TOLEDO EDISON COMPANY

DAVIS-BESSE NUCLEAR POWER STATION

COURSE OF ACTION REPORT

SEPTEMBER 9, 1985

CONTROL COPY NO. 15 ISSUED TO USNRC, WASHINGTON

TOLEDO EDISON

JOHN P. WILLIAMSON
Chairman and Chief Executive Officer
(419) 249-5225

Docket No. 50-346

License No. NPF-3

Serial No. 1182

September 10, 1985

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
United States Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Denton:

In accordance with our responsibility pursuant to 10CFR50.54(f), I am submitting this letter and its associated attachment as our response to your August 14, 1985 letter (Log No. 1798) to Mr. Joe Williams, Jr., Senior Vice President - Nuclear, Toledo Edison, concerning the June 9, 1985 loss-of-feedwater event at the Davis-Besse Nuclear Power Station.

While this event resulted in no impact on the health and safety of the public, or release of radioactivity, the number of equipment malfunctions and the implications associated is unacceptable to me. As you indicated in your letter it is essential that we identify and resolve any programmatic and management deficiencies that contributed as underlying causes to the June 9 event, and we are doing that.

I believe you will find the attachment to this letter "Toledo Edison - Course of Action," explicitly addresses the concerns identified in your letter and the attachment thereto. As I stated in a February 4, 1985 letter to Mr. Keppler, Davis-Besse is our responsibility and I have committed the company to a program that will lead the NRC to rate our operation of the Davis-Besse facility as one of superior quality. The June 9 event has caused me to further strengthen this commitment and to take actions to expedite all efforts in our pursuit of excellence.

In my previous letter to Mr. Keppler, I indicated our intent to provide the leadership and the resources necessary to elevate performance of our operation of Davis-Besse. This effort was well underway prior to the June 9 event. As you are aware, retired Admiral Joe Williams, Jr. has assumed the position of Senior Vice President - Nuclear at Toledo Edison. Mr. Williams was committed to join us prior to June 9 and has since assumed the leadership role in assuring we achieve the standards of excellence that both he and I require.

Our investigation of the June 9 event and the definition of the Course of Action for achieving excellence have been performed under his direction and with the full commitment of Corporate Management. We have already significantly upgraded the experience level and capabilities of our nuclear management staff and have reorganized and are staffing the Nuclear Mission to assure immediate improvements in the areas of maintenance, training, engineering, materials management, planning and plant management. We have also performed a major review of our salary structure for the Nuclear Mission and will be making any needed adjustments necessary to assure that Toledo Edison can successfully attract additional resources required to achieve our performance goals - and ensure stability of the organization.

I believe the actions already taken have significantly upgraded our capability to perform, but I wish to reiterate that we will follow the course of action necessary to achieve the desired standard of performance. I intend to stay intimately involved as we move ahead and will assure that Mr. Williams is provided with the support he needs to accomplish our common purpose.

We are committed to assuring that all necessary improvements are in place to support restart of the Davis-Besse facility on or about November 1. Following restart of Davis-Besse, we will continue to take the actions necessary to achieve and sustain the highest level of performance that both We and You expect.

I feel confident that you will find the attached document fully responsive to your August 14, 1985 letter. I, Mr. Williams and any members of the Nuclear Mission Management are available to meet with you and your staff to discuss our Course of Action.

Very truly yours,

J P Williamson

John P. Williamson

cc: DB-1 Senior NRC Resident Inspector

TOLEDO EDISON

September 9, 1985

JOE WILLIAMS, JR.
Senior Vice President—Nuclear
(419) 249-2300
(419) 249-5223

Mr. John P. Williamson
Chief Executive Officer and
Chairman of the Board
Toledo Edison Company
300 Madison Avenue
Toledo, Ohio 43652

Dear Sir:

Forwarded herewith is the Toledo Edison Company's Course of Action which is in response to the August 14, 1985 letter from the Nuclear Regulatory Commission.

It answers the questions posed and the concerns expressed in that letter and contains our commitments regarding the specifics of the June 9, 1985 event, and those necessary to upgrade Davis-Besse to the level of excellence addressed in your letter of February 4, 1985 to the NRC.

Very truly yours,

J. Williams, Jr.

J. Williams, Jr.
Senior Vice President, Nuclear
Davis-Besse Nuclear Power Station

JW/bec

10 CFR 50.54(f)

SUBMITTAL IN RESPONSE

FOR

DAVIS-BESSE NUCLEAR POWER STATION

UNIT NO. 1

FACILITY OPERATING LICENSE NO. NPF-3

This letter is submitted in conformance with 10 CFR 50.54(f) in response to Mr. Harold Denton's letter of August 14, 1985. This presents Toledo Edison's Course of Action for restart of the Davis-Besse Nuclear Power Station.

By J. Williams Jr.
J. Williams, Jr.
Senior Vice President, Nuclear

Sworn to and subscribed before me this 10th day of Sept., 1985.

Nora Lynn Flood
Notary Public, State of Ohio
NORA LYNN FLOOD
Notary Public, State of Ohio
My Commission Expires Sept. 1, 1987

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I. INTRODUCTION

In a February 4, 1985 letter (Ref. 1) to the United States Nuclear Regulatory Commission (NRC), Mr. John P. Williamson, Chairman and Chief Executive Officer of Toledo Edison Company (TED) formally responded to the most recent "Systematic Assessment of Licensee Performance" (SALP) report for the Davis-Besse Nuclear Power Station (Ref. 2). In the response Mr. Williamson indicated:

> "I am personally committing this Company to a program that will eventually lead the NRC to rate our operation of the Davis-Besse facility as one of superior quality.
>
> Recovery to a full state of excellence cannot occur in a few weeks or months. We recognize this and we are prepared for a long term endeavor. We have made and will continue to make changes that will obviate or eliminate problems that are amenable to quick resolution. But we recognize that the real causes of our inability to achieve excellence are deeper-rooted and will take longer to identify in detail and to remedy in full."

Based on Mr. Williamson's commitment to improve performance at Davis-Besse, a number of activities were initiated during the spring of 1985. Paramount among these activities was an effort to fulfill the commitment that "...We intend to provide the leadership and the

resources needed to elevate performance of our operation of Davis-Besse to a state of excellence...". A significant step was made in this direction when, in May, retired Vice Admiral Joe Williams, Jr. accepted the position of Senior Vice President, Nuclear at Toledo Edison.

Prior to the announcement of his appointment, Mr. Williams visited Davis-Besse, interviewed key personnel, reviewed relevant documents and reached initial conclusions confirming many of the concerns expressed by the NRC. Based on this review, Mr. Williams concluded that for Davis-Besse to achieve excellence in performance, actions had to be taken to increase the size and enhance the quality of the Nuclear Mission Staff; enhance the management experience in the areas of maintenance, engineering and station management; effectively plan and implement maintenance and modification activities; clarify responsibilities and establish accountability; expedite the implementation of TED's Configuration Management Program; and establish within Toledo Edison an in-depth, in-house engineering capability.

On June 9, 1985, subsequent to Mr. Williams decision to join Toledo Edison, the Davis-Besse Nuclear Power Station experienced a loss-of-main-feedwater transient. A number of equipment failures and an operator error occurred which resulted in a temporary loss of all feedwater flow. Feedwater flow was recovered through manual initiation of the startup feedwater pump and the auxiliary feedwater system. The plant was subsequently brought to a cold shutdown condition. The number of equipment failures which occurred during the June 9 event dictated the need for a thorough investigation into the causes of the failures and completion of the corrective actions necessary to prevent recurrence of such events.

Toledo Edison initiated a program which was summarized in a July 18, 1985 letter (Ref. 3) to the NRC. The specific goals of that program are summarized below:

- To thoroughly analyze the sequence of events, including performing investigations of the various problems to identify root causes.

- To analyze the results of the investigation to determine the existence of potential safety questions.

- To define and implement, prior to restart, any actions determined necessary to assure safe operation of Davis-Besse, and to determine those additional actions not necessary for restart that should be taken to further enhance reliability and facilitate safe operation. In this latter case, definitive plans for their accomplishment will be identified.

- To identify and correct weaknesses in plant programs, such as maintenance, training, procedures and administrative controls. Both the necessary short term (i.e. pre-restart) and longer term corrective actions would be addressed.

- To assure a complete response to NRC identified concerns.

Independently, but in coordination with the TED investigation, the NRC conducted a fact-finding investigation into the June 9 event. The results of this investigation were reported in NUREG-1154 "Loss of Main and Auxiliary Feedwater Event at the Davis-Besse Plant on June 9, 1985" (Ref. 4). By letter to Toledo Edison dated August 14, 1985 (Ref. 5), the NRC enumerated their concerns relative to the specifics of the event and their concerns regarding the apparent existence of programmatic and management deficiencies.

The fundamental NRC concerns were already being addressed as part of a "Course of Action" that Mr. Williams was formulating prior to the June 9 event, or as part of the specific program that TED was implementing in response to the specifics of the June 9 event. The submission of this document, "Davis-Besse Course of Action," reaffirms the commitment to achieve excellence expressed by the Company in Mr. Williamsons' February 4, 1985 letter and attests to the aggressive and responsible pursuit of fulfillment of that commitment. As part of the development of this Course of Action, all of the ongoing performance improvement activities and SALP generated actions have been reassessed and TED's future commitment in those areas is as stated herein.

This document also presents the investigation and corrective action program that TED initiated to consider problems brought to light by the June 9 event. Finally, this document provides specific answers to the concerns raised by the NRC in their

August 14, 1985 letter (Ref. 5) and also provides the basis for restart of Davis-Besse on or about November 1, 1985.

This document is organized as follows:

Section I - Provides a brief introduction to the Davis-Besse Course of Action.

Section II.A - Provides a brief overview of the management concepts that represent the foundation of TED's Course of Action.

Section II.B - Provides a detailed description of the Course of Action, including the actions related to:

- Restructuring and strengthening of Nuclear Mission organization and management.

- Incorporating the activities of previously existing performance improvement programs (e.g. SALP and PEP activities.)

- Improving maintenance planning, procedures and practices.

Section II.C - Provides the results of TED's investigation of the June 9 event including:

- The activities associated with completing the event investigation.

- The results of TED's review of the reliability of decay heat removal systems, including improvements which will be made.

- The analyses performed by TED to assess the safety-related consequences of the June 9 event.

- The procedure and training related lessons learned from the review of operator activities during the June 9 event.

- Control room improvements required based upon the June 9 event experience.

- Actions taken to improve the utilization of the Shift Technical Advisor.

- TED's comprehensive review of the design, operating experience and testing practices for safety related systems.

Section III - Presents conclusions and identifies the scheduled actions that will be taken prior to restart of Davis-Besse, as well as known longer term improvement activities.

Section IV - Includes Appendices containing results of the evaluations. The Appendices will be updated and revised, by future submittals, to reflect completion of additional evaluations and refinement of planned changes. This document and its Appendices will, when complete,

address the questions raised in the August 14, 1985 NRC letter and will provide sufficent detail to justify restart of Davis-Besse. The specific concerns identified by NRC's August 14, 1985 letter (Ref. 5) to Toledo Edison have been addressed in this Course of Action. Table I identifies, for each concern of the NRC letter, the report section which addresses the concern.

TABLE I

COURSE OF ACTION ACTIVITIES RELATIVE TO NRC CONCERNS

Item No. from Enclosure to NRC letter of August 14, 1985	Detailed Course of Action Section Addressing the item
I.A & I.B	II.C.1
I.C	II.C.1 & II.C.2
II.A.1	II.C.3
II.A.2	II.C.2 & II.C.3[1]
II.A.3	II.C.4
II.A.4	II.C.6
II.A.5	II.C.1
II.A.6	II.C.4
II.A.7	II.C.2
II.A.8	II.C.1
II.A.9	II.C.5
II.A.10	II.C.2
II.A.11	II.C.1
II.A.12	II.C.4
II.A.13	II.C.7
II.B.1	II.C.4
II.B.2	II.C.2, II.C.4[2], II.C.5[3]
II.B.3	II.C.2
II.B.4	II.C.3
III.A	II.B.1
III.B	II.B.3
III.C	II.B.2
III.D	II.B.1

[1]. Issues related to single failures

[2]. Issues related to training of plant operators

[3]. Issues related to human factor aspects of control room equipment

II. TOLEDO EDISON'S COURSE OF ACTION

II.A Overview

Section II of this report provides details describing the course of action Toledo Edison is implementing to improve operation of Davis-Besse. This includes actions to strengthen management structure and practices as well as actions taken in response to the June 9 event. Underlying the actions being taken to improve overall management of Davis-Besse is a recognition of the need to accomplish certain objectives. These include:

- Provision of a functional organizational structure that further facilitates the control of, and enhances the quality and safety of operations, maintenance and support services (e.g., engineering) of Davis-Besse.

- Sufficient staffing with competent personnel.

- Compensation of personnel that is competitive in the marketplace.

- Clear articulation of responsibilities of personnel.

- Maximization of in-house capabilities and minimization of the use of contractors to provide higher quality support and increased accountability.

- Controlled use of contractor support, where necessary, ensuring that such support is backed by contractor management commitment.

- Reorganization of engineering staff to provide increased emphasis on leadership with experience in plant operations and operations support.

- Relocation of most Nuclear Mission personnel presently located at the corporate headquarters to the Davis-Besse site. This includes personnel from Nuclear Facility Engineering, Licensing, and Materials Services Department.

- Establishment of a configuration management program that includes accurate equipment/system data and accurate documentation.

- Operation and maintenance of Davis-Besse in accordance with appropriate operating/maintenance procedures which are established and maintained under the umbrella of site-wide Administrative Procedures.

- Training of sufficient quality to ensure personnel are continually competent to discharge their duties.

- Enhanced awareness of industry practices and positions on major issues of interest.

- Appropriate application of quality assurance/quality control practices to the balance of plant.

Specifically as regards the June 9 event:

- The equipment/system failures are being investigated, causes of failures determined, corrective actions taken, and appropriate confirmatory tests conducted.

- The generic implications of the equipment/system failures as they apply to other systems will be identified and addressed.

Finally, sufficient resources will be provided to accomplish the objectives of the TED Course of Action in a timely and responsible manner. This includes implementing those actions found necessary by review of the June 9 event.

II.B. DETAILED COURSE OF ACTION

II.B.1. Restructuring and Strengthening of the Nuclear Mission

Introduction

NRC's letter of August 14, 1985 and Section III of the enclosure thereto identified NRC concerns as to programmatic and management issues that may have resulted in a decreasing level of performance at Davis-Besse. Paragraph III. A of the enclosure to the letter raises a management and programmatic concern regarding "adequacy of Management Practices..." and paragraph III. D of the enclosure reflects concern for the adequacy of resources available and/or being applied to the short-term and long-term corrective measures.

Toledo Edison has begun actions to restructure and strengthen the Nuclear Mission, and to acquire the additional resources necessary to assure the continued safe and reliable operation of Davis-Besse. Consistent with the strengthening of the Nuclear Mission, major changes in management practices are also being implemented.

As stated previously, these actions are not simply a reaction to the June 9 event. In fact some were already in progress prior to June 9. The occurrence of the June 9 event, and the need to thoroughly investigate it and return the plant to service, has served to accelerate the Toledo Edison actions which are described herein.

Summary of Major Changes Within The Nuclear Mission

Prior to the June 9 event, Toledo Edison had already set in motion several activities directed at resolving deficiencies and implementing a program to improve performance. These included activities such as increasing the staffing of the Training Department and implementing of a Management by Objectives program. As stated previously, high on Mr. Williamson's list of priorities was the retention of an experienced manager to function as Senior Vice President, Nuclear. Mr. Williamson initiated discussions with Vice Admiral Joe Williams, Jr., (U.S. Navy Retired) in April, 1985, about assuming the position. After visiting the plant and interviewing key Nuclear Mission personnel, Vice Admiral Williams accepted the position in May, 1985. Mr. Williams' appointment as Senior Vice President, Nuclear, was announced on June 18, 1985. This action was the first step in an aggressive program to expedite a restructured and strengthened management organization dedicated to the effective maintenance and operation of a safe and reliable nuclear power plant.

Prior to Mr. Williams joining Toledo Edison, the Company had already allocated significant resources to a number of important improvement projects as listed below:

- A five-story, 100,000 sq. ft. personnel and maintenance shop facility integral to the station. This shop will enhance maintenance and provide significantly improved facilities for Quality Control, Engineering, and Maintenance/Outage personnel in close proximity to

where the work is being performed. Ground breaking occurred on September 5, 1985 and occupancy is scheduled for November, 1986. The facility will house 380 employees. The cost estimate for the facility is in excess of $15,000,000.

- A greatly expanded Training Facility (34,000 sq. ft. exclusive of the simulator facility), which will include chemistry, health physics, mechanical, and instrumentation & control laboratories. Part of this complex is currently in use and completion of the remainder will be accomplished by December, 1985.

- Installation of an on-site, plant-specific simulator. This effort is being expedited with a scheduled operation date of December, 1988.

- Installation of a diversely powered feedwater pump. This project is currently scheduled for completion prior to startup.

Since his appointment, effective July 1, 1985, Mr. Williams has evaluated the existing management programs and activities of the Nuclear Mission and has implemented, is implementing, or has obtained concurrence of the Chairman of the Board and CEO, Mr. John P. Williamson to implement the following:

- A new organizational structure for the Nuclear Mission. This has has been approved and it will increase the staffing from 699 to approximately 930.

- Salary adjustments will be made to make TED truly competitive in recruiting talent and maintaining stability.

- A new highly experienced Plant Manager has assumed responsibility for the Davis-Besse Plant.

- The previous Plant Manager, with extensive operations experience, has assumed duties as head of the expanding Engineering Division.

- The Assistant Vice President, Nuclear has been assigned to concentrate his attention on Security, Personnel, and Administration. All of these functions are provided by Toledo Edison organizations outside the Nuclear Mission, and active liaison by the Assistant Vice President, Nuclear will assure the Mission's needs are met.

- The position of Assistant Plant Manager, Maintenance has been established and an experienced maintenance manager has been hired for that position.

- The position of Assistant Plant Manager, Operations has been established and filled.

- A new centralized Planning Department, reporting to the Plant Manager, has been established and an experienced manager has been hired as its Superintendent.

- The Maintenance Department has been reorganized and expanded. Experienced personnel have been hired for key positions in the restructured organization.

- The Nuclear Engineering Division has been substantially enlarged, and is being staffed.

- The Training Director now reports directly to the Senior Vice President, Nuclear, rather than to the Assistant Vice President, Nuclear.

- Detailed position descriptions are being written, reviewed and approved.

- Most Nuclear Mission and nuclear materials support personnel that were located at Corporate Headquarters are being moved to the site.

New Organizational Structure of the Nuclear Mission

Toledo Edison has restructured its Nuclear Mission management organization as shown in Appendix B.1.1. The new organization reflects the following features and enhancements.

1. The Senior Vice President, Nuclear reports directly to the Chairman and Chief Executive Officer. This structure has the following advantages:

   - It facilitates the Chief Executive Officer's role and increases his degree of involvement in overseeing the direction being taken by the Nuclear Mission and in fulfilling his responsibilities to the general public, Toledo Edison shareholders and the Board of Directors.

   - It allows for direct communications regarding Davis-Besse's needs to the highest level of management within the Company.

   - It places the Senior Vice President, Nuclear at a level which can effectively command all of the resources necessary to accomplish the Nuclear Mission objectives.

2. All Nuclear Mission directors with the exception of the Nuclear Services Director, report directly to the Senior Vice President, Nuclear.

   - This structure provides for clearly defined lines of authority and responsibility.

   - This structure reflects an effective form of control and accountability, as well as assurance of direct involvement by the Senior Vice President, Nuclear in the decision-making process.

3. The Senior Vice President, Nuclear has relocated to the Davis-Besse site to ensure strong management involvement and direction of day-to-day Nuclear Mission activities.

   - With the reorganization, most Nuclear Mission personnel will be located at the site to enhance communications and teamwork.

Key Management Appointments

A new management team has been assembled within the Nuclear Mission. This new team optimizes the utilization of experienced personnel from within the organization and includes new personnel whose extensive experience and knowledge will further enhance the effectiveness of the Nuclear Mission.

- Senior Vice President, Nuclear Mr. Joe Williams, Jr. has overall responsibility for Toledo Edison's nuclear program. A retired U.S. Navy Vice Admiral, he served 37 years in the Navy, beginning as a Seaman Recruit. He graduated from the U.S. Naval War College in 1956. Admiral Williams commissioned and commanded two nuclear-powered Polaris ballistic missile submarines. He advanced to the rank of Vice Admiral, serving as Commander, Norfolk Naval Shipyard from 1973 to 1974. He also held the position of Commander U.S. Submarine Force Atlantic Fleet.

After his retirement from the Navy, Mr. Williams became the Director of Nuclear Construction and Testing for the Electric Boat Division of General Dynamics Company. He held this position from 1977 to 1981. After leaving General Dynamics Co. he formed a consulting firm, Williams Research and Development Associates, where he gained considerable commercial nuclear power industry experience.

Prior to joining Toledo Edison, Mr. Williams was Senior Vice President - Nuclear Operations, for Cincinnati Gas & Electric Company, during 1983 and 1984. Mr. Williams comes to Toledo Edison with the conviction that the successful management of a nuclear program requires both commitment to excellence in performance within the organization, and an equivalent degree of professionalism from contractors, vendors, and other support organizations.

- Plant Manager Louis F. Storz has worked, since 1983, as Assistant Plant Manager at the Waterford 3 Nuclear Steam Electric Station. Before that, he was Assistant Plant Manager, Operations, at the V.C. Summer Nuclear Station for three years. From 1972 to 1979, Mr. Storz held various positions at the Point Beach Nuclear Plant, including that of Superintendent of Operations.

  A graduate of the U.S. Navy's nuclear and electronics schools, Mr. Storz earned a Bachelor of Science degree in Mechanical Engineering from Purdue University and is a licensed Professional Engineer in the State

of Wisconsin. Mr. Storz earned Senior Reactor Operator licenses for both the Point Beach and Summer plants. Mr. Storz has completed extensive training on Davis-Besse, including simulator training.

Mr. Storz brings to the project a solid nuclear operations background and the commercial nuclear industry experience needed to achieve the improved performance desired at Davis-Besse.

- Superintendent of Planning Michael E. Schefers was previously Planning Superintendent at the D.C. Cook Nuclear Plant, Units I and II, where he started as Chief Scheduler. Before that, he was Director of Site Data Base Management for Cincinnati Gas and Electric Company's Zimmer Nuclear Station.

  Mr. Schefers held increasingly responsible positions for General Dynamic's Electric Boat Division from 1973 to 1983.

  Mr. Schefers brings to the project an extensive background in coordination of complex, technical projects. He has considerable experience in maintenance and outage planning and has established expertise in developing and implementing computer scheduling systems. His recent experience with planning activities for operating nuclear power plants will contribute significantly to improved planning and performance of work at Davis-Besse.

- Maintenance Superintendent   Stephen J. Smith was most recently a consultant specializing in nuclear plant maintenance. From 1978 to 1982, he worked at the V.C. Summer Nuclear Station where he held the position of Assistant Plant Manager, Maintenance.

  Mr. Smith is a graduate of the Navy's nuclear and engineering laboratory technician schools. He joined the commercial nuclear power industry as an Associate Engineer at the Babcock and Wilcox Company in 1977 following twelve years of service in the U.S. Navy's nuclear submarine program. Mr. Smith's extensive experience in establishing and managing maintenance programs at nuclear power facilities will significantly strengthen Toledo Edison's capability in this critical area.

- I&C Superintendent   Carroll V. Phillips has more than 18 years of instrumentation and control (I&C) experience with both the military and the electric utility industry. Most recently, Mr. Phillips spent four years at the Waterford 3 Nuclear Steam Electric Station and also spent one year at TVA's Sequoyah Training Center. The designation of Mr. Phillips as a Superintendent demonstrates Toledo Edisons' recognition of the critical importance of the instrumentation and control function at Davis-Besse, which previously was directed at the Supervisor level. The combination of increased status in the management organization, coupled with the addition of Mr. Phillips, will significantly improve the contribution that the I&C group can make to the operation of Davis-Besse.

- Materials Management Manager Mr. Tom Chiles has been hired to fill this position. Before joining Toledo Edison, Mr. Chiles was Materials Manager at the Waterford 3 Nuclear Steam Electric Station, where he supervised personnel involved with the procurement of materials, computerized inventory control, expediters, and warehouse activities. Previously, he had been the Field Procurement Manager for Burns & Roe where he supervised the leasing and procurement of heavy equipment, piping, pumps, valves, motors, and generators for the Hanford II Nuclear Plant. He developed a set of traffic management procedures, purchasing procedures, expediting and material handling procedures which were used as the basis of nationwide procedures by Burns & Roe.

  Mr. Chiles bring extensive experience in both field and corporate material controls which will be a major asset to the Nuclear Mission in reaching its goal to have a procurement group which actively and effectively supports the Station.

Consolidation and Redirection of Nuclear Engineering

The Mission's Nuclear Engineering Division has been consolidated and redirected. Individuals with extensive operations experience have been integrated into the engineering group. The Engineering Division has been expanded from a single Division to four separate and expanded departments as discussed below.

- Stephen M. Quennoz, formerly Plant Manager of Davis-Besse, has been appointed Group Director, Nuclear Engineering. He brings to this organization the necessary and relevant plant operational background, and the charter to focus engineering activities to clearly support the continued safe and reliable operation of the station.

- A new Nuclear Plant Systems Department has been established within the Nuclear Engineering Division. This Department will provide dedicated expertise in the support of modifications and maintenance of plant systems. A cognizant engineer from this Department will be assigned to each system to handle maintenance problems (e.g. trouble-shooting, preventive maintenance (PM) program, vendor manuals, spare parts), regulatory concerns (e.g. NRC IE Bulletins/Notices, Noncompliances), quality problems (e.g. Nonconformances, Audit Finding Reports, Surveillance Reports,) conditions adverse to quality (e.g. Deviation Reports, Licensee Event Reports,) surveillance testing (e.g. performance trending), and design modifications (e.g. Design Bases, Temporary Modification, System Descriptions, Test Procedures, Safety Evaluations).

  The Nuclear Plant Systems Department is separate from the design engineering staff although both are part of the Nuclear Engineering Division. The Nuclear Plant System Department will be headed by a manager who will interact with the Plant Manager's staff to support daily activities. The Department is responsible for responding to plant problems, providing design orientation information and oversight of all aspects of system operation and maintenance.

The establishment of this new Department in Engineering provides a highly qualified and accountable focal point for performing root-cause determinations for any equipment or system malfunctions. Such an organizational focus did not previously exist at Toledo Edison.

- The station Technical Section has been reassigned to the Nuclear Engineering Division and redesignated as the Operations Engineering Department. This will allow the station staff to concentrate on operations, maintenance, and chemistry & health physics activities. Areas such as reliability and performance (Nuclear Plant Reliability Data System NPRDS), ASME Section XI testing, turbine cycle code analysis, thermodynamic performance testing, computer applications (NSSS software support, SPDS development), reactor core follow (physics testings, fuel handling, reactor physics related codes), operational assessment (VETIP, INPO SOERS, root cause investigation, B&W transient assessment), and projects (DCRDR, ATOG integrated symptom oriented procedure maintenance) will now be the responsibility of the Engineering Division. This action is designed to bolster engineering input and ownership of responsibilities to support the station. The reassignment of the Technical Section also places additional personnel with direct Davis-Besse operational experience in the Nuclear Engineering Division and, when coupled with the newly established Nuclear Plant Systems Department will significantly increase Toledo Edison's capability for performing activities such as post-trip reviews.

- Engineering Services has been separated from the Nuclear Facility Engineering Department to provide a better framework for it to support

the entire Engineering Division. The Engineering Services Department is responsible for the control of records, administrative processing of Facility Change Requests, drawing control, and distribution of vendor manuals. The Department is also responsible for implementation of a configuration management program and will be significantly expanding over the next few years. By providing dedicated supervision to this important area, it will also free up the Nuclear Facility Engineering Department to concentrate on engineering evaluations and design modification activities.

- All members of the corporate engineering staff presently located at Corporate Headquarters will be relocated to the site to facilitate communications and enhance the responsiveness of the nuclear facility engineering, design, system and operations engineering organizations.

Centralization of All Planning Activities

A major component of the Nuclear Mission restructuring is the creation of a centralized Planning Department within the station organization. Previously, planning and scheduling was included in the responsibilities of the Maintenance Department. The creation of a central planning group, independent of the maintenance organization, and headed by a superintendent, will establish control, coordination and accountability of all activities within the protected area of the station. The planning group will assure that appropriate work packages are prepared, spare parts are available, and plant conditions support conducting planned work. The Planning Department has

consolidated personnel drawn from maintenance engineering, facility modification engineering and maintenance planning. The Planning Department contains an expanded, dedicated outage management section and computer systems section, in addition to the staff that is assigned responsibility for the daily planning activities. It is expected that the establishment of this planning group will allow for more efficient planning and scheduling of maintenance work at Davis-Besse.

Restructuring of Maintenance Organization

While Section II.B.3 discusses the maintenance program improvements in greater detail, it is noted here that the maintenance organization has been restructured to facilitate focusing the attention of maintenance on performing field work. In this regard and in addition to increasing the number of shop foremen, general foremen have been added to the electrical, mechanical and I&C areas (See Appendix B.1.1 for a Maintenance Department organization chart.)

Previously, the need to perform a variety of administrative duties diminished the time available for direct supervision of field work. The addition of several foremen per shop will result in more detailed supervision of the work effort. Furthermore, one of the foremen in each shop will be assigned specific responsibilities with respect to training. This foreman will identify training needs, conduct on-the-job training as required, ensure that the apprentice training program progress is satisfactory, and work with the Nuclear Training Department to coordinate maintenance training efforts.

Finally, the maintenance staff has been assigned responsibilities focused solely in support of performing daily maintenance work. Previously, the maintenance staff was utilized to address all aspects of the work effort, which included a significant administrative burden. Administrative duties reduced the time available for the staff to support field activities. The changes which have been made, including the new Nuclear Plant Systems Department, and the enlarged station Planning Department, will relieve the pre-existant administrative burden associated with maintenance activities.

Training Program Enhancements

In addition to the organizational structure changes, a new management approach to the training function will be implemented. Efforts are underway to more clearly define the company's training policy including the delineation of roles, responsibilities, interfaces and authorities of the Nuclear Training Division. The need was recognized to create a clear understanding between the Station and Training organizations with regard to training responsibilities such that qualification and training rests with the line organization, whereas the responsibility for the development and implementation of training programs rests with the training organization.

While Toledo Edison was one of the last nuclear utilities to commit to INPO accreditation, it is now striving to establish high quality training programs worthy of accreditation prior to the NUMARC committed date of December 1986. These performance-based programs are being designed to

provide station personnel with the knowledge and skills needed to do the job correctly the first time. They will be based on the INPO Training Systematic Development (TSD) process.

The commitment to improvement in training is further exemplified by the following:

- New and expanded office and classroom facilities have recently been constructed which provide 26,000 sq. ft. of additional space and more than double the number of classrooms. These facilities and associated equipment significantly enhance the Toledo Edison Training Program capability.

- A major training laboratory construction project for Mechanical, Electrical, Instrument & Control, Chemistry and Health Physics personnel has also begun. These laboratories will add approximately 8000 sq. ft. for training and will aid in providing valuable hands-on equipment training and improve the ability to assess trainee skills. Completion is scheduled for December, 1985.

- The construction of an on-site plant specific simulator modeling the Davis-Besse control room. Bid specifications are being developed. The bid and review process is scheduled to result in contract signing in early 1986. The period from execution of the contract to simulator delivery is normally 32 to 36 months. TED will require as a contract conditon that the simulator be operational by December, 1988. The simulator will provide a greatly enhanced capability to both train and evaluate operators in a control room environment.

- The Nuclear Training Director will ensure policies, procedures, and resources are in place to provide for the ongoing evaluation of TED training programs to assure that needed program improvements and updates are properly instituted.

- The Nuclear Mission organization supports those changes necessary to make the training organization a viable career option. These changes will serve to attract high caliber, experienced individuals to the training instructor position. The training staff will be of sufficient size to adequately fulfill training needs, consistent with the recently restructured organization.

Additional Staffing

Additional resources are needed in order to make the Nuclear Mission more self-sufficient. Increased self-sufficiency will enhance accountability, increase continuity and provide the increase in morale that results when an organization can address and solve its own problems without undue reliance on assistance from outside Toledo Edison. Furthermore, the additional resources will strengthen the quality of the organization by increasing the depth of experience and breadth of capabilities.

There are currently (as of August 1, 1985) 699 approved positions within the Nuclear Mission. Approximately 230 positions are being added to the site staff. Of these 230 positions, over 90 are identified positions for

the Nuclear Engineering Division. This represents a shift in company philosophy - a shift intended to strengthen internal engineering capabilities, reduce dependence on outside consultants, and thereby have engineers working on Davis-Besse problems who are an integral part of the organization and are inherently accountable. In addition to the major changes to the Engineering Division, other key staffing changes include:

- Chemistry & Health Physics (C&HP) will receive additional staff, both in the area of management and technicians. These staff additions will assure that C&HP can more effectively support shift coverage and outage activities without extensive reliance on contractor health physics personnel.

- Operations will have additional people added to the shift structure in order to man the fire brigade internally (i.e., eliminate the need to use Security personnel as part of the brigade) and increase the field support of plant operations.

- Emergency Planning will receive additional planners and technicians in order to continue to improve its performance.

- Quality Assurance/Quality Control will acquire additional staffing to improve the level of attention provided to the assurance of quality for balance of plant systems.

Toledo Edison plans to have all of these positions filled with permanent Toledo Edison employees by the end of 1986. In the interim, the necessary

support will be provided by using contract personnel in all key positions. The goal for having the necessary contract personnel in place is December 1, 1985.

Additional Responsibilities for the Assistant Vice President, Nuclear

As mentioned previously, the Assistant Vice President, Nuclear has been assigned additional responsibilities involving Personnel, Security, and Administration. These areas are outside the direct control of the Nuclear Mission but are vital to its functioning. This assignment will provide a specific nuclear oriented senior management interface, resulting in increased support to the Nuclear Mission from these other organizations. A Personnel Administrator has been assigned to the staff of the Assistant Vice President, Nuclear to provide liaison to the Corporate Planning and Administration Mission on matters involving grievances, employment, management training, benefits and salary. The Assistant Vice President, Nuclear will also act as Chief of Staff to direct staff functions for the Senior Vice President, Nuclear and will function to ensure the mission directors are carrying out the policy and direction established by the Senior Vice President, Nuclear. The assignment of the Assistant Vice President, Nuclear to represent the Nuclear Mission in administrative matters will allow the Senior Vice President, Nuclear to primarily direct his attention to line management activities.

Improvement Of Management Practices

In addition to taking the actions previously discussed in this Section, a number of new programs and practices were, or are being, instituted to improve management effectiveness and Davis-Besse operating performance. These include:

- A program to write a definitive position description for each Toledo Edison employee associated with the Davis-Besse plant. The effort will result in clear statements of responsibilities and accountabilities, and will provide the basis for assuring that specific individuals are responsible for performing the functions required to safely and reliably operate Davis-Besse. These position descriptions are being written by supervisors in concert with the affected individuals and will include a description of exactly what work that person is responsible for performing. This effort has been initiated and is expected to be completed by October 30, 1985.

- The conduct of an extensive salary review. Once the Nuclear Mission site reorganization was formulated and approved, a review was undertaken to determine site-wide uniformity of grade levels, grade level consistency with position descriptions, and actual pay levels within the grade levels. All of these factors were then compared with a number of similarly structured operating nuclear

power plants. This review, which has been completed, identified the need for a substantial increase in pay levels for most positions throughout the site organization. The review has been presented to the CEO and to the President and the results have received their concurrence. The Senior Vice President, Nuclear, has been instructed to submit a detailed plan for a phased adjustment of the salaries of personnel in the organization and has the authority to use the adjusted levels in recruiting the additional personnel required.

- A management style that promotes individual responsibility and personal commitment to performance will be utilized. This involves a number of management practices, all of which contribute to improved personal accountability. For example, the Senior Vice President, Nuclear, conducts a weekly staff meeting which includes all the key managers from the site including managers of contractor personnel. It provides a forum for plant problems to be aired with support and engineering personnel.

- A revised Materials Management System is being put in place. While materials management is not completely under control of the Nuclear Mission, an experienced manager has been hired to work at the site and oversee this important area. Procedures employed in the site's materials management program will be revised to assure that site needs have the highest priority and that the responsible personnel are so instructed. This effort will be closely monitored by Senior Management and if the desired improvements are not demonstrated, additional actions will be taken.

- A configuration management program to assure the effective management of plant changes at Davis-Besse will be established. The need for configuration management has been recognized for the past few years. However, an organized program for configuration management was not adopted. Portions of the concept, however, have been worked on as deficiencies were recognized. One example of this was in the area of drawing control which has received specialized attention in the last few years. Toledo Edison recognizes that this must be an integrated effort to address the problem in a comprehensive, well executed manner. Details of the approach to implementing this program are being reviewed at this time and a request for proposal will be issued by October 15, 1985.

