerely,



J. G. Herbein
Vice President-Generation

JGH:CWS:akf



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

APR 21 1978

Docket No: 50-320

Metropolitan Edison Company
ATTN: J. G. Herbein
Vice President
P. O. Box 542
Reading, Pennsylvania 19603

Gentlemen:

SUBJECT: STEAM GENERATOR QUESTIONNAIRE - THREE MILE ISLAND UNIT 2

By letter dated December 9, 1977 (copy enclosed) we requested other PWR facility licensees to complete and submit a questionnaire on steam generator operating history that was enclosed. The letter stated that the request for information was approved by GAO under a blanket clearance. Questions have been raised about the appropriateness of this request for information in light of the Federal Reports Act and about the referenced GAO blanket clearance. These questions have been discussed with representatives of GAO and it was determined that a clarifying letter should be sent to each recipient of our original letter. GAO has agreed that this request properly fits under the GAO blanket clearance for reports concerning possible generic problems and the applicable GAO clearance number should have been R0072 rather than R0071.

The request for additional information was prompted by the continuing degradation of tubes in all three vendors' steam generators. Such degradation is an important safety concern of the NRC because such tubes form part of the primary coolant pressure boundary. Several forms of degradation that have been observed in steam generators in recent months have included the wastage of tubes at Palisades and other facilities, stress corrosion at Ginna and other facilities, vibration cracking and "dinging" of tubes at the Oconee (B&W) facilities, antivibration bar fretting at San Onofre, and "denting" of tubes and associated support plate "hourglassing" and cracking at Surry, Turkey Point and about 15 other CE and W facilities. These events have prompted the NRC to issue safety Orders. It is this need for important safety information that has dictated this request for additional information.

Our original letter to other licensees acknowledged that selected portions of the information being requested may already be available to the NRC, but not in a convenient format which is readily accessible. We therefore requested that they assist us by returning a single completed copy of the enclosed

Acc. No. 7904300062

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APR 21 1978

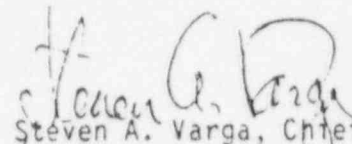
questionnaire. We would like to clarify that an acceptable response to any item in the questionnaire would be to provide specific reference to any information previously submitted to the NRC, by an original response, or any combination thereof, whichever and for whatever reasons you elect to use.

Our original letter further requested that recipients submit any changes or additions to their initial submittal to reflect the future operating experience with their steam generators. This would enable us to maintain the information current, which, as we stated, we will periodically publish and send copies to all participants. As we indicated, this would enable the NRC and others to draw from the operating experience of the entire nuclear industry on an ongoing basis when making safety and other decisions concerning steam generators in PWR plants. We are planning to prepare a submission to GAO for clearance of a request for reporting information regarding changes or additions to your initial submittal under this request.

Based on the above, we request that you assist us by returning a single completed copy of the enclosed questionnaire to the Director of Nuclear Reactor Regulation, U. S. Nuclear Regulatory Commission, Washington, D. C. 20555, within 60 days of receipt of this letter. Please include any comments or suggestions for improving this information system which you may have.

This request for generic information is approved by GAO under a blanket clearance Number R0072. This clearance expires December 31, 1980.

Sincerely,



Steven A. Varga, Chief
Light Water Reactors Branch No. 4
Division of Project Management

Enclosures:

1. Ltr. dated 12/9/77
to PWR Licensees
2. Questionnaire

cc w/enclosures:
See Page 3

APR 21 1978

ccs:

George F. Trowbridge, Esq.
Shaw, Pittman, Potts & Trowbridge
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Washington, D. C. 20036

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Madison Avenue at Punch Bowl Road
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Mr. R. Conrad
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Chairman
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Mr. Richard W. Heward
Project Manager
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260 Cherry Hill Road
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Mr. T. Gary Broughton
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METROPOLITAN EDISON COMPANY

POST OFFICE BOX 542 READING, PENNSYLVANIA 19603

TELEPHONE 215-929-3604

May 5, 1978
GQL 0854

Director of Nuclear Reactor Regulation
Attn: S. A. Varga, Chief
Light Water Reactors Branch No. 4
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Sir:

Three Mile Island Nuclear Station, Unit 2 (TMI-2)
Operating License No. DPR-73
Docket No. 50-320
Small Break LOCA

Enclosed please find the results of Babcock and Wilcox's (B&W) most recent calculations concerning a Small Break LOCA at TMI, (Analysis of Small Breaks in the Reactor Coolant Pump Discharge Piping for the B&W Lowered Loop 177 FA Plants, May 1, 1978) as well as the analysis presented to the NRC staff by B&W at a meeting on April 25, 1978 (Analysis of Small Breaks in the Reactor Coolant Pump Discharge Piping for the B&W Lowered Loop 177 FA Plants). Met-Ed and GPUSC have reviewed the enclosed analyses and concur with the B&W finding that full compliance with 10 CFR 50.46 and Appendix K to 10 CFR 50 is clearly demonstrated for operation at power levels below 2568 Mw(t) (approximately 92% power for TMI-2).

Recent conversations with B&W have indicated that results of additional calculations for power levels up to 2772 Mw(t) will be available to the NRC by approximately June 1, 1978. It is believed that these results will more clearly demonstrate complete compliance with 10 CFR 50.46 and 10 CFR 50 Appendix K at power levels up to 2772 Mw(t).

Maintenance operations at TMI-2 are progressing well, and Mode 2 entry (criticality) is expected to be made on May 14, 1978. It is then expected that the power level will be gradually increased; however, 2568 Mw(t) (92% of full power for TMI-2) for which compliance with 10 CFR 50.46 has been demonstrated is not to be achieved prior to June 8, 1978. Met-Ed, therefore, proposes to submit (prior to exceeding the 2568 Mw(t) power level) correspondence which, based on the B&W calculations now being performed, demonstrates compliance with 10 CFR 50.46 and 10 CFR 50 Appendix K for power levels up to 2772 Mw(t) (100% TMI-2 full power).

Met-Ed has revised the appropriate TMI-2 procedures (Emergency Procedure 2202-13, Loss of Reactor Coolant/Reactor Coolant Pressure and Operating Procedure 2104-1.2, Makeup and Purification Demineralization) as follows:

Acc. No. 4404230328 3pp

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1. Emergency Procedure 2202-1.3 - revised to detail the operator response (see below).
2. Operating Procedure 2104-1.2 - revised to permit operations with one of the makeup pump discharge cross-connect valves open and the other one closed.

There will be two (2) operators designated to respond to a small break LOCA, (1) Control Room LOCA Operator, stationed in the control room and trained to recognize the symptoms and respond to a small break LOCA and (2) Auxiliary Building LOCA Operator, stationed on the primary side of the plant, and trained to respond to a small break LOCA. The Control Room LOCA Operator will, within two (2) minutes after the event, analyze his indications and determine if there is a loss of offsite power concurrent with a diesel or makeup pump failure and a small break LOCA. In the event of that occurrence, by time $T = 2$ minutes, the Control Room LOCA Operator will direct the Auxiliary Building LOCA Operator to proceed to the makeup pump discharge cross connect valve and open it. The Control Room LOCA Operator will then proceed to the HPI valves on the affected train. The Auxiliary Building LOCA Operator will take, at a maximum, 1.5 minutes to arrive at the cross connect valve and at time $T = 3.5$ minutes, be opening the cross connect valve. Opening the cross connect valve will commence within 1.5 minutes ($T = 5.0$ minutes) and at time $T = 10.0$ minutes, the cross connect valve will be fully open.

As described above, when the Control Room LOCA Operator has directed the Auxiliary Building LOCA Operator to take the required action, he will then proceed to the HPI valves on the affected train, arriving in 2.5 minutes. Immediately upon arrival, at the HPI valves, time $T = 4.5$ minutes, the Control Room LOCA Operator will establish communication on the head set with the Control Room and begin to open the affected train HPI valves and will achieve minimum flow within 0.5 minutes ($T = 5.0$ minutes). The HPI valves will be opened manually to obtain 125 gpm flow per leg concurrent with balancing flow to 125 gpm in the unaffected leg electrically from the Control Room. This balancing evolution will take less than 5.0 minutes and will be completed by time $T = 10$ minutes. Prior to the balancing evolution, the Control Room CRO shall verify that the normal makeup valve is closed. These procedure revisions have been fully implemented.

Met-Ed review committees have reviewed these procedure revisions and have determined that (1) there is no increase in the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the safety analysis report in that the procedure revisions mitigate the consequences of the accident previously analyzed; (2) no possibility for an accident or malfunction of a different type that any evaluated in the safety analysis report is created in that the major concern, i.e., pump runout, will not occur under the operator action specified above; and (3) the margin of safety as defined in the basis for any technical specification is not reduced in that 10 CFR 50.46 acceptance criteria is not exceeded.

In addition, it has been determined that utilization of these procedures under any accident condition requiring operation of the HPI pumps will not lead to

May 5, 1978
CCL 0854

degradation of pump performance during any part of the transient. Performance of these procedures provides assurance that the total HPI flow, whether through two legs or four legs, will not exceed 550 gpm. Further assurance that pump runout will not occur results from B&W's indicating that pump runout will not occur as long as the back pressure is greater than the pressure equivalent to 1500 ft. of water (approximately 650 psi). For the largest break analyzed (0.17 ft^2), RCS pressure reaches about 650 psia in about 400 seconds, at which time the HPI valves would already be into the balancing evolution. Conservative calculations based on FSAR and Technical Specification data have been performed and indicate that adequate NPSH exists for at least 7.5 hours while taking suction from the BWST.

Each shift was briefed on the constraints of the license and the small break LOCA procedure requirements. An Operations Order is being written to require each Operations Department person to signify understanding of the procedure changes and manning requirements. Also, each Operations Department person is to physically locate all equipment required to be operated in accordance with the procedure changes. The Operations Order will further require one person on each shift (who is free to respond to the postulated accident) to be stationed in the Control Room at all times, and one person on each shift to be stationed on the primary side of the plant at all times to carry out the required action specified in the procedure changes. A sheet will be attached to the Control Room Log Sheet showing who are the two individuals assigned the responsibilities for carrying out the actions indicated in the procedure changes.

Each shift will be rebriefed at least once per month of the actions required in the procedures.

TMI has performed drills to verify that the assumed operator response time is achievable and within the analysis assumptions.

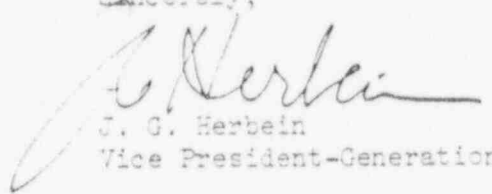
All drills performed to date have shown adequate response (to the point of unseating the cross-connect, and HPI discharge valves) in less than 5 minutes.

Met-Ed will submit a Technical Specification Change Request covering these procedures as soon as possible.

Met-Ed will submit a proposal for a permanent solution by August 5, 1978.

Should additional analyses be performed, Met-Ed will make their results available to the NRC, as soon after their completion as possible.

Sincerely,



J. G. Herbein
Vice President-Generation

JGH:RAL:cjg

cc: Harley Silver (NRC)

Enclosure

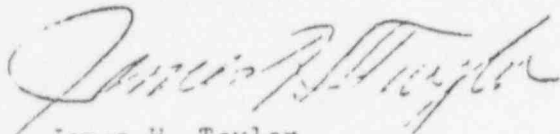
April 25, 1978

Mr. Robert L. Baer
Chief, Reactor Safety Branch
Division of Operating Reactors
Office of Nuclear Reactor Regulation
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Baer:

Attached is a report describing the methods used and the results obtained from B&W's recent studies of small breaks in the reactor coolant pump discharge piping for the B&W lowered loop 177 - fuel assembly plants. This report shows that at power levels up to at least 2568 MWt, full compliance with 10 CFR 50.46 is achieved. B&W is currently extending this study to cover power levels up to 2772 MWt and will supplement the attached information as soon as the studies are complete. We request an expeditious review of this information by the staff.

Very truly yours,



James H. Taylor
Manager, Licensing

JHT/bh

ANALYSIS OF SMALL BREAKS
IN THE
REACTOR COOLANT PUMP DISCHARGE PIPING
FOR THE
B&W LOWERED LOOP 177 FA PLANTS

APRIL 24, 1978

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15pp.

- a. The reactor is operating at 102% of the steady-state power level of 2568 MWt. For breaks greater than 0.1 ft, the analysis utilized a power level of 102% of 2772 MWt.
- b. The leak occurs instantaneously, and a discharge coefficient of 1.0 is used for the entire analysis. Bernoulli's equation was used for the subcooled portion of the transient, while Moody's correlation was used in the two-phase portion.
- c. No offsite power is available.
- d. The reactor trips on low pressure at 1900 psia.
- e. The safety rods begin entering the core after a 0.5 second delay from the time the reactor trip signal is reached.
- f. The RC pumps trip and coast down coincident with reactor trip.
- g. One complete train of the emergency safeguards system fails to operate, leaving two CFTs and only one HPI and one LPI system available for pumped injection to mitigate the consequences of a cold leg break.
- h. The auxiliary feedwater (FW) system is assumed to be available during the transient. Its main function is to remove heat from the upper half of the steam generator during the initial stages of the transient. When the secondary side of the steam generator becomes a source of heat to the primary system, the assumption of auxiliary FW maximizes the energy that must be relieved.
- i. ESFAS signal error band is considered in the analysis to signal the actuation of the HPI system.
- j. The peak linear heat generation rate in the hot pin is the maximum allowed by the Technical Specifications at the 10.5 ft level.
- k. Operator action is taken to increase the HPI flows to the intact cold legs at 10 minutes following the ECCS initiation signal. This assumption is explained more fully below and in section 3.

As most of the breaks evaluated in this spectrum showed core uncover, temperature calculations were necessary. Once core uncover occurs a spatial swell distribution analysis is necessary to assure that only the core covered by mixture is included in the swell level. B&W uses the FOAM code. The code was utilized under the same assumptions as described above with the following additions:

was simulated in our present CRAFT code as a step function at 650 seconds (600 seconds for action, 50 seconds for ECCS signal). This is illustrated in Figure 7.

2.3. Break Spectrum and Results

All evaluations reported in this analysis assume the high pressure injection performances as described in section 2.2. Breaks of 0.3, 0.2, 0.15, 0.1, 0.07, and 0.04 ft² were evaluated. The evaluation of a 0.5 ft² break was reported in BAW-10103A, Rev 3, and shows complete core coverly at all times and thus no temperature excursion. The 0.5 ft² break results are independent of HPI flow and remain valid.

Figure 2 shows the RCS pressure transient for each break. As shown, each accident initiates CFT flow within 2000 seconds except for the 0.04 ft² break.

Figure 3 shows (CRAFT) mixture height as a function of time for each break of the spectrum. As can be seen, breaks of approximately 0.3 ft² and larger than approximately 0.04 ft² uncover part of the core. Various uncover levels and times are observed but all trends are consistent throughout the spectrum.

The 0.04 ft² break achieves a match up of effective ECCS (the HPI injected into the intact cold legs) with the core decay heat and the RCS metal heat at 2500 seconds. After 2500 seconds the mixture level will rise in the core due to excess HPI injection. As the 0.04 ft² break has a level of 14 feet at this time the core never uncovers and no temperature excursion occurs. For breaks smaller than 0.04, the match up will occur at approximately the same time and the core mixture levels will drop slower; thus, for all smaller breaks the core will remain covered.

Figure 4 shows the time duration of uncover for four core elevations as a function of break size. These results are from CRAFT. As can be seen, the maximum degree of uncover and the maximum time of uncover occur for the 0.15 ft² break and is the worst case break. This break can thus be identified as the worst case. A similar uncover occurs for the 0.1 and 0.07 ft² breaks. The 0.07, 0.10, and 0.15 ft² breaks were analyzed for temperature response. The results are shown in Figure 5 and are well within the criteria of 10 CFR 50.46. They provide positive assurance that all breaks of the spectrum are within acceptance criteria.

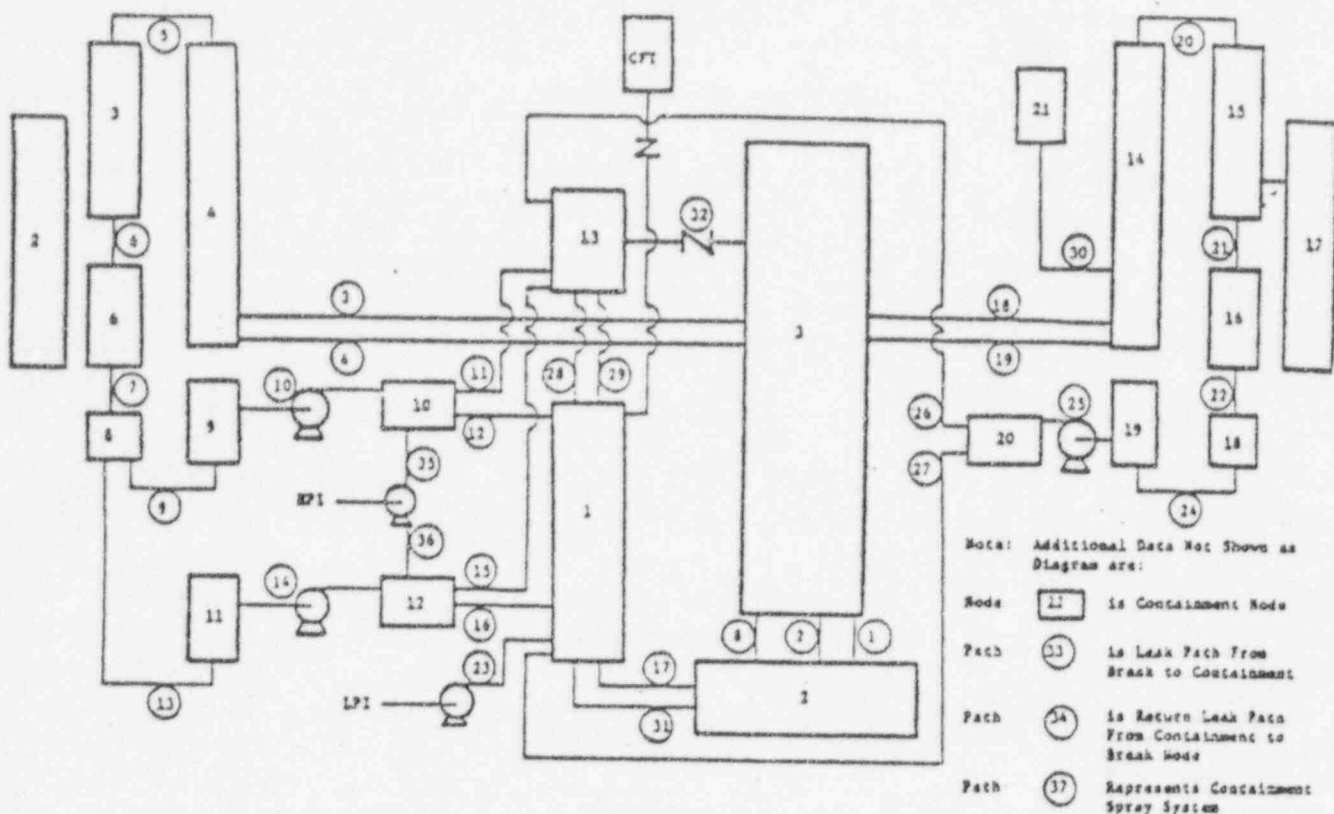
2. If no flow in one train:
 - open pump header cross-connect valves
 - check HPI valve position and open if closed
3. Secure flow through normal makeup line if flow is indicated
4. Throttle HPI valves as required to balance flow and meet run out limits

The above actions initiated at five minutes and completed within 15 minutes subsequent to the ESFAS actuation ensures adequate HPI flow for accident mitigation. In the analysis, credit is taken for the HPI flow as the HPI injection valves are opened. Figure 7 shows the calculated HPI flow for a typical plant as a function of time for a 10 minute valve opening. As shown in Figure 7, the majority of the HPI pump capacity would be delivered with a partial valve opening. For the small break analysis, a linear flow versus valve position response was simulated by a step function increase, 10 minutes after ESFAS actuation.