Reassessment of Existing Corrective Action Programs

- One of the concerns expressed by the NRC with respect to Davis-Besse was the lack of progress in correcting deficiencies or weaknesses identified in earlier NRC reports or enforcement meetings. For example, there were some 175 items being tracked within TED's Performance Enhancement Program alone. As part of developing this Course of Action and including consideration of the resource needs associated with investigating the June 9 event, a reassessment was made of already initiated performance improvement activities to assure that the appropriate resources and schedule commitments existed. This effort is discussed in more detail in the next section.

Both the results of this reassessment and TED's review of the findings contained in NUREG 1154 have been included in the development of the Course of Action. The Senior Vice President, Nuclear and his management team are convinced that certain of the existing improvement efforts will contribute significantly towards supporting enhanced maintenance and safe operation and should be given greater emphasis and support.

As stated previously, continued and strengthened commitment is being made in the areas of configuration management, training program enhancements and maintenance program improvements. In addition to those critical activities, the "new" management team is also advocating greater emphasis to past TED commitments regarding the establishment of site-wide procedures, and the achievement of compliance with applicable Appendix R and other fire protection requirements.

As discussed in Section II.B.2, all open PEP and SALP activities have been appropriately dispositioned.

II.B.2. - Incorporation of Existing Performance Improvement Programs

Introduction

Item III.C of the enclosure to the NRC letter to Toledo Edison dated August 14, 1985 specified a concern regarding: "Adequacy of the implementation of the Performance Enhancement Program (PEP) and any other ongoing corrective action programs."

PEP consisted of interim or short-term actions, which are largely complete, and longer-term Action Plans. The other major corrective action program that Toledo Edison had substantially underway was a SALP improvement program, initiated in response to NRC's Systematic Assessment of Licensee Performance (SALP) 4 Report.

As stated previously in section II.B.1 of this report, both of these programs (i.e. PEP and SALP) have been included in an overall reassessment of Toledo Edison's corrective action/performance improvement programs. The reassessment was undertaken to:

1. Identify and describe all PEP and SALP concerns or commitments.
2. Reassess each item to determine its current applicability and priority for accomplishment.
3. Assure resources needed to accomplish the action exist.
4. Prepare a revised schedule for performance of the specific activities.

The results of this reassessment are discussed below:

Performance Enhancement Program Activities

The original PEP Interim Actions Program contained 159 items. As of July 31, 1985, 16 items were still open. Based upon the reassessment of these items, seven items were assigned to be completed on a priority basis, while the other nine items were assigned to specific line organizations for implementation as part of their normal operation. Appendix B.2.1 contains the PEP Interim Actions and identifies how they were dispositioned.

As of July, 1985, 45 PEP Action Plans were being implemented. Based upon the reassessment, eleven of the plans were designated as high priority to which maximum emphasis and resources will be applied; seven plans were determined to be nearing completion and would be completed as planned; 27 plans were determined to be the responsibility of line management organizations and would be expected to be accomplished in the due course of business consistent with the new management program. Appendix B.2.1 identifies the 45 PEP Action Plans and how they have been dispositioned.

SALP Improvement Program Activities

At the time the reassessment of the SALP activities was performed, 66 items were considered still open. Based upon the review of these items, it was determined that 56 of the activities were on the existing Licensing Commitment Tracking System, and will be completed per the existing schedule. Appendix B.2.1 identifies how the remaining 10 items will be dispositioned.

II.B.3 - Maintenance Improvement Program

Introduction

It is recognized that excellent performance in the conduct of maintenance is a necessary prerequisite to achieving and sustaining excellent plant performance. Both TED and the NRC have identified the need to improve the maintenance program at Davis-Besse. TED is aggressively taking action to improve performance in the area of maintenance. The maintenance improvement program represents a long-term commitment intended to assure increased reliability and improved performance of the equipment at Davis-Besse. The improvement program is addressing several broad areas as listed below:

- Organization
- Administrative and Technical Procedures
- Training
- Preventive Maintenance
- Spare Parts and Materials Control
- Engineering Interface and Support
- Plant Cleanliness and Material Readiness
- Facilities

Item III.B. of the enclosure to the August 14, 1985 NRC letter identified a concern regarding:

"Adequacy of the maintenance program, including maintenance backlog, maintenance procedures and training, vendor interface and correction of identified deficiencies."

A review has been made of all open Maintenance Work Orders (MWO) resulting in all MWO's being scheduled according to their priority. As new MWO's are generated they are assigned a priority and included in the overall schedule for performing maintenance work.

The review of backlogged MWO's, coupled with the significant maintenance program improvements described below, provides assurance that all important maintenance activities will be properly and promptly performed.

Following is a discussion of the improvements being made in each of the areas identified above.

Reorganization of Maintenance Department

The Maintenance Department has been reorganized (see Appendix B.1.1) and personnel changes to strengthen its capability have been made. New senior management personnel with extensive maintenance management experience have been hired and currently occupy the positions of Assistant Plant Manager - Maintenance, Instrumentation and Controls Superintendent and Mechanical Maintenance General Foreman. These new individuals bring a broad background of nuclear maintenance experience to Davis-Besse. The Maintenance Department has been restructured to bring increased supervisory attention to the performance of maintenance activities in the plant. Each discipline in the Department

now has assigned a Superintendent, a General Foreman, a Lead Engineer, and several Foremen.

Previous supervision to craftsmen ratios averaged one supervisor to 23 mechanical craftsmen, one to 26 electrical and one to 19 I&C craftsmen. In the new organization, the supervisor to craftsmen ratios have been improved to one supervisor to 10 mechanical craftsmen, one to six electrical and one to seven I&C craftsmen. A major objective of the reorganization is to assure that sufficient supervisory manpower is available to manage the paperwork and still directly supervise plant maintenance activities.

To ensure that the benefits of this new organization are brought fully to bear on maintenance of the plant and that sufficient communication occurs, the Assistant Plant Manager, Maintenance, meets regularly with all members of the Maintenance staff; daily with Superintendents and General Foremen; monthly with the entire section of each discipline, and quarterly with the entire Maintenance Department. The Assistant Plant Manager, Maintenance, also communicates daily with the Plant Manager and the Assistant Plant Manager, Operations.

Administrative and Technical Procedures

Maintenance Department administrative and technical procedures will be subjected to a major upgrade program. This concentrated upgrade effort is scheduled to commence during September 1985 and will be completed by December, 1986. To expedite this effort, professional procedure development assistance has been obtained from organizations experienced in this field.

The major objectives of the procedure upgrade program will be to:

- Incorporate guidance in administrative procedures derived from the NRC, INPO and other pertinent industry practices

- Incorporate previous maintenance experience in technical procedures.

- Establish better defined administrative and work controls for plant maintenance activities.

- Assure that formalized feedback mechanisms are established that will improve the quality and accuracy of the technical procedures as more experience is gained.

Currently, emphasis is being placed on the improvement of the quality of Maintenance Department technical procedures. The new maintenance organization has established technical positions within each discipline that are directly responsible for the content and accuracy of these procedures. Additionally, new procedures and revisions to existing procedures are being "walked through" by experienced craft personnel, prior to approval, to assure their useability. In those cases where vendor instruction manuals are being used directly to support maintenance activities, each manual must receive a technical review by the discipline technical staff, and be approved prior to each use. This activity is being documented in the work package for each activity. This procedure will be applied to vendor

technical manuals until configuration management controls are established which accomplish the same purpose.

Training

To assure that the Maintenance Department places increased emphasis on training, one foreman in each discipline has been designated as the "Training Foreman." This foreman is responsible to assure that adequate training is provided, training schedules are developed and adhered to, and that personnel are successfully participating in the training program.

The Maintenance Department is adopting the "Training Shift" concept to assure that designated individuals are assigned for specific lengths of time totally devoted to training. The schedule for having maintenance training programs ready for INPO accreditation is being accelerated from the end of 1986 to as close to mid-1986 as possible. To assure that the training program recognizes the needs of maintenance craft personnel, Training Councils have been formed in each discipline. The Training Council consists of craft representation, in a ratio of one craftsmen on the council to 10 craftsmen in the discipline along with the Training Foreman and the appropriate supervisor from the Training Department. The Training Council makes recommendations to the Assistant Plant Manager, Maintenance and the Training Director in all areas concerning the type of courses to be taught, the quality of course material, and training schedules.

Preventive Maintenance

The program for Preventive Maintenance is being subjected to improvements from several perspectives. The newly formed Nuclear Plant Systems Department has been assigned responsibility for review of selected plant systems. Results of the review will be used to improve the quality and effectiveness of the preventive maintenance program. Ongoing reviews of the results of testing, corrective maintenance, and preventive maintenance will provide additional information to upgrade the preventive maintenance program. To facilitate the incorporation of improvements to the Preventive Maintenance Program, the services of professional consultant personnel are being obtained from B&W, Bechtel, and several other experienced organizations. As discussed previously, a central planning organization independent of the maintenance organization has been established to develop and implement an integrated plant maintenance and modifications schedule. In order to assure Preventive Maintenance is completed in a timely manner, the schedule will assign higher priorities to the performance of Preventive Maintenance. The schedule will also ensure that a coordinated approach is used to complete preventive and corrective maintenance activities.

Spare Parts and Materials Control

A program for upgrading spare parts and materials control has been developed and is in the process of implementation. Specific aspects of the program which deal with spare parts adequacy and the inventory control system are being expedited. Aggressive implementation of this program coupled with the hiring of the Materials Manager (see Section II.B.1) will

assure improved material resources are available to support plant maintenance activities.

Engineering Interface and Support

To assure the adequacy of communications between the Engineering Division and the Maintenance Department, an administrative procedure has been developed which:

- Assures that identified concerns will be formally elevated to appropriate levels of engineering and management for resolution.

- Requires the integrated plant schedule to list all concerns with a required response date.

- Identifies the individual responsible to provide a resolution, and the individual responsible to implement the resolution.

This procedure is currently undergoing formal review and comment resolution with issuance scheduled for September 30, 1985. Implementation of this procedure will significantly enhance engineering support of maintenance.

Plant Cleanliness and Material Readiness

A continuing program to improve plant cleanliness and material readiness has been established. This program has several features. The first is a composite (mechanical, electrical, I&C) crew of maintenance craftsmen

under a supervisor reporting directly to the Assistant Plant Manager, Maintenance. The crew is devoted to a systematic, room-by-room, level-by-level walkdown of the plant. The crew is responsible for repairing minor problems, identifying larger maintenance action items, initiating work requests, and establishing schedules and priorities for a dedicated cleaning staff assigned to the crew.

A second feature of the program has been the assignment of daily plant inspection responsibilities to each member of the Maintenance Department management and staff. Each individual has a specific area of the plant which he must inspect daily. Guidance has been provided to the individuals as to what specifically to inspect for. Essentially, each individual is looking for deficiencies related to his particular craft. Deficiencies are documented on Work Requests. Cleaning items are placed on punchlists which are routed to planning and scheduling, or to the composite clean-up crew. Inspection schedules are being rotated on a monthly basis to assure that the entire plant is inspected in this manner every six months.

The requirements of the above programs are being incorporated into a new procedure entitled "Conduct of Maintenance," being developed by the Assistant Plant Manager, Maintenance. The procedure will formally establish management policies concerning the duties and responsibilities of all Maintenance Department personnel and give specific guidance as to the overall goals and objective of the Maintenance Department. The current schedule for approval and issuance of this procedure is October 15, 1985.

Maintenance Facilities Improvements

To enhance the performance of station personnel, a new Personnel Support Facility (PSF) is being constructed. The PSF provides 100,000 sq. ft. of shop and office space. The PSF incorporates the following features:

- State-of-the-art shop equipment which will significantly improve shop repair capabilities.

- A "functional" arrangement of organizations and personnel to provide more efficient handling of Work Orders and Work Packages. This feature brings into close proximity the organizations which require a high level of interface and direct communications. This reduces time lag and promotes efficiency in the processing of all paperwork associated with operating and maintaining Davis-Besse.

- Improved working and office conditions for all staff personnel. This feature will have a significant impact on raising the morale of plant personnel and will help to install a high sense of pride in Davis-Besse and its equipment.

Ground breaking for the new facility took place on September 5, 1985. Preliminary work is already underway to install underground piping and electrical systems and the current schedule requires that the facility be ready for occupancy by November, 1986.

II.C. ACTIONS RELATED TO THE JUNE 9, 1985 EVENT

II.C.1. Event Investigation

Introduction

Items I.A and I.B of the enclosure to the August 14, 1985 NRC letter to Toledo Edison discuss, respectively, the need to complete the investigation of equipment malfunctions and operator errors which occurred during the June 9, 1985 event, and the need to determine the root causes of those malfunctions and errors.

This section discusses the process and methodology applied by Toledo Edison in investigating the June 9 event. Included is a description of the process by which root causes are being determined and possible generic implications are being evaluated. The reports presenting Findings, Corrective Actions and Generic Implications related to equipment involved in the June 9 event are provided in the Appendices to this report. Appendix C.1.1 presents the reports for the items listed on Table 5.1 of NUREG-1154 (Item II.A.11 of the enclosure to NRC's August 14 letter). Appendices C.1.2 and C.1.3 present, respectively, the reports relating to safety-related valves (NRC Item II.A.5) and the reliability of the Pilot Operated Relief Valve (NRC Item II.A.8). Appendix C.1.4 describes the planned confirmatory testing of specific equipment which malfunctioned during the June 9 event.

It should be reemphasized that the content of Appendices C.1.1 through C.1.4 will be updated as the June 9 event investigation reaches its culmination. The final content of these Appendices will completely satisfy the questions raised in the August 14, 1985 NRC letter relative to equipment malfunctions and also support decision-making regarding restart of Davis-Besse.

Background

Following the June 9 event, Toledo Edison initiated an investigation to determine the cause of the equipment failures which occurred. Toledo Edison committed the resources required to conduct a thorough investigation. This investigation was closely coordinated with the NRC Fact Finding Team's evaluation of the event and with NRC Region III personnel. (The NRC Confirmatory Action Letter issued on June 10, 1985 (Ref. 6) specified that work on the equipment involved in the event be held in abeyance until the NRC investigative team could evaluate the event and concur with the proposed actions. Subsequent correspondence (Ref. 7 & 8) clarified how information was to be provided for NRC review and how work was to be controlled). The Toledo Edison investigation has used a four-step process to evaluate each individual instance of anomalous equipment performance. These steps are:

1. Preparation and implementation of an Investigation and Troubleshooting Plan ("Action Plan");

2. Determination of Root-Cause Findings

3. Establishment of Corrective Action and Assessment of Generic Implications

4. Final Resolution and Documentation of Readiness for Restart.

For each step in the process, a formal report (or revision) is prepared, which forms the basis for technical review and assessment of proposed action by Toledo Edison. All of the Investigation and Troubleshooting Action Plans (Step 1) were reviewed with the NRC Fact Finding Team prior to implementation. All of the Findings, Corrective Actions and Generic Implication Reports are included in Appendices C.1.1 through C.1.3 to this report which will be updated as new reports are issued.

The Toledo Edison investigation has been performed by specific Toledo Edison and contractor personnel assigned to Action Plan Teams for each piece of equipment which was involved in the event and which was included in a "Freeze List" agreed upon between Toledo Edison and the NRC Fact Finding Team. In addition, a specific team was assigned to investigate the operating procedures and operations-related activities associated with the event. (See Section II.C.4 for a discussion of this investgation and its findings.)

The Toledo Edison investigation has been conducted in accordance with detailed guidelines. These provide for oversight by an internal Task Force of four members. The Task Force reviews all of the reports from the perspective of the technical content and the bases for any stated conclusions. Actions are not considered complete until the Task Force has approved the related report.

Investigation and Troubleshooting

Table II.C.1.1 presents a list of the equipment which failed or operated in an anomalous fashion during the event. This list represents the "Freeze List" which was agreed upon between Toledo Edison and the NRC Fact Finding Team. Each equipment item on this list was the subject of an Action Plan.

Action Plans were reviewed by the NRC Fact Finding Team prior to release for field related troubleshooting or testing. Each Action Plan followed a similar format. Troubleshooting and investigative activities were preceded by event evaluation and technical analyses.

Analysis and evaluation encompassed the collection and review of operational data covering the period prior to, during and after the transient as well as the maintenance and surveillance testing history of the equipment involved. Vendor engineering support was utilized where needed. From this effort, hypotheses for the root causes of failure or abnormal operation were formulated. The cognizant engineer(s) assigned to the particular Action Plan then developed plans for testing of the hypotheses either through checks, verifications, inspections, trouble-shooting, or equipment operational testing.

TABLE II.C.1.1

ACTION PLAN SUMMARY INDEX

ACTION PLAN	TITLE	NUREG 1154 Table 5.1 Item No.*
1A/1B	Auxiliary Feed Pump Overspeed Trips	4
1C	Auxiliary Feed Pump Manual/Auto Essential Control Problem	4
1D	Auxiliary Feed Pump Turbines Overspeed Trip Throttle Valve Problems	10
5/6/7	Steam and Feedwater Rupture Control System Trip/Main Steam Isolation Valve Closure	2
8	Main Feed Pump Turbine Control System	1
9	Turbine Bypass Valve 2-2 (SP13A2) Problem Analysis	14
10	Review of Operation of the Pilot Operated Relief Valve (PORV)	8
12	Auxiliary Feedwater System Valve Problem Analysis (AF-599 and AF-608)	5
15A&B	Source Range Detectors NI-1 and NI-2 Inoperabilities	7
16	Main Steam Header Pressure	3
18	Startup Feed Valve SP7A Problem Analysis	9
26	Inadvertent Auxiliary Feedwater Pump No. 1 Suction Supply Transfer From Condensate Storage Tank to the Service Water Supply	11
27	Auxiliary Feed Pump Turbine Main Steam Inlet Valve MS-106 problem Analysis	6

* Numbers are the corresponding item number from Table 5.1 of NUREG-1154. Items 12, Turbine Turning Gear, and 13, Control Room HVAC, were not included on the Equipment Freeze List, nor evaluated as part of the Toledo Edison investigation. Exclusion of these items was done with the concurrence of the NRC Fact Finding Team.

Guidelines also were developed and followed to ensure that the field performance of investigations did not result in the loss of information due to disturbance of components or systems. These guidelines are intended to preclude actions which might prevent finding the root cause of the failure.

The significant features of these guidelines are:

- All Action Plans for troubleshooting and investigative work were reviewed with NRC personnel prior to implementation.

- Only activities required by the reviewed and approved Action Plan can be conducted on Equipment Freeze List components unless such activities are: a) required for plant safety, or b) required by Technical Specifications.

- All Maintenance Work Orders (MWO's) relating to the investigation are handled as Nuclear Safety Related.

- Troubleshooting activities and repair activities must be accomplished on separate MWOs.

- MWOs must be approved by the Action Item Lead Individual and reviewed by QC for hold and witness points prior to their implementation.

- Only current drawings and controlled vendor manuals are used.

- The MWO must clearly document the scope, affected equipment, and the desired objective of the investigative activity.

- The sequence of activity must be documented on the MWO, or according to procedures specified in the MWO.

- All as-found conditions must be documented on the MWO. Visual inspections must be conducted and the MWO must document any missing, loose or damaged components.

- When unexpected conditions are noted during the investigation, work must be stopped and the Action Item Lead Individual must be notified. Documentation of the deficiency is required. The Lead Individual must sign off on the discrepancy prior to continuing the investigation.

- The results of the investigation must be documented on the MWO.

- No equipment can be shipped off site without prior approval of Nuclear Facility Engineering and Quality Assurance.

- All failed or removed components/equipment are required to be retained for ongoing review and examination. Complete traceability will be maintained.

Root Cause Findings

The results of investigation and troubleshooting activities are evaluated to determine whether the root cause of the failure or abnormal operation can be definitively ascertained. Following this evaluation, a root cause findings report is prepared. The root cause findings report documents analyses performed, field actions taken and significant findings.

If the investigation requires additional actions or testing, the planned additional activities are described in this report. When a root cause is identified, then a technical justification of findings is included.

Corrective Actions and Generic Implications

The Corrective Actions and Generic Implications are added to the root cause Findings Reports to describe proposed corrective actions that are required to resolve the anomaly and have the equipment or system ready for return to operable status. Corrective actions can include repairs, modifications, procedure changes, training, testing and other necessary actions. Action plans are prepared to support implementation of corrective actions. The generic implications of the findings to other similar equipment, systems or situations is documented for review, with details provided as to the scope of the equipment considered. Where generic corrective actions are known, such corrective actions are included in the report.

Summary of Activities Taken

The Findings, Corrective Actions, and Generic Implications Reports for equipment included on the Freeze List are contained in Appendices C.1.1 through C.1.3 to this report. For convenience, the Freeze List equipment has been grouped in a manner consistent with the concerns detailed in the enclosure to NRC's August 14, 1985 letter. Equipment items which are separately listed in the NRC letter are described in separate Appendices. Thus, the Appendices cover:

Appendix C.1.1	Equipment Items in NUREG-1154 Table 5.1 not separately addressed (Item II.A.11 of the enclosure to NRC's August 14 letter)
Appendix C.1.2	Reliability of AFW containment isolation valves and other safety related valves (Item II.A.5).
Appendix C.1.3	Reliability of the PORV (Item II.A.8)

Revisions to the Appendices of this report will include new Findings, Corrective Actions and Generic Implications Reports as they are changed due to ongoing investigative activities.

Appendix C.1.4 describes the confirmatory test program that Toledo Edison proposes to perform during restart power ascension of Davis-Besse. This program is intended to assure that the corrective actions implemented relative to equipment which malfunctioned during the June 9 event have

achieved their intended purpose of correcting the identified concern. This confirmatory test program is one component of the overall restart program that Toledo Edison will be implementing. Other components of the test program are discussed in Section II.C.7 and its associated Appendices.

II.C.2 - Decay Heat Removal Reliability Improvement Program

Introduction

The June 9 event involved several systems whose safety function is to remove decay heat. The importance of these issues led Toledo Edison to immediately implement a program to improve the overall reliability of decay heat removal at Davis-Besse. A Decay Heat Removal Task Force (DHRTF) was assembled to review all the systems related to decay heat removal including, but not limited to, those which were involved in the event. The task force was chartered to recommend actions which would improve the overall reliability of decay heat removal systems.

Item I.C. of the enclosure to NRC's August 14, 1985 letter to Toledo Edison identified the need for corrective actions to assure the reliability of systems which can mitigate loss of feedwater events. Several other items in the enclosure also address concerns related to decay heat removal. These items and the issues they relate to are: II.A.7, AFW system including the need for a diverse pump; II.A.10, Startup Feed Pump (SUFP) Operating Restrictions; and II.B.3, Plans for installing a new pump to replace the present SUFP. These concerns were addressed by TED's Decay Heat Removal Task Force.

Item II.B.2 of the enclosure to the NRC letter relates to programs to minimize the likelihood of inadvertent actuation of AFW. This concern relates specifically to the Steam Feedwater Rupture Control System

(SFRCS) which is also the subject of Item II.A.2. This system was also considered as part of the Decay Heat Removal Task Force program.

Background

To respond to concerns arising from the June 9, event, a Decay Heat Removal Task Force (DHRTF) was formed. The Task Force reviewed the design and operational features of the Davis-Besse Station for removing decay heat from the reactor coolant system. This included the Auxiliary Feedwater System, proposed Motor Driven Feed Pump, Steam Feedwater Rupture Control System (SFRCS), and Primary System Feed and Bleed capabilities.

The Task Force has recommended improvements to increase the reliability and operability of design features used for decay heat removal at Davis-Besse. In addition, the Task Force provided recommendations for reducing the complexity of SFRCS and simplifying its operation.

The Task Force was comprised of Toledo Edison personnel with specific Davis-Besse engineering and operations experience, and included outside experts with a broad base of experience in nuclear plant design, engineering, and operations. The outside experts included representatives of MPR Associates, Babcock & Wilcox, and Cygna. The Task Force has completed its review and has made recommendations. Those recommendations are now being reviewed in detail to determine if additional analyses are required and to identify appropriate short and long-term actions. The actions that will be taken as a result of this effort to improve decay heat removal reliability and performance of SFRCS are contained in Appendices C.2.1 and C.2.2 respectively.

Task Force Objectives

To achieve substantive improvements in plant reliability, the Task Force set the following specific objectives:

- Reduce the frequency of demands for emergency methods of decay heat removal (i.e., initiating of auxiliary feedwater flow) by assuring continued operation of the normal plant heat removal capabilities (main feedwater and main steam).

- Reduce the number of automatic system responses required to initiate emergency methods of decay heat removal.

- Reduce the potential for common mode failures which could disable means of decay heat removal.

- Evaluate diverse and redundant means of providing decay heat removal.

Task Force Approach

To achieve the above objectives, the following Davis-Besse plant design features for removing reactor decay heat at operating temperature and pressure were evaluated by the Task Force:

- Decay Heat Removal via Steam Generators (Secondary System Cooling)

  This is the normal, and preferred, method of removing decay heat. The Task Force review was directed at ensuring a source of feedwater to the steam generator via the:

  1. Main Feedwater and Main Steam System
  2. Auxiliary Feedwater System
  3. Motor Driven Feed Pump

  This included identifying improvements to the Steam Feedwater Rupture Control System (SFRCS) to reduce the frequency of main feedwater, auxiliary feedwater, and main steam isolation, and to reduce the overall SFRCS complexity.

- Feed and Bleed Cooling (Primary System Cooling)

  This is a backup method of decay heat removal which includes heat removal from the reactor core using high pressure reactor coolant makeup (through high pressure injection or makeup pumps) with energy removal through the Pilot Operated Relief Valve or pressurizer code safety valves.

For each of the Task Force objectives, specific existing design features and capabilities were reviewed and alternative design approaches which would provide significant improvements in plant reliability and operabil-

ity were evaluated. The Task Force used a combination of technical evaluations, preliminary scoping calculations, and engineering judgement in evaluating each alternative. More specifically, the following were considered:

- Plant design documentation including the FSAR, Mechanical, Electrical, and Control System Diagrams, Vendor Technical Manuals and related information as necessary

- Applicable plant operational experience including the June 9 event

- Interviews with Toledo Edison personnel cognizant of specific system and equipment design features and operation

- Interviews with senior plant operators regarding plant operation and response

- Scoping calculations and design comparisons with other plants as required to assess the feasibility and acceptability of alternatives

- Reliability analyses to assess relative improvements expected to be achieved for design improvements specifically related to the auxiliary feedwater system. This was done using existing Probabilistic Risk Assessment (PRA) models for this system.

Summary of Recommendations/Activities

As a result of the Task Force efforts, Toledo Edison has identified plant modifications and operational changes to improve the reliability of decay heat removal which should be pursued in the short term. This includes installation of the new Motor Driven Feed Pump. The implementation of the short term Task Force recommendations relating to AFWS will result in an order of magnitude improvement in AFWS reliability. Additionally, the installation of the MDFP will improve AFWS reliability by another order of magnitude. Other additional modifications and operational changes have been identified for long term implementation. In determining this course of action, current NRC requirements and guidance, including the General Design Criteria, Standard Review Plan, and applicable design standards, were considered.

The Task Force review resulted in specific recommendations for improvements to Davis-Besse systems. Recommendations relating to decay heat removal systems which have been approved and scheduled for implementation are detailed in Appendix C.2.1. Recommendations relating to SFRCS which have been approved and scheduled are described separately in Appendix C.2.2. This separate treatment is solely for convenience since SFRCS concerns were identified in a specific item of the enclosure to NRC's August 14 letter (Item II.B.2). The SFRCS recommendations were arrived at, reviewed, and approved in the same manner as those detailed in Appendix C.2.1.

A probabilistic evaluation of AFWS reliability, including the effect of the modifications being made, is described in Appendix C.2.3.

Technical evaluations are continuing, and may result in the identification of enhancements beyond those already described in Appendices C.2.1 and C.2.2.

II.C.3 Analysis Program

Introduction

Item II.A.1 of the enclosure to NRC's August 14, 1985 letter to Toledo Edison identifies a concern regarding

> "The adequacy of the analyses for loss of feedwater events, including time margins and consequences of alternative sequences."

In addition, item 5 of NRC's Confirmatory Action Letter to Toledo Edison, dated June 10, 1985, required in part:

> "An evaluation of the thermal shock considerations for both Steam Generators" and "the maximum S/G shell differential temperature."

Toledo Edison has instituted an analysis program which addresses these concerns. That program is discussed in this section. Items II.A.2 and II.B.4 of the enclosure to NRC's August 14, 1985 letter to Toledo Edison also identified, in part, a concern regarding "single failures" as they might relate to the Steam Feedwater Rupture Control System (SFRCS) and other safety systems. That concern is also addressed in this section.

Capability to Mitigate Loss of Feedwater Events

Analyses performed by Toledo Edison in 1979 and 1981 verified the procedural adequacy of decay heat removal via the safety grade auxiliary feedwater system as well as by an "equivalent third pump" method. The latter utilized a combination of primary and secondary side cooling using the startup feedwater pump, one makeup pump and the Pilot Operated Relief Valve (PORV). These analyses formed the basis for the procedures used to successfully mitigate the June 9 event.

As a result of the June 9 event, Toledo Edison commenced additional analysis efforts. These analyses evaluated the ability to remove decay heat from the reactor core via the secondary and/or primary systems. These analyses have been focused on:

- Demonstrating the adequacy of plant response under loss of all feedwater conditions, including time margins available for alternative actions.

- Benchmarking of the analytical code utilized.

- Evaluation of desirable system and procedural improvements.

The capability of the Davis-Besse Plant to perform Makeup/HPI feed and bleed cooling of the RCS following a complete loss of feedwater (LOFW) event has been particularly scrutinized. The analyses performed estab-

lished bounding "best estimate" responses of the Davis-Besse Plant to a LOFW event. Different times for operator action were assumed in an effort to provide results that would allow the evaluation of a range of initiating conditions which could be used to identify possible procedural improvements. Results of the analyses demonstrate that, with the use of existing plant equipment and timely operator action, feed and bleed cooling can be successfully employed at Davis-Besse to prevent core uncovery following a complete LOFW event. The analysis results are further described in Appendix C.3.1.

It should also be noted that the NRC Staff, in a presentation to the ECCS Subcommittee of the Advisory Committee on Reactor Safeguards on August 27, 1985, reported preliminary results of their own analytical work which agreed with TED's conclusions.

Effect of the June 9 Event on Plant Components

Toledo Edison requested B&W to evaluate the effect of the June 9 transient on the Davis-Besse steam generators. This evaluation is reported in B&W Document Number 32-115858300 "Davis-Besse Transient (6/85) - OTSG Structural Integrity" which is provided in Appendix C.3.2 of this report. In examining the transient relative to structural adequacy of the Once-Through-Steam Generators, loads on the following portions of the OTSG were investigated:

- Auxiliary Feedwater Nozzle
- Main Feedwater Nozzle

- AFW Jet Impingement Tube Stress
- Thermal Shock on Lower Tubesheet
- Axial Compressive Load in Tubes Due to Shell to Tube Temperature Difference.

The results of this evaluation show that the June 9, 1985 transient had no adverse structural effect on the steam generators. The report of this evaluation is included in Appendix C.3.2.

These results are consistent with the component Functional Specification CS(F)-3-92/NSS-14, which identifies initiation of feedwater to a dry OTSG as a transient with 20 cycles acceptable. B&W indicates that additional cycles may be shown to be allowable. Davis-Besse has recorded four such transients: 12/78, 3/79, 3/84 and 6/9/85.

The cooldown rate of 50° in six minutes that occurred during the June 9 event, is also bounded by the OTSG functional specification. The refill transient analysis uses a 40° drop in one minute. The long term cooldown rate on June 9 was within the specified 100°/hour.

Secondary chemistry remained within specifications, even though AFP pump suction was briefly taken from service water. This is based on sampling done immediately after the event.

Evaluation of the effects of the June 9 event on the Reactor Vessel is included in Appendix C.3.2.

Single Failure Susceptibility of the AFW/SFRCS

NUREG 1154 (Ref 4) and item II.A.2 of the enclosure to NRC August 14 letter raised concerns regarding single failure protection of the AFW/SFRCS actions relating to the Auxiliary Feedwater Containment Isolation Valves (AF 599 and 608).

The particular concern over single failure comes into play during a Main Steam Line Break situation upstream of one of the MSIVs (see Figure 1). This results in the unavailability of that steam generator for cooling. Both pumps are aligned by SFRCS to feed the intact steam generator. However, if both generators depressurize below the SFRCS setpoint for actuation on low steam generator pressure, the perception would be that the AFW containment isolation valve to the intact generator (AF599 or 608) would go shut. It would then require reopening to provide auxiliary feed to the steam generator. The failure of this one valve to reopen is then, the single failure in question.

Specific analyses were run for Main Steam Line Break accidents and documented in the Davis-Besse Final Safety Analysis Report. These include one analysis in section 15 4.4 of the body of the report as well as one

analysis in response to NRC Question 15.4.8 (this already includes a single failure). Both of these analyses were completed prior to the end of 1975. To maximize offsite consequences of this event, assumptions and techniques utilized in the simplified analyses were designed to specifically challenge core thermal limits. This was done by maximizing the amount and duration of the blowdown of the generators. This blow-down caused a high Reactor Coolant System cooldown rate which resulted in the worst core thermal conditions. Single failures were discussed in this initial licensing activity that would worsen the core thermal conditions and are basically inappropriate for the detailed evaluation of the AFW system issue raised in NUREG 1154.

To review the vulnerability of single failure of the AFW system response, the issue is whether the affected steam generator will isolate before a Main Steam Line Break (MSLB) would depressurize the intact generator and close its AFW containment isolation valve. MSLB and AFW/SFRCS single failure was a particular issue in response to NRC question 10.3.6 (FSAR, page 10.36-1). Single failure discussions for SFRCS and AFW were provided in the original licensing process. The resolution of these questions implies that the second AFW valve would not be expected to isolate. However if this specific question would have been raised during the initial licensing action, the issue would probably have discussed the following :

1. The valves AF 599 and 608 themselves have double motor starters installed. This addresses the issue of one valve inadvertently going closed when it is the only flow path to the intact steam generator. This single failure concern was specifically

reviewed and resolved during the original licensing process and documented in the NRC Safety Evaluation Report (Ref. 10) Related to Operation of Davis-Besse (NUREG 0136) Supplement 1, Section 7.4.1 pg. 7-5.

2. Steam line non-return valves installed down stream of the MSIV's limit the effects of a steam line rupture if it occurs in the auxiliary building or containment structure. During power operation the weight of the valve discs is held open by steam flow. Upon loss of steam flow or flow reversal, the valve discs close rapidly. The closure of these valves and therefore the limiting of energy passing through them were given credit in this licensing process for compartment pressurization analyses.

3. Credit was given in the Steam Line Break case for the closure of turbine stop valves (TSV) as a single failure option to the Main Steam Isolation Valves. (NRC SER for Davis-Besse, NUREG-0136 (Ref. 9), Section 14.2.2, pg. 15-3.). The turbine stop valves receive two trip signals. The first signal comes as a turbine trip following a reactor trip and originates from the Control Rod Drive Control System receiving a trip signal from the Reactor Protection System. A later, second signal to the turbine stop valves is received from the steam generator low pressure trip of the SFRCS and also commands valve closure.

4. The turbine stop valves have a significantly shorter response time than the Main Steam Isolation Valves; <2 second vs <6 seconds

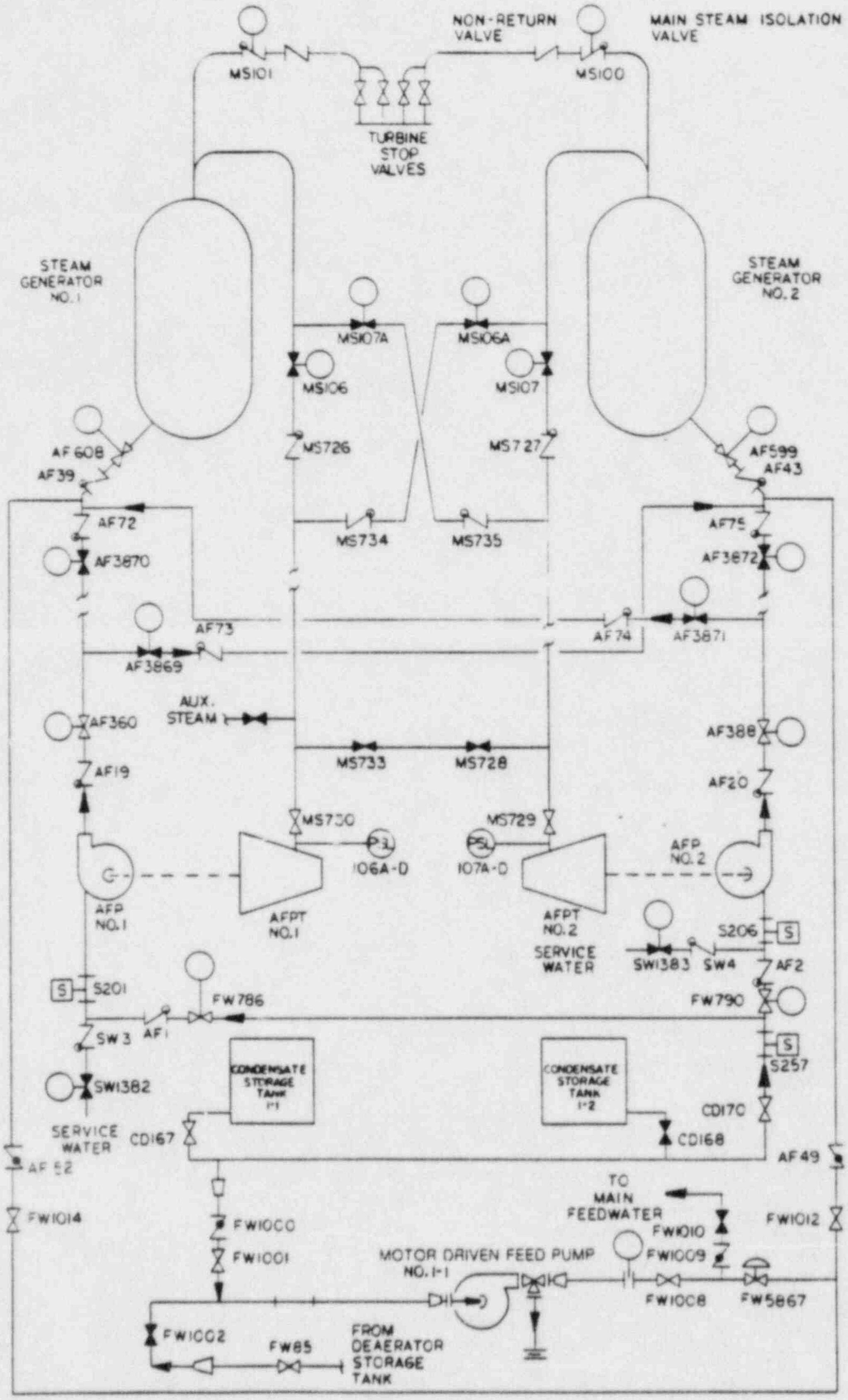
for the MSIVs. If a single failure is being taken elsewhere in the event, the shorter response time of the turbine stop valves would terminate depressurization early.

Prior to return to power Toledo Edison is modifying the SFRCS to disable the second AFW containment valve isolation feature. This single failure is therefore resolved for future operation. Analyses that will be able to more specifically illustrate the applicability of past concerns are being pursued in relation to longer term SFRCS changes and will be provided in Appendix C.3.3 when completed.

Details of the analyses done throughout the FSAR had specific objectives and therefore specific assumptions and techniques for worsening the event. Credit was taken for several equipment components in different portions of the document that could more easily show that the licensing evaluations bound this concern. The specific FSAR discussion and questions relating to AFW and SFRCS would indicate that this need not be considered a single failure potential.

Adequacy of Other Engineered Safety Feature Systems

In light of the single failure vulnerability issue raised for SFRCS, Toeldo Edison is reviewing the Davis-Besse Reactor Protection and Engineered Safeguard Features Actuation System for similar susceptibilities. This action addresses Item II.B.4 of the enclosure to NRC's August 14, 1985 letter. The results are discussed in Appendix C.3.3.



NON-RETURN VALVE
MAIN STEAM ISOLATION VALVE
MS101
MS100
TURBINE STOP VALVES
STEAM GENERATOR NO. 1
STEAM GENERATOR NO. 2
MS107A
MS106A
MS106
MS107
AF608
AF39
AF599
AF43
MS726
MS727
AF72
AF75
MS734
MS735
AF3870
AF3872
AF73
AF74
AF3871
AF3869
AUX. STEAM
AF360
AF388
MS733
MS728
AF19
AF20
MS730
MS729
106A-D
107A-D
AFP NO. 1
AFPT NO. 1
AFPT NO. 2
AFP NO. 2
S206
SERVICE WATER
SW1383
SW4
AF2
S201
FW786
FW790
AF1
SW3
CONDENSATE STORAGE TANK 1-1
CONDENSATE STORAGE TANK 1-2
S257
SW1382
CD170
SERVICE WATER
CD167
CD168
AF52
AF49
TO MAIN FEEDWATER
FW1014
FW1000
FW1010
FW1012
FW1001
MOTOR DRIVEN FEED PUMP NO. 1-1
FW1009
FW1008
FW5867
FW1002
FW85
FROM DEAERATOR STORAGE TANK

FIGURE 1

II.C.4. Review of Operations Procedures and Training

Introduction

The review of the June 9 event indicated that operations personnel performed admirably. Difficulties were experienced, but they did not preclude the prompt restoration of auxiliary feedwater flow. These difficulties did, however, identify the need for an assessment of the event from the perspective of operations procedures, practices and training.

Several of the items in the enclosure to NRC's letter to Toledo Edison of August 14, 1985 also discussed operational procedure concerns. These included Item II.A.3 regarding potential adverse effects of plant physical security and administrative features on operator actions; Item II.A.6 concerning the adequacy of procedures and training for reporting events to the NRC Operations Center; Item II.A.12 concerning the adequacy of procedures including determination that provisions calling for "drastic" action are clear and precise; and, Item II.B.1 concerning the adequacy of procedures, equipment and training for starting or restarting equipment for mitigating a loss of feedwater event.

Toledo Edison has conducted a review of the operational implications of the June 9 event, which included the considerations raised by the NRC. That review, and the resulting actions, are discussed in this section and Appendices C.4.1 and C.4.2. Appendix C.4.1 discusses the

actions which will be taken relative to operating procedures and training. Appendix C.4.2 discusses actions related to the effects of physical security provisions on plant operations.

Review Approach

Toledo Edison's review was intended to determine whether operator actions taken during the event were in compliance with existing procedures. It also included verification that the procedures were technically consistent with the latest Babcock & Wilcox Abnormal Transient Operating Guidelines (ATOG). Where concerns were identified, the root cause was determined and recommendations were made to change procedures, hardware, training, or administrative practices as necessary, to address the root cause.

An action plan committee, chaired by the Operations Superintendent, conducted the review. The committee included representatives from Operations, the Technical Section, and the Training Department.

Overall, while recommending some changes and improvements, the committee concluded that operator actions during the event were appropriate and that the procedures were technically correct.

The results of this review are discussed in Appendices C.4.1 and C.4.2 as noted above.

II.C.5. Control Room Improvement Program

Introduction

Item II.A.9 of the enclosure to NRC's letter to Toledo Edison dated August 14, 1985 identifies as a concern regarding "The adequacy of Control Room instrumentation and controls." This section describes what actions Toledo Edison has taken or will take to address this concern.

Background

As a result of the accident at TMI-2, the NRC, in NUREG 0737, required that all plants develop and implement a Detailed Control Room Design Review (DCRDR) program. Toledo Edison, with the assistance of Impell Corporation and Essex Corporation, developed a DCRDR program plan which was submitted to the NRC on June 15, 1983 (Ref. 12). Through the implementation of the program plan, a list of Human Engineering Deficiencies (HED's) was identified, classified and submitted as a summary report to the NRC on June 29, 1984 (Ref. 13). Among the HED's classified as significant were the location and physical arrangement of the Steam Feedwater Rupture Control System (SFRCS) manual actuation pushbuttons and the location of the SFRCS trip reset pushbuttons for the Startup Feedwater Valves (SP7A, SP7B). These deficiencies contributed to the June 9 event. The fact that these

had been previously identified in the DCRDR indicates that there is no apparent need to question the DCRDR evaluation process as a result of the June 9 event. The event does indicate, however, a need to reassess the priority and schedule for implementing corrective actions related to the significant HEDs. This reassessment will be accomplished as part of the Systems Review and Test Program described in Section II.C.7 of this report.

As part of the System Review and Test Program, System Review Groups will consider the significant HEDs identified by the DCRDR. All significant generic HEDs will be considered as well as the specific HEDs related to systems being reviewed under the program. Each HED reviewed will be assessed to determine whether correction is required in the short-term, i.e. prior to restart, and these will be resolved. Remaining HEDs, those not requiring pre-startup resolution, will be addressed as part of the continuing implementation of the DCRDR program.

With respect to the significant HEDs which affected the course of the June 9 event, appropriate compensatory or corrective actions will be implemented prior to restart. The SFRCS Manual actuation switches will be rearranged consistent with appropriate human factor considerations prior to restart. In addition, guards will be installed over the switches which are used most infrequently. The new arrangement has been reviewed for human factors considerations. In the new arrangement, low steam generator pressure actuation switches for a given channel will be in the same relative location in each column of switches. Thus, an operator will no longer have to actuate the <u>first</u> switch in one

column and the second switch in the other column (for example) to manually initiate actions for low pressure in one steam generator. In the longer-term, changes to the SFRCS logic are expected to reduce the total number of switches to four, which will then be relocated to the SFRCS panel.

The other major control room design problem experienced was related to the pushbutton arrangement for the startup feedwater valves used when aligning the Startup Feedwater Pump. This problem is no longer considered relevant since the new motor-driven feed pump will be aligned differently and any operational considerations related to use of the new pump are being considered as part of the design process.

One change not identified in the DCRDR will be made. Based upon experienced gained from the June 9 event, the PORV position indication, currently located on the Post-Accident Monitoring Panel (PAM), will be duplicated at a position adjacent to the PORV control switch. This will provide an improvement in the currently acceptable PORV position indication and allow the operator to better monitor PORV position.

II.C.6 Shift Technical Advisor

Introduction

Item II.A.4 of the Enclosure to NRC's letter to Toledo Edison dated August 14, 1985 identifies as a concern: "The availability of and role for the Shift Technical Advisor assistance during complex operating events." This section describes changes which have been made to address this concern.

Background

Prior to and including June 9, 1985, Shift Technical Advisors (STAs) at Davis-Besse stood 24 hour shifts. For part of their shift, t e STAs used sleeping facilities in the Davis-Besse Administration Building (DBAB). The DBAB is located on the Davis-Besse site, but outside the protected area. During the June 9, 1985 event, the STA had to drive approximately one-half mile to reach the plant. The STA arrived in the control room within 10 minutes of being notified of the trip.

Immediate Actions

The rotation of STAs has been modified such that the duty is now carried out in 12 hour shifts rather than 24 hours. The STA now spends his entire shift within the protected area and has an office

within 1-2 minutes of the Control Room. This assures that the STA is immediately available to the control room and would be immediately knowledgeable of plant conditions.

As part of the Performance Enhancement Program (PEP), STAs have been receiving training to give them the degree of knowledge which would be necessary to fulfill the responsibilities of the Emergency Duty Officer. The training will allow the STA to assist the Shift Supervisor in determining appropriate Emergency Action Levels and Protective Action Guidelines. The STA will advise the Shift Supervisor of these conditions; however, the Shift Supervisor will maintain the overall responsibility of Emergency Duty Officer. This training will be completed for all current STAs before restart.

Long-Term Actions

For the long-term, new STAs are being trained who will be assigned permanently to operating shifts. These personnel, presently considered Assistant STAs (ASTAs) were hired in early 1984. They are presently participating in an intensive training program. The program includes both classroom training and practical, on-shift, training in alternating blocks of six weeks each. The program is intended to qualify the ASTAs to take the NRC Senior Reactor Operator (SRO) exam. Continued implementation of this program will include:

- Simulator training for all ASTAs to begin in early September, 1985.

- Additional classroom training.
- A final shift assignment of 5 to 6 months duration to complete practical qualification.
- Additional simulator training.
- NRC SRO examination.

Arrangements are also being made for the ASTAs to obtain practical operating experience at a university reactor. This experience is intended to support their receipt of SRO licenses, since they do not have licensed RO experience. The long-term program will be completed and the new STAs, will be a functioning part of each shift by January 1, 1987.

II.C.7 System Review and Test Program

Introduction

Toledo Edison has established a program to review the history of systems important to the safe operation of the Davis-Besse Station. This review will be performed under the auspices of the Nuclear Mission's Engineering Division. The review is intended to identify problems which may potentially impact the ability of those systems to perform the functions they must perform for safe operation of the plant, to identify the corrective actions necessary to resolve those problems, and to identify any special testing of the system that should be performed during restart power ascension. The program will also review the scope of surveillance testing conducted on those systems to assure they are properly tested.

Background

The June 9 event focused concern on equipment maintenance at Davis-Besse. Equipment problems of a recurring nature contributed to the event. Toledo Edison shares the concern of the NRC regarding assurance of adequate maintenance of all systems and components and the proper identification of the root cause of any such failures. It was concluded, therefore, that it is necessary to evaluate past equipment history to identify significant or recurring equipment problems to assure that the root cause is identified and corrected.

The June 9 event also revealed that the scope of surveillance testing required improvment to assure that the systems would function under a wide range of possible system conditions. Toledo Edison believes that the scope of surveillance testing must be sufficient to assure that the systems will perform their design functions. Finally, the System Review and Test Program activity will also integrate the generic implications information resulting from the event investigation to assure that appropriate consideration is given to these factors in the power ascension test program.

Program Objectives

The objectives of the System Review and Test Program can be stated as follows:

- Evaluate systems important to safe plant operation to identify known significant or recurring maintenance and operations problems and propose corrective actions, where appropriate.

- Implement short-term corrective actions on a schedule consistent with timely restart of the unit.

- Evaluate the scope of existing surveillance test program for each system important to safe plant operation. Identify additional testing required to assure that systems will perform the functions important to safe plant operation.

- Identify testing requirements necessary to verify the adequacy of new system modifications.

- Prepare and conduct a test program to assure that systems important to safe plant operation are fully functional.

Scope of Review

The systems selected for review in this program are those deemed to have the most impact on the safe operation of the Davis-Besse Station. Not all of the systems included in the scope of review are covered by Technical Specifications; and conversely, not all those systems mentioned in Technical Specifications are included in the scope of this review. The systems included in the scope of this review are listed in Table II.C.7.1.

TABLE II.C.7.1

SYSTEM REVIEW AND TEST PROGRAM

SPECIFIC SYSTEMS INCLUDED

Group 1	Reactor Coolant System
	High Pressure Injection
	Core Flooding System
	Decay Heat Removal and Low Pressure Injection
	Containment Spray System
	Containment Emergency Ventilation
	Containment Air Cooling and Hydrogen Control
	Makeup and Purification System
Group 2	Electrical 125/250 VDC (Includes Battery Room H&V)
	Electrical 4.16 KV System (13.8/4.16 KV Transformers)
	Electrical 480 V Distribution (Includes Inverters and Required Transformers)
	Electrical 13.8 KV System (Includes Startup and Auxiliary Transformers)
	Emergency Diesel Generators (Includes "Q" Fuel Oil Tanks and Diesel Room Ventilation)
	Instrument AC Power (Includes Inverters and Required Transformers)
Group 3	Anticipatory Reactor Trip System
	Control Rod Drive Control System
	Incore Monitoring (Includes Core Exit TC)
	Reactor Protection System
	Steam Feedwater Rupture Control System
	Safety Features Actuation System
	Integrated Control System
	Security System

Group 4 Control Room Normal and Emergency H&V Systems
Station and Instrument Air
Station Fire Protection
Component Cooling Water System
Service Water System

Group 5 Auxiliary Feedwater System
Main Steam
Steam Generator System
Main Feedwater System

The system history review will apply to each of the above listed systems. Although surveillance testing, as required by Technical Specifications is not applicable to some of the above systems, periodic testing requirements, as necessary to assure operability of those systems, will be reviewed.

Program Approach

Five System Review Groups have been established to conduct this program. Systems are assigned to each in accordance with the groupings indicated in Table II.C.7.1. The groups consist of Toledo Edison engineering personnel and experienced support personnel from the nuclear industry. For each system, the lead review responsibility will be assigned to a specific Toledo Edison individual. The support personnel are highly qualified industry representatives experienced in system design, operation, and testing.

The groups will conduct a review of past system performance by selected review of available documentation and interviews of Station personnel experienced in the operation, maintenance, and testing of the systems. The review will identify known recurring problems, and the review groups will propose corrective actions as necessary, to resolve those problems. The groups will also review surveillance testing associated with each system to identify and resolve weaknesses in the program.

The results of these efforts will be documented by the System Review Group and then will be reviewed and approved by an Independent Process Review Group. This group is composed of senior Toledo Edison engineering personnel and other top level industry experts operating in accordance with a formal charter.

System Performance Review

A review of past equipment performance requires an examination of historical information on the systems. Such information is available in many different formats. The following types of historical information are being considered:

- Licensee Event Reports (LERs) and Deviation Reports (DVRs). These provide information on the more significant system and component failures. The total number of LERs and DVRs is relatively small, and the information contained in the reports is generally concise.

- Nuclear Power Plant Reliability Data System (NPRDS) reports. There are more of these, but they are somewhat less complete than the LERs and DVRs.

- Maintenance Work Orders (MWOs), the most voluminous source of available information. MWOs document all types of activities. In addition to corrective actions, MWOs are used to document preventive maintenance and contain system modification work.

- Outstanding Facility Change Requests (FCRs). These provide a convenient listing of identified problems and proposed corrective actions. The total number of outstanding FCRs is relatively small, and the information is easily accessible.

- Human Engineering Deficiencies (HEDs) which were developed as part of the Detailed Control Room Design Review program. The HEDs document deficiencies related to the man-machine interface between the operator and control room indications and controls.

- Transient Analysis Program (TAP) Reports. These document the results of post-trip or transient reviews. These reports can be redundant with LERs and DVRs for systems covered by Technical Specifications, but are useful for problems related to systems not covered in Technical Specifications.

- Davis-Besse plant personnel experience is an additional significant historical information resource. Davis-Besse's operating history has been sufficiently short, and the Station staff has been sufficiently stable to provide reasonable assurance that plant personnel are aware of most significant and recurring equipment problems.

The system review program will, to varying degrees, take advantage of all of the above data sources. The information available in LERs and DVRs, outstanding FCRs, HEDs and TAP reports will be examined to identify known equipment problems. To the extent practical, MWOs and NPRDS data will also be reviewed. As a minimum, outstanding MWOs as well as Preventive Maintenance activities will be reviewed. The results of these reviews will provide a basis for questions to be asked during interviews of Station Operations and Maintenance personnel.

The review of documentation and information obtained from the interview process will identify any recurring problems which will be documented.

Corrective Action Generation

Depending upon the significance of the problem, corrective actions may be either short term or long term. The System Review Groups will evaluate each identified problem against an established set of criteria to determine the significance of the problem and whether short term or long term corrective action is required.

For those problems determined to require short term corrective action, proposed resolutions will be developed by the System Review Groups. These actions will be completed prior to restart. Corrective actions for problems slated for long term resolution will be identified after startup.

Short term corrective action may include hardware modifications or procedural changes. In cases where the corrective action may require an unreasonably long time to resolve, compensatory actions will be considered for interim use. Alternative corrective actions will be proposed, where feasible, to allow the most effective to be selected for implementation.

The evaluation of the problems for significance and a description of the proposed corrective actions will be documented in a report which will be

presented to the Independent Process Review Group (IPRG). The IPRG will review the problem evaluation and proposed corrective actions. The IPRG will accept or reject the proposals or will recommend alternatives to the proposed corrective actions. Upon approval by the IPRG, the chosen corrective action will be implemented.

Surveillance Test Review

Prior to startup, the System Review Groups will evaluate the scope of surveillance testing that currently exists for their respective systems. The groups will review the testing for completeness and adequacy of testing with respect to design basis conditions. Concerns identified by the group will be documented and proposed test outlines for newly required testing will be created. The results of each system testing review will be forwarded to the IPRG. The IPRG will review the identified concerns and concur with the need for additional testing, if appropriate. The IPRG will evaluate the proposed test outline and conceptually approve the testing as appropriate.

After the newly generated test requirements are conceptually approved, the System Review Group will initiate the development of new or revised surveillance tests which will be processed in accordance with existing procedural programs.

Test Program

In conjunction with the development of new surveillance test requirements, the System Review Groups will develop proposed test outlines for post modification testing on their assigned systems. If testing beyond the scope of the newly modified surveillance test program is required, an outline for a proposed Test Procedure (TP) will be developed. These test outlines will be submitted to the IPRG in the same manner as the surveillance test outlines. Test Procedures will be developed following approval of the outlines by the IPRG.

The new or revised surveillance tests, new test procedures, and other surveillance testing necessary to satisfy Technical Specification operability requirements will be scheduled and conducted in accordance with existing plant testing programs. The results of tests performed on systems will be reviewed by the designated System Review Group. The System Review Group will assume the responsibility for resolution of any identified problems.

III. CONCLUSIONS

Toledo Edison submits that the Course of Action presented in this document provides definitive evidence that corrective actions to resolve previous management and programmatic problems of Davis-Besse have been taken. The new Toledo Edison program assures that necessary management, staff resources, facilities, and management practices exist to establish Davis-Besse as an excellent operating facility.

Toledo Edison's management, both Corporate and Nuclear Mission, are fully committed to this Course of Action. This position, as stated by the Chairman and Chief Executive Officer in his transmittal letter, assures that all actions required to fulfill the Course of Action will be accomplished.

As contained in this document, the results of Toledo Edison's investigation of the June 9 event coupled with the specific corrective actions being taken by Toledo Edison provides assurance that Davis-Besse can be returned to operation, on or about November 1, 1985. In addition, the information presented in this document concerning both the June 9 event and the overall Course of Action provide answers to the concerns raised by the NRC in their letter of August 14, 1985.

Appendix III-1 presents a summary of those actions Toledo Edison intends to take, as detailed in this report. The actions are identified as those which will be accomplished prior to restart and those which are longer term.

Appendix III-2 presents the schedule for major activities to be accomplished prior to restart.

REFERENCES

1. Response to SALP 4 Report, TED to NRC, February 4, 1985 (Serial 1-497)

2. Inspection Report 84-11 (SALP 4 Report), NRC to TED, December 6, 1984 (1-1072)

3. Investigation of June 9 Event, TED to NRC, July 18, 1985 (Serial 1-553)

4. NUREG 1154, Loss of Main and Auxiliary Feedwater Event at the Davis-Besse Plant on June 9, 1985 (Generic Letter 85-13), NRC to TED, July 5, 1985 (1791)

5. NRC Areas of Concern Resulting from June 9 Event, NRC to TED, August 14 1985 (1798)

6. Confirmatory Action Letter 85-06 (CAL 85-06), Loss of Feedwater Flow to Steam Generator, NRC to TED, June 10, 1985 (1183)

7. TED Response to CAL 85-06, TED to NRC, July 1, 1985 (Serial 1-541)

8. Clarification of Item 1 in CAL 85-06, NRC to TED, August 14, 1985 (1-1231)

9. NRC-SER NUREG 0136 (Section 15.2.2, P. 15-3), December 1976

10. NRC-SER NUREG 0136 Supplement 1 (Section 7.4.1, P. 7-5) April 1977

11. Davis-Besse Final Safety Analysis Report (Section 15.4.4, P. 15-104)

12. Update on Detailed Control Room Design Review (DCRDR), TED to NRC, June 15, 1983 (Serial 958)

13. DCRDR Summary Report, TED to NRC, June 29, 1984 (Serial 1057)

ACRONYM GLOSSARY

ABs	Abnormal Procedures
AFP	Auxiliary Feedwater Pump
AFPT	Auxiliary Feed Pump Turbine
AFW	Auxiliary Feedwater
ANS	American Nuclear Society
ASME	American Society of Mechanical Engineers
ASTA	Assistant Shift Technical Advisor
ATOG	Abnormal Transient Operational Guidelines
B&W	Babcock and Wilcox
C&HP	Chemistry and Health Physics
CAGIR	Corrective Action and Generic Implication Report
CNRB	Company Nuclear Review Board
CST	Condensate Storage Tank
DADS	Data Acquisition and Display System
DB	Davis-Besse
DBAB	Davis-Besse Administration Building
DCRDR	Detailed Control Room Design Review
DHRTF	Decay Heat Removal Task Force
DVR	Deviation Report
EAL	Emergency Action Level
ECCS	Emergency Core Cooling System
EDO	Emergency Duty Officer
EP	Emergency Procedure
EPRI	Electric Power Research Institute
ESFAS	Emergency Safety Feature Actuator System
FCR	Facility Change Requests
FSAR	Final Safety Analysis Report
HED	Human Engineering Deficiencies
HPI	High Pressure Injection
HVAC	Heating, Ventilation, and Air Conditioning
I&C	Instrumentation and Control
ICS	Integrated Control System
IE	Inspection and Enforcement
INPO	Institute of Nuclear Power Operations
IPRG	Independent Process Review Group
IST	Integrated System Test
LER	Licensee Event Report
LOFW	Loss of Feedwater
LPI	Low Pressure Injection
MBO	Management by Objectives
MFP	Main Feed Pump
MFPT	Main Feed Pump Turbine
MFW	Main Feedwater
MOVATS	Motor Operated Valve Analysis and Test System
MP	Maintenance Procedures
MSIV	Main Steam Isolation Valves
MU	Makeup
MW_t	MegaWatts Thermal
MWO	Maintenance Work Orders

NI	Nuclear Instrumentation
NPRDS	Nuclear Plant Reliability Data System
NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
NUMARC	Nuclear Utility Management and Human Resources Committee
OTIS	Once Through Integrated System
OTSG	Once Through Steam Generator
PAM	Post-Accident Monitoring Panel
PEP	Performance Enhancement Program
PM	Preventive Maintenance
PORV	Pilot Operated Relief Valve
PRA	Probabilistic Risk Assessment
PSF	Personnel Support Facility
PSI	Pounds per Square Inch
PSIA	Pounds per Square Inch Absolute
PSIG	Pounds per Square Inch Gauge
P-T	Pressure-Temperature
QA	Quality Assurance
QC	Quality Control
RCS	Reactor Coolant System
RO	Reactor Operator
RPS	Reactor Protection System
SALP	Systematic Assessment of Licensee Performance
SFAS	Safety Features Actuation Signal
SFRCS	Steam Feedwater Rupture Control System
SG, S/G	Steam Generator
SOERS	Significant Operating Event Reports
SPDS	Safety Parameter Display System
SRB	Station Review Board
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
SUFP	Startup Feed Pump
SW	Service Water
TAP	Transient Analysis Program
TED	Toledo Edison
TMI	Three Mile Island
TP	Test Procedure
TSD	Training Systematic Development
TSV	Turbine Stop Valves
TVA	Tennessee Valley Authority
USAR	Updated Safety Analysis Report

sm c/13

TOLEDO EDISON COMPANY

DAVIS-BESSE NUCLEAR POWER STATION

COURSE OF ACTION REPORT

SEPTEMBER 9, 1985

CONTROL COPY NO. 15 ISSUED TO USNRC, WASHINGTON

VOLUME 2

IV APPENDICES

Detailed information regarding the results of efforts described in the Course of Action report are contained in these Appendices.

The number of each Appendix relates to the corresponding section of the main report. Appendices relating to a section of the Detailed Course of Action (Part II of the Course of Action Report) are numbered using the letter and number designation of the report section followed by a sequential appendix number. Thus, Appendices C.1.1, C.1.2, C.1.3 and C.1.4 all relate to section II.C.1, Event Investigation, of the Course of Action Report.

As noted in the Course of Action Report, these appendices will be updated and reviewed by future submittal to reflect completion of additional evaluations and refinement of planned changes.

For convenience, the Table of Contents for both Volumes of the Course of Action Report is reproduced on the following pages.

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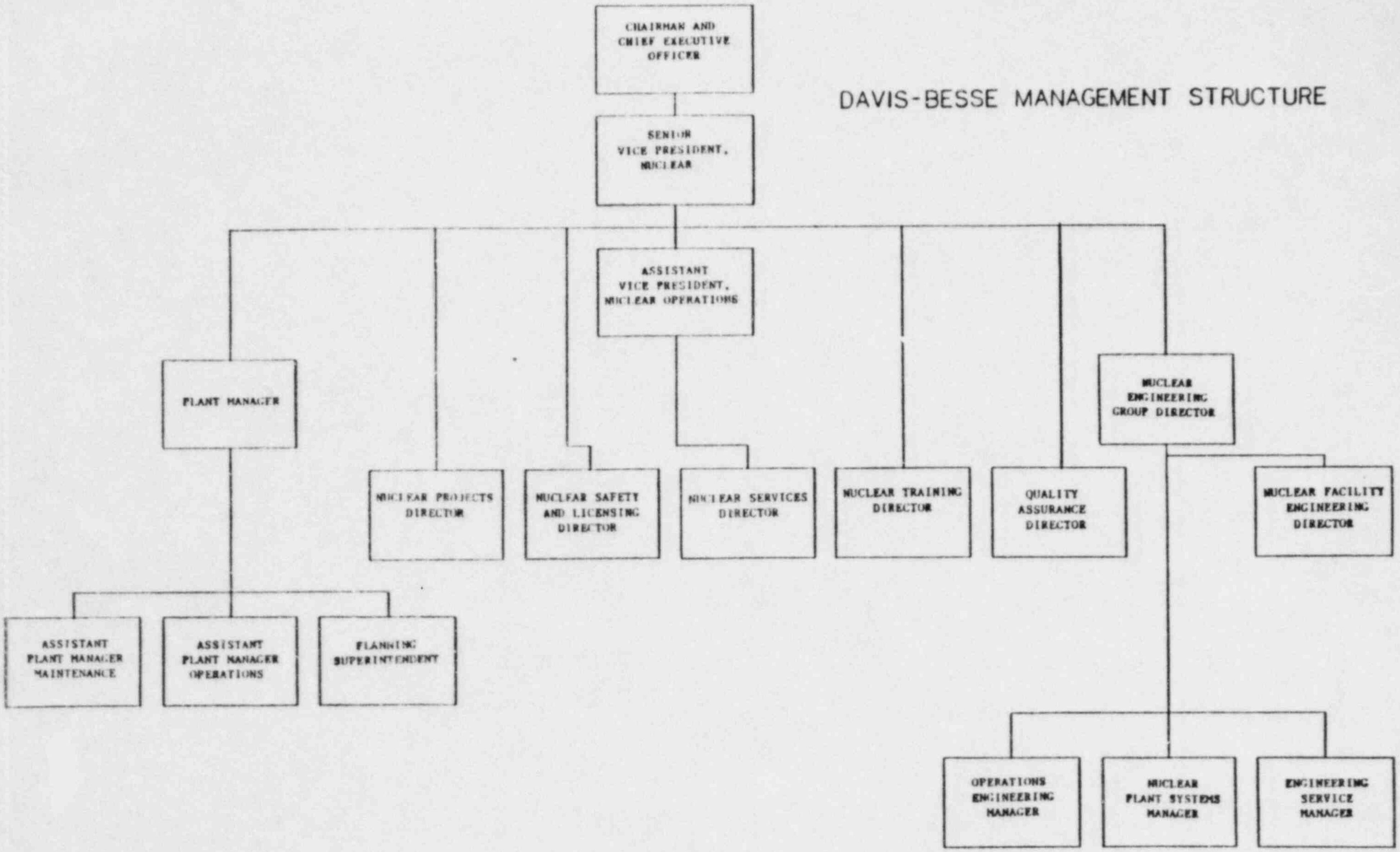
APPENDIX B.1.1 - CHARTS OF ORGANIZATION

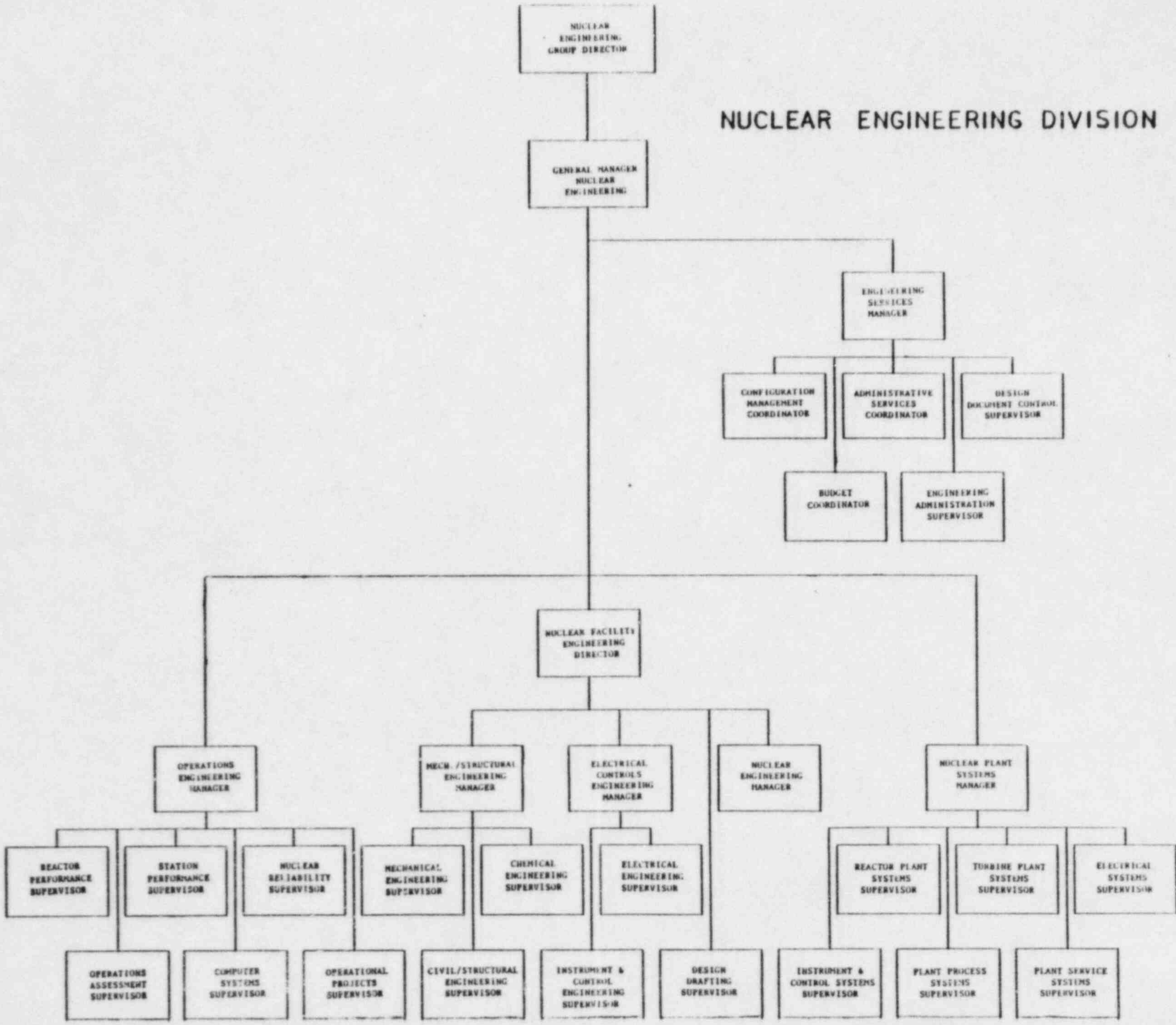
Presented in this Appendix are three organization charts:

- Davis-Besse Management Structure
- Nuclear Engineering Division
- Davis-Besse Maintenance Department

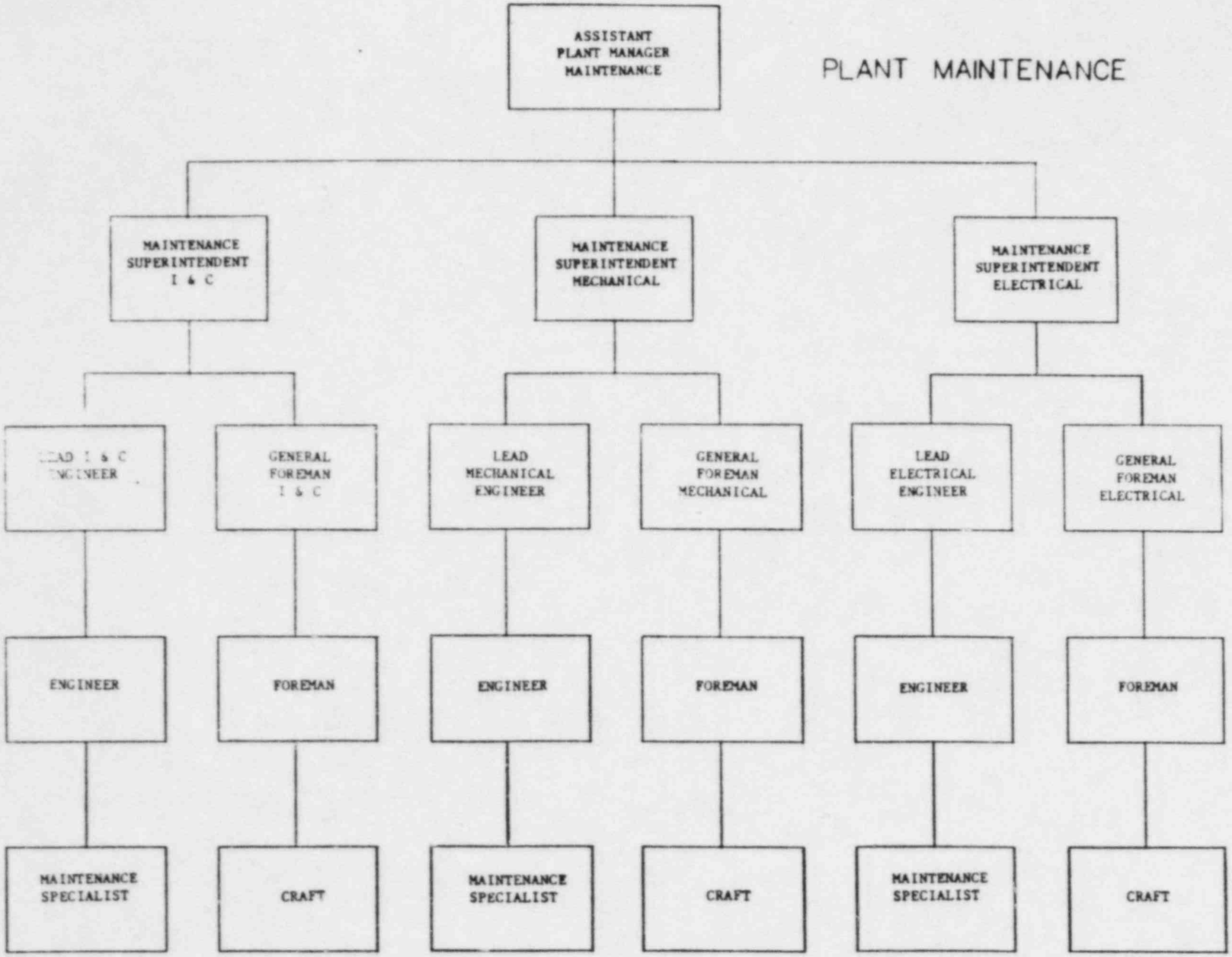
DAVIS-BESSE MANAGEMENT STRUCTURE



NUCLEAR ENGINEERING DIVISION



PLANT MAINTENANCE



APPENDIX B.2.1 REASSIGNMENT OF PERFORMANCE ENHANCEMENT PROGRAM (PEP) AND SALP IMPROVEMENT PROGRAM (SALP) ACTIVITIES

As stated in Section II.B.2, all of the open items in both the PEP and SALP programs were reassessed during July-August, 1985. As a result, the open PEP and SALP items have been grouped into three (3) priority rankings. These are:

- Items which are high priority and will receive commensurate emphasis and resources.