4. Evaluation of Other B&W Supplied Plants

- a. Davis-Besse - The DB-1, 2 and 3 Plants have been analyzed for a spectrum of small breaks at the RCP discharge in accordance with an approved small break evaluation model. This analysis is reported in BAW-10075A, Rev 1, March 1976. In addition, the Davis-Besse 1, 2, and 3 units have a split high pressure injection and makeup system design. The Davis-Besse HPI pumps, therefore, have considerably higher capacity at the system pressures experienced.
- b. 205 and 145 FA - These plants have been analyzed for a spectrum of small breaks at the RCP discharge in accordance with an approved small break evaluation model. These analyses are reported in BAW-10074A, Rev 1, and BAW-10062A, Rev 1, March 1976. In addition, the 205 and 145 FA HPI systems contain cross connects between the two HPI trains downstream of the HPI injection valves. These cross connects effectively achieve the same flow split as the operator action assumed in the current 177 FA lowered loop analysis and the flow split is achieved when the HPI pump is started.

Figure -1. CRAFT2 Noding Diagram for Small Break



Node No.	Identification
1	Downcomer
2	Lower Plenum
3	Core, Core Bypass, Upper Plenum, Upper Head
4,14	Hot Leg Piping
5,15	Steam Generator Upper Head, SG Tubes (Upper Half)
6,16	SG Tubes (Lower Half)
8,18	SG Lower Head
9,11,19	Cold Leg Piping (Pump Suction)
10,12,20	Cold Leg Piping (Pump Discharge)
13	Upper Downcomer (Above the Q_L of Nozzle Belt)
21	Pressurizer
22	Containment

Path No.	Identification
1,2	Core
3,4,18,19	Hot Leg Piping
5,20	Hot Leg, Upper
6,21	SG Tubes
7,22	SG Lower Head
8	Core Bypass
9,13,24	Cold Leg Piping
10,14,25	Pumps
11,12,15,16,26,27	Cold Leg Piping
17,31	Downcomer
23	LPI
28,29	Upper Downcomer
30	Pressurizer
32	Vent Valve
33,34	Leak & Return Path
35,36	HPI
37	Containment Sprays

FIGURE 2. PRESSURE

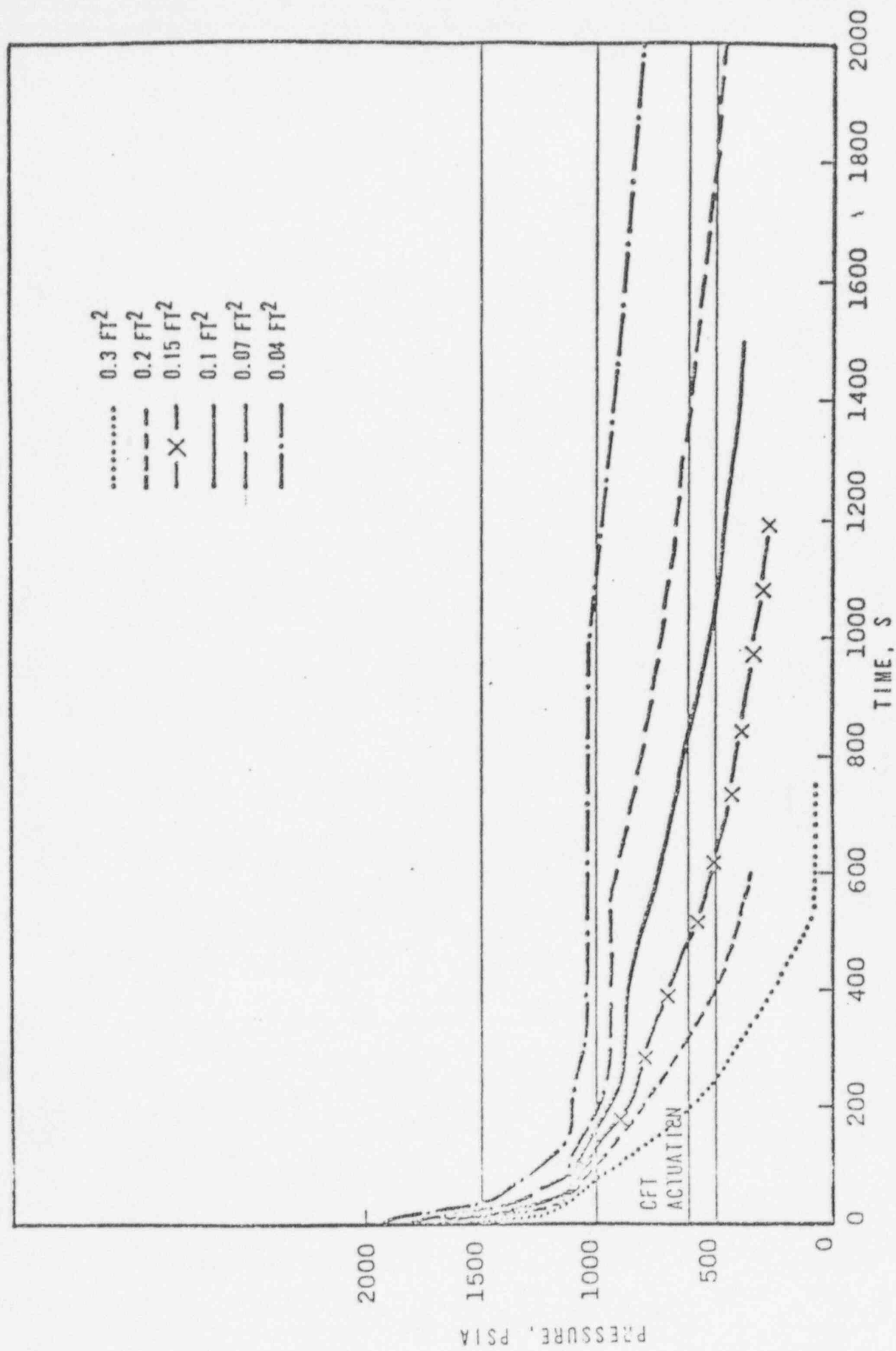


FIGURE 3. CORE MIXTURE HEIGHT
(CRAFT)