- Items which, while not high priority, are close to completion and will be completed as scheduled.

- Items which will be accomplished in the normal course of business. In this instance, specific "products", such as a statement on managerial style" committed as part of PEP Action Item A-4, will not be produced. Rather, the new management team will assure that the underlying concept becomes an integral part of the way work is accomplished at Toledo Edison.

A list for each ranking is presented below. For each item, reference is made to its source. For PEP items which were interim actions, original classification was by a scheme using two numbers separated by a dash (e.g., 08-1(17)). PEP Action Plans are identified by a letter combination and number (e.g., D/P-1). SALP improvement items were not numbered in either scheme and are simply labeled "SALP".

I. Emphasis and Resources will be applied to the following PEP Implementation Plans Interim Actions and SALP Items On A Priority Basis

- Prepare detailed position descriptions for all personnel positions in the new organization (B-3). This action will be completed by October 30, 1985.

- Management by Objectives (A-2 and E/SP-9) - An integrated approach to goals, objectives and strategic planning within the nuclear mission. This is ongoing and will be a continuous process.

- Management Training (A-3) - Establish a core of management training programs to present basic management skills. Actions are in progress to hire a supervisor who will be responsible for this effort.

- Merit Review & Salary Administration (B-1 and B-2) - Implement a merit review system to reflect performance and maintain a salary administration program to attract and retain key experienced quality personnel. This will be completed by November 1, 1985.

- Configuration Management (C/CM-1) - Implementation of the program to establish a data base for equipment and systems, provide system descriptions, and ensure accurate documentation of administrative systems and procedures. Includes PEP Interim

Actions on System Auxiliary Diagrams (06-1(04)), Alpha Drawing Logs (12-1(02)), Drawing Control Project (12-1(09)), and Drawing Log (12-1(18)). The Request for Proposal (RFP) for this multi-million dollar effort is in final draft form.

- Fire Protection (D/FP-1) - Provide cost-effective fire protection improvements and decreased regulatory exposure, including protection of employees and capital investment. Includes PEP Interim Action 14-1(03). All high priority modifications will be completed before the start of Cycle 6.

- Nuclear Mission Procedures (D/P-1) - Provide a means to generate and maintain nuclear program procedures necessary to control inter-divisional nuclear program activities. This activity is scheduled for completion by June, 1986.

- QA Awareness Program (D/QA-1) - Identify and document individuals' responsibilities for adherence to the QA program and train personnel on these roles. Initial training of TED personnel will be accomplished by September, 1986.

- STA capability to assume Interim EDO Function (E/SP-2) - Provide training to allow Shift Technical Advisor to assist the Shift Supervisor in performing the interim Emergency Duty Officer Function. This training will be completed prior to startup.

- Fill 13 positions' in Nuclear Training (08-1(17)) - A priority with the new management. All but five are filled; the remainder will be filled as quickly as possible.

- Fill 10 positions in Licensing - (10-3(04)) - Five positions have been filled. Filling the remaining five open positions is priority with the new management.

II. <u>The following are well along and will be completed as now scheduled.</u>

- Personnel Division Resources Support (B-5) - Increase manning of Personnel to support the needs of the Nuclear Mission. Actions are ongoing as described in Section II.B.1 of the Course of Action Report. Targeted date for full staffing by TED personnel is December 1, 1986.

- Records Management System Enhancements (C/RM-1&2) - Addresses activities needed to ensure that the Nuclear Mission can effectively use the Records Management System and the hardware and software upgrades needed to address system weaknesses. This effort should be completed by the end of the year.

- Administrative Control of Software (E/SP-7) - Identify plant modifications requiring software changes and administratively control the software changes made. This will be complete by September 30, 1985.

- Improve Reliability of Security Computer (E/SP-13) - Upgrade and relocate the Central Alarm Station and improve the operation of the security computer including reducing downtime. This should be completed by December 31, 1985.

- Improve Performance of Security Detection Equipment (E/SP-14) - Upgrade of the perimeter detection system has just been completed.

- Improve the Integrated Living Schedule Program (F/TS-4) - Educate Toledo Edison personnel on the ILSP plan to ensure it is used appropriately in the planning, scheduling and budgeting process. This will be completed during March, 1986.

- Determine an initial list of those balance of plant systems and/or components to which a quality program should be applied (SALP). This will be completed during September, 1985.

- Commence implementation of a balance of plant quality program (SALP). This will occur during September, 1985.

- Develop 1985 emergency preparedness audit checklists (SALP). This is currently ongoing.

III. The following items will be pursued in the normal course of business and will not be the subject of the intense attention devoted to Category I.

NOTE: The description of each item presented below generally represents how it was originally described as part of PEP or the SALP improvement program. As noted previously specific "products" committed as part of these items may not be produced. The new management team and practices discussed in Section II.B.1 of the Course of Action Report will, rather, assure that the underlying concept becomes an integral part of how Toledo Edison does business.

- Management Style (A-4) - Develop and issue a statement on managerial style which is embraced as the policy for the Nuclear Mission.

- Continuation of the Performance Enhancement Program (A-6) - Provide a vehicle through which the PEP concept can be continued in the future to address problems which occur similar to those previously identified.

- Human Resource Planning & Career Pathing (B-4) - Implement a Human Resource Planning Program that identifies resource needs adequate to achieve Mission Company strategies and goals and prepares/plans for fulfillment of those needs.

- Supervisory-Employee Relations (B-6) - Increase the effectiveness of communications between Foremen/Supervisors and workers.

- Stress Management (B-7) - Educate Davis-Besse employees on ways to reduce stress in the work environment.

- Employee Involvement & Communication Program (B-8) - Develop an operational, phased program to improve the level of participation, involvement and communication at Davis-Besse.

- Increase TED Awareness of Fire Protection (D/FP-2) - Increase personnel and plant safety through awareness of the risks associated with fire hazards.

- Commitment Management (D/L-1) - Develop and implement a commitment management program.

- QA Procedures Review Group (D/QA-2) - Define the duties/ responsibilities and staff the QA Procedures Review Group.

- Action Plan for Safety Evaluations (D/SM-1) - Improve the quality of safety reviews, safety evaluations and their review/approval.

- SRB Performance Criteria (D/SM-2) - Provide criteria for reviews by and conduct of the Station Review Board.

- CNRB Meeting With the Corporate Management (D/SM-3) - Provide for a dialogue between the CNRB and Corporate Management to better identify responsibilities and expectations of both.

- CNRB Training (D/SM-4) - Ensure that CNRB members are aware of their responsibilities in meeting Technical Specifications and the CNRB charter review requirements.

- CNRB Subcommittee for Screening Documents (D/SM-5) - Enhance the review and participation by CNRB members by allowing for subcommittee review of routine documents.

- Improve preparation of CNRB Member (D/SM-6) - Enhance the operation of the CNRB by improving member performance and participation.

- Information for CNRB Review (D/SM-7) - Improve the flow of appropriate information to the CNRB for review.

- Procedures for Nuclear Safety Related Activities (D/SM-8) - Provide procedures to control Nuclear Safety Related activities.

- Nuclear Industry Operating Experience (D/SM-9) - Provide a method to establish requirements and guidelines for receipt, handling, distribution, review and response of nuclear industry operating response data.

- SRB Training (D/SM-10) - Ensure SRB members and alternates understand SRB functions and responsibilities.

- Program for Safety Management Improvements (D/SM-11) - Evaluate the present Safety Management program and develop improvements where needed.

- Hazardous Chemical Safety (E/SP-1) - Provide improved worker safety by identification of hazards.

- Failure Analysis Program (E/SP-4) - Develop a program to identify recurring equipment problems.

- Station Procedure Error Reduction Plan (E/SP-5) - Reduce the number of errors in plant procedures.

- Improve the FCR Process (F/TS-1) - Ensure better design work packages in a shorter time frame.

- Establish Realistic Schedules and Priorities (F/TS-3) - Enhance existing resources within the Nuclear Mission in complying with Integrated Living Schedule Program commitments.

- Improve the Engineer's Performance (F/TS-5) - Retain senior level engineering expertise by providing training and increasing accountability.

- Improve Project Management Performance (F/TS-6) - Upgrade project management approach by giving Project Managers authority and support within the Nuclear Mission.

- Complete a Review of Procedures and correlate them with the USAR (06-1(01)). To be included in annual USAR review.

- Nuclear Safety to monitor C&HP Projects (06-2(01)) - ALARA FCRs will be addressed by Prioritization Subcommittee of the Davis-Besse Work Scope Committee (DBWSC).

- Define Role of Maintenance Planning Group (07-1(05)) - Addressed by the new organization.

- Evaluate Preventive Maintenance Program (07-1(07)) - To be addressed by new organization.

- Obtain Contractor Support for Certain Programmatic Requirements such as SAR Update (10-3(07)) - To be addressed in Licensing Department routine activities.

- FCR Closeout (12-1(06)) - Part of the new management philosophy.

- Update Control Logic Diagrams (12-2(05)) - Part of duties under the reorganization.

- Update USAR to address inconsistencies (12-3(02)) - To be addressed in regular USAR update.

- Review by Emergency Planning and QA of the checklist for Emergency preparedness QA audit requirements prior to audit initiation will be documented in the entrance review notes (SALP).

- The emergency planning activity scheduling system will be formally implemented for all future commitments (SALP).

- Nuisance alarm reduction program is supported by quarterly review of control room annunciator alarms in the "ALARMED" condition (SALP).

- When an alarm is classified as a nuisance alarm, corrective action is undertaken to eliminate distraction to control room operator (SALP).

- Corrective action will be undertaken to extinguish alarms caused by failure/malfunction and repair of the failure is known to be delayed for a significant period of time (SALP).

- Resolve remaining nuisance alarms through FCR process (SALP).

- Division directors will receive monthly commitment reports of the emergency planning activity scheduling system (SALP).

APPENDIX C.1.1 - NUREG 1154, TABLE 5.1 EQUIPMENT DEFICIENCIES

Introduction

This Appendix contains the Findings, Corrective Actions and Generic Implications Reports generated as a result of the investigations into the equipment failures (or in some cases perceived failures) which occurred during the June 9, 1985 event. The equipment investigations cover the "Freeze List" equipment identified through discussions between Toledo Edison and the NRC Fact Finding Team.

An index of the reports is provided in Table C.1.1.1 which provides the Toledo Edison Action Plan Number, the latest revision, and a descriptive title. Reports which are still preliminary are so indicated in the title. A preliminary status means the report has not yet proceeded to definition of Corrective Actions and Generic Implications or that additional information is expected to be provided in a later revision. Although further change is expected, preliminary reports have received Task Force review as described in Section II.C.1 of the Course of Action report prior to publication.

Reports not identified as preliminary are considered complete at this point. No substantive changes are expected to these reports, based on presently available information. Subsequent reviews or findings of additional relevant information, however, may lead to unanticipated revisions to these reports prior to restart of the unit.

TABLE C.1.1.1
INDEX OF FINDINGS, CORRECTIVE ACTIONS AND GENERIC IMPLICATIONS REPORTS

Action Plan No.	Revision	Title
1A, 1B, 1C	1	Auxiliary Feed Pumps Overspeed Trips - Preliminary
1D	2	AFPT Overspeed Trip Throttle Valve Problem - Preliminary
5, 6, 7	2	SFRCS Trip/MSIV Closure
8	2	Davis-Besse Main Feed Pump Turbine and Control System Failures - Preliminary
9A, 9B	2	Davis-Besse Turbine Bypass Valve Actuator Failure
10[1]	2	Pilot Operated Relief Valve (PORV) Operation
12[2]	2	Auxiliary Feedwater System Valves AF599 and AF608
15A	(Later)	Source Range Nuclear Instrumentation NI-1, Channel 2
15B	(Later)	Source Range Nuclear Instrumentation NI-2, Channel 1
16	2	Main Steam Header Pressure - Preliminary
18	2	Startup Feedwater Valve SP-7A Problem Analysis
26	3	Service Water Transfer - Preliminary
27	3	Main Steam System Valve MS-106

[1] This report is provided in Appendix C.1.3
[2] This report is provided in Appendix C.1.2

PRELIMINARY FINDINGS, CORRECTIVE ACTIONS, AND GENERIC IMPLICATIONS REPORT

TITLE: Overspeed Trips of the Auxiliary Feed Pump Turbines on 6/9/85 at Toledo Edison's Davis-Besse Nuclear Power Station

REPORT BY: Dan Wilczynski
Chuck Rupp

PLAN NO. 1A & 1B/1C

REV	DATE	REASON FOR REVISION	WRITTEN BY	APPROVED BY
0	8/31/85	Initial Issue	Wilczynski Rupp	L. A. Grime
1	9/09/85	General Correction	Wilczynski Rupp	L. A. Grime

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I. INTRODUCTION

A. Purpose

This report documents the troubleshooting and investigative actions performed to identify the root cause of the overspeed trips of the Auxiliary Feed Pump Turbines (AFPTs) at Davis-Besse on 6/9/85. Also presented in this report are the proposed corrective actions to eliminate the cause of the overspeed trips and a summary of the proposed confirmatory testing to ensure proper system operation.

Mode 3 testing which attempts to recreate the overspeed conditions is no longer considered to be necessary or advisable. This conclusion is based on several factors:

1) Induction of water can be defined as root cause. Discussions with the vendor and the experience at other plants utilizing Terry Turbines provide confidence in the root cause identification. Several other plants have experienced similar problems with AFPT overspeed and have implemented corrective actions to eliminate water induction.

2) Possible equipment damage. Prior to 6/9/85, Toledo Edison discovered damage to pipe supports on the steam inlet lines to the AFPTs which was attributed to the water slugs created by steam condensation in the lines. Recreation of
1 the 6/9/85 overspeed has the potential of damaging components, piping, and/or supports. Also, overspeed of the AFPTs could result in equipment damage or personal injury if the overspeed protection were to fail.

3) The uncertainty of event recreation. Analysis by Toledo Edison personnel and consultant engineers has concluded that the dynamic situation that resulted in AFPT overspeed is sensitive to many different variables. Exact duplication of the 6/9/85 event will not be possible. Therefore, the probability that AFPT overspeed could be achieved during Mode 3 testing is not certain.

B. Event Description

On Sunday, June 9, 1985, normal feedwater flow to the steam generators was interrupted. The reactor was automatically shutdown and reactor heat was removed via steaming through the main steam safety valves and the atmospheric vent valves. The water level in the steam generators was decreasing and at 1:41:03 a Steam and Feedwater Rupture Control System (SFRCS) full trip was initiated on Channel 1 due to a low water level in Steam Generator #1 (SG #1). This SFRCS actuation attempted to initiate auxiliary feedwater flow by opening the steam supply valve, MS 106, from SG #1 to auxiliary feedwater pump turbine (AFPT) #1 (See Figure 1). Five seconds after the initial SFRCS actuation (1:41:08) the reactor operator inadvertently initiated

an SFRCS low pressure trip on both channels and both steam generators. This low pressure trip of SFRCS is intended to respond to a steam line break or other equipment failure resulting in depressurizing a steam generator. The manual low pressure SFRCS trip initiated the following, as designed:

1. Sent a close signal to MS 106 (which had an open signal at the time) and MS 107 (which was closed at the time).

2. Sent a close signal to AF 608 and AF 599, containment isolation valves on auxiliary feedwater path to steam generator #1 and #2, respectively.

3. Sent an open signal to MS 106A (steam supply for AFPT #1 from steam generator #2) and MS 107A (steam supply for AFPT #2 from steam generator #1) in an attempt to operate both AFPTs on opposite SGs.

4. Sent an open signal to auxiliary feed pump discharge valves AF 3869 and AF 3871.

5. Sent a close signal to auxiliary feed pump discharge valves AF 3870 and AF 3872.

Each AFPT tripped on overspeed (4500 RPM) approximately 25 seconds after initial roll.

II. BASIC OPERATION OF OPERATION

The Auxiliary Feedwater System (AFWS) is required to provide feedwater flow to the steam generators (SGs) upon loss of the main feedwater pumps or upon loss of all normal or reserve electric power to remove decay heat and/or promote natural circulation.

The AFW system consists of two separate pumps and turbine drivers. The turbines receive main steam from either steam generator, depending on the emergency actuation signal supplied by SFRCS. The normal steam supply paths are; SG #1 supplying steam to AFPT #1 through MS 106 and SG #2 supplying steam to AFPT #2 through MS 107. In the case of a low pressure condition in a steam generator, the system is realigned to isolate the bad generator and the good generator will supply steam to either AFPT through the cross connect valves (MS 106A and MS 107A).

The AFPTs at Davis-Besse are Terry Steam Turbines. The #1 AFPT was equipped with a Woodward model PG-PL governor and the #2 AFPT was equipped with a Woodward model PGG governor.

III. SUMMARY OF TROUBLESHOOTING AND INVESTIGATIVE ACTIONS

A. Change Analysis

In order to determine the reasons for the 6/9/85 overspeed trips a change analysis was performed to compare the operation of the

AFPTs on 6/9/85 to past quick starts of the system. The change analysis reviewed five previous plant trips (3/2/84, 1/15/85, 3/21/85, 4/12/85, 6/2/85) as well as several surveillance tests (STs) to attempt to identify a distinguishing factor between 6/9/85 and other system operations.

The one difference that was found was that the 6/9/85 plant trip was the first time that the AFPTs were run solely on the cross connect steam supply lines. Also, 6/9/85 was the only actual overspeed trip of the AFPTs at Davis-Besse.

During the change analysis phase, maintenance and modification records were checked to determine whether there was any work performed prior to 6/9/85 that could have caused an overspeed to occur. This review did not reveal any evidence that could support the overspeed trips.

B. Data Search

1. Investigation of Other Utility Experience with Overspeed Trips

Problems with overspeed trips of Terry Turbines is not unique to Davis-Besse. Nuclear Power Experience (NPE) includes descriptions of turbine overspeed incidents at three plants which have been attributed to condensation in the steam supply lines to the turbines. The major features of these incidents as documented by NPE are discussed in this section.

In addition to the incidents which were directly attributed to condensation, there are other instances of actual turbine overspeed (as contrasted to spurious overspeed trips). These are generally attributed to governor valve malfunctions or improper adjustment. In most cases, these incidents appear to have been the result of specific malfunctions of the governor such as clogged or dirty oil, miscalibration, corrosion, or faulty electronics. It cannot be established whether condensate or condensation during startup may have also had some effect on these other incidents.

Plant #1

In June of 1977, the turbine drive auxiliary feed pump (EPF-2) tripped on overspeed upon initial start in a surveillance test. A new governor was installed; however, the problem persisted. The cause of the problem was then attributed to condensation in the steam line. Modifications were made to the drain system to increase its capacity. Subsequent multiple starts from cold conditions showed that the problem had apparently been corrected. However, on July 17, 1977, the main feed pumps tripped and upon auto start of the auxiliary feed pump EFP-2, that pump tripped

on overspeed. The turbine was reset and the immediate restart was successful. Subsequent first start overspeed trips were experienced on July 22, 23, 25, and August 1. The cause was determined to be condensation buildup in the steam inlet lines. In addition to the previous modifications of the drain system, a bypass valve was installed to prevent condensate buildup. Satisfactory operation of the turbine was demonstrated.

Plant #2

In July of 1979, the turbine for auxiliary feed pump 2P7A tripped when it was started automatically by an Engineered Safeguards Features Actuation System (ESFAS) signal. It is stated that the overspeed trip was due to water in the steam supply line. Water was blown from the line and the turbine was successfully started three times. In September of 1979, the turbine for auxiliary feed pump 2P7A was manually started and the turbine tripped on overspeed. The turbine was then restarted three times to verify its operability. The apparent cause was stated as water in the steam supply header. Additional drains were installed. These additional drains were evidently not completely successful since in April, 1980, the turbine for feed pump 2P7A again tripped when it was started in response to an ESFAS actuation. The turbine was successfully restarted on three successive starts after the overspeed.

However, on October 11, 1981, steam driven emergency feedwater pump 2P7A tripped on overspeed following a manual start during a unit trip recovery. This overspeed trip was attributed to condensation in the steam lines which resulted from insulation not being reinstalled and a steam trap remaining isolated after a maintenance activity. The insulation was replaced and the trap was placed back in service. Also, the trap bypasses were opened to ensure that condensation would not occur in the lines. Pump 2P7A was tested, found operable, and returned to service.

Plant #3

On August 25, 1982, it was found that the drive turbine for auxiliary feed pump 2P-140 was tripping on overspeed during starting. It is stated that the tripping was caused by condensate in the steam supply header and throttle valve. Some drains were modified to improve their effectiveness.

Although the investigations by other plants into similar problems with overspeed of Terry Turbines upon startup have not been definitive as to the mechanism by which water causes the turbine to overspeed, they appear to strongly indicate that condensate in the steam lines is detrimental to turbine operation. Their approaches to corrective action have been to reduce the amount of condensate and in

some cases to keep the lines hot by bypasses or repeated starting of the pumps.

2. Vendor Experience

Discussion between MPR Associates and Terry Steam Turbine (the turbine supplier) have revealed that water induction to the turbine can indeed cause an overspeed condition. The relationship to overspeed is based on Terry Turbine's knowledge of turbine design as well as some testing performed in 1969. The testing involved injecting quantities of water into the turbine to verify the turbine's ability to withstand the water. One of the observations during testing was that turbine speed increased after the water had cleared the governor valve. Although no testing data is available, the information below describes the testing based on discussions with Terry Turbine personnel involved with the test.

The initial set of tests involved operating the turbine on steam, injecting cold water into the pipe upstream of the turbine, and observing the turbine response. The amount of water was varied between 50 and 600 gallons. During the transient, turbine speed and governor valve position were measured. The turbine behavior is described below:

> As the slug came through, the turbine speed began to fall. The turbine control, or governor, began to develop an error signal due to the speed decrease and attempted to further open the governor valve. However, apparently because of the effect of water flowing through the valve, the valve was not able to respond to the control signal. Terry refers to this as "waterlock" of the valve. Speed continued to fall until the slug was cleared, at which point steam was applied to the turbine and the valve could respond. Since an error signal was present, the valve opened causing a rapid acceleration of the turbine. Terry said that the turbine speed would increase quickly and overshoot before settling back to the demanded speed. The overspeed trip in these tests was set higher than normal, so they observed no overspeed tripping of the turbine. But they did see large overshoots in speed as the water slug cleared.

The final set of tests involved quick starting the turbine with 600 gallons of water initially in the inlet lines. A valve was opened to admit high pressure steam behind the water slug to force the slug through the turbine. It is not known whether the governor valve started fully open or was opened simultaneously with the steam supply valve. Turbine response is described below:

The turbine accelerated as the water was forced through the machine. The governor gained control of the acceleration. When the water was expelled and steam was applied to the turbine, there was an increase in turbine speed but the governor was able to maintain control.

The Terry Turbine Company representative has said that the governor valve used in the testing was not the same design used at Davis-Besse. The valve in the tests is thought to have been more susceptible to being affected by hydraulic forces due to water flow. However, the Davis-Besse governor valve cannot be guaranteed not to lock up due to water flow because it was designed to run with steam.

Terry Turbine has also stated that water could also cause a turbine overspeed by flashing through the turbine nozzles and thereby, due to the increased mass flow, impart more energy to the turbine wheel and potentially cause an overspeed.

3. Toledo Edison Experience

To further support the root cause of water causing the overspeed trips, a review of past AFPT quick starts was performed. This review involved analyzing the plots of turbine speed versus time during the starting transient. The review clearly showed a difference in stability of the turbines (especially AFP #1) when run on cold supply lines versus hot supply lines. When the turbines are started with cold steam supply lines, the turbine speed is very erratic during acceleration to rated speed. However, when the turbines are started with hot steam supply lines, the speed graphs are very smooth with a constant acceleration to rated speed. (See Figures 2 and 3 for typical AFPT speed graphs of cold versus hot lines.)

The erratic turbine speed is attributed to the formation of water slugs when the steam is introduced into the cold supply lines.

C. Field Actions

Two "hands on" investigations were performed to eliminate other possible causes. The first was performed on 6/9/85 at approximately 1:00 p.m. (about 10 hours after the unit was stable). The AFPTs were "quick-started" on the normal steam supply paths via MS 106 and MS 107. The pump discharge path during this testing was through the min-recirc line only, just as it was during the overspeed trips of 6/9/85. The piping was still hot at this time and both AFPTs started without any erratic control. The governors functioned properly and accelerated both units to rated speed within 40 seconds as designed. This testing indicates

that it wasn't a governor problem that caused the overspeed trips earlier on 6/9/85.

The second investigation was a visual inspection of both governors by a Woodward Governor Representative to verify that the governors were in proper order. The inspections were performed under Maintenance Work Orders (MWOs) 1-85-2131-00 and 1-85-2132-00. The visual inspection identified that both governors contained no deficiencies that would impair proper operation.

D. Analysis

To better define the possibility of condensate in the steam supply causing the overspeed trips, analyses were performed to determine the amount of water available due to steam condensing in the cold steam supply piping and to simulate the transient formation and transport of condensation in these lines.

1. Amount of Water Available

Initial calculations were performed by MPR Associates Inc. to determine the mass of water condensed as a result of heating the AFPT steam piping from 70°F to 535°F. These calculations were intended to give "ball park" numbers and therefore the assumptions were made that the entire pipe heats up from room temperature (70°F) to the nominal SG temperature (535°F) and that all the heat given up by the condensing steam goes to heating the pipe. The results are shown in Table 1, values are pounds of water generated. The actual values will be less due to the real parameters involved, (i.e., the effect of piping insulation, the effect of flow on heat transfer, the time required to heat the pipe, etc.).

Steam From	AFPT #1	AFPT #2
MS 106	790	---
MS 106A	1490	---
MS 107	---	260
MS 107A	---	900

TABLE 1

These results show that large quantities of water can be generated in the steam supply lines. Also the cross connect lines are capable of generating more water than the normal supply paths. This is due to the increased length of cold horizontal piping when the system is run on the cross connect lines.

When comparing the amount of water generated from MS 106 to AFPT #1 to the amount of water generated from MS 107A to AFPT #2 it is not evident why AFPT #1 has never tripped on overspeed when run on MS 106. However, the isometric

drawing of these two routings shows that the MS 107A line is comprised of long horizontal runs and a vertical rise which tends to more easily cause a slug formation when compared to the MS 106 piping which is comprised of a series of shorter horizontal runs and vertical drops. This tendency against slug formation is postulated to be the reason why AFPT #1 had never oversped in the past. It also points to the complexity of the phenomenon.

2. Transient Flow Analysis

A transient flow analysis was performed by MPR Associates Inc. to simulate the effects of the 6/9/85 transient. The computer model used solves the mass, momentum, and energy conservation for the piping system including the effects of the heat transfer to the pipe wall.

The results of the transient flow analysis indicate that a significant amount of water is formed in the steam supply piping to the AFPTs as a result of the sequence of events which occurred on 6/9/85. Within 30 seconds after the initial opening of valve MS 106, the analysis indicates that the pipe immediately upstream of AFPT #1 is completely filled with water. Also, the pipe directly upstream of AFPT #2 is calculated to be about half full of water at the same time. This is shown in Figures 4 and 5.

This transient analysis substantiates the fact that large amounts of water can be generated when steam is initiated into the long cold piping. In addition, it shows that the condensate can be expected to reach the turbines in approximately the time frame required to support the observed overspeed trips of the AFPTs (25-30 seconds).

IV. RESULTS/CONCLUSIONS OF FINDINGS

A. Direct and Root Cause

The direct and root cause is judged to be Hypothesis A of the original troubleshooting report (Reference #4).

Hypothesis A:

Water slugs in steam piping to the turbine due to residual condensation or rapid condensation of steam while heating long, cold steam supply path to AFPTs caused the overspeed trips.

B. Disproved Hypotheses

As part of the original troubleshooting report, four (4) other possible causes for the AFPT overspeeds were developed. Of those four, two were eliminated in the original report based on

data collected during the 6/9/85 plant trip and previous AFPT initiations. Those two were:

Hypothesis C:

Sudden decrease in pump load due to a sudden flow reduction when pump discharge flow is abruptly stopped at the closed valves AF 599 and AF 608.

Hypothesis E:

Loss of pump suction source resulting in no pump load.

A third hypothesis was disproved by the 6/9/85 testing and the governor inspections performed by a Woodward representative. It was Hypothesis D of the original troubleshooting report.

Hypothesis D:

Governor problems had caused the overspeed trips.

The final hypothesis was Hypothesis B.

Hypothesis B:

AFPT #1 rolling on steam from MS 106 prior to receiving steam flow from crossover (Double Start).

This is highly unlikely to have occurred based on an examination of the sequence-of-events log which suggests that steam flow would not have been interrupted. This judgement is based on the timing of the cycling of valves MS 106 and MS 106A. This hypothesis also does not explain the overspeed trip of AFPT #2 because it was run on steam from MS 107A only.

V. TECHNICAL JUSTIFICATION OF FINDINGS

The basis for the direct and root cause determination is:

1. Other utilities have experienced overspeed trips of similar turbines due to water in the steam supply.

2. Toledo Edison experience shows that when the steam supply lines are hot (i.e., small amounts of water generated), the AFPTs accelerate to rated speed without any erratic behavior.

3. Terry Turbine has stated that water in the steam supply can lead to an overspeed condition.

4. Analysis has shown that the existing piping configuration will generate significant amounts of water due to condensation and that this water will reach the turbine during the initial starting transient.

Presently the method by which water causes an overspeed is not precisely known. It could be any combination of the following:

1. Governor valve becomes "water-locked" and is open too far when water clears, therefore allowing too much steam to flow into the turbine which leads to an overspeed.

2. Water entering the turbine flashes through the turbine nozzles thereby releasing more energy than required and the turbine accelerates to the overspeed setpoint.

3. Water entering the turbine slows the turbine down. The governor tries to maintain turbine speed by opening the governor valve further. When the water clears, the valve is open too far to be able to control turbine speed below the overspeed setpoint.

Even though the method is uncertain, it is apparent that the water is the cause of the overspeed trips of the AFPTs that occurred at Davis-Besse on 6/9/85.

VI. PLANNED CORRECTIVE ACTIONS

To eliminate the water which is judged to have caused the overspeed trips, Toledo Edison has decided to reconfigure the steam supply system to the AFPTs. The new configuration would provide the ability to sustain the steam piping in a hot and pressurized condition whenever the AFPTs are required to be operable. By keeping the piping hot, the amount of water delivered to the turbines during a start would be reduced to a negligible quantity. The system change is highlighted below:

- Valves MS 729 and MS 730 (turbine inlet isolation valves located approximately ten (10) feet from the turbines) will be replaced with pneumatically operated control valves.

- Valve opening time will be adjustable to allow control of steam flow during initial stages of turbine starting. This flexibility will alleviate the possibility of overspeeding the turbine when opening a supply valve near the turbine as has been experienced at several other power plants.

- Valves MS 106, 106A, 107, and 107A will be normally open to pressurize the supply lines up to the new control valves. These valves will retain their close signals to act as containment and steam generator (SG) isolation valves.

- Steam trap capacity of the supply lines will be reviewed for adequacy. New traps will be added as required.

- Steam supply lines to the AFPTs will be analyzed as high energy lines. Support, whip restraint, impingment barrier, and environmental qualification modifications will be performed as required.

- o The new control valves will be opened on an SFRCS actuation signal.

- o In addition to the piping changes, the existing Woodward model PG-PL governor on AFPT #1 will be changed to a Woodward model PGG governor to increase governor reliability. This change-out was originally planned for the 1986 refueling outage.

These modifications or other alternatives to keep the piping hot and pressurized will be performed prior to restart of the Davis-Besse unit. After the modifications are performed, Toledo Edison will perform a series of tests to confirm that the new system configuration will operate as designed.

VII. PLANNED ADDITIONAL ACTIONS

The new auxiliary feed pump steam supply system modifications will be tested after implementation is complete. The testing will consist of the following:

1. Several quick starts of both AFPTs to verify that the units accelerate to rated speed without any erratic behavior. This testing will also verify that the turbines reach rated speed in less than 40 seconds as required by Davis-Besse Technical Specifications. During these quick starts the following data will be collected:

   - o Pipe movement will be measured to verify that piping and hanger loads are within design limits.

   - o Governor valve position will be monitored to verify proper governor operation.

   - o Turbine speed versus time will be recorded to verify a smooth acceleration ramp.

2. AFPT stability will be checked. This will be done by momentarily increasing turbine speed by using the overspeed test device. Turbine speed will be plotted to verify that the governor resumes control after the instability input is removed.

3. All steam traps on the steam supply piping will be checked for operability and adequate removal capacity during the steady state condition (i.e., lines pressurized with turbine stopped). This testing will ensure that condensation will not accumulate in the piping during the long periods when the AFPTs are idle.

4. Testing will be performed to verify the hypothesis of Action Plan 1C. (Hypothesis - Trip throttle valves being only partially open limited steam flow and thus limited RPM. This was perceived as not being able to control AFPT speed from the control room.)

All of these modifications and testing will combine to assure Toledo Edison that the Auxiliary Feed Water System is functional to perform its intended safety function at any time as required.

VIII. GENERIC IMPLICATIONS

The design of the Davis-Besse Plant utilizes only two quick start steam driven turbines (AFPT #1 and #2) to supply motive power to equipment. Therefore, there are no generic implications beyond the two AFPTs.

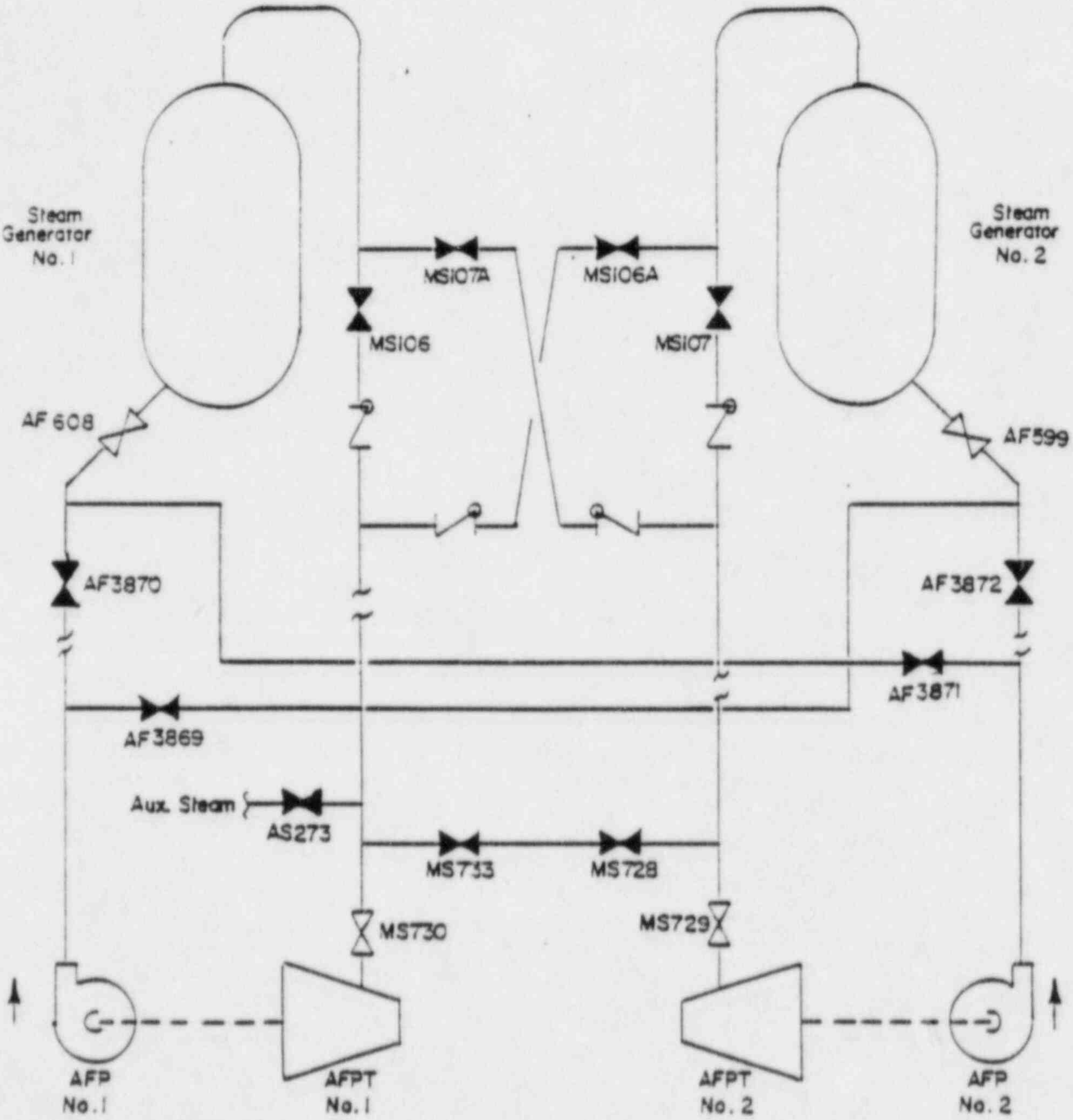
IX. REFERENCES

1. Telephone conversation documentation between MPR and Terry Steam Turbine Company, (7/2/85).

2. Steam condensation calculations by MPR, (4/5/85).

3. Draft transient flow analysis by MPR.

4. Action Plan 1A & 1B Investigation & Troubleshooting Report, Rev. 1 (6/25/85).



SCHEMATIC REPRESENTATION OF
AUXILIARY FEED PUMP TURBINE STEAM PIPING SYSTEM

Figure 1

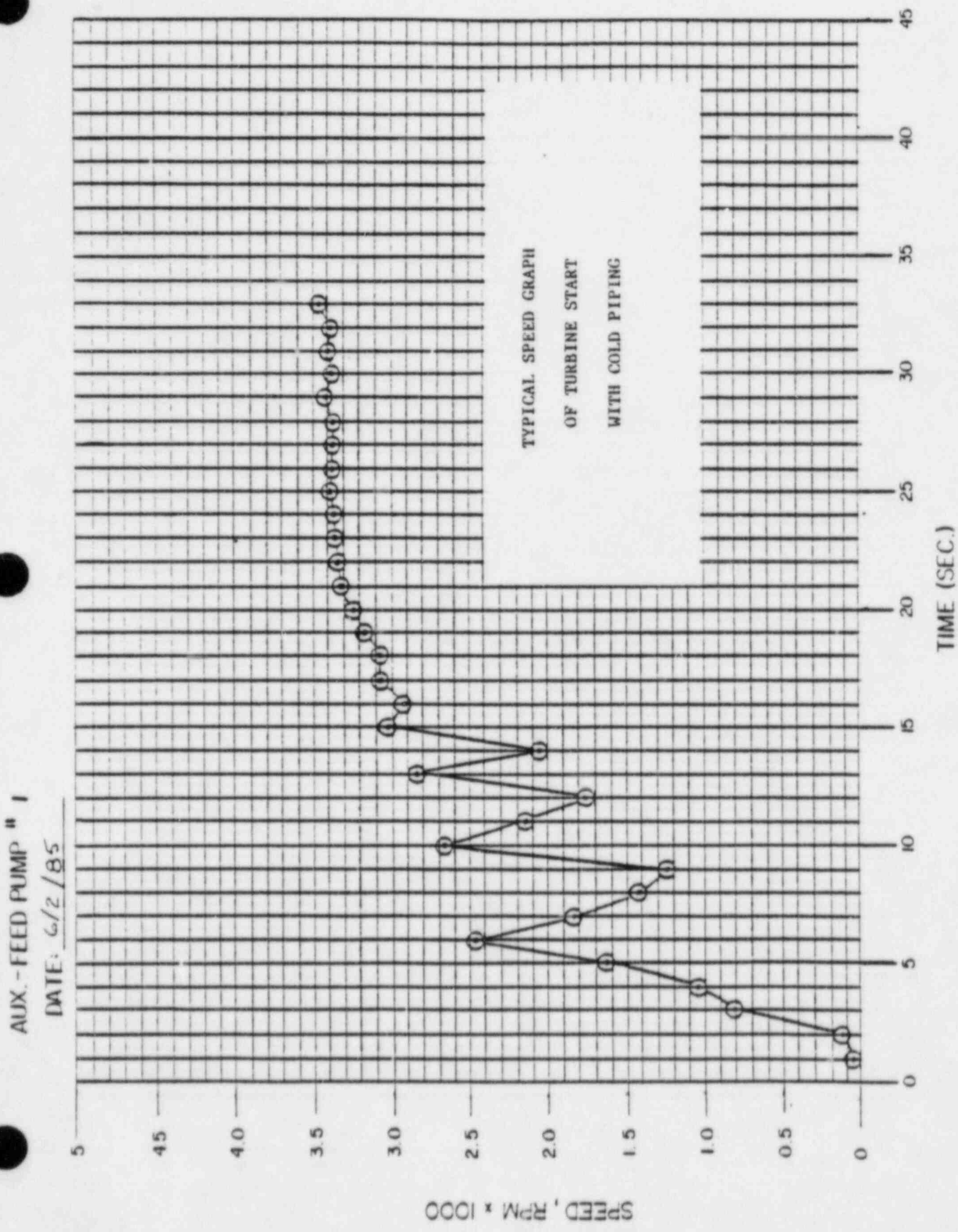

AUX.-FEED PUMP # 1
DATE: 6/2/85
TYPICAL SPEED GRAPH
OF TURBINE START
WITH COLD PIPING
SPEED, RPM x 1000
5
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0
0
5
10
15
20
25
30
35
40
45
TIME (SEC.)

Figure 2

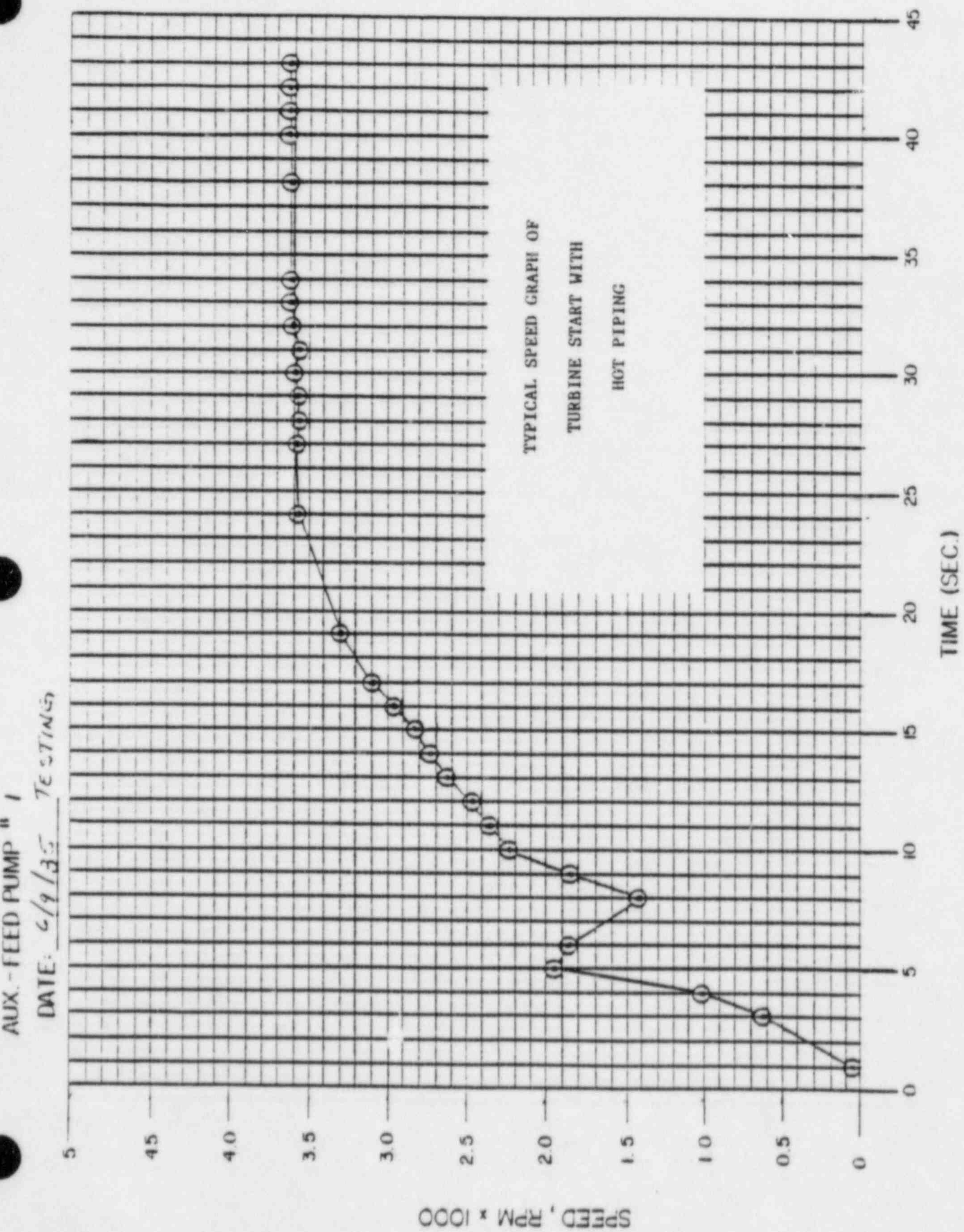
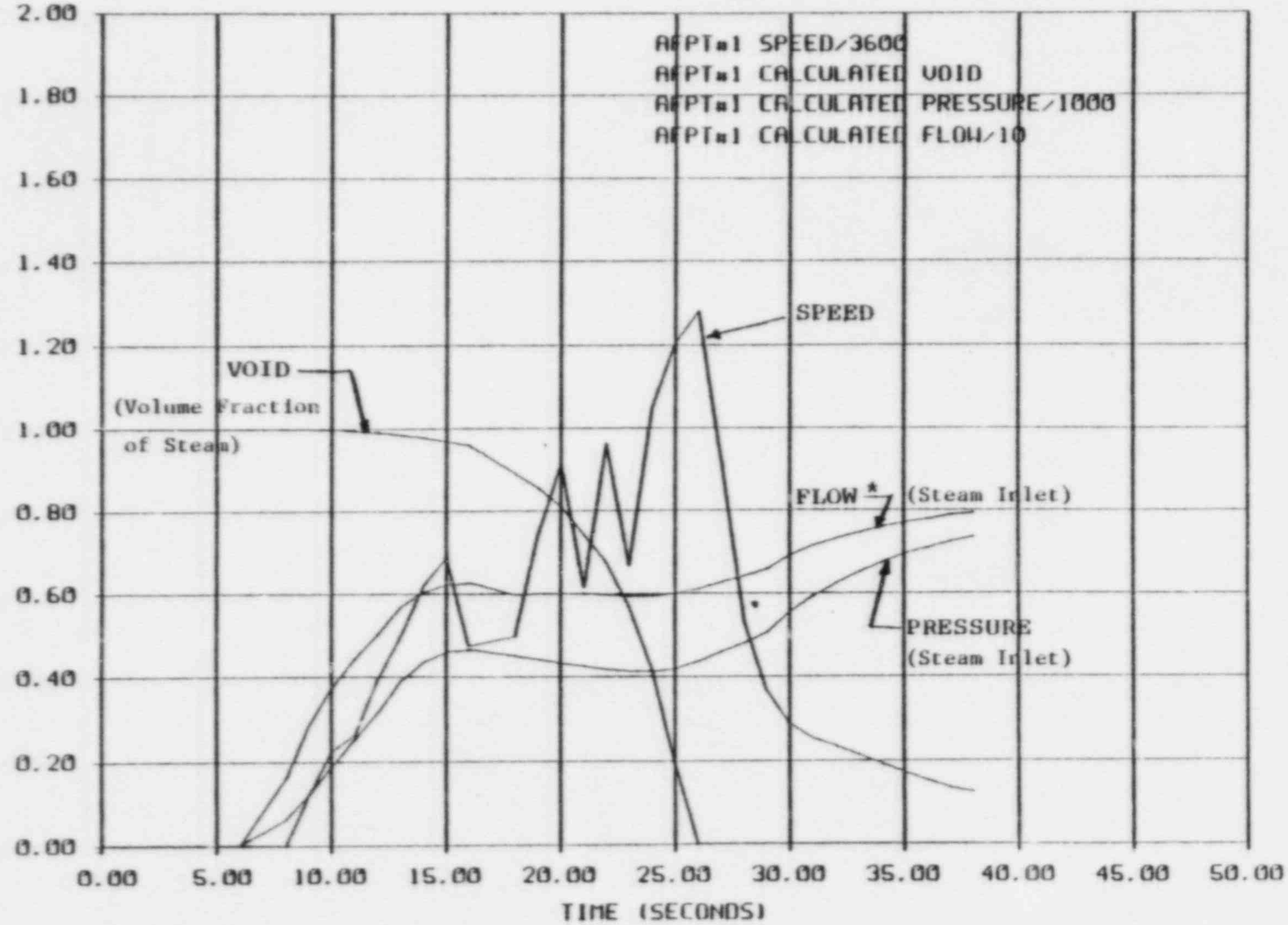

AUX.-FEED PUMP # 1
DATE: 6/9/35 TESTING
TYPICAL SPEED GRAPH OF
TURBINE START WITH
HOT PIPING
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
0
5
10
15
20
25
30
35
40
45
TIME (SEC.)

Figure 3

COMPUTER MODEL OF AFPT #1 PARAMETERS ON 6/9/85



DATE: 08-20-1985

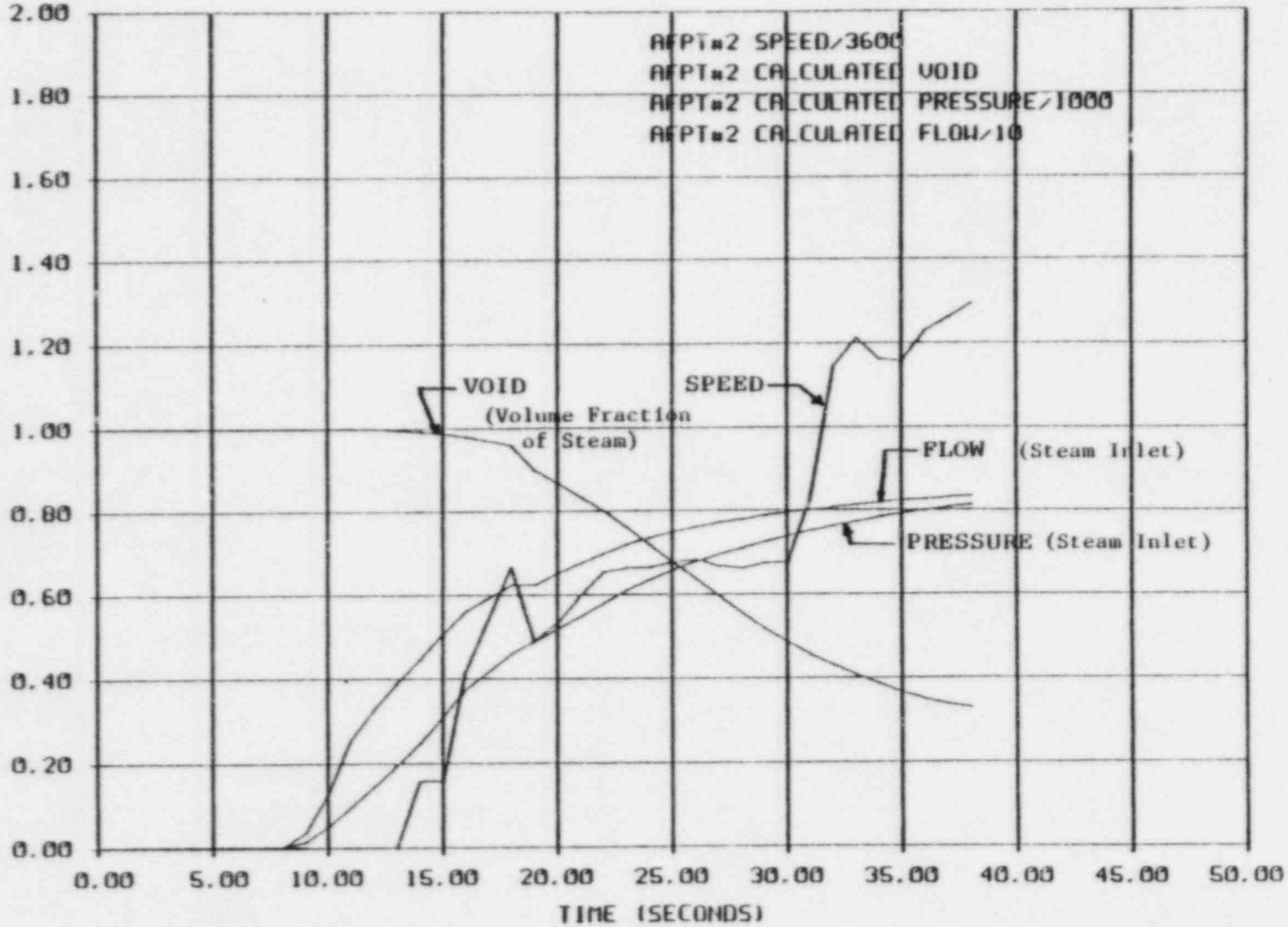
FILE: DBCOM

JUNE 9 TRANSIENT - BOTH TURBINE DRIVEN PUMPS TRIPPED

Figure 4

* Modeling Misrepresentation - Flow actually decreases after the overspeed.

COMPUTER MODEL OF AFPT #2 PARAMETERS ON 6/9/85



DATE: 08-20-1985

FILE: DBCOM

JUNE 9 TRANSIENT - BOTH TURBINE DRIVEN PUMPS TRIPPED

Figure 5

PRELIMINARY

FINDINGS, CORRECTIVE ACTIONS, AND GENERIC IMPLICATIONS REPORT

TITLE: AFPT OVERSPEED TRIP THROTTLE VALVE PROBLEM

PREPARED BY: R. J. Gradomski PLAN NO. 1D

DATE PREPARED: August 9, 1985 PAGE 1 of 34

REV.	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE
0	8/9/85	Initial Issue	R. Gradomski	B. Beyer
1	8/19/85	Add Corrective Actions	R. Gradomski	L. Grime
2	8/30/85	General Corrections	R. Gradomski	L. A. Grime

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I. ISSUE/CONCERN

During the reactor transient of June 9, 1985, the Auxiliary Feedwater Pump Turbines (AFPT 1-1 and 1-2) were started and then automatically tripped on overspeed. Equipment Operators (EOs) were dispatched to determine the problem and restart the AFPTs.

While attempting the restart, the operators experienced difficulty in relatching and opening the trip throttle (T&T) valves. The EOs were successful in their attempts to relatch and open the T&T valves after several minutes and the AFPTs were restarted. This findings report addresses only the problem with relatching of the T&T valve. The report will be revised to cover the problem with T&T valve opening after further scheduled testing is completed.

II. BASIC PRINCIPAL OF OPERATION

The following is a description of the operation of the overspeed trip mechanism (OTM) in tripping the T&T valve:
(Refer to Figure 1 for the location of each component.)

1. A spring loaded weight is attached to the turbine shaft. As the speed of the rotating shaft increases, centrifugal force on the weight overcomes the force of the spring causing the weight to extend out from the shaft.

2. At 4500 RPM, sufficient outward movement of the weight causes the weight to strike the leaf spring.

3. The leaf spring and connected tappet move upward. (The manual trip lever provides this upward movement when manually tripping the OTM.)

4. As the tappet moves upward, it removes the interference and allows the head lever to move toward the turbine.

5. The head lever and attached connecting rod are pulled by spring force in the trip direction. The limit switch operated by the head lever changes state to show "trip" on the control room annunciator and alarm printer.

6. As the connecting rod moves in the trip direction, it applies a "hammer blow" through the slotted link connection in the trip crank to the trip hook.

7. The trip hook disengages from the T&T valve latch-up lever allowing the T&T valve closure spring to drive the valve stem and disc to the closed position. The limit switch on the T&T valve changes state to show "not fully open" on the computer alarm printer.

From Figure 1 the relatching of the valve trip mechanism involves two actions: first, the trip tappet must be reset, and second, the trip hook must be engaged with the latch-up lever so that the valve stem can be raised.

The resetting of the tappet can be achieved by pulling the connecting rod toward the valve. This moves the head lever so that the tappet spring can force the tappet down into the reset position. When the tappet is down, the head lever and connecting rod are positioned toward the valve. The head lever limit switch changes state to show "norm" on the computer alarm.

The valve can be latched by turning the valve handwheel in a direction which would close the valve. Although the valve is already closed, it is necessary to rotate the handwheel in the CLOSE direction in order to raise the nut attached to the latch-up lever to a position where the trip hook and latch-up lever can be engaged. When the latch-up lever reaches the top of its travel, the trip hook engages. After the hook is engaged, the valve is latched and rotation of the valve handwheel in the OPEN direction raises the valve stem to open the T&T valve. When the valve is fully open, the T&T valve limit switch changes state to show "full open" on the computer alarm printer.

III. SUMMARY OF TROUBLESHOOTING AND INVESTIGATION

The troubleshooting and investigation involved the following major elements:

- o. The plant records, specifically the station alarm printout, the Data Acquisition and Display System (DADS) output, and the security alarm printouts, were evaluated to determine a chronology of events associated with the trip and restart of the AFPTs. This detailed chronology is presented as Attachment 1 to this report.

- o. The physical condition of the OTMs and T&T valve latching mechanisms was inspected and the operation of the linkages was checked. The results of these inspections are summarized in Attachment 2 to this report.

- o. The operators were interviewed as to their actions relative to relatching the valves. The guidance in existing plant procedures and the training received by the operators on the relatching operation were also reviewed. The specific items of significance from these interviews and reviews are presented in Attachment 3 to this report. Attachment 1 (the chronology) also reflects the results of the operator interviews.

The major conclusions from these investigations are summarized below:

- o. The chronology shows that the OTM for AFPT 1-2 was reset very soon after the EOs entered the room -- within about a minute. Evidently, there were no serious problems with reset of this turbine. However, there were problems with opening the T&T

valve on AFPT 1-2 and that problem prevented immediate operation of that turbine.

- The chronology shows that the T&T valve for AFPT 1-1 was evidently opened without resetting the OTM. Turbine AFPT 1-1 was started; however, it tripped about two and a half minutes later while a manual speed change was in process, but not as a result of overspeed. The OTM was reset very shortly after the mechanism's spurious trip (less than a minute) and the turbine successfully restarted.

- The physical inspections and operational checks of the OTM linkage and the T&T valve latch mechanisms showed some abnormal conditions. These conditions may have contributed to the difficulty in resetting the OTM or to the spurious trip of AFPT 1-1. However, the mechanisms on both turbines were shown to be capable of being reset when properly operated. Therefore, these conditions did not prevent resetting the OTM and relatching the valve. It was also demonstrated that it was possible to latch the valve and open it without resetting the OTM. In that condition the valve is not positively latched -- it is prevented from tripping only by friction on the latch faces.

- The procedures provided to the operators did not clearly identify that the valve relatching also required the OTM tappet to be reset. The training on the relatching operation included little hands-on operation of the mechanisms.

IV. RESULTS/CONCLUSIONS OF FINDINGS

A. Direct Cause of Problems

The most probable cause of the spurious trip of AFPT 1-1 was the operator's failure to reset its OTM prior to latching and opening its T&T valve. The investigations showed that it was possible to open a T&T valve without resetting of the OTM and that this would result in the valve latch mechanism being in a metastable condition from which it could spuriously trip.

The reported difficulty of relatching the T&T valve was probably a direct result of the operator's attempts to latch the valve without resetting the OTM. Investigations showed that opening the T&T valve without resetting the OTM requires the latch parts (trip hook and latch-up lever) to be held engaged while the valve is opened and until they are loaded sufficiently for friction to hold the latch parts engaged.

The investigations show that the OTM could have been reset and the T&T valve relatched, had the operators involved been more familiar with the required manipulations of the linkage. That is, the trip and latching mechanisms, even though they are not simple and straight forward to operate, were apparently not defective and were capable of being reset as was demonstrated by the successful relatching of AFPT 1-2. Note, however, that if the OTM on AFPT 1-2 had not been reset, AFPT 1-2 would have

probably had problems in latching similar to those experienced on AFPT 1-1.

B. Root Causes of Problems

A number of significant root causes for the apparent failure of the operator to reset the OTM before latching the T&T valve were identified:

1. The reset or tripped condition of the OTM is difficult for the operators to determine. The design of the linkage does not include any labels, operator aides, or easily identified position indication.

2. The procedural instructions for relatching the T&T valves are incomplete and if strictly followed would not assure a properly reset mechanism.

3. The training given to the operators did not provide for adequate hands-on experience for a specialized operation which would have to be performed under stress.

C. Disproved Hypotheses

The investigations evaluated four previously identified hypotheses and another potential cause. These are discussed below:

Hypothesis 1. The tappet of the turbine trip mechanism did not return to its normal position while attempting the relatch evolution. It was shown in the investigation that the tappet would freely return to its reset position when the connecting rod was pulled to its reset position. The leaf spring that provides the return force to the tappet was functional. The tappet was not bound and moved freely. Since the control room alarm printout did not indicate that the head lever actuated the limit switch, the linkage of AFPT 1-1 was evidently not moved far enough to allow the tappet to drop to the reset position.

Hypothesis 2. The spring that provides the relatching force for the trip hook is defective or inadequate. It was determined that the spring provided adequate force to latch the trip hook when the OTM was properly reset. The spring condition was satisfactory.

Hypothesis 3. The pivot point of the trip hook is not sufficiently free to assure proper engagement of the trip hook to latch-up lever. It was demonstrated that the trip hook was sufficiently free to engage the lever when a proper reset and latching sequence was used; however, some misalignment of the parts was noted and is discussed in Attachment 2. The pivot point of the trip hook was well lubricated.

Hypothesis 4. The linkage mechanism may not be adjusted correctly. The Terry Turbine Co. representative verified the proper adjustment of the linkage. Additionally, when the proper reset sequence was followed, the OTM reset and operated correctly. It should be noted that the linkage operated as expected to trip the turbine during the initial overspeed conditions.

In the process of investigating the operation of the OTM linkage, it was found that a force on the connecting rod in the trip direction would sometimes dislodge the tappet from the reset to the tripped position. Although there is some possibility that this could have been the cause of the spurious trip of AFPT 1-1, the force required is large and no mechanism to get such a force has been identified during the June 9, 1985 event.

It is also possible that an operator, by forcing the connecting rod in the trip direction after resetting the OTM mechanism (as an attempt to assure that the OTM had reset), could inadvertently trip the OTM. This apparently did not occur since it would have led to multiple indications of operation of the head lever limit switch on the alarm printout. These were not present.

V. PLANNED ADDITIONAL ACTIONS

No further investigations are planned. The direct and root causes of the spurious trip of AFPT 1-1 T&T valve have been identified. 2

Step 4 of Action Plan 1D, addressing the difficulty of opening of the trip & throttle valve, will be completed in conjunction with Action Plan 1A, 1B testing. | 2

VI. TECHNICAL JUSTIFICATION OF FINDINGS

The direct cause of the difficulty in latching and the spurious trip of AFPT 1-1 has been established as the failure of the operator to properly reset the OTM prior to latching and opening the T&T valve. The root causes have been identified as: 1) lack of consideration of human factors in the linkage design so that a clear indication of the OTM position was not available to the operator, 2) procedures which did not adequately define the actual actions required to reset the OTM and relatch the T&T valve, and 3) training which did not adequately prepare the operators for performing the relatching activity under stress. Accordingly, the overspeed trip mechanism linkage should be removed from the freeze list so that corrective action may begin. However, the T&T valve, exclusive of the trip linkage, should remain on the freeze list until the testing on the valve opening force is completed and this finding report is revised to cover the difficulty in opening the T&T valve which occurred on AFPT 1-2.

VII. SPECIFIC CORRECTIVE ACTIONS

A. Required Corrective Action:

The following actions have been identified to correct existing deficiencies related to the identified root causes and prevent similar problems associated with the AFPT OTM.

Human Factors Considerations

1. Design and install local indication (trip/reset) of the OTM. Additionally, supply simplified local operating instructions. This item is to be completed prior to plant restart.

2. Paint the yoke of the T&T valve, the latch-up lever, trip hook, and connecting rod (unthreaded portion), for both AFPTs, a yellow color to distinguish this equipment as important in the operation of the overspeed trip. Additionally, the manual trip lever should be painted red. This item is to be completed prior to plant restart.

3. Install local position indication on both T&T valves. This indicator has been requested by the operators and will be installed prior to plant restart.

4. Provide enhanced communication for EOs in the AFPT rooms. EOs in both pump rooms should be able to communicate simultaneously with each other and the control room while operating the AFPTs. This item is to be completed prior to plant restart.

Procedural Considerations

5. Modify the affected procedures (reference Attachment 4) to reflect the proper reset sequence for the OTM and to also check that alarm points S007 and S017 reflect the reset condition on the control room alarm printer and annunciator. This modification is to be completed prior to plant restart.

6. Modify ST 5071.04 to ensure that the T&T valve and OTM are properly reset after the completion of testing. This modification is to be completed prior to plant restart.

Training Considerations

7. Operators will receive instruction on the theory of operation for the OTM and T&T valve. This instruction is to be completed prior to plant restart and will include all physical and procedure changes made as a result of this report. This instruction will also be incorporated in operator annual requalification.

8. Operators to complete "hands-on" training in the proper reset of the OTM and opening of the T&T valve with steam pressure > 800 psi. This training is to be completed with the plant in Mode 3 during restart. This training will also become a requirement for operator qualification.

B. <u>Additional Planned Action:</u>

The following are corrective actions to discrepancies noted during the course of these investigations that are not related to root cause but are included for completeness.

1. Install "no step" indication on the handwheel of both T&T valves. These are to be installed prior to plant restart.

2. Install "no step" indication on the connecting rod of each OTM. These are to be installed prior to plant restart.

3. A semi-annual preventative maintenance (PM) item specifically for cleaning and lubrication of the T&T valve and OTM of each AFPT will be instituted. This PM is to include: 1) the removal of old, built-up grease and grime from the T&T valve and OTM, 2) lubrication at all grease fittings, 3) lubrication of the sliding nut, screw spindle, and external guides of the T&T valve, and 4) lubrication of all other pivot points and sliding surfaces of the OTM excluding the

mating surfaces of the latch-up lever to trip hook and tappet to head lever. This semi-annual PM will also check the tightness of the connecting rod adjustment lock nut, overspeed trip device hold down screws, and the proper adjustment and alignment of the OTM. Also, to determine the need for touch-up painting on identified surfaces. This item is to be created and completed prior to plant restart.

4. A refueling outage preventative maintenance (PM) item will be institued to: 1) perform NDE on the tappet leaf spring, 2) confirm proper adjustment of the tappet, 3) perform dimensional inspection of the tappet nut and head lever, connecting rod to trip hook lever, and trip hook to latch-up lever mating surfaces. This item to be completed prior to the next refueling outage.

5. Replace the trip spring for the T&T valve on both AFPT's. Reference Terry Turbine letter to T. D. Murray of February 3, 1984. The springs will be replaced prior to plant restart.

6. Institute a new surveillance test, or equivalent, to exercise the T&T valves weekly while in plant modes 1,2 or 3 by turning the handwheel in the closing direction through the distance equal to ¼ of the total lift of the valve. This item will fulfill a manufacturers recommendation.

7. Straighten the bowed connecting rod and ensure that the connecting rod adjustment lock nut is tight on the AFPT 1-2 OTM. Reference Non Conformance Report (NCR) 85-0114. This correction must be completed prior to plant restart.

8. Replace the connecting rod socket on the head lever for the OTM on AFPT 1-2. Reference NCR 85-0114. This item must be replaced prior to plant restart.

9. Retighten the hold down screws for the OTM on AFPT 1-1. Reference NCR 85-0113. This action must be completed prior to Action Plan 1A/1B testing. | 2

10. Adjust the trip hook crank to obtain perpendicular alignment between the connecting rod and the trip hook pivot shaft for both AFPT OTMs. Reference NCR 85-0114. This alignment must be completed prior to plant restart.

11. Replace the head lever and tappet nut for both AFPT OTMs. Refrence NCR 84-0114. This item is to be completed prior to plant restart.

The following are actions that are being considered to enhance performance with respect to the operation of the AFPT's.

12. Investigate means to enhance the local manual control of the AFPT's. This will include, but not limited to local indication of steam generator level and manual control of the auxiliary feedwater pumps using the T&T valve. Appropriate training in the manual operation will have to be provided.

13. Investigate means to provide for remote reset of the AFPTs, if they trip on overspeed. This would include:

    a. The addition of an electric trip solenoid and

    b. A motor operator on the T&T valve.

    Consideration will be given to whether the additional complexity created by the above modifications will, in fact, effect the auxiliary feedwater system reliability.

VIII. GENERIC IMPLICATIONS

A. Significance

There are no other Terry Turbines like the AFPT at Davis-Besse and consequently there are no generic implications for many of the identified problems. There are, however, some broad implications of the root causes of the problems with the reset of the AFPT's. These are:

1. There may be other crucial operations which the operators are called upon to perform locally under conditions of stress which are not straightforward and for which the equipment human factors could be significantly improved.

2. There may be other inplant operations for which the existing procedures are inadequate or incorrect.

3. There may be other operations for which specific hands-on-training is needed to assure that the operations will be correctly performed in times of stress. This issue is specifically addressed in the final report for Action Plan 3, Operator Actions and Procedural Adequacy, Item III. A.6.

In addition to the generic implications of the root causes discussed previously, there may be generic implications of two other conditions which were observed in the investigations. Specifically:

1. Equipment was found to have been damaged by being used to support personnel (by being stepped on).

2. Temporary scaffolding was placed in locations which reduced the access to critical equipment and communications.

B. Planned Action

The potential generic problems described above may also be factors in some of the other events on June 9, 1985. Determination of whether these potential problems are present elsewhere at Davis-Besse is beyond the scope of the investigation of the AFPT overspeed trip and reset problems. As a result, selection of specific corrective action s not appropriate in this report. However, to assure that the observations are addressed, action plans for each of the identified items will be prepared.

ATTACHMENT 1

CHRONOLOGY OF EVENTS RELATED TO RESTART AFTER OVERSPEED TRIP

The following chronology describes the time sequence of events related to the tripping and reset of the Auxiliary Feed Pump Turbines (AFPTs) as determined from the plant records of June 9, 1985. The records utilized were the station alarm printer output, the output of DADS, and the security computer records. This chronology also includes comments indicating the most probable interpretation of each recorded event. These comments are based on the investigations conducted to date and interviews of the operators. (See also Attachments 2 and 3.)