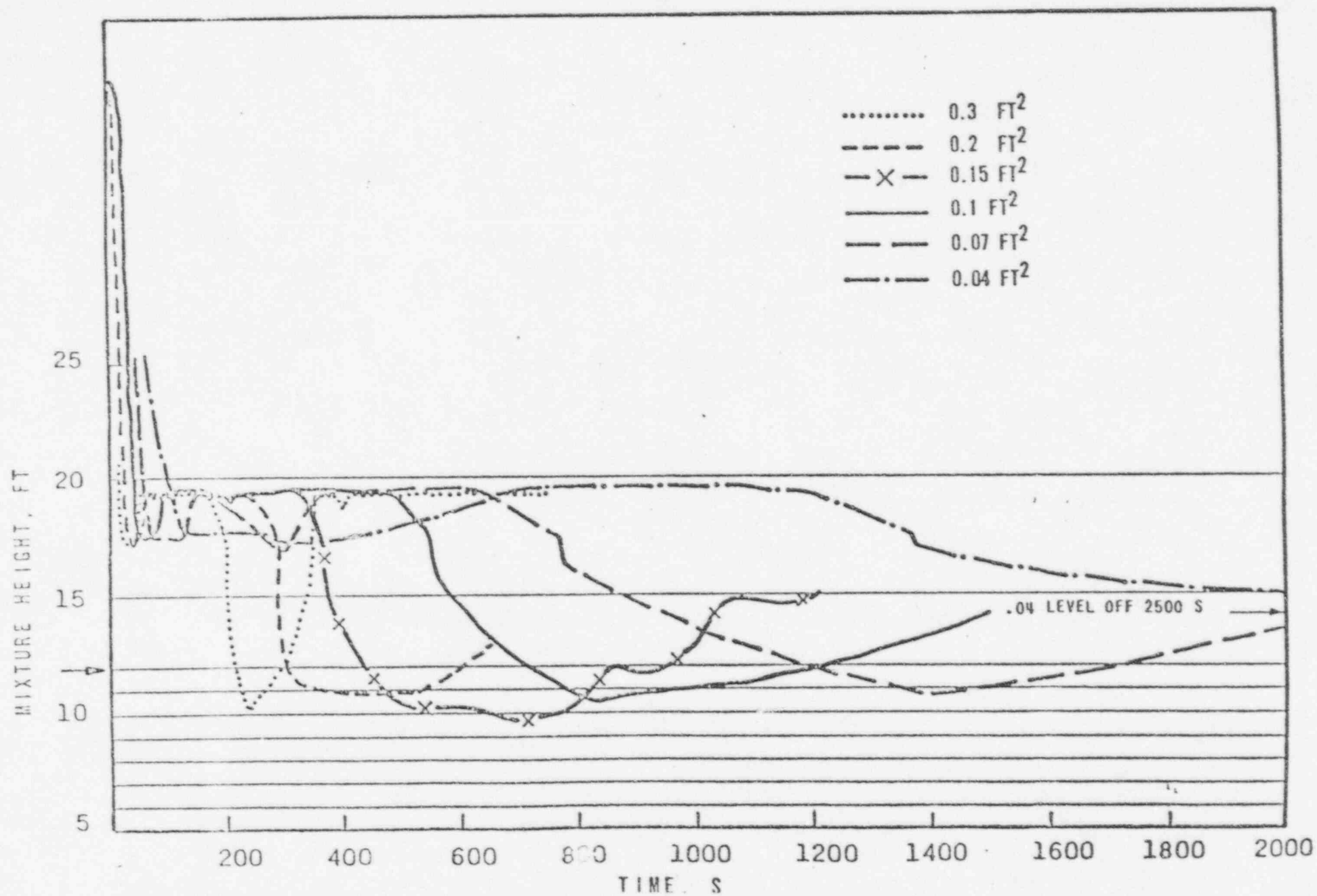


FIGURE 4. CORE UNCOVERY TIMES VERSUS BREAK SIZES

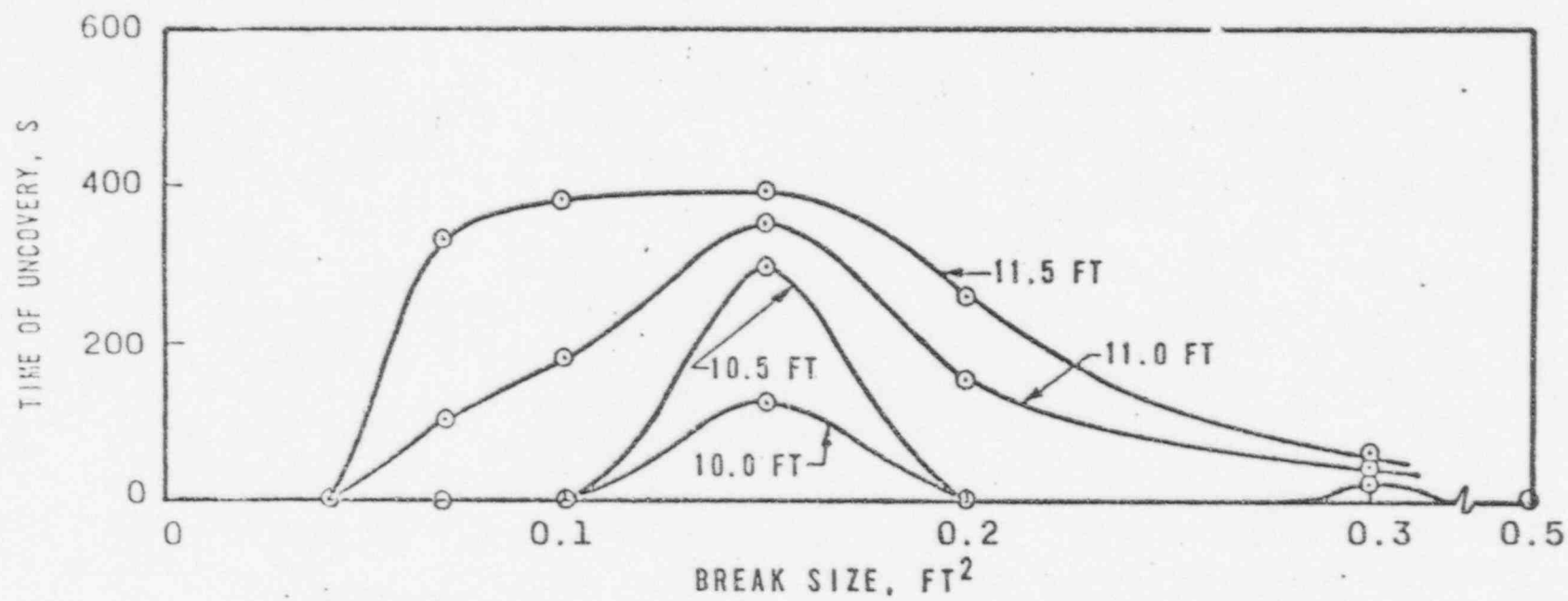


FIGURE 5. PEAK CLADDING TEMPERATURE

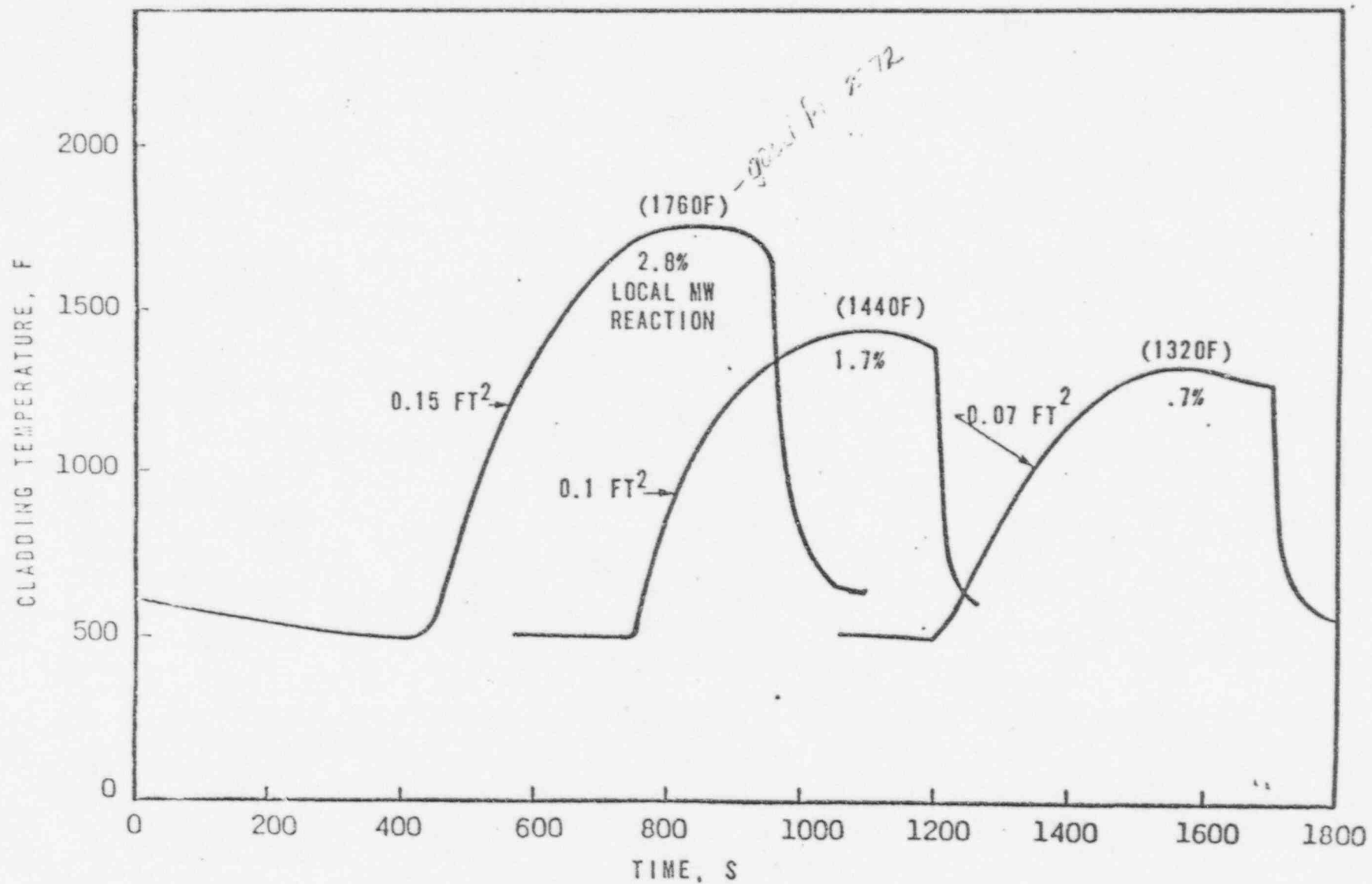


FIGURE 6. AXIAL POWER SHAPE

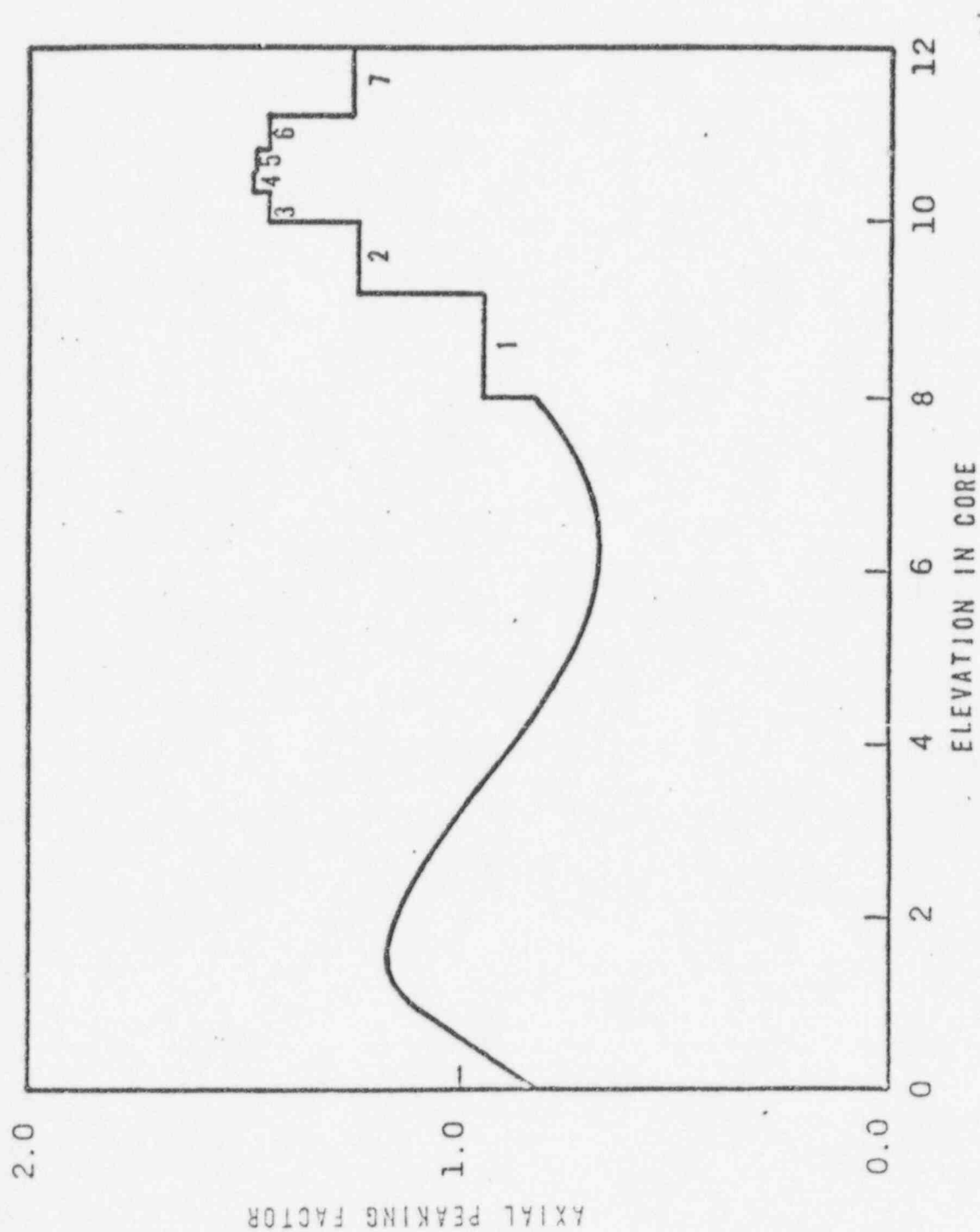
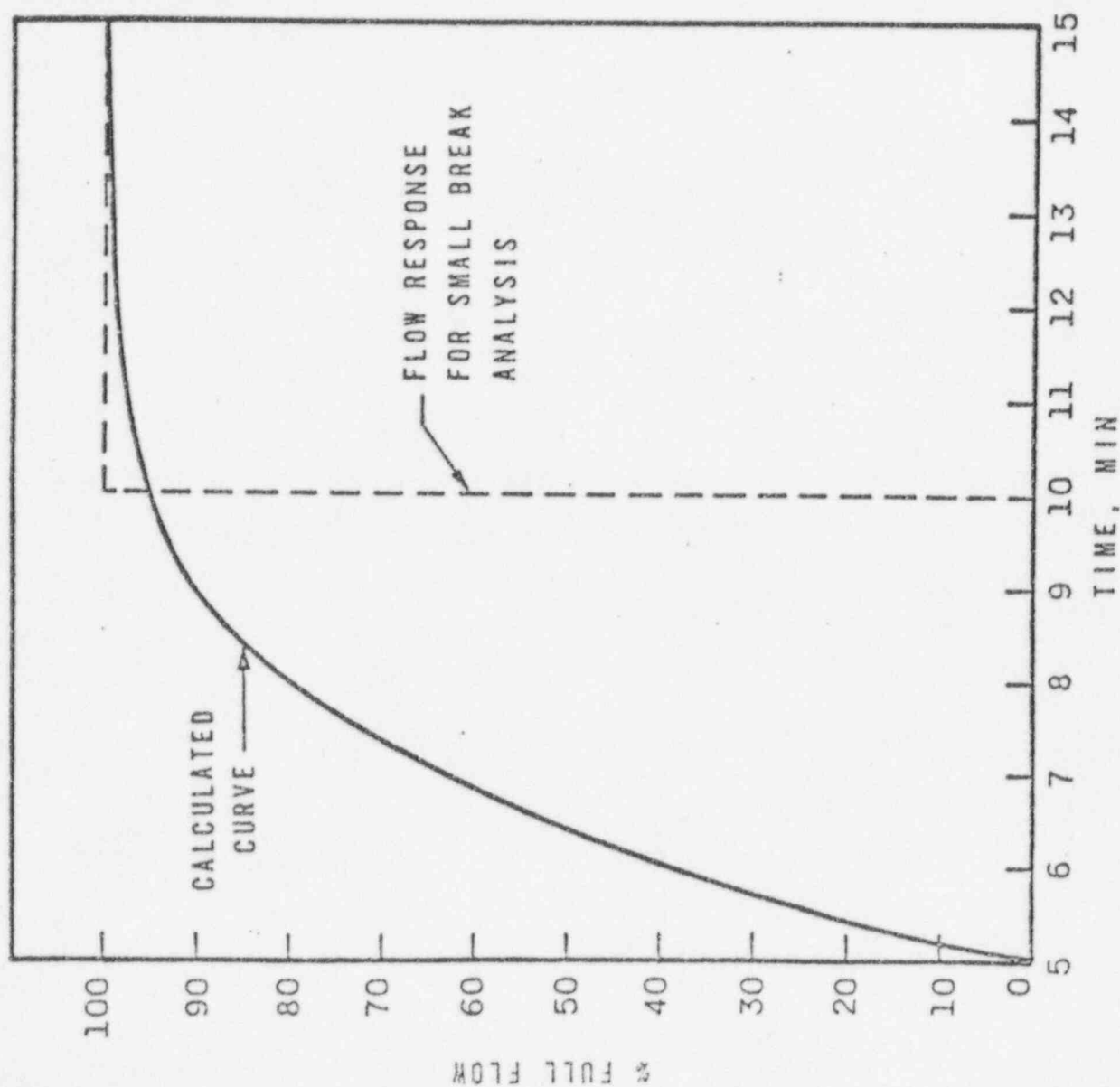


FIGURE 7. FLOW VS VALVE POSITION
(Based on Actual Cy VS Valve
Position for Ocone HPI Valves)



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Figure 8 PEAK CLADDING TEMPERATURE
VS
BREAK SIZE

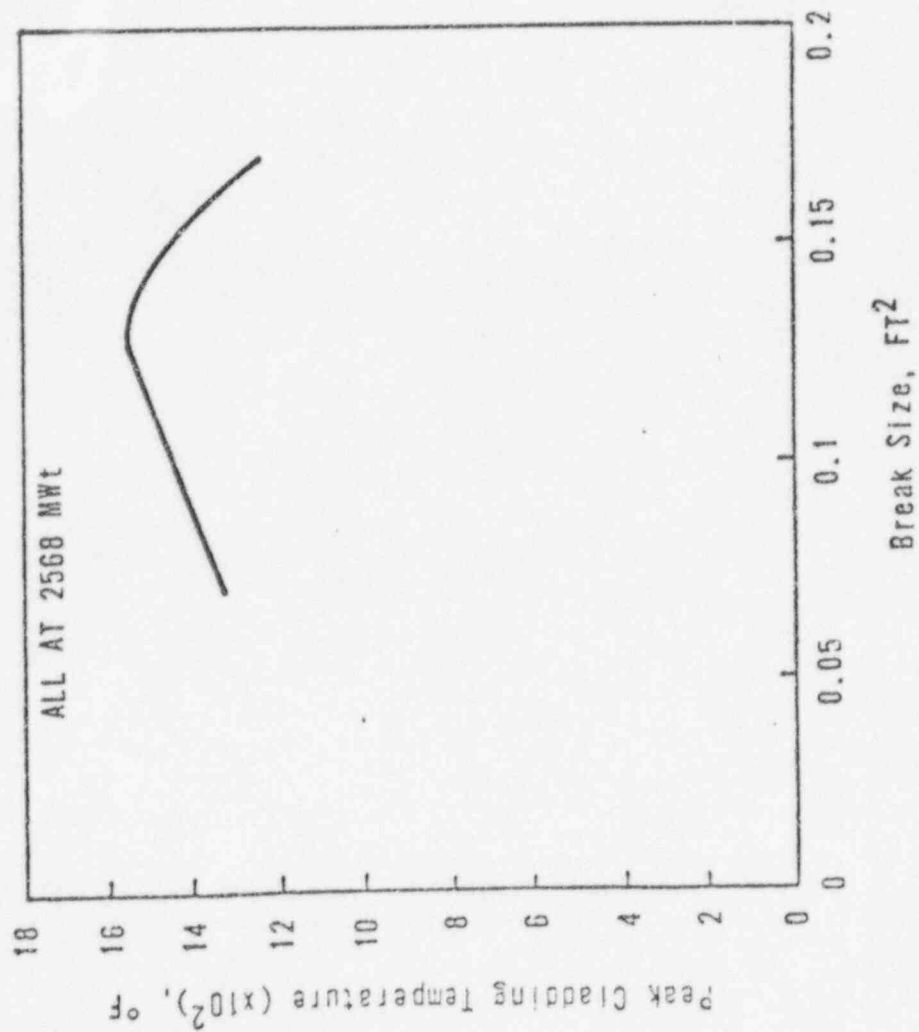


FIGURE 6. AXIAL POWER SHAPE

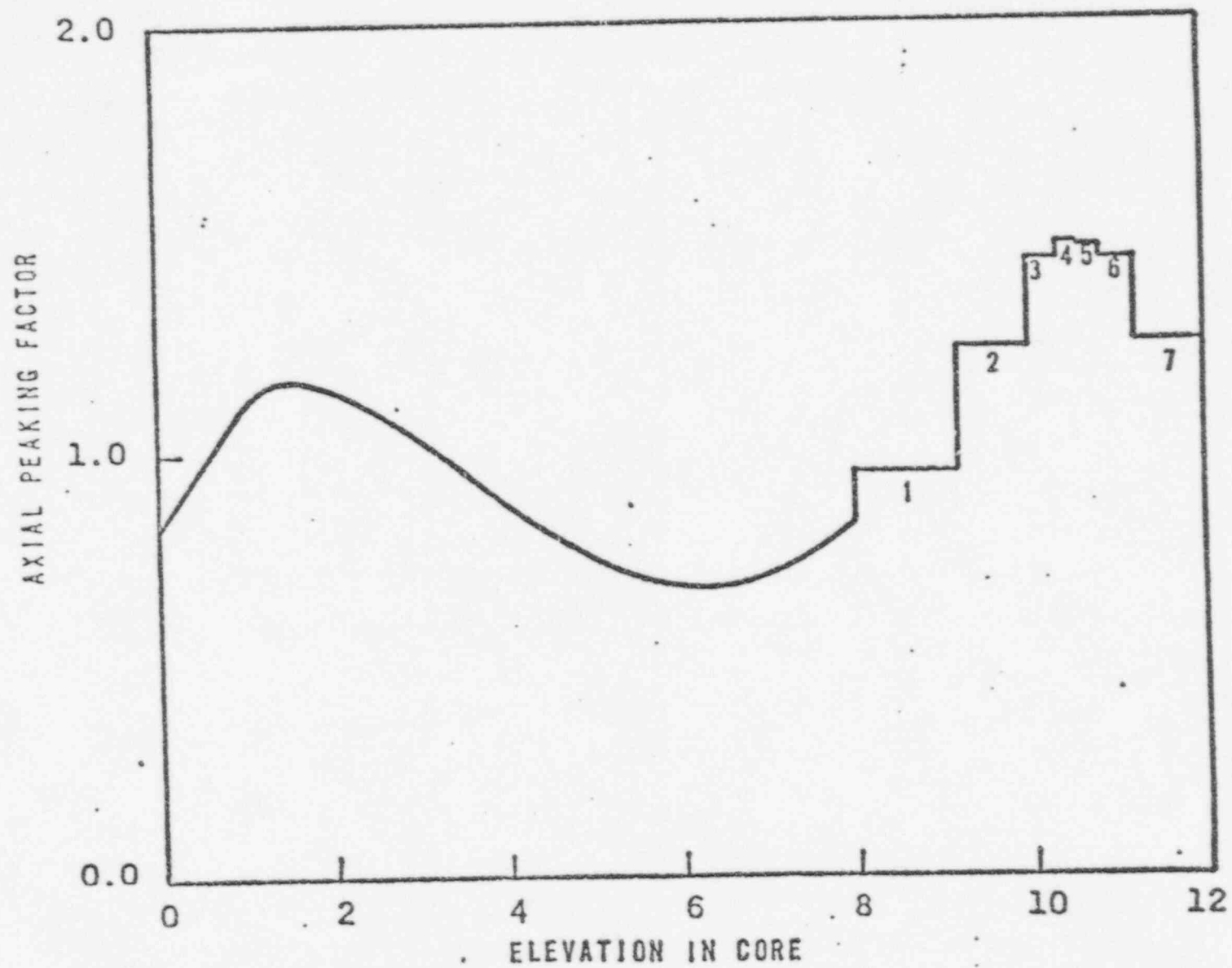


Figure 4 DURATION OF UNCOVER FOR THREE CORE LEVELS
(11.5 FT, 11.0 FT, 10.5 FT)
(NOTE 10.0 FT DOES NOT UNCOVER)

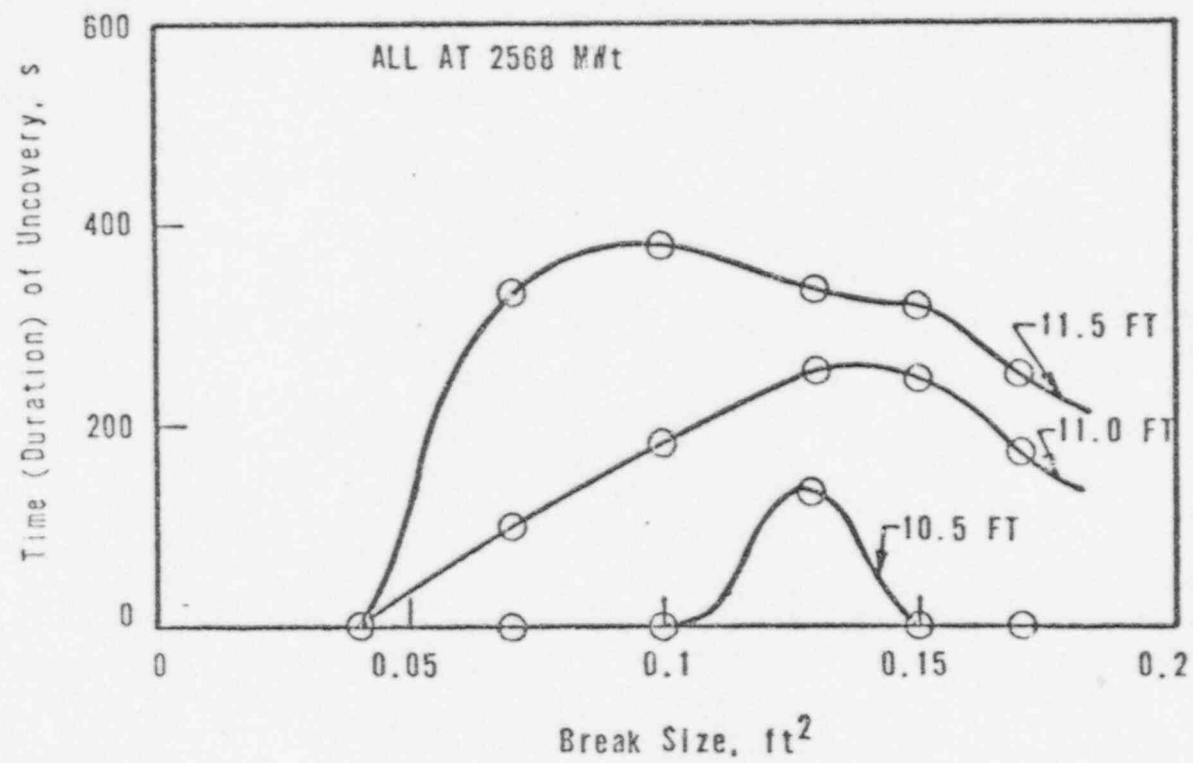


Figure 2 PRESSURE

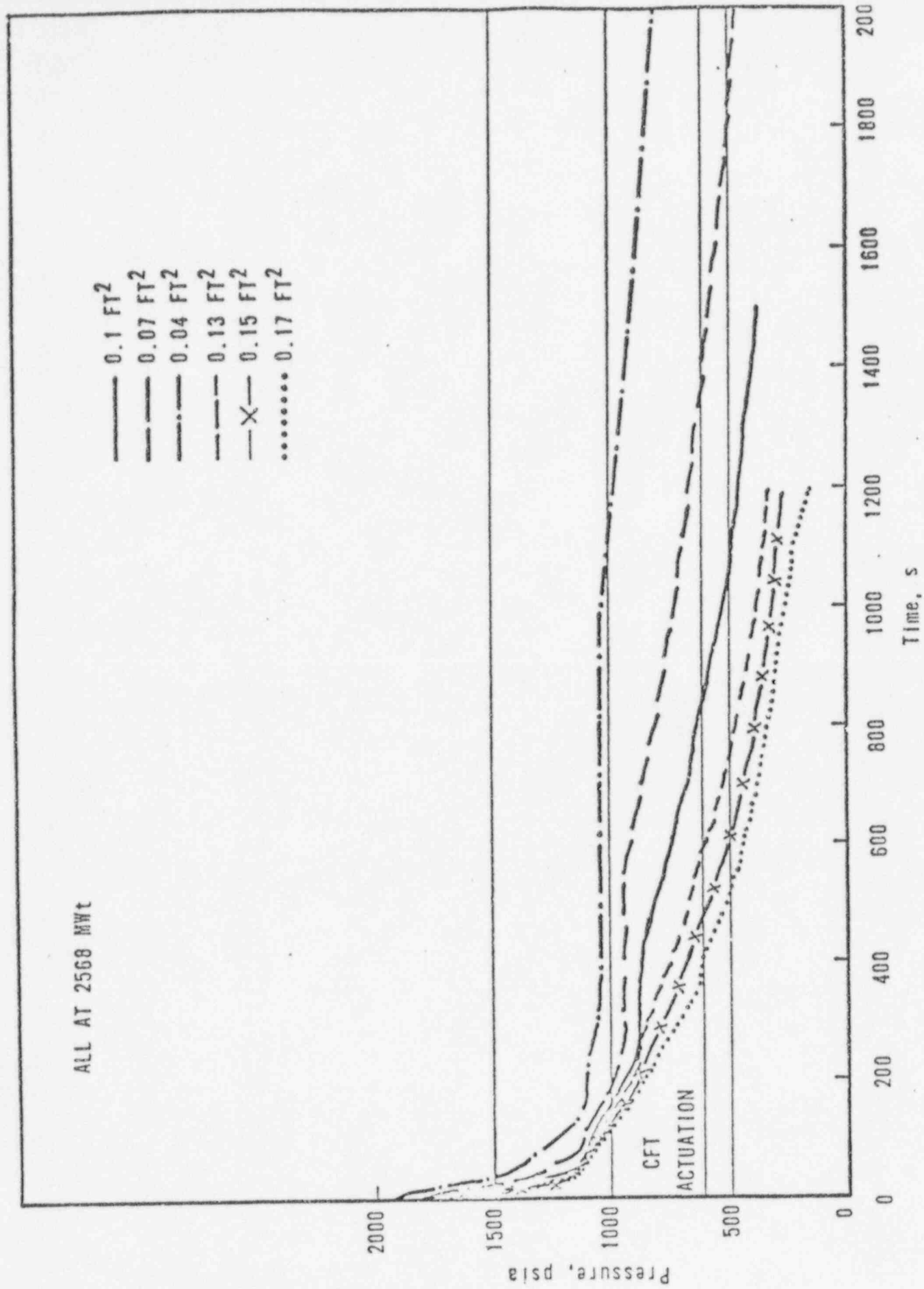


TABLE 1

PEAK CLADDING TEMPERATURE VERSUS BREAK SIZE
(All at 2568 MWt)

<u>Break Size (Ft²)</u>	<u>Peak Cladding Temperature (°F)</u>	<u>Maximum Local MW Reaction (%)</u>	<u>Time of Peak Temperature (sec.)</u>
0.04	Core Stays Covered With No Temperature Excursion		
0.07	1320	.73%	1600
0.1	1440	1.68%	1080
0.13	1551	1.72%	820
0.15	1455	1.67%	740
0.17	1248	0.72%	650

Local metal-water reaction is shown in Table 1. The highest value is 1.72% for the 0.13 ft² break. This value is well below the local oxidation limit for the large breaks utilized in BAW-10103 for the whole-core metal-water reaction calculation. Thus, the whole-core metal-water reaction results given in section 8 of BAW-10103 is conservative for small breaks. The degree of clad damage is bounded by the large break results which produce higher clad temperatures. Thus, all criteria of 10 CFR 50.46 are met. This analysis is conservative for many reasons as detailed in the writeup and meets all evaluation criteria. This analysis shows that all 177 lowered loop plants meet the criteria of 10 CFR 50.46 if operated at or below 2568 MWt power and in conjunction with the specified operator action.

3. Operator Action

The ECCS analysis used as a basis for this report assumes that the operative HPI train (one train is lost due to a single active failure) provides emergency core cooling water to the RC loop containing the break. It is conservatively assumed that the break is on the lower portion of the reactor coolant pump discharge piping resulting in the total loss to the system of 50% of the available HPI flow. Acceptable mitigation of the accident requires more than the 50 % of this flow from one HPI pump. If, following the LOCA, it is assumed that one train of HPI does not start it is necessary to take operator action to achieve a flow split wherein no more than 30% of the remaining pump's flow goes into the cold leg containing the break. The following is a description of the action required for a typical plant.

1. Upon ESFAS signal check for flow through both HPI trains.
2. If no flow in one train:
 - open pump header cross-connect valves
 - check HPI valve position and open if closed
3. Secure flow through normal makeup line if flow is indicated
4. Throttle HPI valves as required to balance flow and meet run out limits

1. The power shape shown in Figure 6 was used but implemented with a radial peaking factor of 1.0. This represents the average channel condition which is appropriate for use in swell level calculations.
2. Steam production due to heat from the primary metal, core and lower plenum flashing, was conservatively underpredicted. Although the CRAFT model accurately predicted these effects, full credit was not included in the FOAM simulation as a conservative computational convenience. This simulation, therefore, underpredicts both the swell level and the steaming rate. Consequently, more core uncover and lower coolant flow are used in the heat-up evaluation.