TIME*	COMPUTER POINT ID	DESCRIPTION
1:41:31	S007/Z001	AFPT-1 overspeed trip/stop (T&T) valve started to close. Comment: The AFPT tripped at its correct setpoint and the T&T valve closure is instantaneous. These events are confirmed by the AFPT speed data.
1:41:44	S017/Z002	AFPT-2 overspeed trip/stop (T&T) valve started to close. Comment: The AFPT tripped at its correct setpoint and the T&T valve closure is instantaneous. These events are confirmed by the AFPT speed data.
1:45	Security Computer	Hatch to AFPT 1-2 room open.
1:45:50	S017	AFPT-2 overspeed trip reset. Comment: The EO had successfully reset the OTM. On July 5, 1985, it was noted that the OTM must be in its full reset position before the switch associated with the alarm point changes state. There were no additional trip alarms throughout the event which means that the OTM was properly holding in the reset position. The EO began to open the T&T valve, handwheel rotated in the counterclockwise direction, until the "free play" was removed. At that time,

		the EO could not move T&T valve disc from its seat by hand.
1:46	Security Computer	The door to AFPT 1-1 was opened.
1:46:33	S008	AFPT-1 showing speed increase. Comment: During these 33 seconds, the EO stated that he had tried to reset the OTM. The computer alarm printer, by absence of reset printout, indicates that the OTM was not moved a sufficient distance to cause the switch for alarm point S007 to change state. The limited movement would not allow the tappet to reset. On July 5, 1985, this EO had demonstrated the amount of movement applied on June 9, 1985. His understanding of the operation of the OTM had him pull the connecting rod until the trip hook met with the latch-up lever. It is noted that the connecting rod to trip hook is a slotted connection that allows additional movement of the connecting rod to reset the OTM. The appearance of the trip hook meeting with the latch-up lever does not mean that the OTM was pulled sufficiently to allow reset. It was demonstrated on July 5, 1985 that the movement on June 9, 1985 would cause neither: 1) the tappet to reset, nor 2) the switch to change state. The EO at this time during the June 9 event, physically held the trip hook to the latch-up lever and cracked open the T&T valve. The OTM was not reset. This evolution was shown possible on June 29, 1985 and July 5, 1985. During both investigations, the hook could be held on the lever, the T&T valve opened, the OTM not reset and the switch not change state. The OTM for AFPT 1-1 was not reset until 1:58:57.
1:52	Security Computer	A third EO logged into the AFPT rooms.

1:52:21	S018	AFPT-2 showing speed increase. Comment: The third EO, after viewing that the OTM was reset, realized that the T&T valve needed additional force to move the disc from its seat. At that time, he applied a valve wrench to the handwheel and partially opened the T&T valve.
1:52:53	Z002	AFPT-2 T&T valve fully open. Comment: The pump speed was 2,433 RPM at this time and increased slowly to 3,752 RPM at 1:53:51. The third EO stated that after moving the T&T valve disc from its seat, that the T&T valve became easy to open.
1:53:51	Z002	AFPT-2 T&T valve not fully open. Comment: Believing that the AFPT governor was not controlling properly, the EO took control of pump speed via the T&T valve to reduce pump speed. This mode of operation continued until 2:01:58.
1:56:08	Z001	AFPT-1 T&T valve fully open. Comment: Pump speed is approximately 3500 RPM. The EO was apparently controlling pump speed locally using the T&T valve.
1:58:39	Z001	AFPT-1 T&T valve not fully open and turbine speed dropping rapidly. Comment: The third EO, controlling the pump locally, had attempted to reduce the pump speed by placing the valve wrench on the handwheel and closing the valve. During this process, the trip hook disengaged from the latch-up lever and the T&T valve slammed shut. It is noted that there was no indication of OTM reset. It was shown that engagement without the OTM being reset is unstable due to the connecting rod/springs providing a constant force in the disengagement direction. A review of pump speed data confirms the EO's statement that the T&T valve "tripped" shut.

1:58:57	S007	AFPT-1 overspeed trip reset. Comment: After the T&T valve slammed shut, the third EO properly reset the OTM.
1:59:02	S008	AFPT-1 showing speed increase. Comment: The third EO, after resetting the OTM, began to open the T&T valve. AFPT-1 was controlled locally via the T&T valve for the remainder of the event with no further problems associated with the T&T valve or OTM.
2:01:58	Z002	AFPT-2 T&T valve fully open. Comment: Previous to this, attempts were made to place control of the pump in automatic from the control room (2:01:11). At 2:01:24, the pump control was placed in manual from the control room and it was realized that the T&T valve must be fully open so that the governor throttle valve could function. The pump was then manually controlled from the control room for the remainder of the event with no further problems.

* Times are Modcomp time. 6 seconds have been added to DADS time. Access times are only to the nearest minute.

ATTACHMENT 2

INSPECTION OF CONDITION AND OPERATION OF OVERSPEED TRIP AND VALVE LATCH MECHANISMS

This attachment summarizes the results of the investigations performed to verify the physical condition of the mechansims and confirm their operability. These investigations were performed without steam and without disassembly.

In accordance with the "Guidelines to Follow When Troubleshooting or Performing Investigative Actions Into the Root Cause Surrounding the June 9, 1985, Reactor Trip, Rev. 4", Maintenance Work Orders (MWO's) were prepared. Activities associated with MWO 1-85-2063-00 (AFPT 1-1) and MWO 1-85-2065-00 (AFPT 1-2) were conducted on June 29, 1985.

Both MWO's required the performance of Steps 1, 2, and 3 of Action Plan 1D. Representatives of the Nuclear Regulatory Commission (Messrs. W. Rogers and N. Choules), Terry Turbine Co. (Mr. J. Kregel), and MPR Associates, Inc. (Mr. T. Clark) were present during investigative actions conducted on June 29, 1985. Additional investigations associated with Rev. 01 of the aforementioned MWO's were conducted on July 5, 1985.

The specific observations considered to be potentially important either in this problem or to be potential future problems are discussed below:

1. Exercise of the OTM Linkage

   All checks associated with Step 3 of Action Plan 1D were completed. All items performed their respective functions. The "exercises" were performed using the sequence for manually tripping and resetting the OTM, as stated in Section II of this report, were successful. However, incomplete engagement of the trip hook to latch-up lever was noted on AFPT 1-1 when latching of the valve was attempted without resetting the tappet in the OTM.

   The EO involved with AFPT 1-1 on June 9, 1985 demonstrated how he had attempted to reset the OTM. His understanding of the operation of the OTM had him pull the connecting rod until the trip hook met with the latch-up lever. The movement of the OTM so that the trip hook met with the latch-up lever was not sufficient to allow either the turbine end of the OTM to reset or the limit switch to change state.

2. Engagement of Latch Without Tappet Reset

   During the performance of Action Plan 1D, Step 3, it was noted that Section 6.11 of Surveillance Test (ST) 5071.01.26 (Attachment 3) did not provide adequate direction for resetting the OTM. The purpose of the surveillance test is to exercise the OTM and is not primarily intended to train operators. The wording of the ST places secondary importance in resetting the OTM with the primary emphasis on engagement of the trip hook to latch-up lever. During the exercising, it was shown possible to engage the trip hook with the latch-up lever without resetting the OTM. By holding the hook in the engaged

position and <u>opening</u> the valve, it was possible to load the latching faces and thereby hold the hook is place with friction. In this condition, the spring forces would be acting to disengage the hook. Note that in this condition:

a. The valve was metastable and could trip without any action of the overspeed mechanism.

b. The turbine would have had no overspeed trip protection even though it could have run.

3. <u>AFPT 1-1 and 1-2 OTM Reset Stability</u>

It was demonstrated that the OTM could be tripped when the connecting rod was pulled hard in the trip direction, particularly when done repeatedly. This should not occur. One experienced EO stated that in order to determine if the OTM has reset, he pulls in the connecting rod in the trip direction. This action could result in the retripping of the OTM. The retripping is attributed to a worn tappet and head lever that would not allow the proper interference between parts when the OTM was reset.

4. <u>Alarm Indications</u>

On July 5, 1985 additional investigations were conducted under revision 1 to the previously listed MWO's. The purpose of the additional investigations was to correlate the computer alarm printer data from 1:41:31 to 2:01:58 on June 9, 1985 with reported EO actions. It was observed, from the June 9, 1985 computer alarm printer data, that there was one trip and one reset for each of the AFPT OTM's. The following summarizes these investigations:

a. It was noted that OTM must be in its full reset position before the limit switch, which indicates head lever position, changes state. This shows that if the OTM were not moved far enough to allow the tappet to return to its normal position, then the switch would not change state. An associated test showed that if the OTM were repeatedly moved from the tripped to reset position, with the tappet manually prevented from resetting, then multiple trips and resets were recorded on the alarm printer. This test demonstrates that the computer alarm printer would indicate if the OTM were being moved sufficiently but failed to reset.

b. It was demonstrated that the trip hook could be manually held engaged with the latch-up lever and that T&T valve fully opened without resetting the OTM. This action would <u>not</u> result in an overspeed trip "norm" (reset) on the computer alarm printer. The "norm" indication would only be received when the OTM was moved far enough to allow reset of the mechanism.

5. AFPT 1-2 Connecting Rod

AFPT 1-2 OTM was noted to have a "bowed" connecting rod and loose lock nuts (Figure 1). Although these conditions existed, the OTM was within adjustment. The connecting rod provides the mechanical connection between the turbine trip mechanism (device) and the T&T valve. Proper adjustment is verified by assuring that the gap between the connecting rod link pin and the front edge of the slot is not less than 1/4" (see Figure 1, Detail A) in the reset position. Improper adjustment of the connecting rod could cause either 1) improper engagement of the trip hook to latch-up lever, or 2) failure of trip hook to disengage with the latch-up lever. Operational checks did not show that the bowed rod or the loose connections caused the problems with the OTM.

6. AFPT 1-1 Hold Down Screws

Two of the AFPT 1-1 turbine trip device hold down screws were noted to be loose. There are three screws that hold the device to the turbine shaft casing. Although two screws were loose, the third was tight preventing rotational or vertical movement and maintaining the position of the device.

7. AFPT 1-1 and 1-2 Leaf Springs

Attempts were made to view the leaf springs for both AFPT's from the overspeed trip adjustment port. Direct and fiberscopic (AFPT 1-2 only) examinations to the extent possible without disassembly, did not detect any unusual conditions. As discussed, spring integrity was verified by exercising and confirming the free motion of the tappet.

8. AFPT 1-1 Trip Device Cleanliness

There was some build-up of dirt on the mechanisms. However, based upon the exercising of the mechanism, particularly the tappet and leaf spring, it was concluded that the observed grime build-up on the overspeed trip device would not, by itself, cause the tappet not to return to its normal position during proper relatching of the OTM. The connected leaf spring appears to provide positive return force to the tappet as discussed in Section IV.

9. AFPT 1-2 Connecting Rod to Head Lever Ball Joint

A ball and socket is provided as the connection of the connecting rod to the turbine trip device head lever. The socket on the AFPT 1-2 linkage appeared to be oblong versus a normally round geometry. This was shown not to cause binding of the OTM and the ball moved freely in the socket.

10. AFPT 1-2 Pump Room Environment

The auxiliary feed pump rooms are congested, particularly the room for AFPT 1-1 which contained scaffolding. It was noted by both EO's

that some scaffolding had been removed from the AFPT 1-2 room. The scaffolding had caused problems with access and operator mobility in the pump rooms while attempting to restart the pumps on June 9, 1985.

It was found that the communications were not adequate to permit the EO to communicate with the control room while he was in a position to operate the OTM linkage or the T&T valve.

The pump rooms are not particularly well lighted in the area of the T&T valves and the OTM linkage. The EO's indicated that some light bulbs may have been burned out on June 9, 1985.

11. Lateral Alignment of Linkage

Inspection of the linkage showed that the connecting rod is slightly non-perpendicular to the axis of the trip hook pivot shaft in the horizontal plane. This results in a slight misalignment between the clevis at the end of the connecting rod and the trip crank. This may lead to some resistance to movement at this joint in the linkage. This appeared to have contributed to less than complete engagement of the trip hook with the latch-up lever on some occasions. However, a small force manually applied to the trip hook was sufficient to bring the hook and the latch-up lever into full engagement in all cases.

ATTACHMENT 3

RESULTS OF OPERATOR INTERVIEWS, PROCEDURAL AND TRAINING REVIEWS

A. Operator Interviews

The operators involved in the June 9, 1985 attempts to restart the AFPT's were interviewed and asked to demonstrate and recall their actions at that time. The significant items from those interviews are as follows:

1. The EO involved with AFPT 1-1 on June 9, 1985, demonstrated how he had attempted to reset the OTM. His understanding of the operation of the OTM had him pull the connecting rod until the trip hook met with the latch-up lever. The movement of the OTM so that the trip hook met with the latch-up lever was not sufficient to allow either the turbine end of the OTM to reset or the limit switch to change state.

2. The EO's involved on June 9 were interviewed on June 15. In that interview, the EO involved with AFPT 1-1 used the palm of his hand to show how he attempted to keep the trip hook engaged to latch-up lever. This action would be required if the OTM were not reset since manual force would have been necessary to overcome the spring force holding the OTM in the tripped direction. It was demonstrated that with sufficient force on the trip hook, the hook could be engaged with the latch-up lever without resetting the OTM. This engagement was unstable and could be disengaged with slight disturbances of the mechanism such as T&T valve operation or mechanical shock. If engagement was maintained, the T&T valve could be opened.

   In addition to the items noted above, the operator interviews were used in preparing the comments in the chronology of events presented in Attachment 1.

B. Procedures For Reset and Latching

Typical of plant procedures which include instructions for reset and relatching of the trip and throttle valve is Section 6.11 of Surveillance Test (ST) 5071.01.26. This procedure states the following:

"6.11 Perform the following to exercise the overspeed trip mechanism:

_____6.11.1 Using the manual trip lever, manually trip the trip throttle valve.

_____6.11.2 Turn the trip throttle valve handwheel clockwise until the sliding nut rises and engages the latch up lever to the trip hook.

NOTE: It may be necessary to pull on the trip throttle valve linkage to fully energize the latch up lever to the trip hook.

_____6.11.3 Verify the latch up lever and the trip hook are fully engaged.

_____6.11.4 Turn the trip throttle valve handwheel counterclockwise until the trip throttle valve is fully open.

_____6.11.5 Turn the trip throttle valve handwheel 1/4 turn clockwise.

_____6.11.6 Seal the trip throttle valve handwheel.

Independently Verified____________________

_____6.11.7 Verify computer point Z001 (Z002) AFPT 1 (2) Stop Valve reads "OPEN".

_____6.11.8 Verify the red IL ICS 38E (38J) AFPT 1 (2) Governor Valve fully open light is on."

It is particularly important to note that the procedure steps ignore the trip tappet, head lever, connecting rod, and alarm indication of reset in the control room. As was verified in the inspections, unless the connecting rod is pulled in the reset direction, the tappet will not reset. That is, simply engaging the latch hook with the latch-up lever will not move the head lever enough to allow the tappet to drop to the reset position. Consequently, this procedure is technically incorrect.

C. Operator Training

Discussions were held with the training staff to ascertain the depth of the information provided to the EO's. The discussions centered around the hands-on training conducted on November 2, 1983 and actions taken by the Training Department as a result of the Institute for Nuclear Power Operations (INPO) Significant Operating Experience Report (SOER) 82-8, dated August 4, 1982.

As a result of the normal Toledo Edison (TED) review process for INPO SOER's, SOER 82-08 was transmitted to the training department with the recommendation to include the SOER in Reactor Operator/Senior Reactor Operator required reading and non-licensed operator requalification training. The SOER did not indicate potential problems with the operability of the OTM. The SOER was primarily intended to warn of a deficiency in the verification of OTM reset. It was noted at other plants utilizing Terry Turbines that the OTM could be in the tripped condition and without control room indication, these pumps would then not be available for operation. Toledo Edison reviewed this SOER and determined that Davis-Besse did in fact have control room indication of the condition of the OTM. According to training personnel, the information of the SOER was given to the operators. It is noted that

the SOER did not detail trip or reset operations and therefore, training personnel relied on the detail included in the existing plant procedures.

The EO training conducted on November 2, 1983, was a 20 minute session conducted in the AFPT pump room. There were seven operators and one instructor. Of those seven operators, the three principal operators involved in the AFPT restart of June 9, 1985 were present. The training instructor stated that the training was largely a demonstration and that all operators were not given an opportunity to physically trip and reset the mechanism. There was no lesson plan for this training session.

ATTACHMENT 4

AFFECTED PROCEDURES LIST

Surveillance Tests (ST)

5071.01 Auxiliary Feedwater System Monthly Test

5071.02 Auxiliary Feedwater System Refueling Test

System Procedure (SP)

1106.06 Auxiliary Feedwater System

Periodic Test (PT)

5150.01 Auxiliary Feed Pump Turbine Overspeed Test

Alarm Procedures (AP)

3010.15 Auxiliary Feedwater Pump 1 TRBL

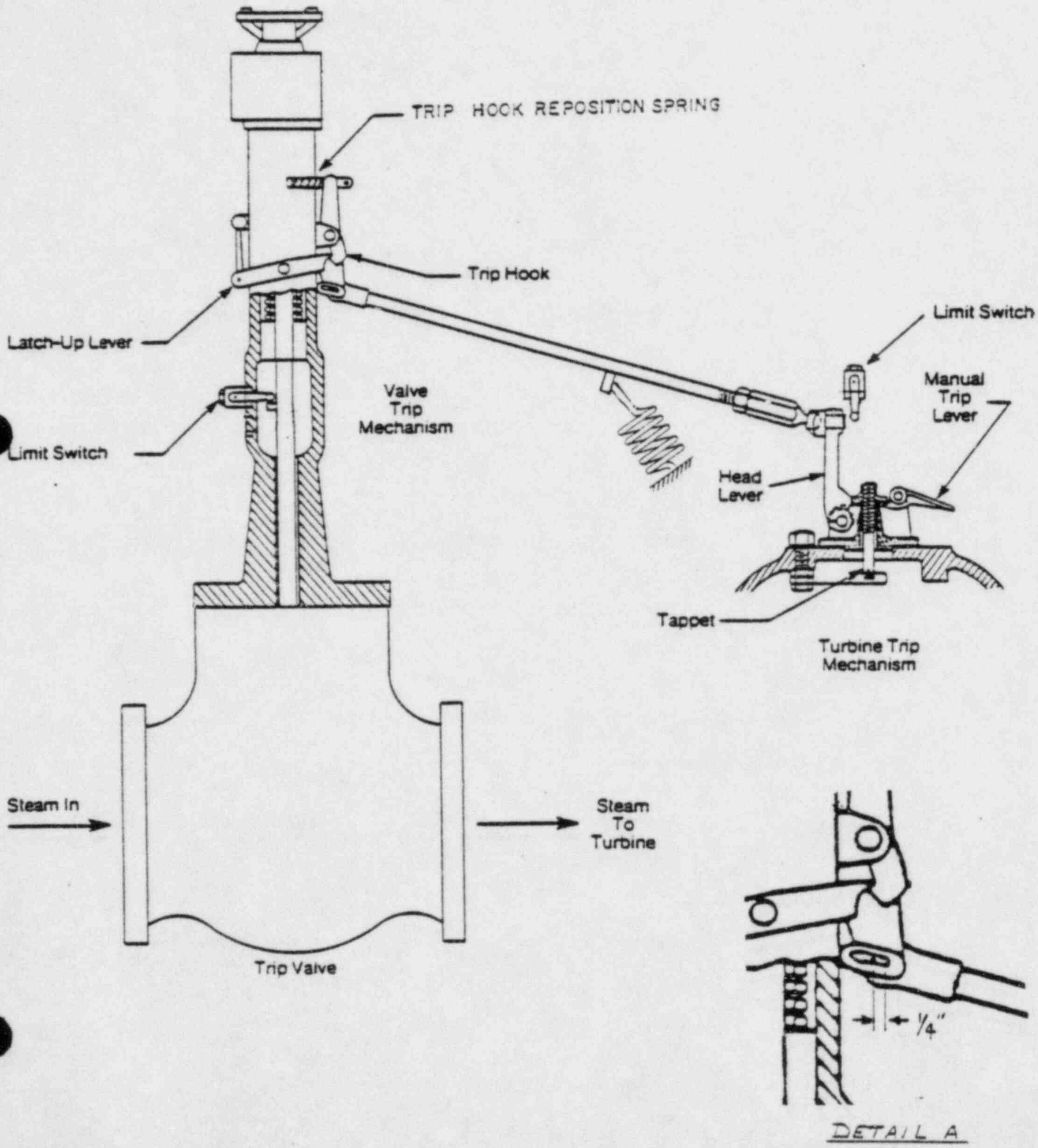
3010.16 Auxiliary Feedwater Pump 2 TRBL

3010.47 AFPT 1 Over SPD Trip

3010.48 AFPT 2 Over SPD Trip

Latching AFW Turbine Trip Valve

Figure 1



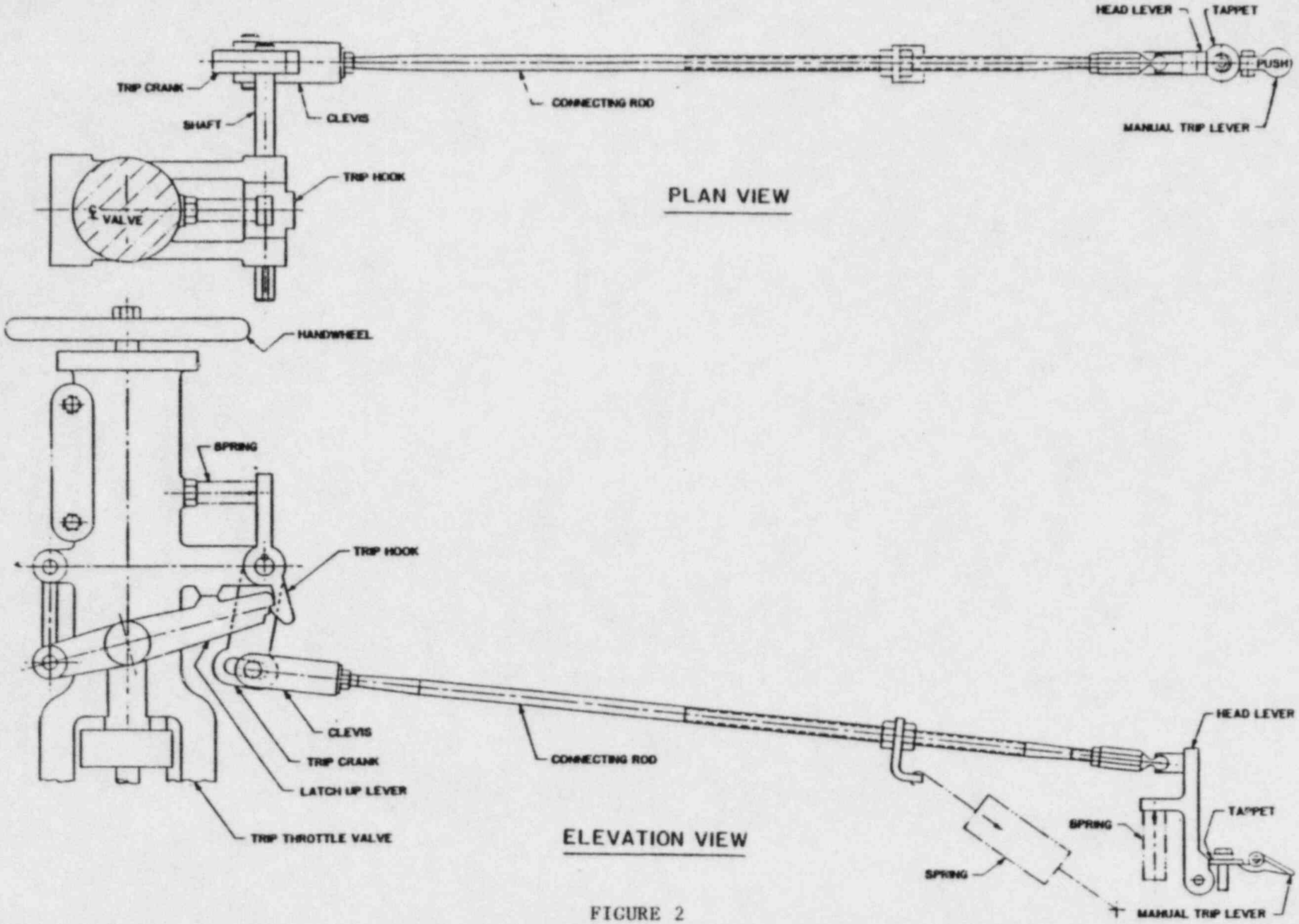


FIGURE 2

AUXILIARY FEED PUMP TURBINE
OVERSPEED TRIP LINKAGE

(VALVE LATCHED, TAPPET RESET)

PRELIMINARY FINDINGS, CORRECTIVE
ACTIONS AND GENERIC IMPLICATIONS REPORT

TITLE: TOLEDO EDISON - SFRCS TRIP/MSIV CLOSURE

REPORT BY: L. C. STALTER (TED)
S. C. JAIN (TED)

PLAN NO. 5, 6 & 7

REV	DATE	REASON FOR REVISION	WRITTEN BY	APPROVED BY
0	8/24/85	Initial Issue	L. Stalter S. Jain	L. Grime
1	8/28/85	Corrective Actions Added	L. Stalter S. Jain	L. Grime
2	9/7/85	Revised Root Cause Description	D. Mominee	L. A. Grime

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I. Issue Of Concern

This report is intended to summarize the results of troubleshooting performed in relation to the inadvertent trip of the Steam and Feedwater Rupture Control System and spurious closure of the Main Steam Line Isolation valves.

On June 9, 1985 a low Steam Generator (SG) level full trip of the Steam and Feedwater Rupture Control System (SFRCS) occurred immediately following the main turbine trip and closure of associated stop valves. This was observed from the alarm log of the event. Closure of both Main Steam Isolation Valves (MSIV) followed approximately 5 seconds after the SFRCS full trip. Additionally, other valves which normally would have actuated, given a full SFRCS trip, did not actuate. No previous spurious low SG level trips of the SFRCS have been observed at Davis-Besse (DB) prior to the 1984 Refueling Outage.

Although occurrence of a (spurious) full trip of SFRCS during the June 9, 1985 trip is evidenced by computer alarm Q963, there is a question regarding its validity because of the observed inadequate performance of this alarm function in the recent past. This report aims at the issues of the occurrence of spurious SFRCS trip, the SFRCS full trip, the SFRCS full trip alarm function and the closure of MSIVs without actuation of other SFRCS associated valves. 2

II. Basic Principle Of Operation

The Davis-Besse SFRCS is an instrumentation system designed to provide the following:

1. Initiation of auxiliary feedwater (AFW).
2. Signals for isolation of main feedwater and main steam lines under all trip conditions except a loss of four reactor coolant pumps.
3. The selection and isolation of appropriate steam generator(s) to ensure AFW supply only to a "good" (pressurized above 600 PSI) steam generator.

The first two functions are provided when the following sensed parameters exceed the predetermined setpoints. The last function is provided only for a steam generator low pressure condition. A simplified logic diagram for the SFRCS is shown on Figure 11.

- Steam generator low level
- Steam generator high level
- Steam generator-main feedwater high differential pressure
- Steam generator low pressure
- Loss of all four reactor coolant pumps

The SFRCS utilizes a one-out-of-two taken twice logic and is divided into four logic channels. Logic channels 1 and 3 form Actuation channel 1 and logic channels 2 and 4 form Actuation channel 2. One logic channel of the actuation channel is supplied by AC power and

the other logic channel is supplied by DC power. Contact outputs from "deenergize to actuate" SFRCS output relays are utilized in the field control circuits for the SFRCS actuated equipment. The actuated equipment includes solenoid operated (e.g. MSIV, startup control valves) as well as motor operated (e.g. auxiliary feed pump turbine main steam inlet valves.) Most components require both logic halves of an actuation channel to trip for the valve to actuate, but are actuated only by one (associated) actuation channel. Each MSIV and each startup control valve can be closed by either one of the two 2
actuation channels.

Of particular interest to this report is the steam generator level input to the SFRCS. Each SFRCS logic channel receives signals from two differential pressure level transmitters, one on each steam generator. The steam generator level instrumentation utilizes a composite high and low level bistable which provides input to the SFRCS logic for protective function. Referring to Figure 1, the two level transmitters associated with an actuation channel of SFRCS (D1 & E1 or D2 & E2) share the level sensing taps with another level transmitter which is used for controlling steam generator level with auxiliary feedwater (C1 or C2). Since each steam generator level is monitored by both actuation channels (all four logic channels), each steam generator has two sets of level sensing taps.

The function of the MSIVs is to isolate the steam generators from a main steam line break and to preserve steam supply to provide motive steam to run the auxiliary feedwater pump turbines. This isolation is initiated by the SFRCS on all parameters listed above except the loss of all four reactor coolant pumps. The MSIVs are also closed on a Safety Features Actuation System (SFAS) initiation on high-high containment vessel pressure (38.4 PSIA).

The MSIVs are air operated, balanced-disk stop valves. A spring actuator is provided for rapid closure of the valves. The valves are held open by air operators. A nitrogen accumulator is provided for each valve in case of loss of plant air. The MSIVs are controlled using solenoid valves and pneumatic pilot valves which are configured as shown in attached Figure 2.

An annunciator alarm and "sequence-of-events" computer alarm is provided for the SFRCS full trip. This full trip alarm is activated when an actuation channel of the SFRCS (both logic halves) has tripped on any one or more of the five SFRCS initiating parameters. The alarm function utilizes a time delay relay which provides a nominal delay of approximately two (2) seconds to prevent the alarm from resetting prior to being sensed by the computer. Receipt of the full trip alarm provides indication of a full trip of an actuation channel of the SFRCS. See attached Figure 3 for the alarm control circuitry.

III. Summary of Troubleshooting and Investigation

Following is a summary of troubleshooting and investigation performed for the spurious SFRCS trip and MSIV closure. The summary directly correlates with the action plan steps provided in the SFRCS/MSIV closure action plan. For ease of reference, the action plan step is reiterated and details of troubleshooting activities are listed thereafter.

A. Field Actions performed.

Action Plan Step 2A

"Perform a test by injecting an analog signal or signals at the input to the Steam Generator Level Instrument Cabinets to verify that, for a "full SFRCS trip" of short time duration, the SFRCS output corresponds to that which occurred on 6/9/85."

Maintenance work order (MWO) 1-85-2235-08 verified that the minimum time required to generate a close signal for an MSIV was 7.5 milliseconds.

Maintenance Work Order 1-85-2235-13 established that the minimum time required to generate a close signal for a startup feedwater control valve to actuate was 26.7 milliseconds. NOTE: This was Action Plan Step 14.

Data from Westinghouse indicates that the pickup time for a starter is approximately 66 milliseconds for AC starters and 25 to 75 milliseconds for DC starters. Verification of actual time response for these remaining items is pending.

During the testing, it was noticed that SFRCS Logic Channel 2 was providing a spurious one half trip due to power supply noise. The power supply was replaced to allow testing to continue. The remaining channels were checked to ensure they did not have the same type of failure. None did. This was added to the action plan as Steps 12A (MWO 1-85-2235-12) and 13 (MWO 1-85-2235-11). 1

Action Plan Step 3A

"Test the time delay relay (shown on TED drawing E-42B, sheet 54) in the SFRCS "full trip" reset logic to verify the total time the SFRCS full trip was in effect."

Maintenance Work Order 1-85-2235-01 measured this time delay relay response. It reset in 1.084 and 1.096 seconds, and tripped in 0.024 seconds both times.

Action Plan Step 4A

"Visually inspect each steam generator starting level transmit ter for loose connections, cleanliness."

This inspection for loose connections and a check of cleanliness was done under MWO 1-85-2235-02. The result was that all transmitters were found to be clean, and only one (1) connection was deemed to be "slightly loose". It was noted that this connection still appeared to make good contact and was not considered to contribute to the spurious SFRCS actuation.

Action Step 4B

"Verify the response time of each Steam Generator startup level transmitter in both increasing and decreasing direction."

Maintenance Work Order 1-85-2235-02 verified the response times of each transmitter for a step change from the full output down to 63% of full scale and from 150" to 285" increasing (normal operating level up to above the trip setpoint).

The response times ranged from 148 to 288 milliseconds in the decreasing direction, and from 104 to 120 milliseconds in the increasing direction.

Action Plan Step 4C

"Verify the calibration of each SFRCS steam generator startup level transmitter."

Maintenance Work Order 1-85-2235-02 was conducted which verified that all steam generator startup level transmitters listed above were in calibration with the exception of LTSP9B9 which would cause the bistable to trip 20 inches above the normal trip setpoint.

Action Plan Step 8

"Perform response time testing on the old and new bistable modules (both trip and reset times) to evaluate its overall impact on SFRCS response characteristics."

Maintenance Work Order 1-85-2235-06 tested the response time (step change) of the old (original) analog modules and bistables (installed prior to the 1984 refueling outage.)

Maintenance Work Order 1-85-2235-03 was performed to obtain 1
the response time of the new analog/bistable units which were installed in the 1984 outage and were in place June 9, 1985.

The response time of the new Analog/Bistable Units was determined to be 2 to 9 milliseconds slower than the old analog modules and bistable modules combined.

Action Plan Step 9

"Energize the turbine trip circuits and monitor each SFRCS channel power supply output to determine existence of power signal inter ference and/or cross-channeling of signals."

Maintenance Work Order 1-85-2235-04 was performed which monitored the SFRCS while deenergizing the turbine trip circuits. The results showed no interference and cross channeling.

Action Plan Step 10

"Conduct a test to determine no inadvertent ties exist between the outputs of the power supplies for the two half channels in an actuation channel."

This test was conducted and determined that no ties exist between the power supplies of the SFRCS channels (MWO 1-85-2235-10).

Action Plan Step 11

"Prior to and during Mode 1 operation, perform testing on steam generator startup range level instrumentation supplying the SFRCS to determine the magnitude and frequency of hydraulic and/or electronic noise as sensed by this instrumentation."

Test not yet conducted.

B. Analysis Performed

Two activities have been completed to support Action Plan Steps 1A and 5. Step 1A relates to analysis of available data from Davis-Besse and other operating Nuclear Power Plants to determine effects of sudden turbine stop valve closure on level sensing instrumentation.

Step 5 relates to analysis of the present level transmitter configuration as compared to the transmitter configuration in place prior to the 1984 Refueling Outage.

1. Review of available data

A review of past pre-operational testing at Davis-Besse has revealed oscillations in indicated startup range level following a turbine stop valve closure. Only one occasion was encountered when such data was recorded with high enough frequency to exhibit drastic oscillations in level transmitter output. This data was taken for a turbine trip from 75% full power and was logged every 200 milliseconds. The data showed that level transmitter output can change by as much as 60 inches following a turbine trip (see attached Figures 4 and 5). It is noted that this behavior is

exhibited by a Bailey BY transmitter and a Rosemount 1153 transmitter is considerably more responsive as discussed later in this section.

A review of transient reports from three other units all reveal oscillatory behavior in the level transmitter output following reactor/turbine trips apparently due to pressure oscillations in the steam line following valve closure. This behavior is evident from the attached Figures 6 through 9. It is concluded from the above review that significant fluctuations in level transmitter output are expected to occur following a turbine trip or load rejection. These fluctuations can, therefore, result in spurious actions by control systems (e.g., SFRCS) which sense such oscillatory behavior. The frequency and magnitude of these oscillations has the potential of resulting in several momentary trips of the protection system.

2. <u>Analysis of Responsiveness of Level Transmitter Configurations</u>

To evaluate and compare the relative responsiveness of the level transmitter configurations prior to and after the 1984 Refueling Outage, an analysis was conducted to study such response of the level instrumentation to rapid steam flow and a pressure transient produced by a turbine trip. Analysis was conducted by MPR Associates and preliminary results are summarized below.

Per the analysis, the maximum amplitude of main steam pressure disturbance produced by a turbine trip is calculated to be approximately 70 PSI, though the amplitude of pressure pulse reaching the steam generator may be smaller (e.g., 40 PSI). The frequency of pressure disturbance is estimated to be 1.25 Hertz.

During the 1984 Refueling Outage, Bailey BY transmitters were replaced with Rosemount 1153 transmitters. This caused a change to the hydraulic configuration of the startup range level transmitters. This change is considered to affect their responsiveness.

The Rosemount transmitter has a small displacement, approximately 0.04 cubic inches versus 1.5 cubic inches for the Bailey transmitter. As a consequence, the break frequency (indicative of the pass band) of the startup range level system hydraulics was increased by the change from about 0.6 hz. to about 2½ Hz. The damping of the electronics of the level transmitter has a break frequency in the neighborhood of 0.8 Hz.

Prior to the 1984 outage pressure disturbances produced by the turbine trip -- which are characterized by a frequency of about 1.25 Hz., were attenuated by the level sensing system by a factor of roughly 6. After the 1984 outage, when the BY transmitters were replaced, the level sensing system attenuated the pressure disturbance by no more than a factor of 2.

Prior to the outage, the maximum apparent level swing following a turbine trip would have been no more than 12 feet and is expected to be around 5 to 6 feet in Channel 2 and 4 to 7 feet in Channel 1. However, since the 1984 outage at Davis-Besse, the amplitude of the level swings "seen" by the SFRCS level switches may be as much as 30 feet on Channel 2 and 20 feet on Channel 1. The actual amplitudes are probably less than these figures because of the attenuation of the pressure wave in the steam pipe and the "mixing" of the tube bundle pressure and annulus pressure to determine the response of the reference leg.

3. Analysis of SFRCS Actuation Times

The attached Figure 10 pictorially describes the postulated phenomenon which is considered to have resulted in partial actuation of the SFRCS. As noted earlier, the SFRCS actuates several different types of components including AC and DC motor-operated valves and solenoid-operated valves. There are three types of solenoid valves actuated by the SFRCS. One type utilizes a single solenoid (e.g. the Main Feedwater Control Valves SP6A and SP6B). The second type utilizes a combination of solenoid valves and a set of auxiliary relays (e.g. the Startup Control Valves SP7A and SP7B). Yet another type employs a combination of solenoid valves and pneumatic pilot valves (e.g. the Main Steam Line Isolation Valves. The relative SFRCS actuation times for each of the above type valves is depicted on the attached figure. Manufacturer-supplied data is utilized where such data has not yet been measured in the field. Once such field verification is completed, it may be concluded that multiple SFRCS trips of very short durations may have resulted in partial actuation of SFRCS and closure of the MSIV's. The momentary trips, in turn, may have been caused by oscillations in steam generator level transmitter outputs resulting from turbine stop valve closure.

From the above analysis, it is concluded that the spurious SFRCS trip on June 9, 1985 did occur because of the above phenomenon which is prevalent following a main turbine trip. The frequency of such trips may have resulted in several "momentary" SFRCS trips especially in Actuation Channel 2 because such effects are more pronounced for the Channel 2 level transmitter configuration.

C. Significance of Findings

The troubleshooting and investigative activities and the analytical efforts completed to date strengthen the support for hypothesis 1 as a dominant cause for the spurious full trip of SFRCS trip and MSIV closure. However, confirmatory tests as outlined in the existing action plan are ongoing and need to be completed prior to establishment of a definite root cause. This findings report will be revised accordingly once results from these tests are available.

IV. Results/Conclusions of Findings

A. Direct Causes

None were found.

B. Root Causes

Root cause is deemed to be Hypothesis 1. 2

C. Disproved Hypothesis

Hypothesis-2 (SFRCS Trip)

The spurious full trip of SFRCS may have been caused by some cross-talk between two logic channels of a given actuation channel. It is noted that the SFRCS contains two actuation channels. Each actuation channel consists of two logic channels (half channels). It may be hypothesized that cross-talk between the two half channels may cause spurious computer alarms (and closure of both MSIV's). Such spurious cross-talk may also be hypothesized to cause full SFRCS trips due to associated power supply failures or an electrical transient that may occur on a turbine-generator trip.

Possibility of the above hypothesis is, however, considered remote since the two logic channel halves of each actuation channel of the Davis-Besse SFRCS are electrically redundant and separate. The SFRCS does not utilize shared power supply commons (as is the case for the Safety Features Actuation System). Thus a path for this cross-talk is not considered possible. Moreover, one logic half of an actuation channel is AC powered and the other is DC powered. This provides additional redundancy and diversity. Further, the main turbine trip circuits are powered from non-1E power sources separate from those that power the SFRCS channels.

Based on the above it is concluded that spurious cross-talk between the two halves of an actuation channel or between the

main turbine trip circuits and the SFRCS circuits resulting from the above mentioned conditions, i.e. power supply failures or an electrical transient caused by a turbine-generator trip is apparently not the most probable root cause for the SFRCS full trip. However, Action Plan steps 9 and 10 included tests for verification of such separation.

Action Plan Step 9 verified that there was no interference and/or cross-channeling of signals resulting from turbine trip circuits.

Action Plan Step 10 verified that no ties exist between the power supplies of the SFRCS channels.

Hypothesis-3 (SFRCS Trip)

Because of several modifications (See Section III) made either to the SFRCS logic (FCRs 81-178, Rev. 0, and Rev. A) or to the associated analog bistable circuitry (FCRs 80-110, Rev. 0 and Rev. A) in the 1984 refueling outage, it may be postulated that a logic malfunction or an SFRCS circuitry misoperation may result in inadvertent operation of an actuation channel. The observed SG low level full trip may be hypothesized to be associated with either the revised (then subsequently "re-stored") logic boards or the modified analog bistable circuitry.

The above hypothesis is again only remotely possible since the integrated SFRCS test (ST 5031.18) conducted following the completion of FCRs 80-110 Rev. 0, Rev. A and 81-178 Rev. 0 verified proper operation of both the system logic and the SFRCS functions associated with a low level condition in either steam generator. This test did not identify any malfunctions in system logic and function negating the hypothesis that the spurious trip may have been caused by a malfunction of SFRCS logic. However, the attached action plan addresses a review of the SFRCS surveillance test program to determine whether the system logic design is adequately tested and that the logic operation is in compliance with the design.

Action Plan Step 7 (yet to be completed).

Hypothesis-6 (MSIV Closure)

Independent of the SFRCS, it may be postulated that the MSIV closure was caused by a malfunction within the MSIV closure circuitry which includes the solenoid valves and air operated pilot valves. Although the probability of such a malfunction, pre-existent or that occurring during the transient, that could affect both MSIV's is considered to be very low, the attached action plan provides for testing of this logic circuitry to verify proper operation.

Action Plan Step 6 (yet to be completed).

V. Specific Corrective Action

A. Required Corrective Action

1. System induced spurious signals during a transient following a turbine trip need to be filtered out to prevent SFRCS actuation which causes the MSIV's to close and other SFRCS equipment to not actuate. It has been determined that a filter having a band pass from 0.0 Hz to 0.1 Hz will provide the necessary signal rejection capability yet still provide system response necessary to meet the requirements of the Davis-Besse technical specifications. This filter will be installed (FCR 85-161) at the input to the SFRCS Low and High Level trip bistables.

2. Testing as described in the Action Plan Step 11 will be performed.

   "Prior to and during Mode 1 operation, perform testing on steam generator startup range level instrumentation supplying the SFRCS to determine the magnitude and frequency of hydraulic and/or electronic noise as sensed by this instrumentation."

   This monitoring will remain in place until the adequacy of the corrective actions can be verified.

3. Other corrective actions to be determined. 1

B. Planned Additional Action

1. During the testing, it was noticed that SFRCS Channel 2 was providing a spurious one half trip due to power supply noise. The power supply was replaced to allow testing to continue. The remaining channels were checked to ensure they did not have the same type of failure. None did.

   Toledo Edison had prepared a Facility Change Request (FCR 84-102) to install a cabinet cooling system (fans and filters). This FCR has been elevated in priority to provide the engineering and equipment necessary to implement additional cooling capability to the SFRCS cabinets. This will be implemented as soon as it is possible.

2. System modifications will be performed to ensure complete actuation of SFRCS on genuine input trip parameter conditions.

VI. Generic Implications

A. Significance

The timing problem identified in this action plan is not considered to have generic implications for other systems at Davis-Besse. It is only associated with the SFRCS.

The increased response capabilities due to the installation of more sensitive transmitters could effect other systems. Systems which operated with large displacement bellows are more responsive to normal fluctuations which occur and could cause undesirable responses.

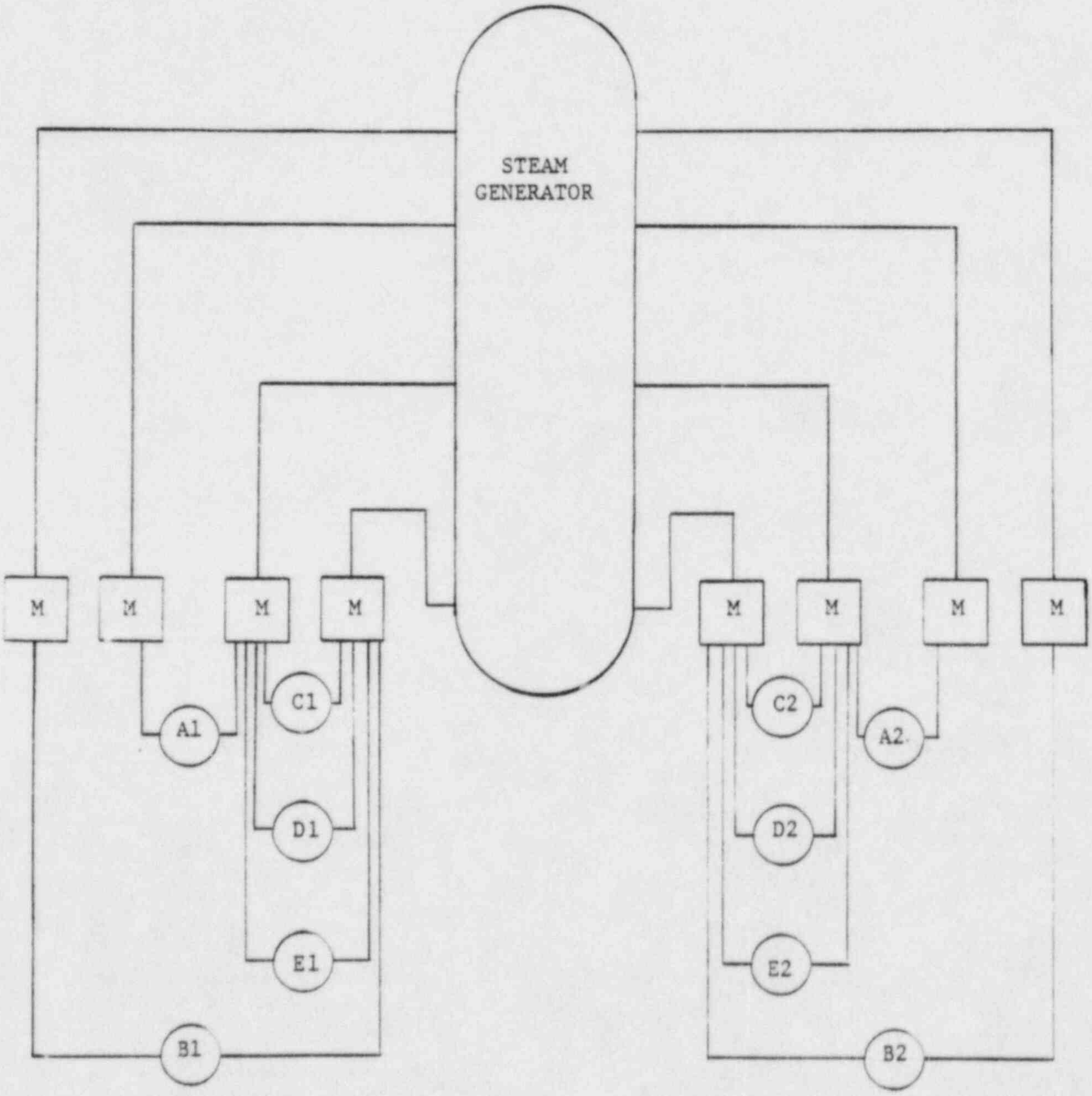
B. Planned Actions 1

The increased response capability as a result of installing more sensitive transmitters was also addressed in the Reactor Protection System. FCR 85-103 was in the implementation stage when the June 9 event interrupted the work. We plan to complete the implementation of this FCR prior to entering Mode 1.

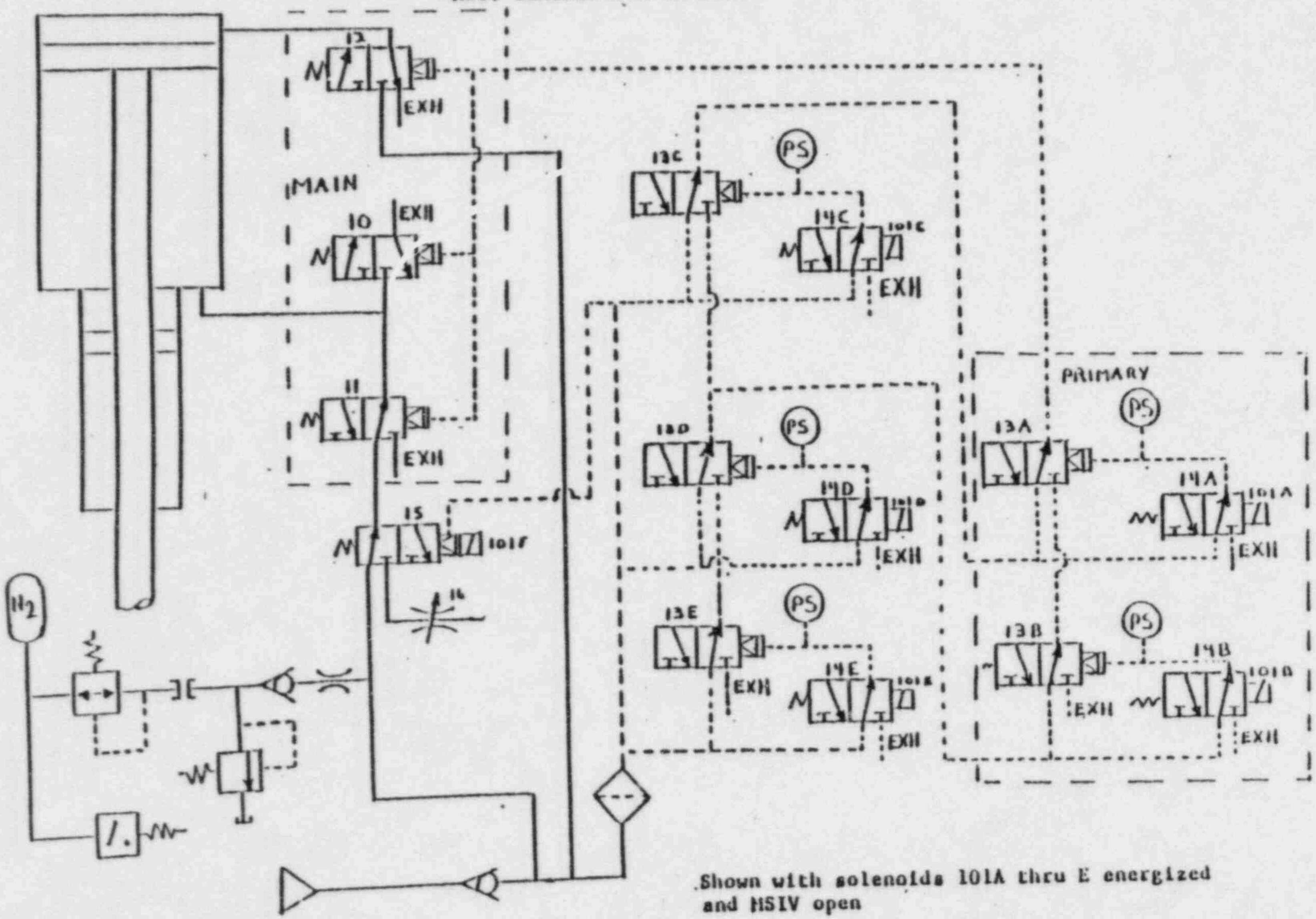
Figure 1

ARRANGEMENT OF OTSG LEVEL TRANSMITTERS

A1/A2	-	Operate Range Level Transmitter	Changed in 1983
B1/B2	-	Full Range Level Transmitter	- Changed in 1984
C1/C2	-	Startup Level Control Transmitter	- Not Changed
D1/D2	-	Startup Level SFRCS Actuation Transmitter	- Not Changed
E1/E2	-	Startup Level SFRCS Actuation Transmitter	- Not Changed
M	-	Manifold	- Not Changed

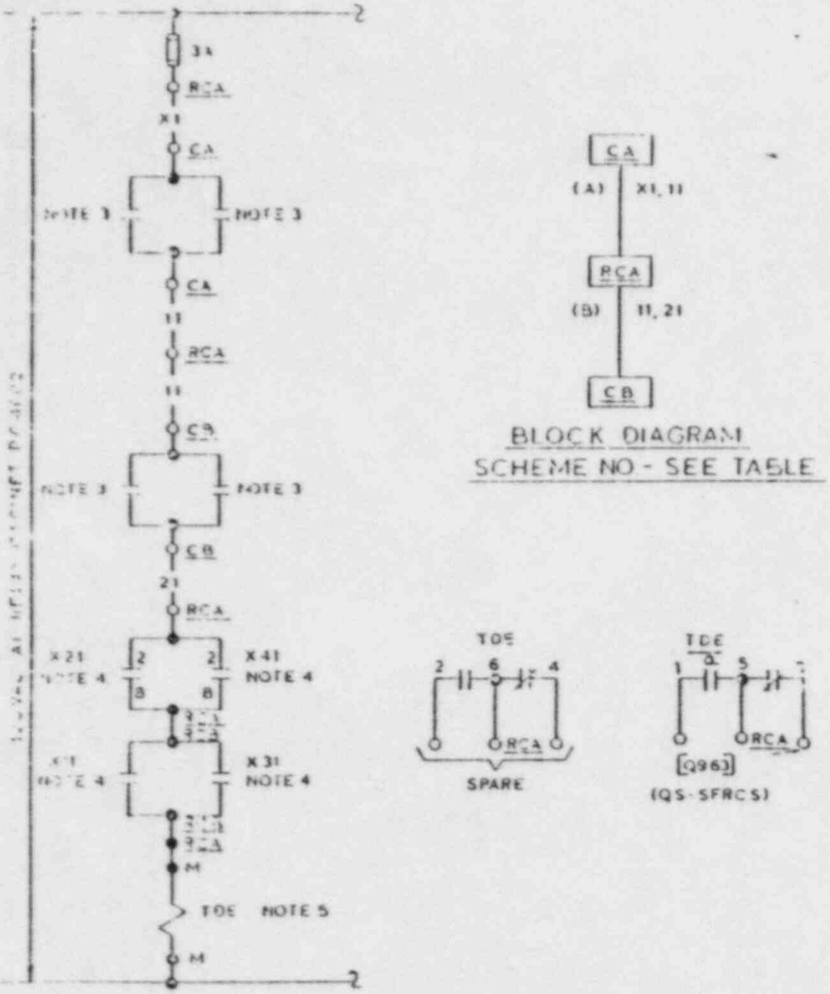


MSIV CONTROL AIR DIAGRAM



Shown with solenoids 101A thru E energized and MSIV open

Figure 2



SCHEME NO.	START UP NO.	CHANNEL	EQUIPMENT LOCATION			
			RCA	RCB	CA	CB
TC C1	93	B	RC4602	4C4601	C5762A	C5792

NOTES:

1. FOR GENERAL NOTES, SEE DWG E-42B INDEX SHEET
2. ALL WIRING SHALL BE # 12 AWG
3. N.O. CONTACT OPENS ON HALF TRIP OF SFRCS DUE TO:
   a. LOW STEAM PRESSURE
   b. LOW STEAM GENERATOR LEVEL
   c. HIGH REVERSE DIFFERENTIAL PRESSURE
4. N.O. CONTACT OPENS ON LOSS OF ALL FOUR REACTOR COOLANT PUMPS SEE DWG E-42B SH 53
5. TIME DELAY ON ENERGIZATION RELAY, AGASTAT MODEL 7012AB TIME SETTING AT 2 SECONDS

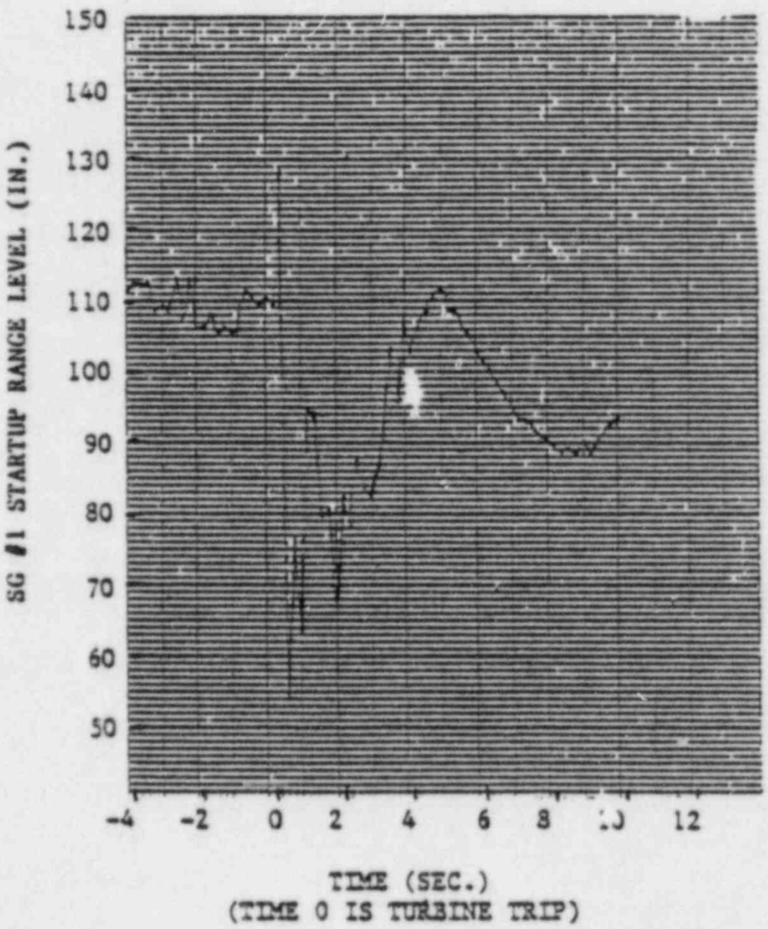
Figure 3

DAVIS-BESSE NUCLEAR POWER STATION
THE TOLEDO EDISON COMPANY
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

ELEMENTARY WIRING DIAGRAM
TURBINE AUXILIARIES
SFRCS FULL TRIP ALARM

BECHTEL COMPANY	JOB NO.	DRAWING NO.	REV
	7749	E-42B SH54	0

Figure 4



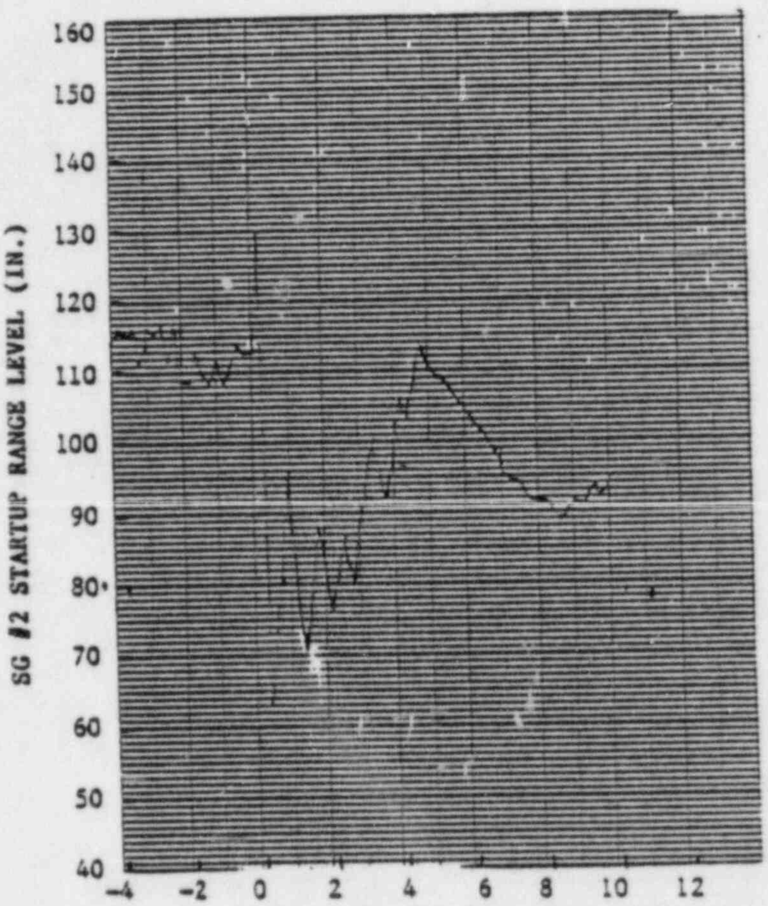
DRAWN BY: M. Flockenhaus 7/2/85

CHECKED BY: Sushil Jain 7/2/85

DATA FROM 75% TURBINE TRIP TEST (TP 800.14)

APRIL 2, 1978 (DELOG INTERVAL 0.2 SEC.)

Figure 5

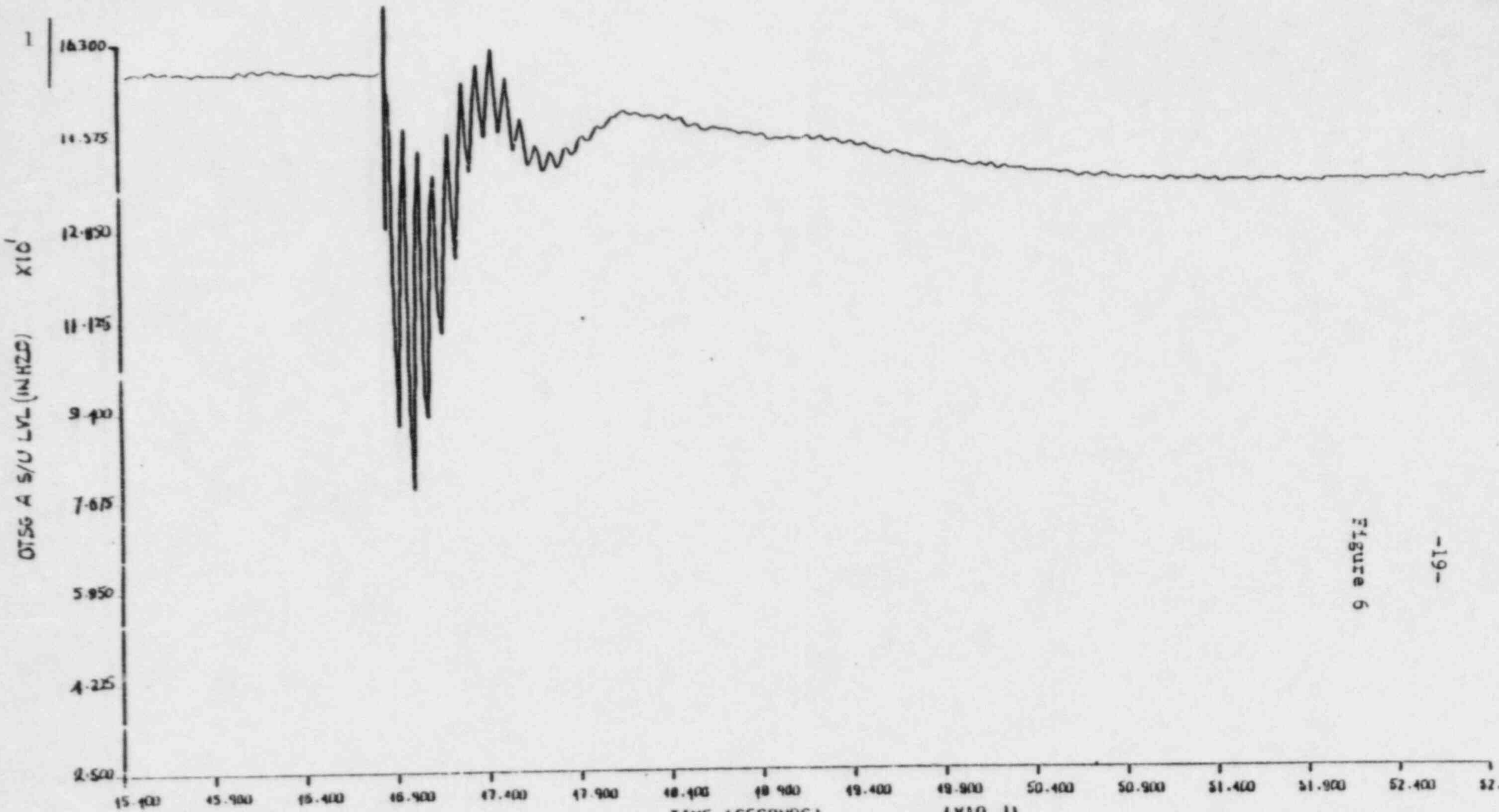


TIME (SEC.)
(TIME 0 IS TURBINE TRIP)

DRAWN BY: M. Flockenhaus 7/2/85
CHECKED BY: [illegible] 7/2/85

DATA FROM 75% TURBINE TRIP TEST

(TP 800.14) APRIL 2, 1978 (DELOG INTERNVAL 0.2 SEC.)