The heat-up calculation was performed using the THETA code in the manner described in section 5 of BAW-10104. The following additional assumptions are utilized in the THETA evaluation:

1. The power shape of Figure 5 was used with a radial power factor of 1.8. This maximizes steam superheating and sets the peak local power at 10.5 ft at the technical specification LOCA limit.
2. Coolant flow and mixture level were taken directly from the FOAM calculations.
3. End of life pin pressures were used to conservatively predict the incidence of fuel pin rupture.

2.2. High Pressure Injection System Performance

The previous arrangement of the HPI system allowed for one pump to inject into the reactor coolant system (RCS) at two locations. As one injection point could be in the region of the break, 50% of the one HPI flow could fail to penetrate the reactor vessel. This flow would, therefore, not be available to provide core cooling. The proposed operator action, section 3, will provide four points of penetration of the RCS. Therefore, only 25% of the HPI flow would be lost.

Since the flow from one HPI pump will now be distributed to four injection points and to assure conservatism in allowing for injection line loss differences, this analysis assumes 30% of the HPI is injected into the broken cold leg. The implemented action starts at 5 minutes after an ECCS signal and is concluded 15 minutes after the signal. The resultant HPI flow can be conservatively represented as a linear ramp from 5 to 15 minutes. This ramp

1. Introduction

On April 14, 1978, B&W reported that previous small break analyses had not been based on the worst break location. This report indicated that the worst case break had now been determined to be at the reactor coolant pump discharge. A spectrum of small breaks has been examined for the B&W 177-FA lowered loop plants using the small break evaluation model described in BAW-10104, Rev 3, "B&W's ECCS Evaluation Model." These results show that it is necessary to use operator action during the early stages of the postulated accident, to effectively mitigate the accident consequences and meet the criteria of 10 CFR 50.46. Operator action is used to achieve sufficient and balanced flow through all four HPI injection lines. This report shows that operation up to at least 2568 MWt is possible within the criteria of 10 CFR 50.46 and Appendix K.

2. Evaluation

2.1. Method of Analysis

The analysis method used for this evaluation is that described in Chapter 5 of BAW-10104, Rev 3, "B&W's ECCS Evaluation Model." Specifically, the model, except for break size, break location, and core power, is the same as utilized in Appendix C of BAW-10103A, Rev 3, "ECCS Analysis of B&W's 177-FA Lowered-Loop NSS." The analysis uses the CRAFT2 code to develop the history of the reactor coolant system hydrodynamics. The CRAFT model uses 19 nodes to simulate the reactor coolant system, two nodes for the secondary system, and one node for the reactor building. A schematic diagram of the model is shown in Figure 1 along with the node descriptions. Control volumes (nodes) in and around the vessel are all connected by a pair of flow paths to permit counter-current flow. The break is assumed to be located at the bottom of the cold leg piping between the reactor coolant pump discharge and the reactor vessel. The Wilson, Grenda and Patterson average bubble rise model is used for all nodes. Within the core region, however, a multiplier of 2.38 is applied to the calculated bubble rise velocity.

Appendix F of BAW-10104 demonstrates that a multiplier of 2.38 in CRAFT2 gives a mixture height within $\pm 2\%$ of that predicted by FOAM. Thus, no FOAM analysis will be needed if the CRAFT2 mixture level remains above the core by 2% of the active length.

The following assumptions are made for conditions and system responses during the accident:



METROPOLITAN EDISON COMPANY

A SUBSIDIARY OF METROPOLITAN EDISON UTILITIES CORPORATION

POST OFFICE BOX 542 READING, PENNSYLVANIA 19603

TELEPHONE 215 - 929-3601

May 11, 1978
GQL 0915

Director of Nuclear Reactor Regulation
Attn: S. A. Varga
Light Water Reactors Branch No. 4
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Sir:

Three Mile Island Nuclear Station Unit 2 (TMI-2)
Docket No. 50-320
Operating License No. DPR-73

The occurrence, at Crystal River 3, of two separated Burnable Poison Rod Assemblies (BPRA's) has raised the concern that a similar incident might occur at Three Mile Island, Unit 2. Although such an event is not considered likely, based upon the satisfactory performance of other B&W operating reactors, Metropolitan Edison deems it prudent to take certain precautionary measures to provide further assurance that the BPRA's will remain in place. Of the various options available, we have determined that the best course of action is the installation of positive retention devices, which were recommended by B&W. These retainers have been designed and are undergoing test and evaluation at B&W.

Currently, it is our intention to install the retainers on all BPRA's following completion of startup and acceptance testing. As discussed below we are confident that the plant can be operated for up to 75 full flow days prior to installation of the retainers.

TMI-2 NSS operation to date has been with three primary coolant pumps in service. Later portions of the initial startup phase and full power operation will be conducted with all four coolant pumps in service. Crystal River 3 operated for about 300 days with four pump flow before the first indication of BPRA separation occurred. Based on the performance of CR-3 and other B&W 177 Mark B4 Fuel Assembly plants and on wear measurements of the fuel assembly BPRA holdown latches at Crystal River 3, Arkansas Nuclear One-1, Oconee-2, it is conservatively estimated that TMI-2 can reliably operate for up to 75 days of the full four pump flow.

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May 11, 1978
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Results to date of the B&W investigation of the CR-3 event indicate that the separation of BPRA's may be due to a long term wear phenomenon causing separation of the BPRA holddown latch. Coolant flow and the resultant net hydraulic lift compared with the wet weight of a BPRA appears to be a primary factor in the holddown latch wear rate. Latch hardness is also a significant factor. The 68 BPRA's and holddown latches in TMI-2 are of the same design used in all B&W 177 FA reactors.

Analysis of the TMI-2 BPRA hydraulic lift force for four pump flow indicates less nominal lift than at Crystal River 3. The holddown latch assembly minimum hardness on TMI-2 fuel assemblies is also equal to or greater than the hardness of the Crystal River 3 holddown latch assemblies which experienced the highest wear. Thus, TMI-2 can be expected to experience a lower wear rate than Crystal River 3. However, to account for other undefined factors which may influence wear rate, a factor of 4 has been applied to the highest wear rate observed at Crystal River. On this basis, an allowable limit of 75 days of TMI-2 four pump operation has been established.

Wear data from Oconee 2 and ANO-1 for fuel assemblies which operated for as long as 600 full flow days lend confidence that the use of Crystal River wear data coupled with a safety factor of 4 is conservative for TMI-2. Davis Besse with higher calculated lift and comparable minimum holddown assembly hardness has operated without incident for greater than 150 full flow days. Rancho Seco, also with calculated higher lifts but with much higher minimum holddown latch assembly hardness operated for greater than 500 days without incident. Oconee 3 and TMI-1, with calculated lift forces in the same range but slightly lower than TMI-2, both operated for greater than 500 full flow days without incident.

Operation with three pumps precludes BPRA net lift with a very large margin thus avoiding conditions under which wear can occur. To date, all operation in TMI-2 has been with 3 coolant pumps in service. TMI-2 will not be operated past 75 days of accumulated full flow operation, prior to retainer installation, without further justification. The NRC will be informed of the results of any investigations which may change the basis for the allowable period of four pump operation.

Thus, based on the considerations described above, there is a very low probability of a BPRA separating from a fuel assembly in TMI-2 before retainers are installed. These retainers will insure BPRA locking for the remainder of first cycle operation.

In the very unlikely event that a BPRA may become separated during plant operation the consequences to the core are within the bounds of the analysis addressed in the FSAR. Depending upon its location within the core a separated BPRA will have a varying impact upon assembly power peaking. With a significant increase in power peaking the event would be detected by the

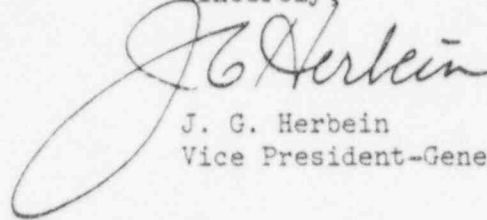
May 11, 1978
GQL 0915

tilt alarm or power distribution monitoring and appropriate corrective action would be taken. Lesser power increases would be within the allowable peaking limits considered in the Technical Specifications. In addition, the change in by-pass flow as a result of BPRA removal, is negligible.

The consequences of a BPRA separating from the core are bounded by the results of the Ejected Rod Accident analyzed in the FSAR. The reactivity worth of a single BPRA is only 30 to 40% the worth of a control rod and is less than the maximum ejected rod worth of 0.65% $\Delta K/K$ used in the FSAR. The consequence of a stuck control rod assembly (CRA) is a normal design consideration for calculating shutdown margin. All FSAR accidents are analyzed with the reactivity effects of the most reactive control rod stuck out of the core. The effect of a separated BPRA would be less than a stuck control rod for the same incident.

Based upon the above discussion it is concluded that there is a very low probability of a BPRA separating from the core during the limited period of four pump operation; also, any consequences to the core from such a separation are bounded analyses contained in the TMI-2 FSAR.

Sincerely,

J. G. Herbein
Vice President-Generation

JGH:RAL:dkf

cc: H. Silver



METROPOLITAN EDISON COMPANY

POST OFFICE BOX 542 READING, PENNSYLVANIA 19603

TELEPHONE 215 - 929-3601

May 19, 1978

GQL 0970

Director of Nuclear Reactor Regulations
Attn: Mr. S. A. Varga, Chief
Light Water Reactor Branch 4
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Sir:

Three Mile Island Nuclear Station Unit 2 (TMI-2)
Docket No. 50-320
Operating License No. DPR-73
Pseudo Ejected Rod Test Deletion

B&W has recommended that Met-Ed delete the pseudo ejected rod worth test performed at 40% power from the TMI-2 Startup and Test Program. B&W's recommendation is based on the fact that the predicted ejected rod worth is extremely small, and the prediction has been verified at other plants. We agree with B&W's recommendation. Therefore, we propose to delete the at power ejected rod test in that, performance of the test would generate unnecessary radiowaste and consume up to 24 hours of time that could be used more productively.

In discussions with members of your staff, several questions were asked concerning deletion of this test. Answers to these questions are attached.

Deletion of the ejected rod worth measurement at power is justified, because: (1) the predicted rod worth is substantially less than the safety analysis limits; (2) actual measurement of zero power ejected rod worth was less than the safety analysis limit; and (3) actual measurements on similar cores at other plants (Davis Besse and Rancho Seco) have confirmed the extremely low ejected rod worth predictions and the validity of the prediction methods.

Based on the above, we request your concurrence in deleting the ejected rod worth measurements at 40% power.

Sincerely,

J. G. Herbein
Vice President-Generation

JGH:RAL:tas
Attachment

Rec. No. 7904300049

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Answers to NRC Questions Concerning Rod Worth

Question 1:

Provide a comparison of measured/predicted rod worth for Groups 1-4, 5, 6, 7, and 8 and ejected rod worth at zero power for TMI-2.

Answer:

ZERO POWER ROD WORTH

<u>Rod/Group</u>	<u>Predicted* (%Δk/k)</u>	<u>Measured (%Δk/k)</u>
Group 1-7	10.22	10.04
Group 5	2.22	1.85 (inserted from 79% to 0% withdrawn)
Group 6 and 7	3.36	3.165
Group 8 (APSR)	0.41	0.385
Rod H - 14	0.87 (Gr. 5 @ 49%)	0.611 (Gr. 5 @ 50%)

*Physics test manual values were predicted using 2 zone 20 PDQ, described in BAW-10116A, with all full length rods being inserted from fully withdrawn to fully inserted. Group 8 was inserted from fully withdrawn to its null position.

Question 2:

Are the Rancho Seco and TMI-2 cores the same and were they analyzed identically? Why do the TMI-2/Rancho Seco predictions differ?

Answer:

The TMI-2 and Rancho Seco (and Davis Besse) cores are essentially the same. The major difference between the two cores is the presence of the Gadolinia demonstration burnable poison rods in TMI-2. These poison rods, however, have only a minor influence on rod worths.

The predictive analyses for the Rancho Seco (and Davis Besse) were performed using 3D - PDQ (1-zone) while TMI-2 analyzed using 3D FLAME (1-zone). The predicted and measured values for ejected rod worth are given in Table 1 below. The major difference between the predictions for TMI-2 and those of Davis Besse and Rancho Seco are believed to be a result of the analyses being performed at differing Group 6 and 7 withdrawals (75% for Rancho Seco* and 83.3% for TMI-2) rather than the influence of the demonstration poison rods or predictive code utilized. This reasoning is demonstrated in Table 2 as calculated by a pin-by-pin 2D PDQ (see BAW 10116A). Also, those four assemblies with Gadolinia are enriched to 1.80 w/o instead of the Batch 1, 1.98 w/o.

*and 75% for Davis Besse

TABLE 1: EJECTED ROD WORTH AT POWER

	<u>Prediction</u>	<u>Code</u>	<u>Measurement** (%$\Delta k/k$)</u>
Rancho Seco	0.035	PDQ	0.047
Davis Besse	0.035	PDQ	0.021B
TMI-2	0.01	FLAME	-

**The acceptance criteria is $< 0.65\% \Delta k/k$ which is more than an order of magnitude greater than predicted or measured.

TABLE 2: TMI-2

GROUP ROD WORTHS, WITH AND WITHOUT GADOLINIA POISON RODS

<u>Group</u>	<u>TMI-2, No Gd.</u>	<u>TMI-2, With Gd.</u>
1-7	9.73	9.64
5	2.08	1.99 (4 of 12 CRA's inserted into Gd. bearing assemblies)
6	1.88	1.89
7	1.48	1.45



METROPOLITAN EDISON COMPANY

POST OFFICE BOX 542 READING, PENNSYLVANIA 19603

TELEPHONE 215 - 929-3601

May 25, 1978
GQL 0987

Director of Nuclear Reactor Regulations
Attn: Mr. S. A. Varga, Chief
Operating Reactors Branch No. 4
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555



Dear Sir:

Three Mile Island Nuclear Station Unit 2 (TMI-2)
Operating License No. DPR-73
Docket No. 50-320
Small Break LOCA

It has come to our attention, through conversations with Mr. Harley Silver of your staff, that our submittal of May 5, 1978, did not adequately address our intentions for power escalation at TMI-2. Please be assured that Met-Ed will not escalate power beyond 2568 Mw(t) at TMI-2 until the following events have transpired:

- 1) Babcock and Wilcox (B&W) complete their analysis of the results of a Small Break LOCA for operation at 2772 Mw(t).
- 2) Met-Ed has reviewed and concurred with these analyses, and has submitted them to the NRC.
- 3) The NRC has accepted the validity of the B&W Analysis (as submitted by Met-Ed) for a Small Break LOCA at power levels of 2772 Mw(t).

Sincerely,

J. G. Herbein
Vice President-Generation

JGH:RAL:cjg

cc: Harley Silver (NRC)

Acc. No. 7905070527

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June 7, 1973

Mr. Steven A. Varga, Chief
Light Water Reactors Branch 4
Division of Project Management
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Varga:

Earlier today, Messrs. Tokar and Meyer of the NRC asked several questions of B&W relating to BAW-1496, "BPRA Retainer Design Report", which was forwarded to you by my letter of June 2, 1978. The questions were directed primarily towards use of the retainer for holddown of modified orifice rod assemblies (MORA). This letter is being provided to formalize B&W's responses to these questions so that they may be used in support of licensing activities associated with retainer use.

The MORA used with primary neutron sources can be visualized by referring to Figure 3-1a of BAW-1496. The orifice rod assembly (ORA) spider is the same shape as that shown in Figure 3-1a. The MORA is produced from a standard ORA by removing the four Y-shaped arms of the spider and the eight orifice rods attached to these arms. In addition, the four orifice rods on the inner rod circle created by the remaining straight spider arms (on the fuel assembly diagonals in Figure 3-1a) are removed slightly below the spider. A short rod portion remains below the spider arm and the nut above the spider remains. In essence, the MORA is now a spider arrangement with four straight arms and four unmodified orifice rods at the outermost location on these arms. The nuts at the inner location on the straight arms are retained because they act as locating fixtures for the retainer as described on Page 3-2 of BAW-1496. The weight of the MORA is approximately eight pounds after modification as compared to fifteen pounds prior to modification.

The minimum holddown criteria for retainer use is that the margin to component lift must be greater than thirty pounds with the retainer in use. Analyses performed by B&W (taking into account the hydraulic forces acting on the MORA, the MORA weight, and the retainer holddown force) show that the net holddown on an MORA with a retainer installed is approximately thirty-five pounds in the Davis-Besse 1 reactor. Therefore, this design criteria is met.

June 7, 1978

The fuel assembly growth criteria stated on Page B-2 of BAW-1496 is based on a fuel assembly design burnup used as a basis for the retainer design. Since the maximum burnup seen in one cycle of operation will be less than the burnup used as a design basis, the fuel assembly growth criteria is met. It should be noted that the retainer will be used for only one cycle of operation.

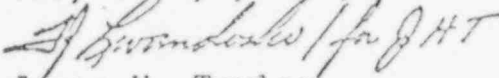
It is postulated that a retainer failure could cause release of a retainer and, possibly, an MORA into the reactor vessel. The neutronic and thermal-hydraulic consequences of this event are insignificant. Although interference with control rod motion is very unlikely, this concern has also been considered. Analyses of stuck-out control rod transients for B&W 177-FA plants have shown that these plants can be safely shut down in this event. Therefore, should interference with control rod motion occur, the plant could still be safely shut down.

The major concern associated with retainer failure is plant damage and potential outages for repair. This damage would be prevented by the Loose Parts Monitoring System (LPMS) which is provided on all B&W operating plants. The LPMS has the capability to detect a failed retainer in either the reactor vessel or steam generator. The importance of LPMS indications has been emphasized to plant operating staffs to preclude possible equipment damage in the unlikely event of retainer failure.

Even though the retainer is designed for only one cycle of operation, B&W will recommend to utilities using the retainer that surveillance inspections be made following retainer use to provide additional confirmation of acceptable operation. The results of these discussions will be provided to the NRC and definite plans will be provided as they are formulated.

We hope that this adequately answers the questions raised in the discussion today. Should any further information be required, please contact Mr. W. R. Gray (Ext. 2553) of my staff.

Very truly yours,


James H. Taylor
Manager, Licensing

JHT:dsf

Mr. Steven A. Varga

Page 3

June 7, 1978

cc: R. B. Borsum (B&W)
 L. B. Engle (NRC)
 H. Silver (NRC)
 M. Tokar (NRC)
 L. E. Roe (Toledo Edison)
 R. W. Heward (General Public Utilities)

bcc: J. S. Tulenko
 J. C. Deddens
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 G. O. Geissler
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 R. Berchin
 L. R. Pletke
 E. G. Ward
 W. R. Gibson
 R. E. Kosiba
 J. P. Jones
 G. M. Olds
 J. T. Janis

June 1978

JUSTIFICATION FOR REMOVAL OF
ORIFICE ROD ASSEMBLIES IN
THREE MILE ISLAND UNIT 2, CYCLE 1

Babcock & Wilcox

7904200142 ₂₉₀

June 1978

JUSTIFICATION FOR REMOVAL OF
ORIFICE ROD ASSEMBLIES IN
THREE MILE ISLAND UNIT 2, CYCLE 1

BABCOCK & WILCOX
Power Generation Group
Nuclear Power Generation Division
P. O. Box 1260
Lynchburg, Virginia 24505

Babcock & Wilcox

1. INTRODUCTION

This report provides justification for continued operation of the first cycle of Three Mile Island Unit 2 (TMI-2) at the rated core power of 2772 MWt following the removal of orifice rod assemblies (ORAs) from the core. The ORAs are used to limit bypass flow through fuel assemblies with empty guide tubes. A system flow of 102% of design flow has been used in these analyses which offsets the increased core bypass flow due to removal of ORAs.

An evaluation of thermal-hydraulic performance has been made based on the increase in system flow and removal of ORAs and has been compared to the analyses presented in the TMI-2 FSAR¹ and Fuel Densification Report.² This evaluation shows that the effects of the removal of forty ORAs and the increase in reactor coolant flow rate provide improved safety margins relative to those reported in the TMI-2 FSAR¹ and Fuel Densification Report.²

The use of retainers³ to provide positive holddown of burnable poison rod assemblies (BPRAs) in the remainder of cycle 1 has also been considered.

2. THERMAL-HYDRAULIC DESIGN

The thermal-hydraulic design evaluation supporting continued cycle 1 operation used the methods and models described in reference 2 with the following exceptions:

1. An increase in core bypass flow due to ORA removal.
2. An increase in system flow.
3. The inclusion of retainers to provide positive holddown of BPRAs.

During the initial portion of cycle 1 operation, fuel assemblies which did not contain control rods, BPRAs, or neutron sources had ORAs installed in the guide tubes to minimize core bypass flow. The maximum core bypass flow, with ORAs installed in forty fuel assembly locations, was 6.04% of system flow. Thirty-eight ORAs will be removed for the remainder of cycle 1. Two fuel assemblies will contain primary neutron sources and modified ORAs. The thermal-hydraulic analysis assumed a total of forty vacant fuel assemblies and resulted in a maximum core bypass flow of 7.6%.

As previously noted, a system flow of 102% of design flow was used in the analysis (see Table 2-1) which offsets the affect of the increased bypass flow. This system flow rate is conservatively based on a predicted four-pump flow rate of 105% of design flow as verified during startup testing.

Retainers will be installed on all fuel assemblies containing BPRAs and primary neutron sources with modified ORAs. This retainer design is described in reference 3. The additional form loss due to retainer installation has been included in the calculation of core flow distribution. The limiting fuel assembly does not contain a BPRA during cycle 1 operation.

Maximum design conditions and significant parameters are shown in Table 2-1 for cycle 1 operation with and without the ORAs.

The potential affect of fuel rod bow on DNBR was considered by incorporating suitable margins into DNB limited core safety limits and RPS setpoints (pressure temperature limit and flux/flow setpoint). The maximum rod bow penalty was calculated from the equation:

Table 2-1. Thermal-Hydraulic Design Conditions

	<u>TMI-2 FSAR</u>	<u>Densif'n Report</u>	<u>Revised Cycle 1</u>
Design power level, MWt	2772	2772	2772
System pressure, psia	2200	2200	2200
RC flow, gpm	369,600	369,600	377,000
Vessel inlet coolant temperature, 100% power, F	557	557	557.2
Reference design radial-local power peaking factor	1.783	1.783	1.783
Reference design axial flux shape	1.5 cos	1.5 cos	1.5 cos
Hot channel factors			
Enthalpy rise	1.011	1.011	1.011
Heat flux	1.014	1.014	1.014
Flow area	0.98	0.98	0.98
Active fuel length, in.	144.0	141.7	141.7
Average heat flux, 100% power, Btu/h-ft ²	185,000 ^(a)	188,000 ^(b)	188,000 ^(b)
CHF correlation	W-3	BAW-2	BAW-2
Minimum DNBR, 112% power	1.39	1.62	1.65

(a) Based on the active fuel length and cold fuel pin diameter.

(b) Based on the densified active fuel length and hot fuel pin diameter.

3. TRANSIENT ANALYSIS

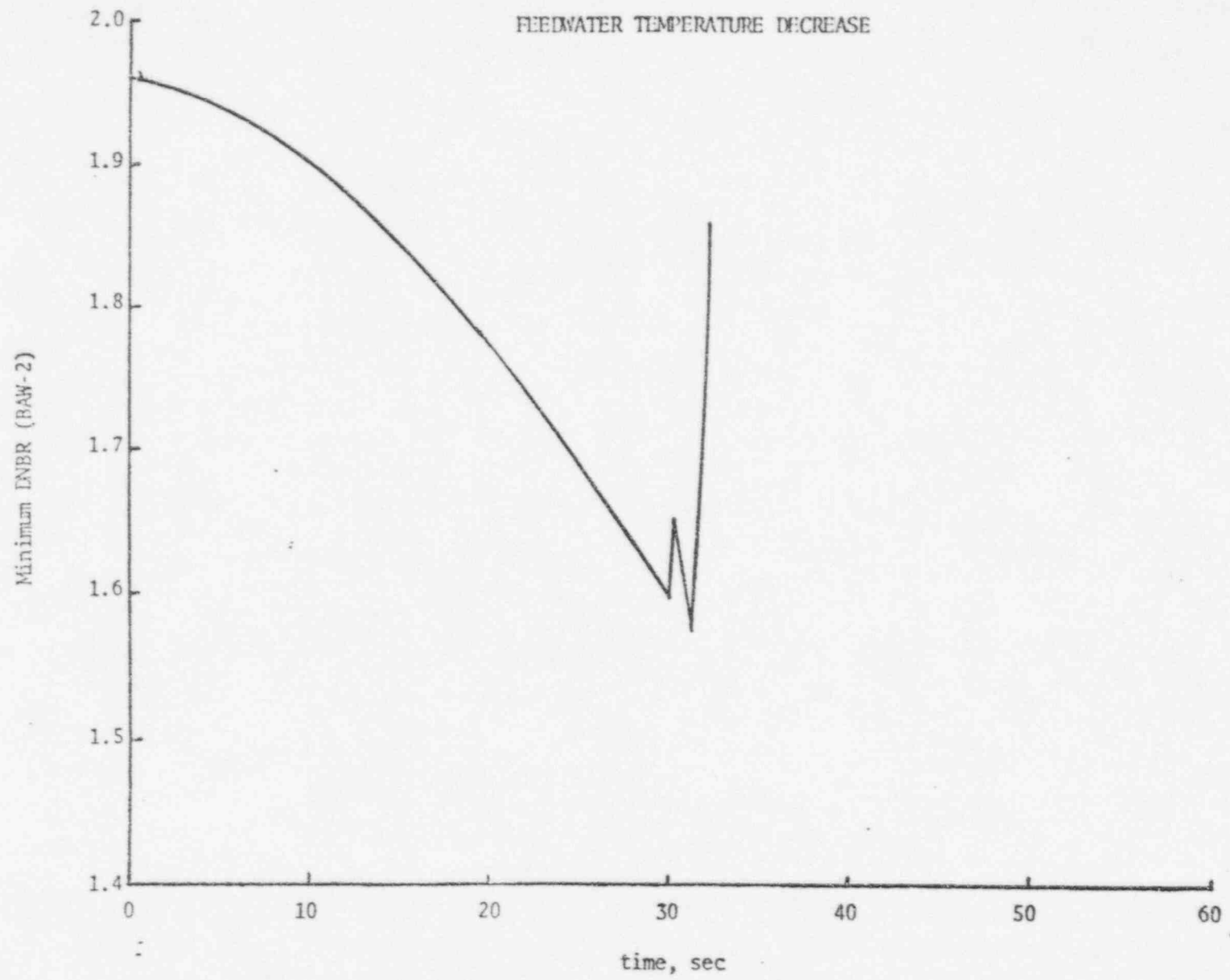
The DNBR related transients presented in reference 2 have been reviewed for applicability to operation with the ORAs removed. The four pump coastdown is the loss-of-coolant-flow (LOCF) transient analyzed in the Densification Report. The minimum DNBR during this transient was 1.65 (BAW-2). The initial conditions for these transients are at 102% power. Re-analysis at 102% power with ORAs removed shows an increase of 1% in the initial DNBR. The higher initial minimum DNBR makes the results of the transients analyzed for the Densification Report applicable and conservative for the revised cycle 1.

All loss-of-coolant flow transients, with the exception of the loss of one pump from four pump operation, will result in a reactor trip initiated by the pump monitors. The most limiting LOCF transient for which the pump monitors provide DNBR protection is the four pump coastdown which has been shown to be acceptable.

The one pump coastdown from four pump operation is the most limiting flow transient by virtue of its use in determining the flux/flow trip setpoint. The flux/flow trip is based on preventing the minimum DNBR from going below the design value plus the rod bow penalty. Therefore, a one pump coastdown with the resulting flux/flow reactor trip will result in the most limiting DNBR during normal operation.

The TMI-2 FSAR¹ has been reviewed for the most limiting DNBR transients of moderate frequency since the one pump coastdown does not appear directly as an accident. The most limiting FSAR transient is the excessive heat removal accident (feedwater temperature decrease). This transient has been re-analyzed for revised cycle 1 operation with the same input as used in the FSAR. The results of the re-analysis are shown on Figure 3-1. The minimum DNBR is 1.58 (BAW-2) versus a 1.43 (W-3) reported in the FSAR.

Figure 3-1. Feedwater Temperature Decrease



4. CORE LOADING PLAN

Figure 4-1 shows the revised core loading plan for the remainder of cycle 1. All fuel assemblies are remaining in their original core locations, i.e., no fuel shuffle will take place. The changes occurring are:

1. Retainers will be installed on all BPRAs.
2. Thirty-eight ORAs will be removed.
3. Two ORAs will be modified and installed in the primary neutron source locations (B-12 and P-4).

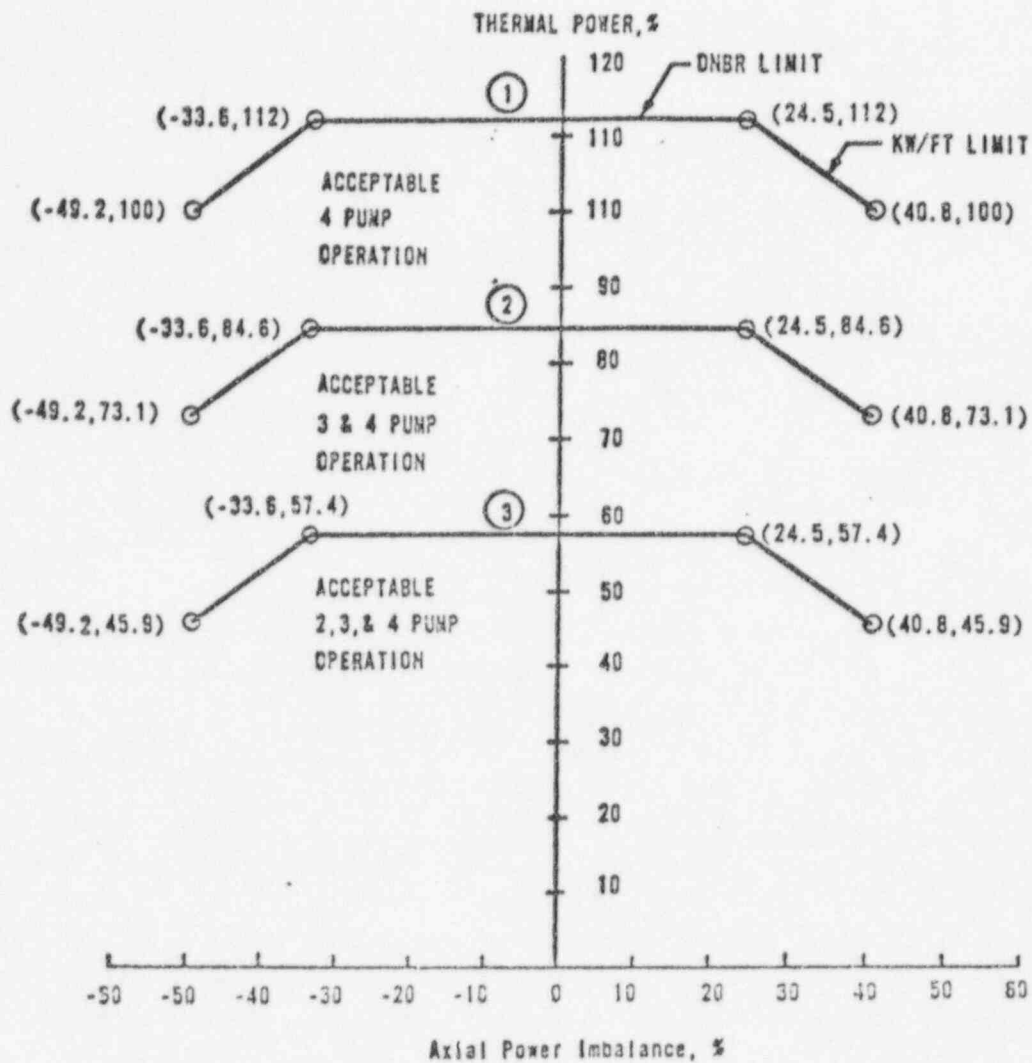
5. PROPOSED MODIFICATIONS TO TECHNICAL SPECIFICATIONS

The Technical Specifications have been revised for the remainder of cycle 1 operation. Changes were the result of the following:

1. The pressure-temperature limits have been revised to incorporate the affects of ORA removal, retainer installation, and rod bow penalty.
2. System flow of 102% of design flow was used.
3. The low pressure setpoint has been raised to account for the LOCA small break analysis (backup function only).
4. Instrument drift numbers have been included for calibration drift in accordance with item 2.C.(3)f. of the operating license.

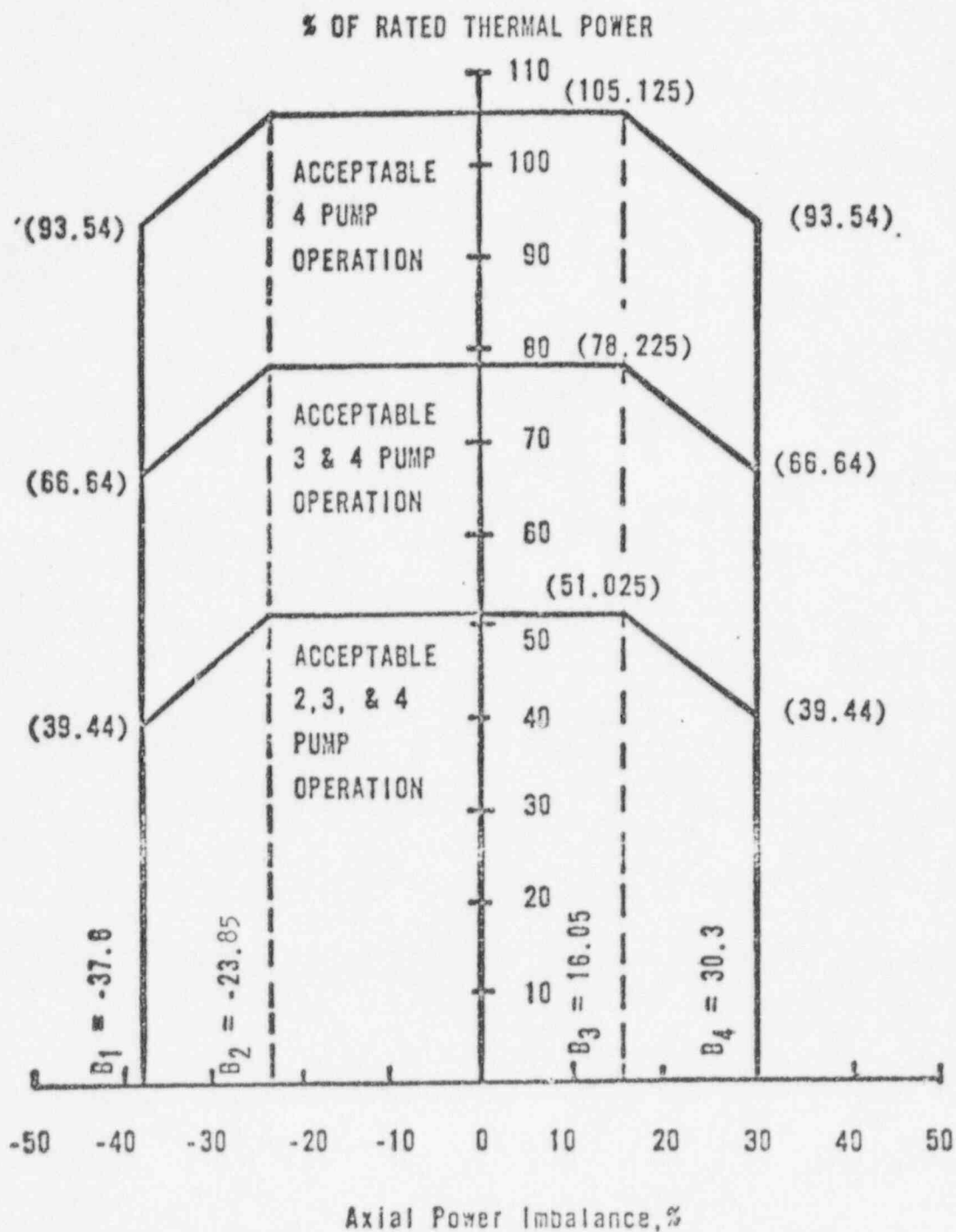
Figures 2.1-1, 2.1-2, 2.2-1, 2.2-2, and 2.1 (Tech Spec numbering) illustrate the revisions to previous Technical Specification limits.

Figure 2.1-2. Reactor Core Safety Limits



CURVE	REACTOR COOLANT FLOW (GPM)
1	377,000
2	280,400
3	182,800

Figure 2.2-2. Allowable Value for Nuclear Overpower Based on
RCS Flow and Axial Power Imbalance



REFERENCES

- ¹ Three Mile Island Nuclear Station, Unit 2 -- Final Safety Analysis Report, Docket No. 50-320.
- ² Three Mile Island, Unit 2 Fuel Densification Report, BAW-1455, Babcock & Wilcox, Lynchburg, Virginia, July 1977.
- ³ BPRA Retainer Design Report, BAW-1496, Babcock & Wilcox, Lynchburg, Virginia, May, 1978.
- ⁴ NUREG-0432, Three Mile Island Nuclear Station Unit 2 Technical Specification, Appendix A to License No. DPR-73, February 8, 1978.



METROPOLITAN EDISON COMPANY

POST OFFICE BOX 542 READING, PENNSYLVANIA 19603

TELEPHONE 215 - 929-3601

June 30, 1978
GOL 1138

Director of Nuclear Reactor Regulation
Attn: S. A. Varga
Light Water Reactors Branch No. 4
U.S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Sir:

Three Mile Island Nuclear Station Unit 2 (TMI-2)
Operating License No. DPR-73
Docket No. 50-320
Steam Generator Questionnaire

Attached for your information and use is a completed copy of the Steam Generator Operating History Questionnaire which was enclosed with your letter dated April 21, 1978. This questionnaire has been answered with respect to the TMI-2 (B&W) Once Through Steam Generators.

Sincerely,

J. G. Herbein
Vice President-Generation

JGH:JRS:cjg

Attachment: Enclosure 1; Steam Generator Operating History Questionnaire

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E015
5.11 11

ENCLOSURE 1
STEAM GENERATOR OPERATING
HISTORY QUESTIONNAIRE

NOTE: All percentages should be reported to four significant figures.

I. BASIC PLANT INFORMATION

Plant: Three Mile Island - Unit 2
Startup Date: July 1978 (Hot Functional Testing)
Utility: Metropolitan Edison Co.
Plant Location: Middletown, PA
Thermal Power Level: 2772 Mw
Nuclear Steam Supply System (NSSS) Supplier: B&W
Number of Loops: 2
Steam Generator Supplier, Model No. and Type: B&W OTSG
Number of Tubes Per Generator: 15,531
Tube Size and Material: 0.625" OD, 0.034" Wall, 56' 2 3/8" Lgth, Inconel

II. STEAM GENERATOR OPERATING CONDITIONS

Normal Operation

Temperature: Primary - 608°F Inlet
FDW - 570°F
STM - 570°F
Flow Rate: Primary - 68.94×10^6 #/hr
STM - 6.12×10^6 #/hr Allowable Leakage Rate: 1 GPM Total
Primary Pressure: 2155 Psig
Secondary Pressure: 925 Psig

Accidents

Design Base LOCA Max. Delta-P: 925 Psig
Main Steam Line Break (MSLB) Max. Delta-P: 2200 Psig

III. STEAM GENERATOR SUPPORT PLATE INFORMATION

Material: Carbon Steel
Design Type: Breeched Opening
Design Code: SA-212-B
Dimensions: 118 3/8" Dia.
Flow Rate: 5.3×10^5 LB/hr.
Tube Hole Dimensions: ≈ 0.320 in. min. radius tube
Tube Hole Dimensions: ≈ 0.320 in. min. radius tube

IV. STEAM GENERATOR BLOWDOWN INFORMATION

Frequency of Blowdown: Continuous @ <15%FP; 0 @ >15% FP

Normal Blowdown Rate: 5 GPM

Blowdown Rate w/Condenser Leakage: N/A

Chemical Analysis Results

Results	Parameter Control Limits
Cation Cond - 1 umho	< 10 umho
Na - 0.05 ppm	< 1 ppm
CL - 0.05 ppm	< 1 ppm

V. WATER CHEMISTRY INFORMATION

Secondary Water

Type of Treatment and Effective Full Power (EFP) Months of Operation:
Hydrazine/Ammonia (AUT) 0 EFP

Typical Chemistry?

pH = 8.0 - 9.2 Na < 0.01 ppm
Cation Cond. = 0.3 umho 0.2 - 30-50 PPS

Feedwater

Impurity Limits: Fe < 100 ppb Pb = 0 ppb
O₂ < 7 ppb Hydrazine = > 0.1 ppm
Total Ca < 20 ppb Cation Cond. < 0.5 umho/cm
pH = 8.0 - 9.3

Condenser Cooling Water

Typical Chemistry or Impurity Limits: No specific limits

Mineralizers - Type: None

Cooling Tower (open cycle, closed cycle or none): Closed Cycle

VI. TURBINE STOP VALVE TESTING (applicable to Babcock & Wilcox (B&W) S.G. only)

Frequency of Testing

Actual: Not yet performed

Manufacturer Recommendation: Weekly

Power Level At Which Testing Is Conducted

Actual: Not yet performed

Manufacturer Recommendation: 0 to 22% or 80 to 100%

Testing Procedures (Stroke length, stroke rate, etc.)

Actual: Full stroke, approx. 13 sec. full cycle

Manufacturer Recommendation: full stroke, approx. 13 sec. full cycle

VII. STEAM GENERATOR TUBE DEGRADATION HISTORY (See attached sheet, Page 10)

(The following is to be repeated for each scheduled ISI)

Inservice Inspection (ISI) Date:

Number of EFP Days of Operation Since Last Inspection: NA

(The following is to be repeated for each steam generator)

Steam Generator Number:

Percentage of Tubes Inspected At This ISI:

Percentage of Tubes Inspected At This ISI That Had Been Inspected At
The Previous Scheduled ISI: N/A

Percentage of Tubes Plugged Prior to This ISI:

Percentage of Tubes Plugged At This ISI:

Percentage of Tubes Plugged That Did Not Exceed Degradation Limits:

Percentage of Tubes Plugged As A Result of Exceedance of Degradation
Limits:

Sludge Layer Material Chemical Analysis Results: N/A

Sludge Lancing (date): N/A

Ave. Height of Sludge Before Lancing: N/A

Ave. Height of Sludge After Lancing: N/A

Replacement, Retubing or Other Remedial Action Considered: (Briefly
Specify Details) None

Support Plate Hourglassing: None

Support Plate Islanding: None

Tube Metalurgical Exam Results:

Fretting or Vibration in U-Bend Area (not applicable to B&W S.G.) AS OF (4)

Percentage of Tubes Plugged	Other Preventive Measures

Wastage/Cavitation Erosion AS OF (4)

Hot Leg: (Repeat this information for the cold leg on Combustion Engineering (C.E.) and Westinghouse (W) S.G.)

Area of Tube Bundle (1)	a	b	c	d	e
% of Tubes Affected by Wastage/Cavitation Erosion					
% of Tubes Plugged Due to Exceedance of Allowable Limit (2)					
% of Tubes Plugged That Did not Exceed Degradation Limit					
Location Above Tube Sheet (3)					
Max. Wastage/Cavitation Erosion Rate for Any Single Tube (Tube Circum. Ave) (Mills/Month)					
Max. Wastage/Cavitation Erosion in Any Single Unplugged Tube (Tube Circum. Ave) (Mills)					

Cracking AS OF (4)

Caustic Stress Corrosion Induced in C.E. and W S.G.

Flow Induced Vibration Caused in B&W S.G.

Cracking (Con't)

Hot Leg: (Repeat this information for the cold leg on C.E. and W S.G.)

Area of Tube Bundle (1)	a	b	c	d	e
% of Tubes Affected By Cracking					
% of Tubes Plugged Due to Cracking					
% of Tubes Plugged That Did Not Exceed Degradation Limit					
Location Above (3) Tube Sheet					
Rate of Leakage From Leaking Cracks (gpm)					

Denting (Not applicable to B&W S.G.) AS OF (4)

Hot Leg: (Repeat this information for the cold leg on C.E. and W S.G.)

Area of Tube Bundle (1)	a	b	c	d	e
% of Tubes Affected by Denting					
% of Tubes Plugged Due to Exceedance of Allowable Limit (2)					
% of Tubes Plugged That Did Not Exceed Degradation Limit					
Rate of Leakage From Leaking Dents (gpm)					
Max. Denting Rate for Any Single Tube (Tube Circum. Ave) (Mills/Month)					
Max. Denting in Any Single Unplugged Tube (Tube Circum. Ave) (Mills)					

1975-1976

TABLE KEY

NOTE: All percentages refer to the percent of the tubes within a given area of the tube bundle.

(1)

Area of the Tube Bundle	No. of Tubes Within the Area
a. Periphery of Bundle (wi/20 rows for B&W; wi/10 rows for C.E. and <u>W</u>)	
b. Patch Plate (wi/4 rows)	
c. Missing Tube Lane (B&W only) (wi/5 rows)	
c. Flow Slot Areas (C.E. and <u>W</u> only) wi/10 rows)	
d. Wedge Regions (C.E. and <u>W</u> only) (wi/8 rows)	
e. Interior of Bundle (remainder of tubes)	

(2)

Allowable Limit for Wastage/Cavitation Erosion:

Allowable Limit For Denting:

(3)

1. Specifies area between the tube sheet and the first support plate
2. Specifies in the following locations: (list the additional locations)

Wastage/Cavitation Erosion:

Cracking:

(4)

Specify the date of the inspection for which results have been tabulated.

VIII. SIGNIFICANT STEAM GENERATOR ABNORMAL OPERATIONAL EVENTS

DATE	SUMMARY
	(Include event description; unscheduled ISI results, if performed; and subsequent remedial actions)
4-23-78	Rapid pressure transient due to improper MS Safety Valve Operation

IX. CONDENSER INFORMATION

Condenser Material (Tubes)	Tube Date	Leakage Rate (gpm)	Detectable Limit	Detection Method
SS-ASTM A249 Type 304		0		Cation Cond. Na+

X. RADIATION EXPOSURE HISTORY WITH RESPECT TO STEAM GENERATORS

Date	Exam Dosage (Man-Rem)	Repair Dosage (Man-Rem)	Comments
None			

XI. DEGRADATION HISTORY FOR EACH TYPE OF DEGRADATION EXPERIENCED FOR TEN REPRESENTATIVE, UNPLUGGED TUBES FOR WHICH THE RESULTS OF TWO OR MORE ISI'S ARE AVAILABLE N/A

If the results for ten tubes are not available, specify this information for all those tubes for which results are available.

(repeat the following information for each tube and degradation type)

Steam Generator No:

Tube Identification:

Type of Degradation: (specify denting, wastage, cavitation erosion, caustic stress corrosion cracking, or flow induced vibration cracking)

(repeat the following information chronologically for each ISI for which results are available)

ISI Date:

Amount of Degradation: (specify amount and units)

EFP Months of Operation Since Last ISI for Which Results are Given:

Item VII. Steam Generator Tube Degradation History: This information documents the result of the preservice examination. An ISI has not yet been conducted.

Preservice Inspection Date: December 1977; EFP Days of Operation is not applicable.

	<u>OTSG A</u>	<u>OTSG B</u>
Percentage of tubes inspected at PSI:	100%	100%
Percentage of tubes plugged prior to this PSI:	unknown	unknown
Percentage of tubes plugged at this PSI:	.084%	.155%
Percentage of tubes plugged that did not exceed degradation limits:	23.07%	12.5%
Percentage of tubes plugged as a result of exceedance of degradation limits:	76.42%	87.5%
Tube Metallurgical Exam Results	*	None

*A tube with an eddy current indication of a 55% O.D. defect was removed. Metallurgical examination revealed a scab or lap presumably from tubing manufacture with a depth of about 50%.



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

JUL 11 1978

MEMORANDUM FOR: ✓ D. B. Vassallo, Assistant Director
for Light Water Reactors, DPM

FROM: H. Silver, Project Manager, Light Water
Reactors Branch No. 4, DPM

THRU: S. A. Varga, Chief, Light Water Reactors
Branch No. 4, DPM

SUBJECT: ITEMS FOR TMI-2 HEARING BOARD

The following items have arisen lately on TMI-2 which may be of interest to the hearing board. (The appeal board is still convened.)

1. Purge Valve Operability

In response to concerns raised by the Containment Systems Branch, the Mechanical Engineering Branch has identified certain requests for additional information regarding operability of the containment purge valves. These requests deal with confirmatory information to more completely document the ability of the containment purge valves to close if they are in use at the time of a LOCA. Present technical specifications restrict the time these valves may be open with the reactor critical to 90 hours per year. Responses to our requests are not expected to raise any issues which represent significant safety problems.

2. Burnable Poison Rod/Orifice Rod Assemblies

At another operating B&W reactor, it was found that two burnable poison rod assemblies (BPRA) had been ejected from the core and pieces of several components had been carried into the steam generator inlet plenums. The reactor was safely shutdown and no damage was done which represented a significant safety issue.

B&W concluded that this problem was due to wear in the BPRA ball-lock coupling caused by hydraulic lifting of the BPRA during operation with all four reactor coolant pumps. B&W proposed installation of a BPRA retainer which would provide positive holddown against

Acc. No. 7905070248 280

C/35 10

JUL 11 1978

all lift forces, and Met Ed has stated their intention to install this device on all BPRA's. B&W has submitted B&W-1496, BPRA Retainer Design Report, for our approval, but our review is not yet complete.

The same ball-lock device is also employed on orifice rod assemblies (ORA) in B&W reactors. During the inspection of these devices at another B&W reactor, wear similar to that on the BPRA's was observed. B&W has concluded that for some plants, including TMI-2, the ORA's should be removed. This will require revised thermal-hydraulic analyses for the core, but based on such analysis already completed for other reactors, these are expected to be acceptable. These analyses for TMI-2 have recently been submitted and will be reviewed and approved prior to plant startup.

TMI-2 has been shut down for several weeks for correction of operating problems and is not scheduled to start up prior to early August 1978. Met Ed at its own risk has already completed the installation of the BPRA retainers and removal of the ORA's. As noted above, startup will not be permitted prior to approval of all supporting documentation.

3. Auxiliary Transformer

The licensee has informed us that recent studies have shown that for the normal operating range of the grid, operation with a single auxiliary transformer will not provide adequate voltage levels to support operation of balance-of-plant auxiliaries and engineered safety features. Met Ed proposed both short term and long term corrective action which they believe to be in accordance with General Design Criterion 17 and the TMI-2 FSAR. See Met Ed letter of May 30, 1978, and LER 78-35/IT attached for additional information. We have not yet completed our review of this information. As noted above, TMI-2 is expected to be shut down until August, 1978, by which time our review should be complete.

Harley Silver
Harley Silver, Project Manager
Light Water Reactors Branch No. 4
Division of Project Management

cc: See next page



METROPOLITAN EDISON COMPANY

POST OFFICE BOX 542 READING, PENNSYLVANIA 19603

TELEPHONE 215 - 319 3601

May 30, 1978

GGL 0961

Director, Nuclear Reactor Regulation
Attn: Mr. S. A. Varga, Chief
Light Water Reactors Branch No. 4
U.S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Sir:

Three Mile Island Nuclear Station, Unit 2 (TMI-2)
Operating License No. DPR-73
Docket No. 50-320

In response to questions raised by Mr. Harley Silver of your staff,
enclosed please find information concerning the potential problem as-
sociated with the loss of an auxiliary transformer at TMI-2.

Sincerely,

C. G. Harbein
C. G. Harbein
Vice President-General

JGH:RAL:cjs

cc: Director of Nuclear Reactor Regulation
Attn: Harley Silver
Light Water Reactors Branch No. 4
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Attachment

7904270560 *sep*

AUXILIARY TRANSFORMER CONDITIONS (TMI-2)

On May 3, 1978, Metropolitan Edison Company was notified by the TMI-2 Architect Engineer (Burns & Roe) that a potential problem existed with the TMI-2 Auxiliary Transformers.

The results of a Burns and Roe voltage study indicated that with only one auxiliary transformer in operation and with the plant at full load, the bus voltage would be reduced to the extent that, in the event of a LOCA, some safety loads would not be picked up. This could result in the blowing of control fuses on the safety-related components.

Met-Ed found this situation to be reportable in accordance with Section 6.9.1.3.h of the TMI-2 Technical Specifications. Therefore, on May 9, 1978, Met-Ed submitted Licensee Event Report (LER) 78-35/17 to the Commission. This LER identified the potential problem and offered several possible corrective actions which might be taken, these included:

- a) The unit will not be operated above a power level compatible with safe single transformer operation
- b) selective balance of plant load shedding will be installed
- c) or the automatic bus transfers to the other auxiliary transformer for designated buses will be disabled.

Since May 9, 1978 when these potential solutions were submitted to the NRC, Met-Ed and Burns and Roe have been working to determine which solution best meets both the safety requirements and yet allows TMI-2 to operate most satisfactorily. The solution reached is as follows:

I. Short Term Correction Action:

The Unit Auxiliary load will be maintained less than or equal to 43 MW whenever 4 RC pumps are in operation. When only 3 RC pumps are in operation, the load on the 4160 V buses will be limited to 40 MW. These loading values (43 MW and 40 MW) have been analyzed (for single auxiliary transformer operation) by Burns and Roe and found to be acceptable for maintaining voltage levels sufficient to pick up safety-related components in the event of a LOCA.

Maintaining unit loadings at or below the levels indicated above has been administratively accomplished through procedural changes to the TMI-2 Unit Startup and Power Operation procedures. Essentially, these procedural changes allow TMI-2 to startup and escalate power to the point at which the above-mentioned loadings are established. Loadings on the Auxiliary Transformers and on the 4160 V buses are monitored in the TMI-2 Control Room. Operation of additional equipment and the further escalation of power level are then prohibited.

The Burns and Roe Voltage Program demonstrates that with unit loadings

limited to the values mentioned above, the loss of an auxiliary transformer, and subsequent transfer of load to the remaining transformer would result in voltage levels sufficient to pick up all safety-related components necessary to mitigate the consequences of a LWA, and comply with General Design Criteria 17 of 10 CFR 50 Appendix A.

The Burns and Roe Voltage Program used in making these determinations is the same program which was used for the TMI-2 Voltage Optimization Studies. The accuracy of this program was verified through field measurements at that time.

II. Long Term Corrective Action

In order to operate safely throughout the normal grid range (232-242KV) a longterm correction action of selectively tripping plant loads upon the loss of any Auxiliary Transformer has been developed. A system of relays will be installed which will ensure that whenever an Auxiliary Transformer becomes de-energized, the following plant loads will be tripped:

- A) 2 - Circulating Water Pumps
- B) 1 - Condensate Booster Pump
- C) 1 - Heater Drain Pump

Burns and Roe has performed an analysis (using the above-mentioned voltage program) to show that tripping the above-mentioned loads will provide the following 480 USS bus voltages:

480 V USS* Voltage (1 Auxiliary Transformer Operation)

<u>Grid Voltage</u>	<u>Normal</u>	<u>LOCA (Prior to Last EG Components Starting)</u>	<u>Post LWA</u>
232 KV	426V	411V	401 V**

** This is the voltage level after all EG components have started. 407V is needed for starting components, however, components will safely operate at a much lower voltage (368 volts).

As can be seen from this chart, the voltage available for starting the last safety-related components (411 V) exceeds the voltage required for starting those components (407 V). Also, the voltage available after all safety-related components are started (401 V) is 12% in excess of the voltage needed to keep those components operating (368 V).

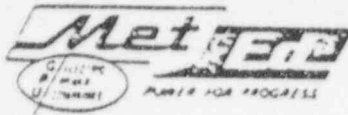
It is hoped that these long term corrective actions can be implemented within the next six weeks.

The results of tripping the above mentioned loads upon the de-energization of an Auxiliary Transformer will be an automatic reduction of plant output to approximately 80%. (This will be accomplished automatically by the RGS system due to the trip of the Condensate Booster Pump.

*Unit Substation

It should be noted that the short term and long term corrective actions which are being adopted, were presented as corrective actions A and B in LER 78-35/1T.

It is our belief that through our implementation of the above-mentioned short term and long term corrective action, TMI-2 complies with 10 CFR 50 Appendix A, General Design Criterion 17, and with the TMI-2 FSAR.



METROPOLITAN EDISON COMPANY

POST OFFICE BOX 542 READING, PENNSYLVANIA 19603

TELEPHONE 215 - 929-0601

May 9, 1978
GGL 0690

Mr. B. H. Grier, Director
Office of Inspection and Enforcement
Region I
U. S. Nuclear Regulatory Commission
631 Park Avenue
King of Prussia, Pennsylvania 19406

Dear Sir:

Three Mile Island Nuclear Station Unit 2 (TMI-2)
Operating License No. DPR-73

Enclosed please find Licensee Event Report 78-35/17 which is submitted
in accordance with Section 6.9.1.8.h of our Technical Specifications.

Sincerely,

Signed J. G. Harbein

J. G. Harbein
Vice President-Generation

JGH:RAL:ccjg

Enclosure: LER 78-35/17

cc: Harley Silver (NRC)

78-35/17

7904200050

LICENSEE EVENT REPORT

CONTROL BLOCK: 

(PLEASE PRINT OR TYPE ALL REQUIRED INFORMATION)

0	1	P	A	T	M	I	2	2	0	0	-	0	0	0	0	0	-	0	0	3	1	2	2	2	2	1		
7	8	LICENSEE CODE						14	LICENSE NUMBER										25	LICENSE TYPE					30	37	44	50

CON'T

0 1 8
REPORT SOURCE 50 61 0 5 0 0 0 7 2 0 58 69 0 5 0 3 1 3 5 75 0 5 0 0 7 3 30
DOCKET NUMBER EVENT DATE REPORT DATE

EVENT DESCRIPTION AND PROBABLE CONSEQUENCES (10)

02 While in Mode 5 the TMI-2 architect engineer (Burns & Roe) notified the licensee.

03 single auxiliary transformer operation within the normal operating range of the system.

7 4 will not provide sufficient voltage levels for operation of the 100 V motor control

05 | during periods of peak unit auxiliary demand. Because the unit has not been opera:

75 | at a power level requiring maximum unit auxiliary, there are no significant differences in

07 | adverse effect on the health and safety of the public.

38

3 9
 8

SYSTEM CODE
 2 2 (11)

CAUSE CODE
 X (12)

CAUSE SUBCODE
 2 (13)

COMPONENT CODE
 2 2 2 2 2 2 (14)

COMP SUBCODE
 2 (15)

VALVE SUBCODE
 2 (16)

(17) LSR 90
 REPORT
 NUMBER

EVENT YEAR		SEQUENTIAL REPORT NO		OCCURRENCE CODE		REPORT TYPE		REVISION NO.	
7	8	0	3	5	0	1	T	—	0
21	22	23	24	25	26	27	28	29	30

ACTION TAKEN		FUTURE ACTION		EFFECT ON PLANT		SHUTDOWN METHOD		HOURS				ATTACHMENT SUBMITTED		APPROX FORM SUB		PRIME SUPP		COMPONE MANUFACT	
X	18	X	19	Z	20	Z	21	0	0	0	0	X	22	N	23	Z	24	Z	25

CAUSE DESCRIPTION AND CORRECTIVE ACTIONS (27)

1	3	Single transformer operation voltage studies conducted by the applicant engineer
---	---	--

[] [completing the voltage optimization studies, showed that within the normal operating

range of the grid (232 to 238KV) a single auxiliary transformer can't provide adequate

13 | voltage levels to support operation of the Unit Engineering Safety Association and its

of plant auxiliaries. (Continued)

8 9 FACILITY STATUS
1 3 3 30

10 POWER OTHER STATUS 30
10 0 0 12 29 NA 13 44

METHOD OF DISCOVERY DISCOVERY DESCRIPTION 31
C 31 Not identified by AE 36

ACTIVITY CONTENT
RELEASED OR RELEASE AMOUNT OF ACTIVITY (35) LOCATION OF RELEASE (36)

PERSONNEL EXPOSURES										
NUMBER		TYPE		DESCRIPTION						
1	7	0	0	0	17	2	28	NA		

PERSONNEL INJURIES										
NUMBER				DESCRIPTION						
1	2	3	4	5	6	7	8	9	10	
				40						41

LOSS OF OR DAMAGE TO FACILITY		(40)
TYPE	DESCRIPTION	
1	(41)	

~~7904200064~~ 3rd

Cause Description and Corrective Actions

In order to assure adequate voltage level, one of following corrective actions will be taken: A) the unit will not be operated above a power level compatible to safe single transformer operation; B) selective balance of plant load shedding will be installed; C) or the automatic bus transfers to the other auxiliary transformer for designated bus will be disabled.

NARRATIVE TO ACCOMPANY LER 78-35/17

On May 3, 1978, the results of the single auxiliary transformer voltage study were received from the Architect Engineer (Burns & Roe). The voltage values calculated for the 480 V Motor Control Centers, for a normal voltage of the 230 KV grid were below the required 407 V AC necessary to assure safe operation of the magnetic controllers and prevent control power fuse blowing. These voltage values are based on having the maximum unit auxiliaries in service during the summer months, with all circulating water pumps in service.

This item was determined to be a violation of Technical Specification 6.9.1.8.h, in that the Safety Evaluation Report states that each unit auxiliary transformer is sized to carry the unit full load auxiliaries and the energized safety features auxiliaries. Since the ESF bus powered from the inoperable transformer is designed to fast transfer to the remaining transformer, the potential to disable both ESF trains due to control power fuse blowing exists.

Follow up studies have verified that by automatically shedding selected Balance of Plant loads upon auxiliary transformer failure, adequate voltage levels are available at the 480 V Motor Control Centers throughout the normal operating range of the 230 KV grid.



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

July 14, 1978

Docket No.: 50-320

Metropolitan Edison Company
ATTN: Mr. J. G. Herbein
Vice President
P. O. Box 542
Reading, Pennsylvania 19603

Gentlemen:


RE: THREE MILE ISLAND UNIT NO. 2

We have recently sent the enclosed letter to Babcock & Wilcox Company regarding the potential for excessive control rod guide tube wear at facilities using the B&W design. This information is required to assess the significance of control rod guide tube wear at your facility.

We requested the required information from the vendor, in order to provide us with an overall assessment of this problem and to minimize the amount of utility, vendor and NRC staff work required. However, should this approach to obtain the necessary information not be successful, a direct response to the enclosed questions, from each licensee utilizing the B&W design, will be required.

We request your cooperation with B&W in generating and analyzing the control rod guide tube wear data necessary to address this concern.

Sincerely,


Domenic B. Vassallo, Assistant Director
for Light Water Reactors
Division of Project Management

Enclosure:
Letter to B&W dated
June 13, 1978

Acc. No. ~~8002030073~~ 200

C/367

Metropolitan Edison Company

-2-

ccs:

George F. Trowbridge, Esq.
Shaw, Pittman, Potts & Trowbridge
1800 M Street, N. W.
Washington, D. C. 20036

Mr. I. R. Finfrock
Jersey Central Power and Light Company
Madison Avenue at Punch Bowl Road
Morristown, New Jersey 07960

Mr. R. Conrad
Pennsylvania Electric Company
1007 Broad Street
Johnstown, Pennsylvania 15907

Chauncey R. Kepford, Esq.
Chairman
York Committee for a
Safe Environment
433 Orlando Drive
State College, Pennsylvania 16801

Mr. Richard W. Heward
Project Manager
GPU Service Corporation
260 Cherry Hill Road
Parsippany, New Jersey 07054

Mr. T. Gary Broughton
Safety and Licensing Manager
GPU Service Corporation
260 Cherry Hill Road
Parsippany, New Jersey 07054



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

June 13, 1978

Babcock & Wilcox Company
ATTN: Mr. James H. Taylor
Manager, Licensing
Nuclear Power Generation Division
P. O. Box 1260
Lynchburg, Virginia 24505

Gentlemen:

Significant wear has been found in control rod guide tubes at the Combustion Engineering (CE) NSSS facilities. The guide tube wear has been primarily located at the axial location where the control rod is "parked" in the fully withdrawn position during normal operation. CE postulates that the wear is caused by a flow induced vibration of the Inconel control rod against the softer Zircaloy guide tube. Corrective actions, including increased operability surveillance, step insertion of control rods and extensive sleeving of both new and irradiated guide tubes, have been taken at all affected CE facilities.

We realize that your NSSS design is different from the CE system, however, we believe that a similar wear problem could exist at facilities using your NSSS design. You are requested to provide the enclosed additional information for all B&W facilities with operating licenses within 60 days of the date of this letter.

Sincerely,

Brian K. Grimes, Assistant Director
for Engineering & Projects
Division of Operating Reactors

Enclosure:
Request for Additional
Information

7910240826 SEP

REQUEST FOR ADDITIONAL INFORMATION
INTEGRITY OF CONTROL ROD GUIDE TUBE (CRGT)

BABCOCK & WILCOX FACILITIES

Answers to the following questions should be supported with data and drawings to the extent possible.

1. Describe the details of any routine surveillance of fuel assemblies performed at your facilities using your NSSS design.
2. Have examinations of the fuel assembly guide tubes to detect wear been completed at any facility using your NSSS design? If so, provide the following information:
 - a. The method of examination (i.e. destructive testing, eddy-current testing, periscope, borescope, mechanical gage, TV, etc.)
 - b. The areas of CRGT examined.
 - c. Qualification of the examination procedure.
 - d. The number of CRGT sampled at each facility and the applicable operational parameters including: the core location; EFPH; time in service; related control rod parameters; fluence; etc.
 - e. Results of observations or measurements.
3. Were any CRGT destructively tested (e.g., by mechanical or metallographic means) and what observations or measurements were made?
4. What correlations were suggested between operating parameters and CRGT condition?

5. If specific examinations for CRGT wear have not been completed at any facility, either provide other evidence for the absence of wear or answer the following:
 - a. Are examinations planned? If so, provide details as requested in 2 a-d.
 - b. Have out-of-pile wear tests been completed? If so, provide details including qualification of the test procedure and answers to 2 a-d. Address vibration, fatigue, flow visualization, etc.
6. Document any other observations of wear or degradation found in the examination of your fuel assemblies (i.e., grid wear, post wear, etc.). Provide the results of your assessment of the consequence of these observations. Describe any design changes effected to either mitigate the consequences of this wear or eliminate the wear.
7. If CRGT wear has been found at facilities using your NSSS design:
 - a. What have been the attributive causes?
 - b. Have correlations been made to characterize the phenomena with respect to operating procedures and plant specific core parameters?

- c. Are specific locations within the core or particular CRGT within an assembly more susceptible?
8. If CRGT wear has been observed at any facility using your NSSS design:
- a. Describe your efforts to reassess the mechanical integrity of the core with worn CRGT to demonstrate that coolability and scramability exist for the normal, seismic and anticipated operational occurrence loading conditions. Describe the worst condition analyzed.
 - b. Discuss your structural design bases. Indicate if provisions have been made to accommodate wear in the design. What amount of wear or related degradation would be cause for rejection for reload? Provide the allowable stresses used in the structural analysis. Discuss the effects of temperature strain rate, notch severity, irradiation and hydrogen content on mechanical properties used to establish the allowable stresses.
 - c. Provide the results of your structural analysis summarizing the CRGT loads and the primary and secondary stress intensities for normal, fuel handling, and accident loading conditions.
 - d. Discuss the effects of CRGT wear on the thermal-hydraulic performance of the reactor under normal and accident conditions.

9. Discuss any control rod scram testing that has been completed to demonstrate scramability in worn CRGT. Address the effects of worn CRGT on scramability for the worst expected guide tube geometry. Include the strain-deflection limits for control rod functionability.
10. If examinations for CRGT wear have not been or will not be made at representative facilities using your NSSS design, provide justification for continued operation of these facilities.
11. B&W has redesigned the guide tube lock nuts of later design fuel assemblies by making a change from zircaloy to stainless steel to mitigate the effects of observed wear in the upper region of the guide tube. Indicate which design is employed at each B&W designed facility and indicate any observations that have been made to detect wear in this area and/or verify the adequacy of the redesign.



METROPOLITAN EDISON COMPANY

POST OFFICE BOX 882 PHILADELPHIA, PENNSYLVANIA 19603

TELEPHONE 215 - 929-3601

July 24, 1978
GGL 1260

Director of Nuclear Reactor Regulation
Attn: S. A. Varga, Chief
Light Water Reactors Branch No. 4
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Sir:

Three Mile Island Nuclear Station Unit 2 (TMI-2)
Operating License No. DPR-73
Docket No. 50-320
Small Break LOCA

Enclosed please find the results of Babcock and Wilcox's (B&W) most recent calculations concerning a small break LOCA at the reactor coolant pump discharge piping for the B&W lower loop 177 FA plants dated July 18, 1978. Met-Ed and GPUSC have reviewed the enclosed analysis and concur with B&W's finding that full compliance with 10 CFR 50.46 and Appendix K to 10 CFR 50 is clearly demonstrated for operation at power levels of 2772 Mw(t).

This enclosure and the appropriate TMI-2 procedures (Emergency Procedure 2202-13 Loss of Reactor Coolant/Reactor Coolant Pressure and Operating Procedure 2104-1.2 Makeup and Purification Demineralization) described in Met-Ed's letters of May 5, 1978 and May 11, 1978 completely satisfy the conditions of Provision (1) Section IV of the Order of Modification of License dated May 26, 1978. Furthermore, the enclosed B&W analysis provides the necessary justification for operation at a power level of 2772 Mw(t) which has been restricted 2568 Mw(t) by Provision (2) of Section IV.

Therefore, Met-Ed requests that the Order of Modification be amended by deleting Provisions (1) and (2) of Section IV of the Order of Modification of License dated May 26, 1978.

Sincerely,

J. G. Herbein
Vice President-Generation

WHE:cds

Encl.

cc: Pa

Silver (NRC)

Acc. No. 8009040048
~~7904300474~~ 18

C/37
B.01
13

July 18, 1978

Mr. S. A. Varga, Chief
Light Water Reactors Branch #4
Division of Project Management
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555


Dear Mr. Varga:

Attached is additional ECCS small break analyses for B&W's 177 Fuel Assembly Lowered-Loop NSS. These analyses are in accordance with the small break model as approved in BAW-10104A, Rev. 3, "B&W's ECCS Evaluation Model," except for two of the proposed modifications in my letter to you of May 26, 1978. These analyses differ from those in my letter to you of June 19, 1978, in that the proposed Zaloudek Correlation modification was not utilized and two additional breaks were analyzed. These analyses, therefore, are intended to replace those of June 19, 1978.

A power level of 2772 MWt is assumed in these analyses. Credit is assumed for operator action as described in my letter to you of May 1, 1978. Break sizes of .04, .055, .07, .085, .10 and .15 ft² are examined. These attached analyses, along with the break analyses in BAW-10103A, Rev. 3, "ECCS Analysis of B&W's 177-FA Lowered-Loop NSS," constitute a complete spectrum of small break analyses which we believe to be wholly in conformance with 10 CFR 50.46 and 10 CFR 50, Appendix K.

Your expeditious review of this submittal is requested. If you have any questions, please contact me or Henry Bailey (Ext. 2673) of my staff.

Very truly yours,


James H. Taylor
Manager, Licensing

JHT:dsf

Attachment

cc: R. B. Borsum (B&W)

1. Introduction

Analysis of a spectrum of small breaks at the pump discharge has been performed for B&W's 177-FA lowered loop plants. The small break evaluation model described in BAW-10104, Rev 3, "B&W's ECCS Evaluation Model," along with two of the proposed modifications described in the report of May 26, 1978 (J.H. Taylor to S.A. Varga) was utilized for this study. Operator action is used to achieve sufficient and balanced flow through all four high pressure injection (HPI) lines. The operator action is described in detail in the report of May 1, 1978 (J.H. Taylor to R.L. Baer).

The analysis contained herein, coupled with the analyses of BAW-10103A, Rev 3, "ECCS Analysis of B&W's 177-FA Lowered Loop NSS," provide an appropriate spectrum of breaks for the evaluation of a small leak transient. The results of the analyses show that the plants can be operated up to a power level of 2772 MWt within the criteria of 10 CFR 50.46 and Appendix K of 10 CFR 50.

2. Method of Analysis

The analysis method used for this evaluation is that described in Chapter 5 of BAW-10104, Rev 3, "B&W's ECCS Evaluation Model," along with two of the modifications described in the report of May 26, 1978 (J.H. Taylor to S.A. Varga). The two modifications utilized were the two node inner vessel simulation and the phase distributional multipliers for bubble rise in all control volumes within the reactor vessel. The CRAFT2 code is used to develop the history of the reactor coolant system hydrodynamics. The CRAFT model uses 20 nodes to simulate the reactor coolant system, 2 nodes for the secondary system, and one node for the reactor building. A schematic diagram of the model is shown in Figure 1 along with the node descriptions. Control volumes (nodes) in and around the vessel are all connected by a pair of flow paths to permit counter-current flow. The breaks analyzed in this report are assumed to be located at the bottom of the cold leg piping between the reactor coolant pump discharge and the reactor vessel. The Wilson, Grenda, and Patterson average bubble rise model is used for all nodes. Within the reactor vessel, however, multipliers of 2.38 and 2.0 are applied to the calculated bubble rise velocity in the core node and the remaining vessel nodes, respectively. The justification for the use of 2.38 multiplier value in core node is given in Appendix F of BAW-10104. The report of May 26, 1978 (J.H. Taylor to S.A. Varga) justifies the use of a multiplier of 2.0 in the downcomer, lower plenum, and the upper plenum regions.

The following assumptions are made for conditions and system responses during the accident:

- a. The reactor is operating at 102% of the steady-state power level of 2772 MWt.
- b. The leak occurs instantaneously, and a discharge coefficient of 1.0 is used for the entire analysis. Bernoulli's equation was used for the sub-cooled portion of the transient, while Moody's correlation was used in the two-phase portion.
- c. No off-site power is available.
- d. The reactor trips on low pressure at 1900 psia.
- e. The safety rods begin entering the core after a 0.5 second delay from the time the reactor trip signal is reached.
- f. The RC pumps trip and coast down coincident with reactor trip.
- g. One complete train of the emergency safeguards system fails to operate, leaving two CFTs and only one HPI and one LPI system available for pumped injection to mitigate the consequences of a cold leg break.
- h.* The auxiliary feedwater (FW) system is assumed to be available during the transient. Its main function is to remove heat from the upper half of the steam generator during the initial stages of the transient. When the secondary side of the steam generator becomes a source of heat to the primary system, the assumption of auxiliary FW maximizes the energy that must be relieved.
- i. ESFAS signal error band is considered in the analysis to signal the actuation of the HPI system.
- j. The peak linear heat generation rate in the hot pin is the maximum allowed by the technical specifications at the 10.5 ft level.
- k. Operator action is taken to increase the HPI flows to the intact cold legs at 10 minutes following the ECCS initiation signal. This action is explained more fully in the May 1, 1978, report (J.H. Taylor to R.L. Baer)

Since the DRAFT calculations showed partial core uncover for some of the breaks, specifically the 0.055-, 0.07-, and 0.085-ft² breaks, a FOAM analysis was performed to determine the inner vessel mixture height. The FOAM

void fraction in the lower regions of the core and, similarly to the discussion in item b above, will result in a conservative mixture height.

The heat-up calculation was performed using the THETA code in the manner described in section 5 of BAW-10104. The following additional assumptions are utilized in the THETA evaluation:

- a. The power shape of Figure 2 was used with a radial power factor of 1.67. This maximizes steam superheating and sets the peak local power at 10.5 ft at the technical specification LOCA limit.
- b. Coolant flow and mixture level were taken directly from the FOAM calculations. As discussed above, the methods utilized in the FOAM calculations result in conservative values for these parameters.
- c. End of life pin pressures were used to conservatively predict the incidence of fuel pin rupture.

3. Break Spectrum and Results

Topical report BAW-10103A, Rev 3, presents the analysis of a CFT line break, the 0.5 ft² break at the RC pump discharge and the spectrum of breaks at the RC pump suction. As shown in that report, the results of those analyses are wholly in compliance with the criteria of 10 CFR 50.46 and Appendix K of 10 CFR 50. Those analyses are still valid and conservative in light of the impact of the model modifications. The report of May 26, 1978 (J.H. Taylor to S.A. Varga), describes the impact of the modifications.

In the present analysis, breaks of 0.04, 0.055, 0.07, 0.085, 0.10, and 0.15 ft² at the RC pump discharge are evaluated. Figure 3 shows the RC pressure response for each break. As shown, each accident initiates CFT flow within 2200 seconds except the 0.04 ft² break.

Figure 4 shows (CRAFT) mixture height as a function of time for each break of the spectrum. As can be seen from the figure, minor core uncover was calculated for the 0.055-, 0.07-, and 0.085-ft² breaks. For the 0.04-, 0.1-, and 0.15-ft² breaks no core uncover was calculated and, thus, no temperature excursions occur.

The 0.04 ft² break achieves a match up of effective ECCS (the HPI injected into the intact cold legs) with the core decay heat and the RCS metal heat at 3000 seconds. The core has a mixture height of 13.5 feet at this time. After

calculation included all sources of steam production within the vessel, i.e., steam production due to decay heat, flashing, and primary metal heat. To expedite the FOAM analysis, the distribution of the steam sources was chosen to minimize the complexity of the input calculations and, as described in the subsequent paragraphs, results in an underprediction of the swell level. By underestimating the core mixture height, the core steaming rate will also be underestimated; thereby resulting in an overestimation of the steam superheating and the peak cladding temperature.

The axial power shape shown in Figure 2 was used in the FOAM calculation and was implemented with a radial peaking factor of 1.0. Thus, the resultant mixture height is representative of the average channel conditions and is conservative relative to that for the hot channel. To utilize the power shape in FOAM, the shape was divided into 26 axial nodes.

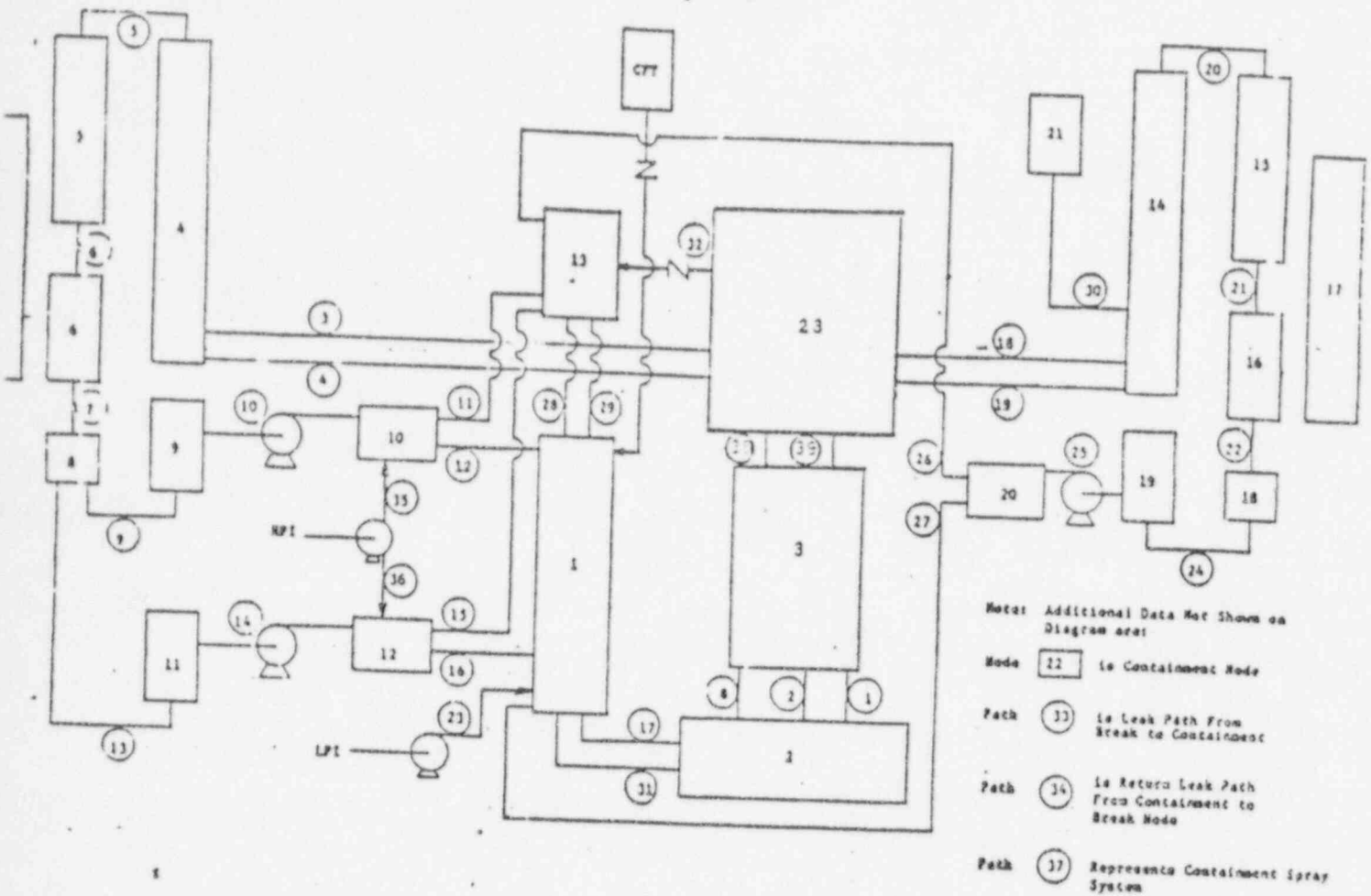
Steam production due to primary metal heating and flashing within the inner vessel was assumed to have a distribution similar to that for decay heat. As such, the complexity in the input generation for FOAM was reduced to finding an "equivalent decay power" which would generate the same amount of steam as that which is produced from all sources. Use of this steam production shape results in conservative core mixture heights for the following reasons:

- a. When the core is uncovered, some of the steam production due to primary metal heating and flashing would not be used in calculating the mixture level. Thus, the mixture height would be underestimated.
- b. By using this shape, the void fraction at the core inlet is zero. In actuality, due to steam production in the lower plenum and the subsequent bubble rise into the core, a void fraction will exist at the core inlet. Furthermore, this initial core void fraction results in additional bubbles rising throughout the core mixture and increases the entire core void fraction. Since the assumed shape underestimates the core void fraction, the mixture height is underestimated.
- c. Since the axial power distribution is skewed towards the top of the core, (see Figure 2) the majority of the steam production will be calculated to occur towards the outlet of the core. Realistically, the total steam production due to primary metal heat and flashing would be skewed towards the bottom of the core. The distribution analyzed will underestimate the

3000 seconds the mixture level will rise in the core due to excess HPI. For breaks smaller than 0.04 ft^2 , the match up will occur at approximately the same time and the core mixture levels will drop slower; thus, for all smaller breaks the core will remain covered and the HPI alone can mitigate the transient.

In performing the analysis, the historical small break spectrum (0.04 -, 0.07 -, 0.1 -, and 0.15-ft^2 breaks) was performed first. As shown by Figure 4, only the 0.07-ft^2 break resulted in core uncover. To further assure that the worst case had been obtained, the 0.055 - and the 0.085-ft^2 breaks were analyzed. These cases resulted in some core uncover but less than that for the 0.07-ft^2 break. All three cases were analyzed for temperature response by utilizing the THETA code; Figure 5 shows the cladding temperature responses. The peak cladding temperature for the worst case break, the 0.07-ft^2 break, was only 1092F which is well below the 2200F criteria of 10 CFR 50.46. Thus, the analysis demonstrates that B&W's 177-FA lowered loop plants can be operated at power levels up to 2772 MWt and satisfy the ECCS acceptance criteria.

Figure 1. CRAFT2 Noding Diagram for Small Breaks



Id No.	Identification	Path No.	Identification
1	Downcomer	1,2	Core
2	Lower Plenum	3,4,18,19	Hot Leg Piping
3	Core	5,20	Hot Leg, Upper
4,14	Hot Leg Piping	6,21	SG Tubes
5,15	SG & Upper Head	7,22	SG Lower Head
6,16	Steam Generator Tubes	8	Core Bypass
7,17	Secondary, SG	9,13,24	Cold Leg Piping
8,18	SG Lower Head	10,14,25	Pumps
11,19	Cold Leg Piping	11,12,15,16,26,27	Cold Leg Piping
10,12,20	Cold Leg Piping	17,31	Downcomer
3	Upper Downcomer	23	LPI
1	Pressurizer	28,29	Upper Downcomer
2	Containment	30	Pressurizer
3	Upper Plenum	32	Vent Valve
		33,34	Leak & Return Path
		35,36	HPI
		37	Containment Sprays

FIGURE - 2

AXIAL POWER SPECTRUM

29912 MHz

177-FA

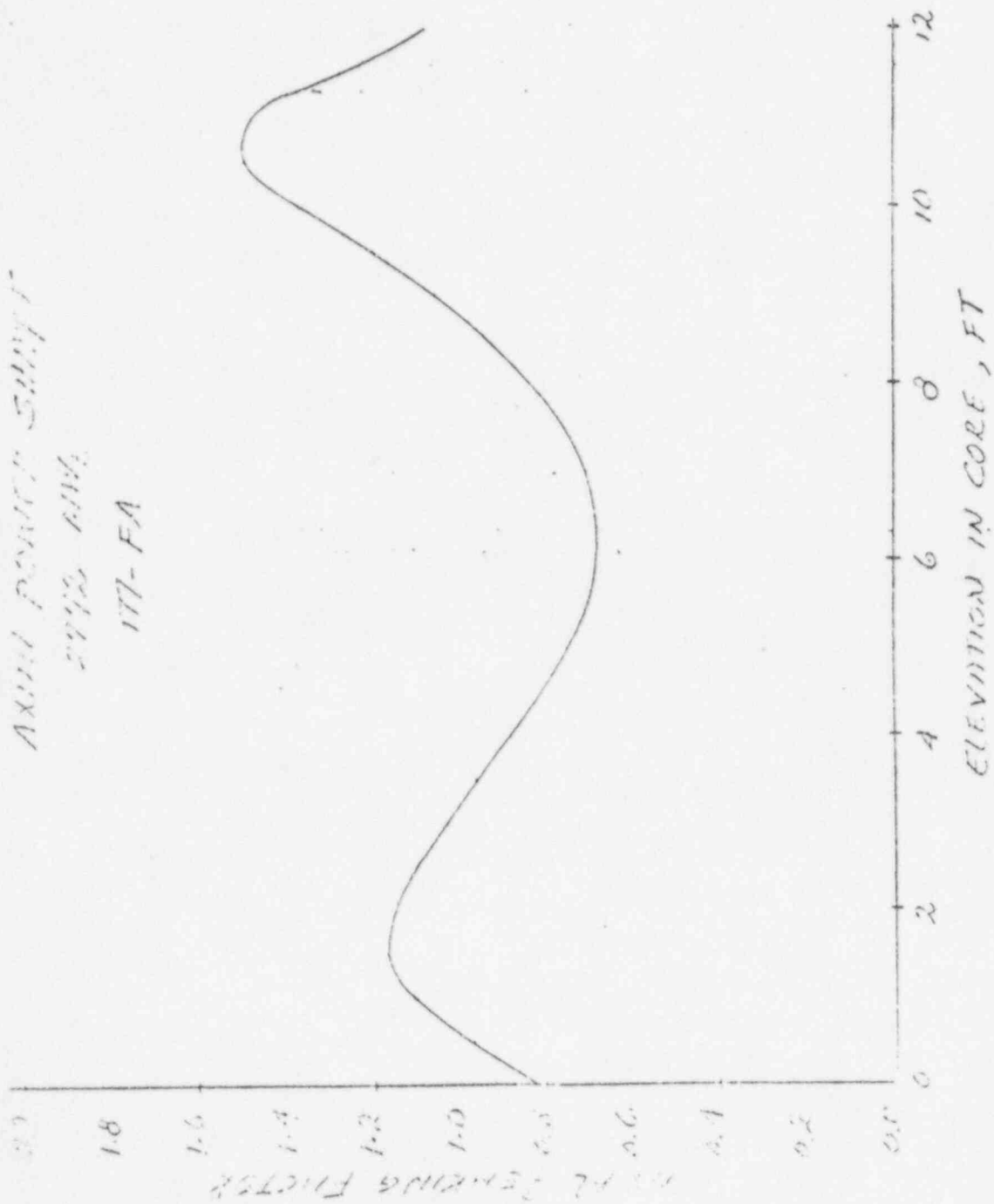


FIGURE - 3
 PRESSURE VS TIME
 2772 MIN
 177- FA

— 0.04 FT²
 — 0.055 FT²
 — 0.09 FT²
 - - - 0.055 FT²
 0.10 FT²
 —X— 0.15 FT²

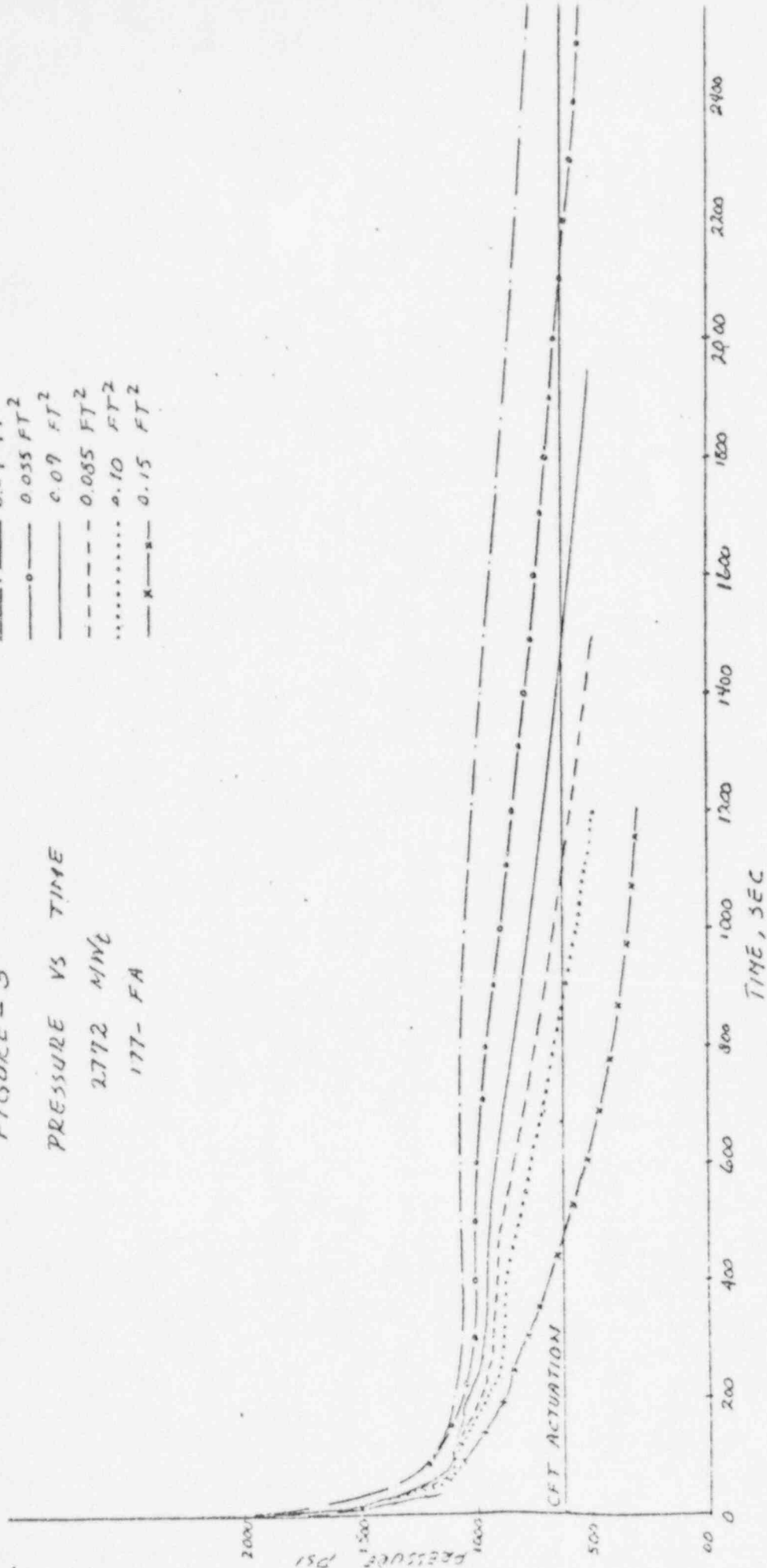


FIGURE - A
MIXTURE HEIGHT

V₀ TIME

2972 MIN/L

177 - FA

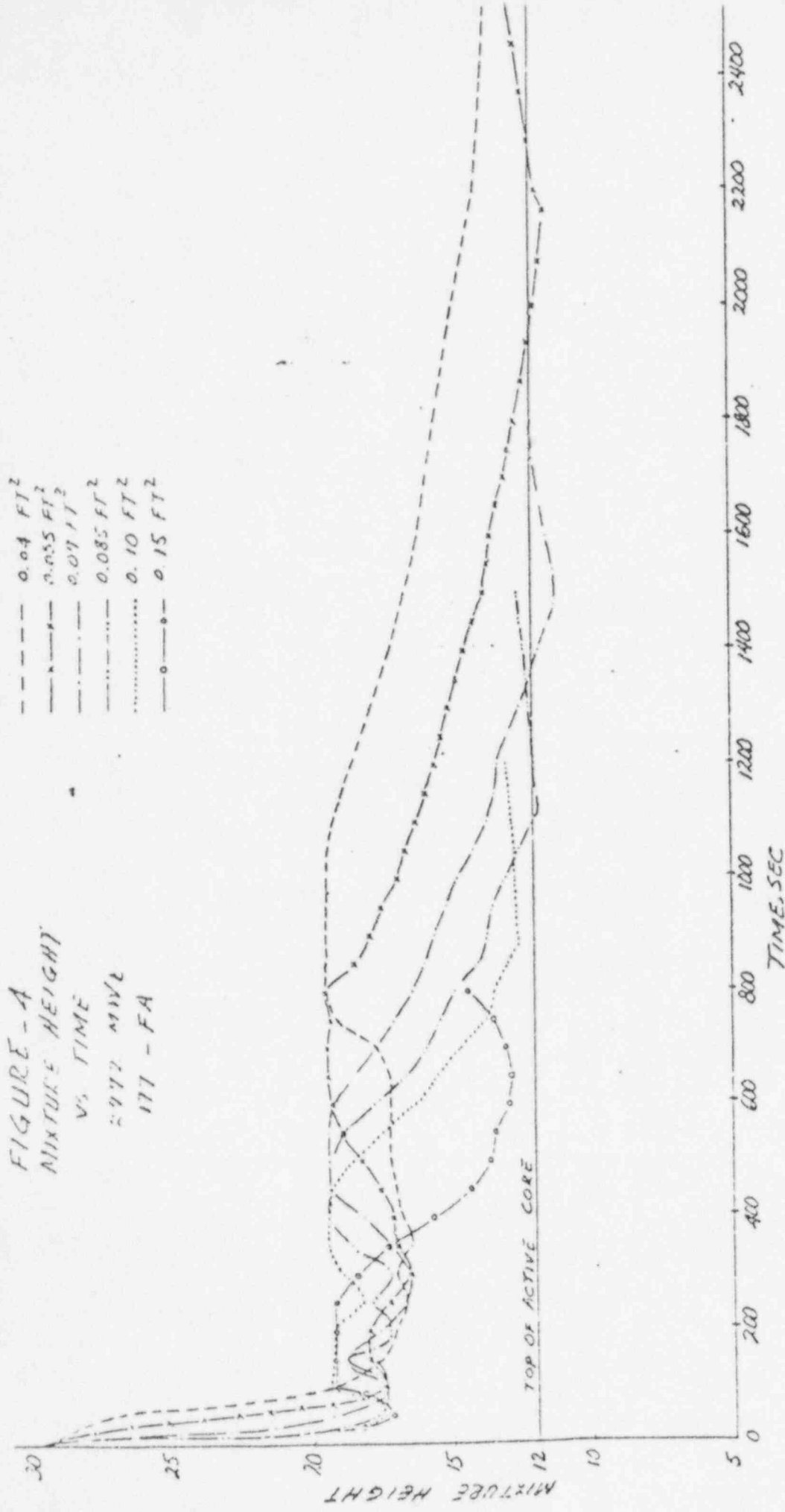


Figure 1
 Comparison of the
 M. T. 1994

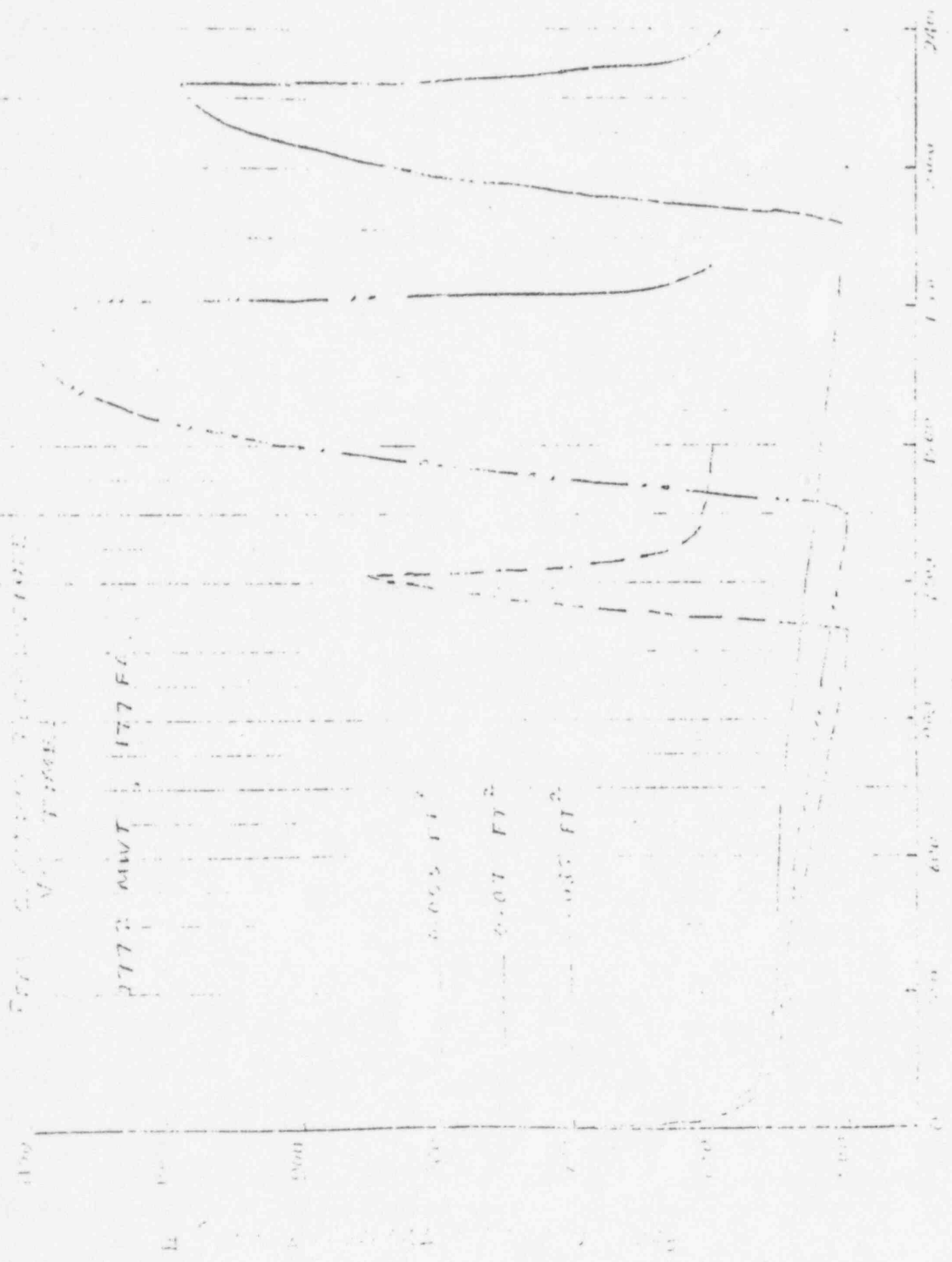


FIGURE 5

FFI7 C-177100 TEMPERATURE

VS. TIME

3773 MWT, 177 FA

0.005 FT²

0.01 FT²

0.05 FT²

100

200

300

400

500

600

0

300

600

900

1200

1500

1800

2000

2400

FEET