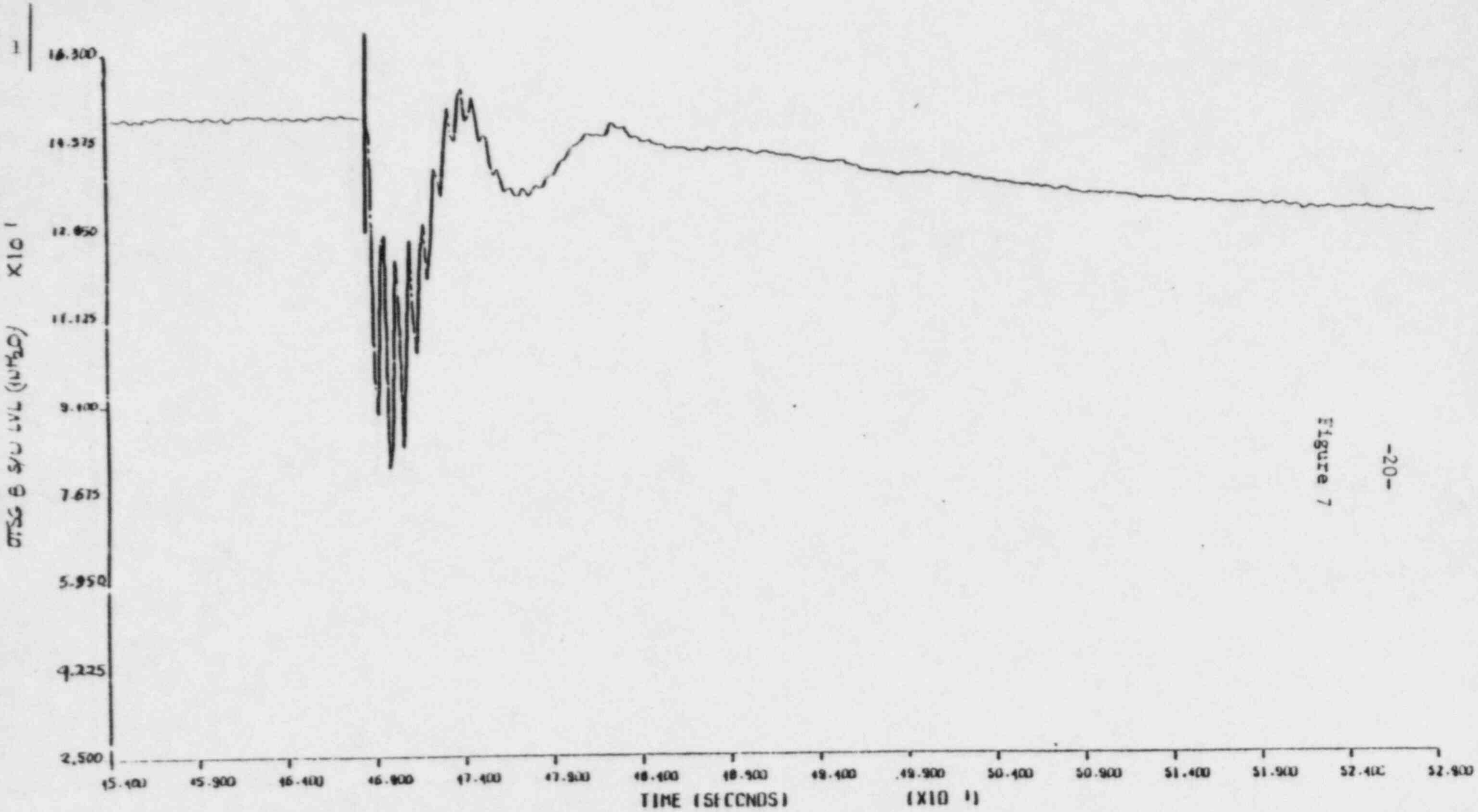


REACTIMETER PLOT TSN=152

Figure 6

FIGURE - 6

STEAM GENERATOR STARTUP RANGE
LEVEL XMITTER RESPONSE
TURBINE TRIP TEST



REACTIMETER PLOT TSN=152

FIGURE -7

STEAM GENERATOR STARTUP RANGE LEVEL XMITTER RESPONSE TO TURBINE TRIP TEST

Figure 7

Figure 8

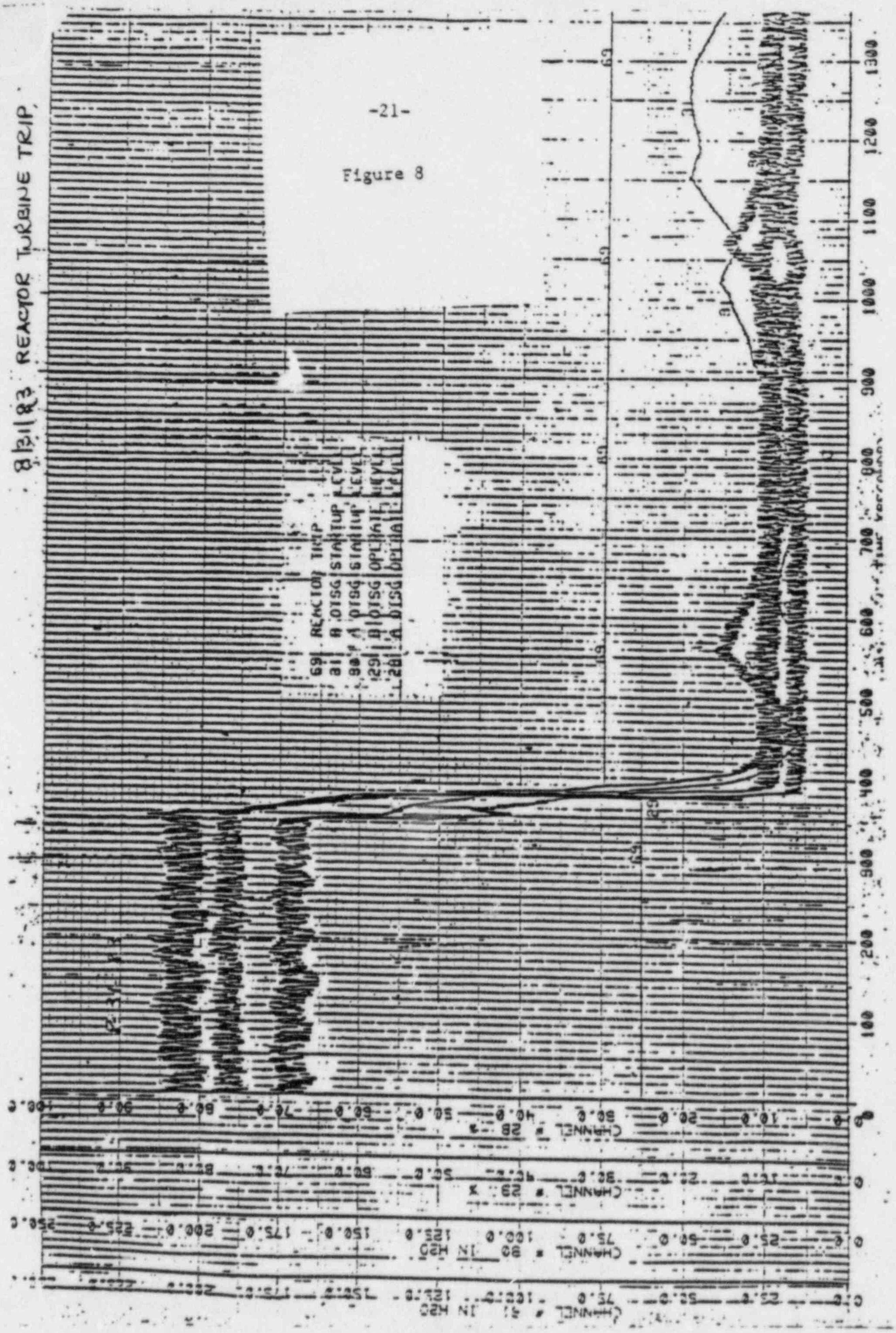
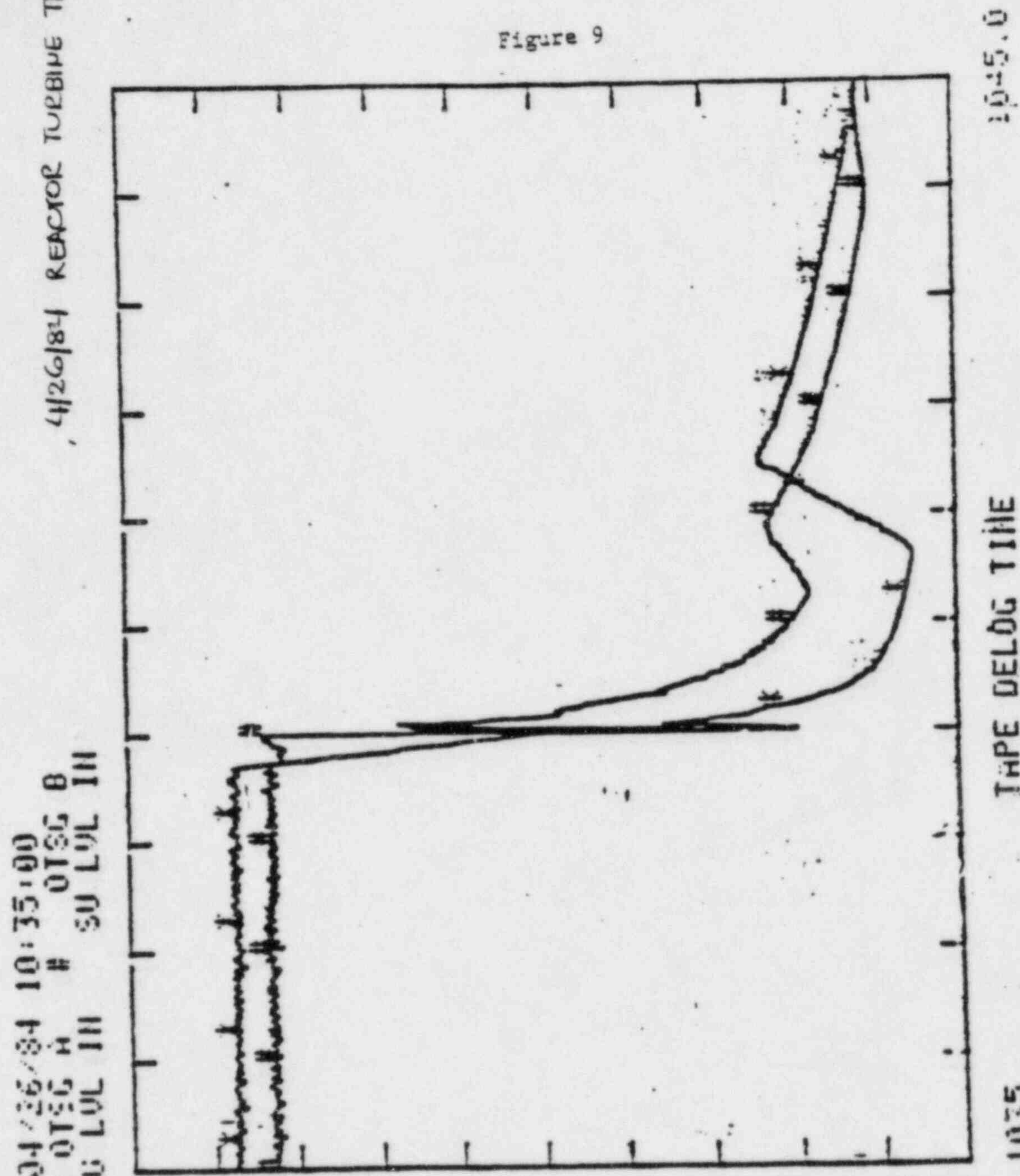
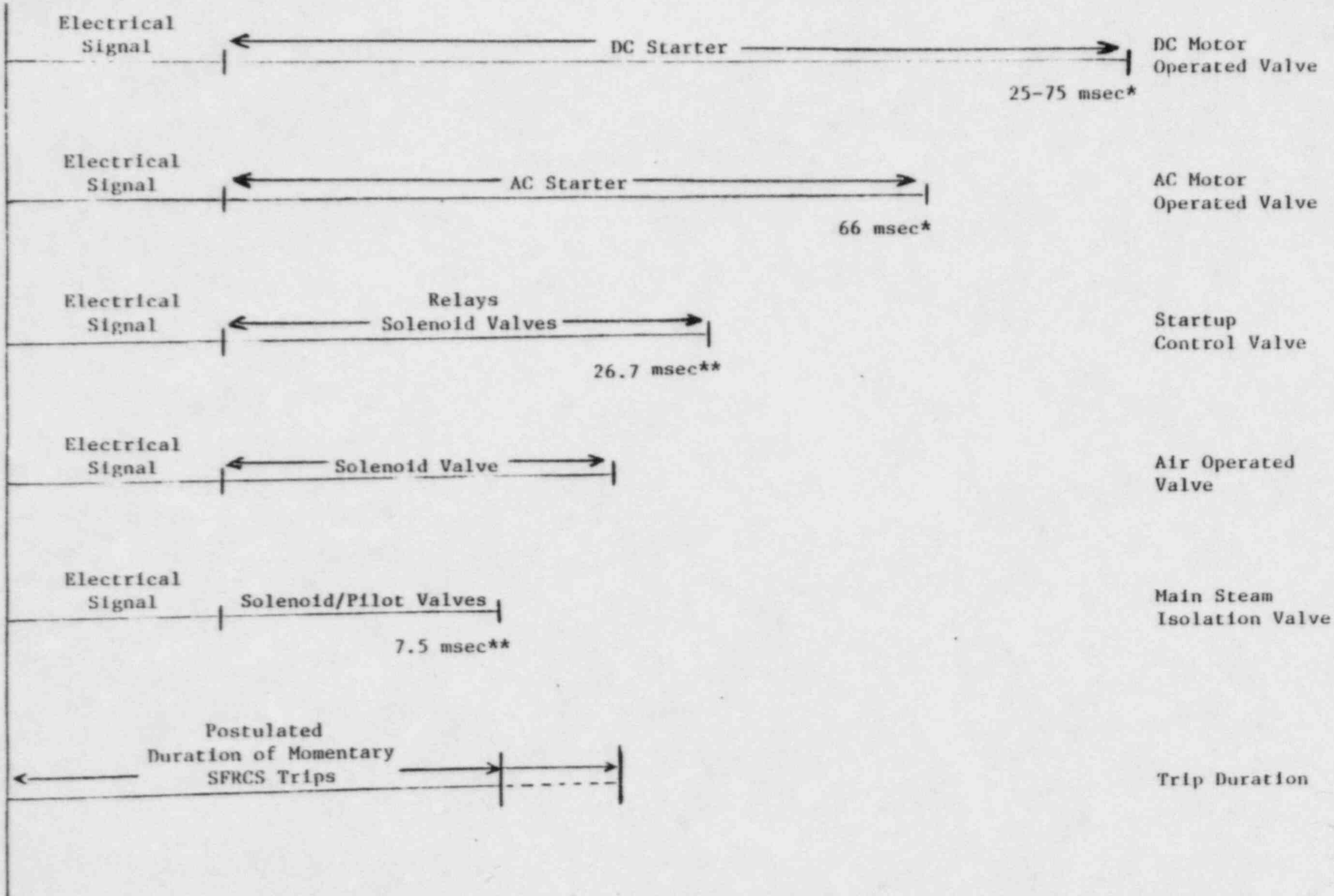

8/31/83 REACTOR TURBINE TRIP
69 REACTOR TRIP
81 B OTSG STARTUP LEVEL
80 A OTSG STARTUP LEVEL
129 B OTSG OPERATE LEVEL
128 A OTSG OPERATE LEVEL
CHANNEL # 80 IN H2O
CHANNEL # 81 IN H2O

Figure 9



OTSG Start-up Level

SFRCS EQUIPMENT TIMING DIAGRAM



* These values are expected values as supplied by the motor starter manufacturer. Field measurement of these values is in process.

** These are measured values.

Figure 10

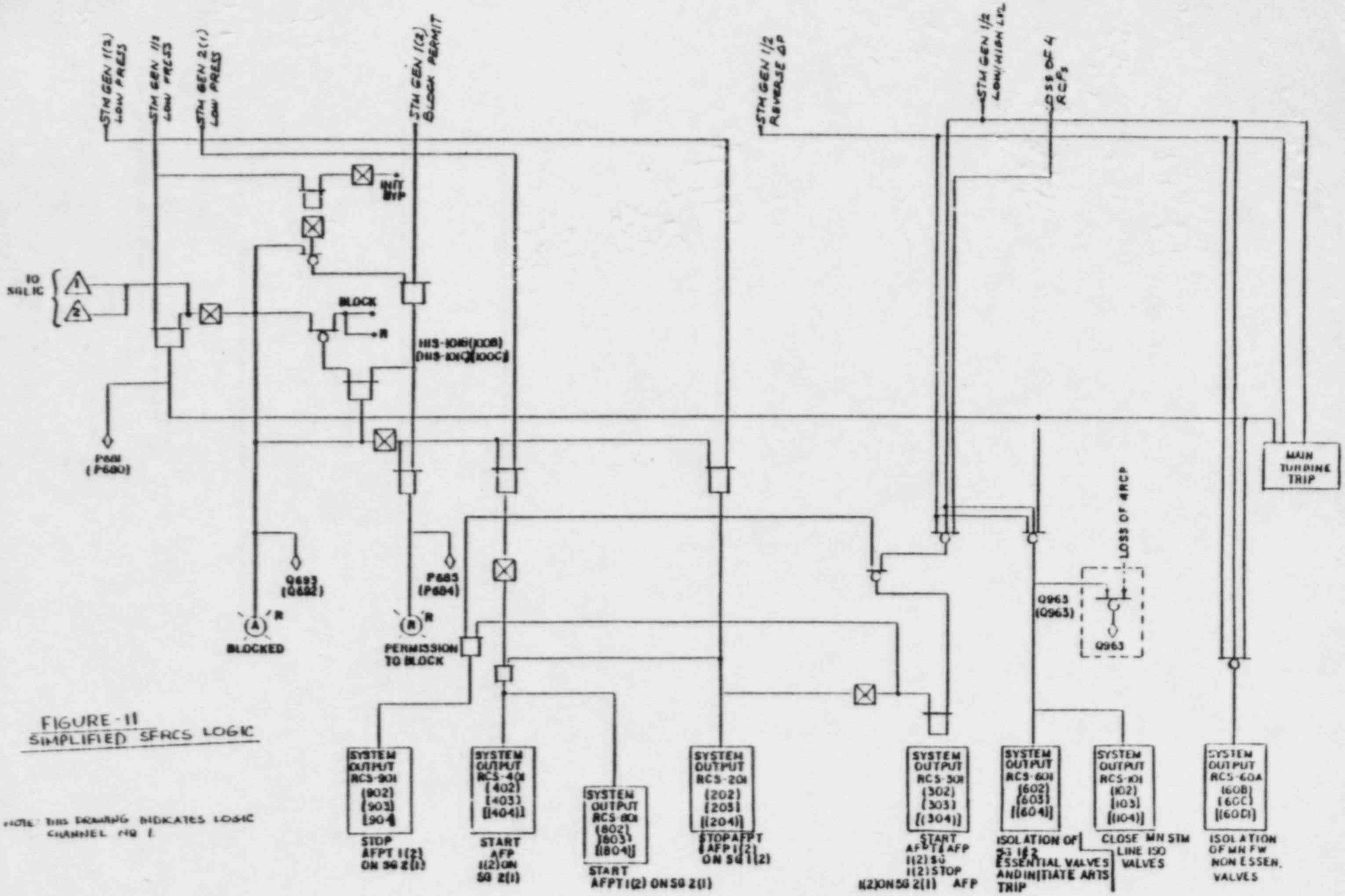
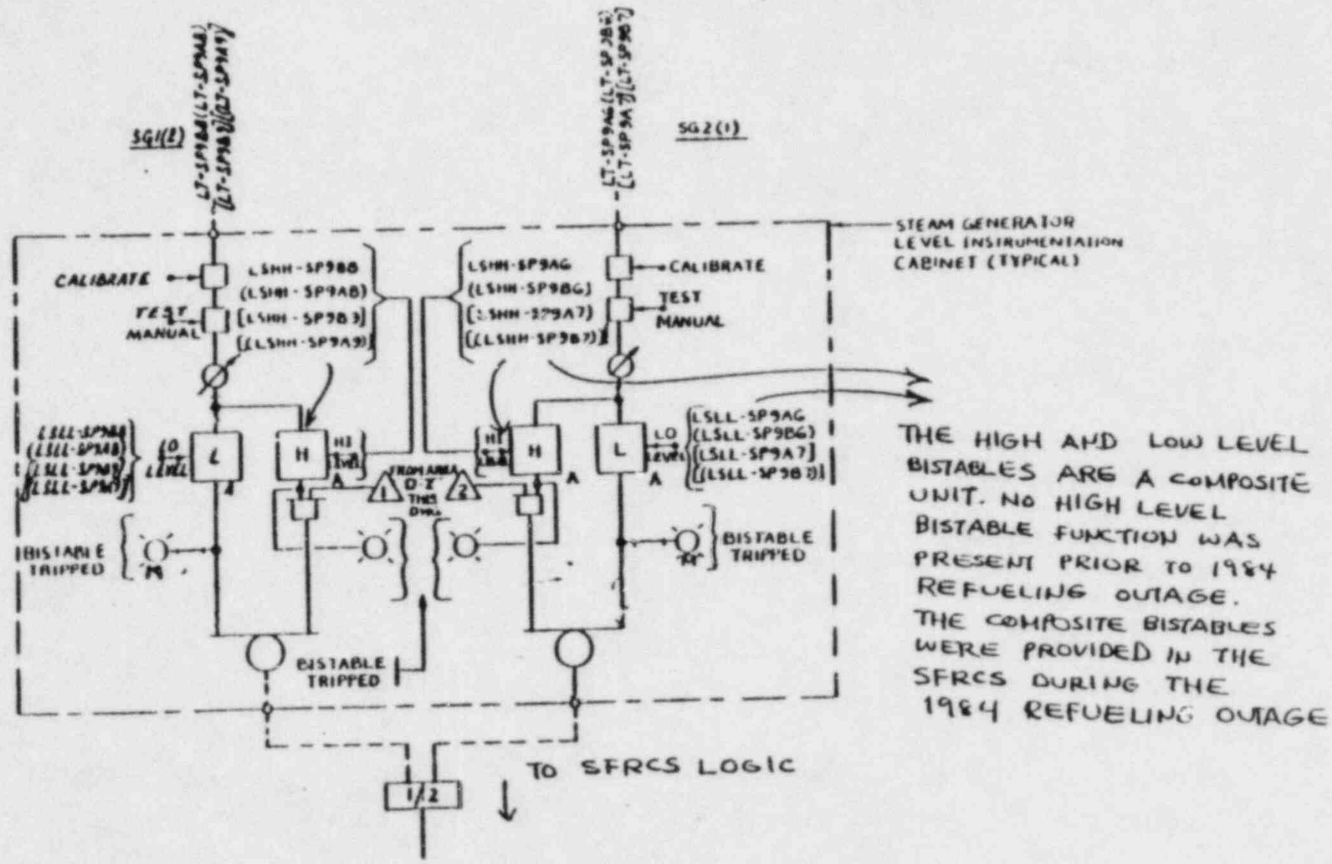


FIGURE-11
SIMPLIFIED SFRCS LOGIC

NOTE: THIS DRAWING INDICATES LOGIC CHANNEL NO 1

Figure 12



SFRCS LEVEL LOGIC

FINDINGS, CORRECTIVE ACTIONS AND GENERIC IMPLICATIONS REPORT

TITLE: TOLEDO EDISON - FEED PUMP TURBINE & CONTROL SYSTEM FAILURE

REPORT BY: J. BLAY (TED)
A. TOPOR (TED)

PLAN NO. 8

REV	DATE	REASON FOR REVISION	WRITTEN BY	APPROVED BY
0	8/16/85	Initial Issue	J. Blay A. Topor	L. Grime
1	8/22/85	Corrective Action Added	J. Blay A. Topor	L. Grime
2	8/30/85	Title Change	J. Blay A. Topor	L. A. Grime

TABLE OF CONTENTS

I. ISSUE/CONCERN

This report addresses the troubleshooting performed and the findings concerning the overspeed trip of Main Feed Pump Turbine (MFPT) 1-1 which was the initiating event of the June 9, 1985 reactor trip.

II. BASIC PRINCIPLE OF OPERATION

Main feed pump turbine speed is controlled by an electronic hydraulic control system called the MDT 20 Electronic Governing System. The circuitry of interest consists of the following (refer to Attachment 1):

1. Signal Converter Circuitry - This circuitry accepts a speed setpoint signal and processes this signal to produce a speed reference signal.

2. Redundant Speed Pickup Feedback Circuitry - This circuitry selects the frequency output from one speed pickup for a measured turbine speed signal.

3. Speed Summation and Valve Lift Reference Circuitry - This circuitry converts the frequency output speed signal from the Redundant Speed Pickup Feedback Circuitry to a voltage speed signal. This circuitry also produces the speed error signal and the valve lift reference signal.

4. Operator/Pilot Valve Position Feedback and Servo Amplifier Circuitry - This circuitry sums the valve position feedback signals from the pilot valve and operating cylinder with the valve lift reference signal to generate a valve position error signal. This signal drives the servo valve to change the position of the pilot valve and operating cylinder.

Two separate shaft speed pickups provide simultaneous speed signals. If a speed pickup should fail the remaining pickup automatically assumes control. The speed pickups generate a frequency signal by means of a toothed wheel on the turbine shaft. The frequency signal is converted to a voltage corresponding to actual turbine speed by the frequency to voltage (F/V) converter.

A speed reference signal is generated in the signal converter circuitry which corresponds to demanded feedwater flow.

The speed reference signal is summed with the turbine speed signal in the Speed Summation and Valve Lift Reference Circuitry. Any difference between the signals is represented as a speed error signal. This error signal goes through an integrating amplifier and compensation network to insure stable operation of the turbine over the specified speed, load, and inlet steam conditions. The resultant signal represents a valve lift reference signal which is applied to a summing amplifier that compares the valve lift reference signal with the actual position of the pilot valve and operating cylinder in the Servo Amplifier Circuitry. The resultant valve

position error signal is amplified by the servo amplifier and transmitted to the servo valve. The servo valve controls the flow of oil to the pilot valve which controls the flow of oil to the operating cylinder. This positions the control valves to obtain the demanded turbine speed.

III. SUMMARY OF TROUBLESHOOTING AND INVESTIGATION

A. Field Actions Performed

1. MWO 1-85-1997-01

   a. Performed a visual inspection on MFPT 1-1.

   b. Performed electronic checks on the MDT 20 circuitry for MFPT 1-1.

   c. Cycled the control valves for MFPT 1-1 to:

      i. Check the hydraulic response
      ii. Further check various electronic circuitry

The following tasks were placed in the Action Plan to allow this work to be performed on the equipment since the MFPTs were on the Equipment Freeze List. These steps are not related to the failure hypotheses for MFPT 1-1.

2. MWO 1-85-1997-02

   a. Determined the computer calibration of MFPT 1-1 speed signal.

   b. Took resistance readings on position 7 board for the circuitry being used for the computer speed input.

3. MWO 1-85-1997-03

   a. Determined the computer calibration of MFPT 1-2 speed signal.

   b. Took resistance readings on position 7 board for the circuitry being used for the computer speed input.

4. MWO 1-85-1997-04

   a. Performed a visual inspection on MFPT 1-2.

   b. Performed electronic checks on the MDT 20 circuitry for MFPT 1-2.

   c. Cycled the control valves for MFPT 1-2 to:

      i. Check the hydraulic response
      ii. Further check various electronic circuits

5. MWO 1-85-1997-05

   a. Performed an inspection on the main oil pump discharge check valves and the pressure regulating valves (PRV) for Unit 2.

6. MWO 1-85-1997-06

   a. Performed an inspection on the main oil pump discharge check valves and the PRV's for Unit 1.

7. MWO 1-85-1997-07

   a. Performed an inspection for oil leaks on Unit 1.

8. MWO 1-85-1997-08

   a. Performed an inspection for oil leaks on Unit 2.

9. MWO 1-85-1997-09

   a. Replaced thermocouple TC4 in MFPT lube oil tank 1-2.

10. MWO 1-85-1997-10

    a. Repaired the adjusting screw disc on PRV 1 and PRV 2 for Unit 1.

11. MWO 1-85-1997-11

    a. Repaired the adjusting screw disc on PRV 1 and PRV 2 for Unit 2.

12. MWO 1-85-1997-12

    a. Fabricated a cover cap for PRV 3 which was missing on Unit 2.

During the circuit board checks on the MDT 20 system for MFPT 1-1 (MWO 1-85-1997-01) a failure was identified in the position 4 circuit board. The F/V converter in the speed summation circuitry indicated 0.0 volts output for a varied input frequency signal.

Further testing was performed by General Electric factory in Fitchburg, Massachusetts to identify if the circuit board or the F/V converter was faulty. The test performed identified the failure to be the F/V converter itself.

The F/V converter was tested at Teledyne Philbrick in Dedham, Massachusetts, to further analyze the failure. This testing identified that the charge dispensing capacitor had failed open. The testing also indicated that the other components within the F/V converter were functioning properly.

During the inspection of the PRV's it was found that the adjusting screws for PRV 1 and PRV 2 on both units were backed off such that the adjusting screw disc was pulled away from the stem. This anomaly had no affect on the operation of the PRV to control downstream oil pressure at the proper preset value.

Sample history of the MFPT lube oil prior to and just after the June 9, 1985 trip indicated that the oil was within specified acceptable limits.

B. Analysis Performed

(Refer to Attachment 2)

1. The output circuitry of the F/V converter was analyzed in a test fixture to determine if the output inverter, buffer transistor, and associated passive components were functioning properly. The testing performed proved the output circuitry was functioning properly.

2. The middle section of the F/V converter, consisting of a diode and two transistors, was removed from the test fixture and analyzed for the proper output signal. This testing proved that these components in the signal path to the output inverter were functioning properly.

3. The input comparator section of the F/V converter was analyzed in the test fixture. This test proved that the input comparator circuitry was functioning properly.

4. The two remaining points of interest in the signal flowpath could not be tested from the external pins of the F/V converter. The top corner of the converter was milled to expose the printed circuit board lands where the capacitor leads and solder joints were located.

   The converter was then analyzed in the test fixture to determine if the junction at the charge dispensing capacitor and the diode bridge showed a square waveform with the desired voltage level. The desired waveform and voltage were observed indicating the circuitry was functioning properly.

5. The output of the charge dispensing capacitor was checked to determine if the output was a ramping wave pattern (refer to Attachment 3). When the capacitor output was tested, a constant 0.6 VDC output appeared without the ramping wave pattern. The absence of the ramping wave pattern indicated that the capacitor was not functioning. A new capacitor of the same type was held to the exposed leads of the non-functioning capacitor. The output of the capacitor was checked and the expected waveform was observed. After bridging the new capacitor across the exposed leads, the F/V converter was tested for proper

operation. The converter was observed to function properly with varied input frequency signals.

6. The printed circuit board land points, which were exposed on the F/V converter during testing, were examined under magnification. This examination showed a good connection between the capacitor leads and the printed circuit board land runs where the leads were wave soldered. Therefore, the internal charge dispensing capacitor is most likely open within the envelope of the capacitor itself.

   Further analysis of the capacitor could not be performed due to the epoxy potting compound which encapsulated the circuit board of the F/V converter. Attempting to remove this epoxy potting compound would destroy the capacitor, resulting in a loss of any information which could be obtained if the capacitor was accessible.

   It is unlikely that the wire leads of the capacitor opened because of their relatively large wire diameter. It is also unlikely that the plates of the capacitor opened because of the relatively large surface area associated with the plates.

   The most likely open circuit point is the weld or solder connection associated with the leads of the capacitor to the plates of the capacitor.

7. The electronic circuitry associated with the MDT 20 control system was designed to withstand vibration effects such that the circuitry could be installed locally at the turbine. With the electronic circuitry installed in the cabinet room where vibrational effects are minimal, it is unlikely that fatigue due to vibration caused the capacitor to fail.

8. The specified rated temperature range for the F/V converter and the failed capacitor are as follows:

F/V Converter	32°F to 158°F
Capacitor	-67°F to 257°F

   With the electronics associated with the MDT20 control system mounted in a temperature controlled environment at 70°F nominal. It is unlikely that the surrounding environmental conditions caused the capacitor to fail.

9. The testing performed at Teledyne Philbrick proved that the electronic circuitry within the F/V converter, excluding the charge dispensing capacitor, functioned properly. As shown in Attachment 2, all connections to the charge dispensing capacitor outside of the module are also connected to the input of solid state devices. These devices are generally susceptible to damage from high

voltage surges. Therefore a voltage surge that could damage the charge dispensing capacitor would most likely damage these solid state devices also. However, these components functioned properly when they were tested.

C. Significance of Findings

A loss of measured turbine speed due to the failure of the F/V converter generated a speed error signal. This error signal caused the control valves to open, therefore, increasing the turbine speed. Under normal conditions the speed error signal goes to zero as the actual (measured) and the demanded turbine speed become equal. With the F/V converters output failed at a fixed output value of 0.0 volts the speed error signal caused the turbine speed to increase until the emergency overspeed governor tripped the turbine.

Conditions which could have adversely effected the electrical components were investigated. These conditions revealed no direct relationship to the failure of the capacitor.

IV. RESULTS/CONCLUSIONS OF FINDINGS

A. Direct Cause

The F/V converter in the speed summation circuitry failed with an output fixed at 0.0 volts.

B. Root Cause

A capacitor in the circuitry of the F/V converter failed in the open position causing the output voltage of the converter to be 0.0 volts. There are no positive indications that the capacitor failure was influenced by any external sources, therefore, it has been judged as a premature component failure.

C. Disproved Hypotheses

1. Loose Connections - no loose connections were found during the visual inspection.

2. Hydraulic/Mechanical Control Problem - the control valves were stroked and the system responded as expected.

V. TECHNICAL JUSTIFICATION OF FINDINGS

Based on the investigation discussed in this report, it is concluded that the overspeed trip of MFPT 1-1 was caused by a failed open capacitor internal to the F/V converter. The data collected from the test performed on the F/V converter supports this conclusion.

The failure which initiated the overspeed trip of MFPT 1-1 has been identified, therefore, both MFPT systems should be removed from the Equipment Freeze List.

VI. SPECIFIC CORRECTIVE ACTION

A. Required Corrective Action

The high reliability record of the MDT 20 control system has been proven to be adequate. The reliability of the components associated with the control system is assured by extensive production reliability testing. The test program consists of a visual inspection, temperature cycling, printed circuit board testing, subsystem performance testing, a 200 hour burn-in of the electronic components and a final electronic test. Refer to Attachment 4 and 5 for further information concerning testing and reliability.

Therefore the speed Summation and Valve Lift Reference Circuit Board will be replaced and calibrated to return the MDT 20 control system associated with MFPT 1-1 to an operational condition.

B. Additional Planned Action

1. Field Actions

a. The bolts securing the cover plate for the solenoid valves will be replaced with shorter bolts. This will eliminate the possibility that the two bolts that were touching wires at the terminal block could wear the insulation due to vibration, therefore, grounding the wire.

b. Oil leaks which are determined to warrant repairs will be repaired.

2. Issues to be Resolved

a. Evaluate modifications to the hydraulic system to eliminate the automatic starting of the standby main oil pump when the control valves are moved.

b. The MDT 20 speed input interface with the computer should be corrected so that the computer indicates turbine speed more accurately.

c. The computer time scan rate for turbine speed and MFP discharge pressure should be increased.

d. The theory associated with the MFPT trips of April 24, 1985, and June 2, 1985, as discussed in Action Plan 8, concerns the Rapid Feedwater Reduction System and the high discharge pressure trip switches. Therefore, the Rapid Feedwater Reduction System and

the high discharge pressure trip switches should be analyzed for possible modifications to improve their performance.

Possible modifications concerning the trip switches which may be considered are:

i. Eliminate the pressure switches. This may require the installation of pressure relief valves.

ii. Installing a time delay to prevent the turbines from tripping due to a short duration pressure spike.

iii. Raising the trip setpoint.

e. Evaluate the need for checking the Rapid Feedwater Reduction target speed setpoint calibration once every refueling outage.

f. Analyze the feasibility of installing monitoring equipment to record MFPT operating parameters.

g. Analyze the control system for possible modifications.

h. Terminate the unused wires on SV-12 and remove the wiring for PL29 which is no longer used.

i. Evaluate the need to install a drain line for the valve actuator cabinet.

VII. GENERIC IMPLICATION

There are no generic implications.

VIII. REFERENCES

1. General Electric Steam Turbine Feed Pump Drive Instruction Manual GEK83602 and associated approved General Electric drawings

2. Action Plan #8, Action Plan For Main Feed Pump Control System

3. Letter from David C. Hollocher, Senior Project Engineer, Teledyne Philbrick to Jeff Blay, Operations Engineer, Toledo Edison, dated August 15, 1985; Subject: Summary and Failure Analysis of Type 4702 F/V Converter

4. Letter from D. R. Pfitzenmaier, Service Supervisor Fossil Plant Services, General Electric to John K. Wood, General Supervisor Facility Engineering, Toledo Edison dated August 1, 1985.

5. Teledyne Philbrick Frequency-to-Voltage Converters 4702/470210 Description Information

6. Teledyne Philbrick Purchase Specifications for the Ceramic Charge Dispensing Capacitor

7. Toledo Edison Maintenance Work Order 1-85-1997-01

8. Toledo Edison Maintenance Work Order 1-85-1997-02

9. Toledo Edison Maintenance Work Order 1-85-1997-03

10. Toledo Edison Maintenance Work Order 1-85-1997-04

11. Toledo Edison Maintenance Work Order 1-85-1997-05

12. Toledo Edison Maintenance Work Order 1-85-1997-06

13. Toledo Edison Maintenance Work Order 1-85-1997-07

14. Toledo Edison Maintenance Work Order 1-85-1997-08

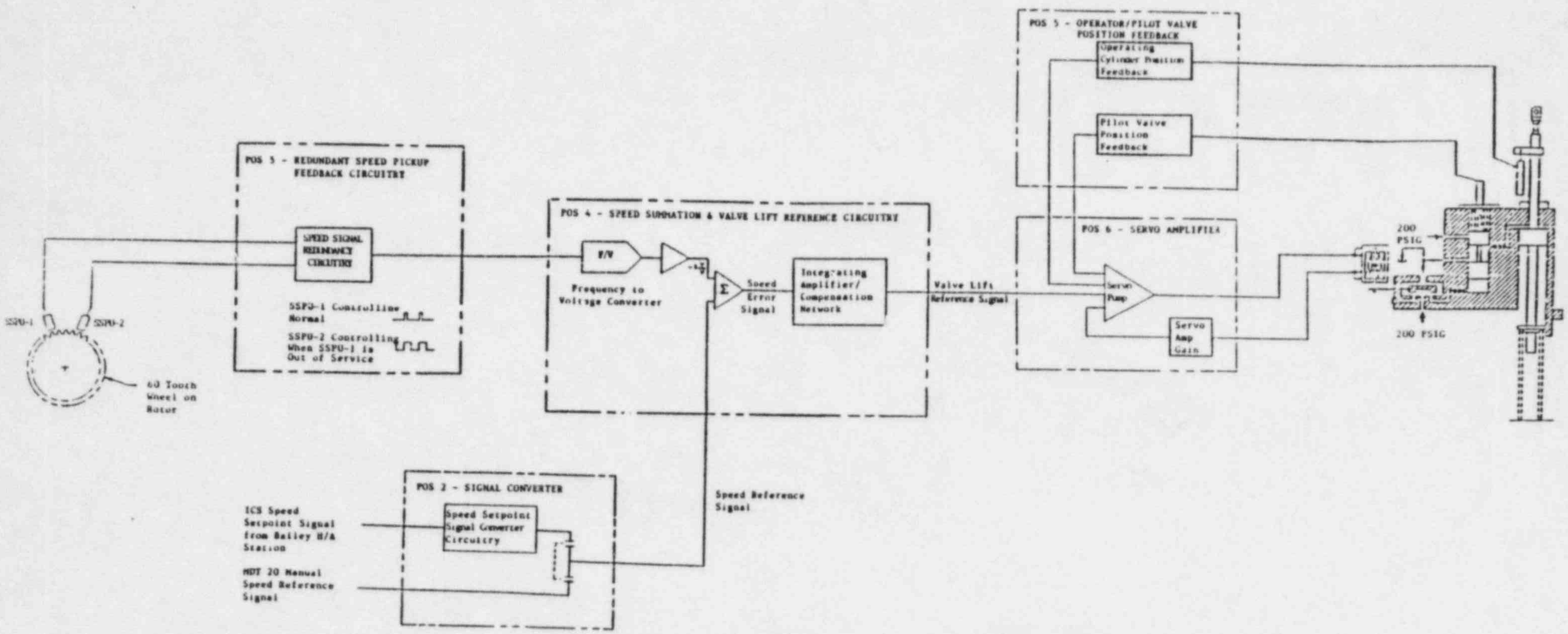
15. Toledo Edison Maintenance Work Order 1-85-1997-09

16. Toledo Edison Maintenance Work Order 1-85-1997-10

17. Toledo Edison Maintenance Work Order 1-85-1997-11

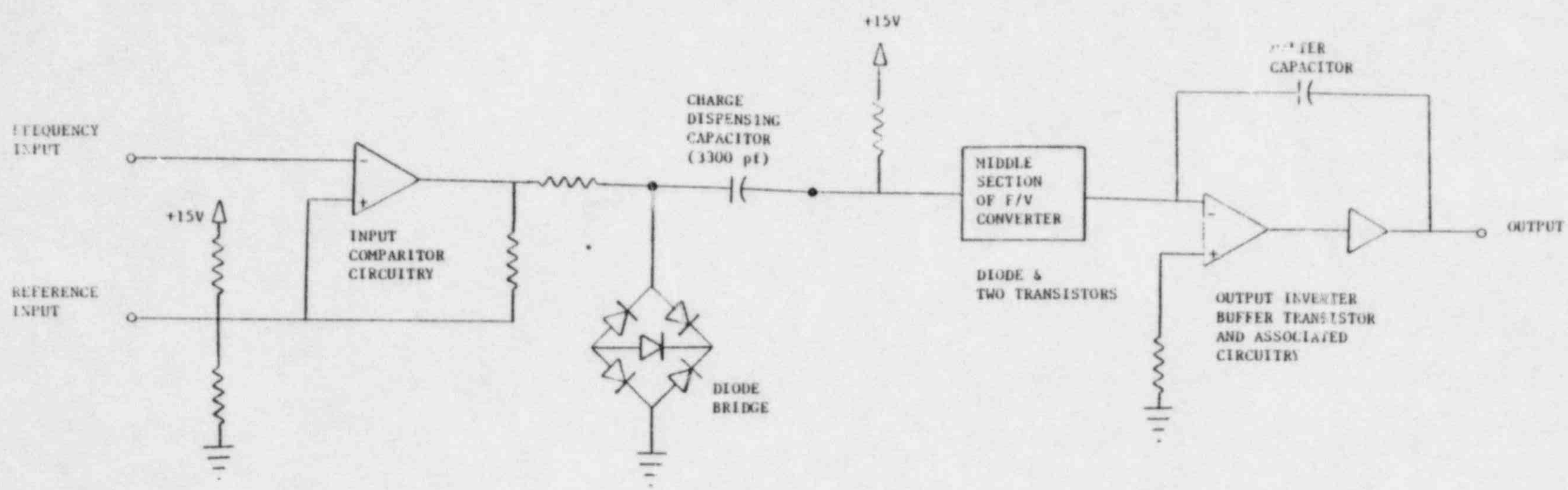
18. Toledo Edison Maintenance Work Order 1-85-1997-12

bj d/13



MDT 20 CONTROL
SYSTEM BLOCK
DIAGRAM

Attachment 1

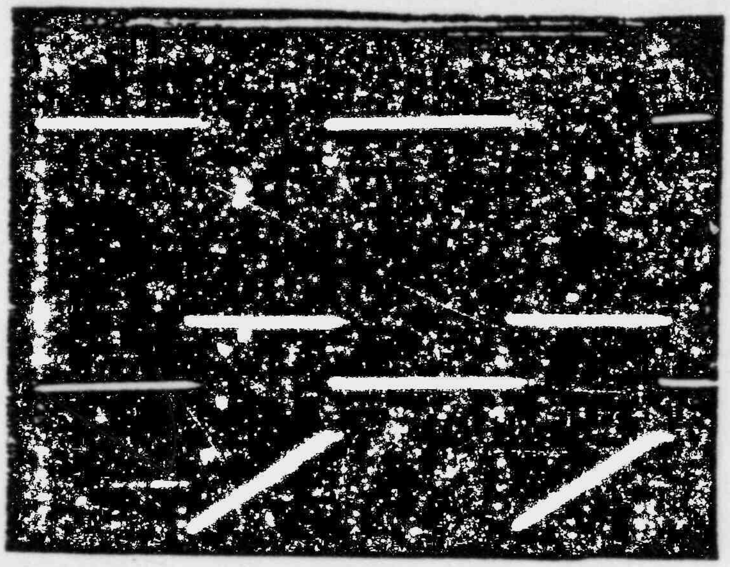


BLOCK DIAGRAM FOR
F/V CONVERTER MODEL 4702

Attachment 2

CHARGE DISPENSING CAPICATOR
INPUT AND OUTPUT WAVE FORMS

AMPLITUDE



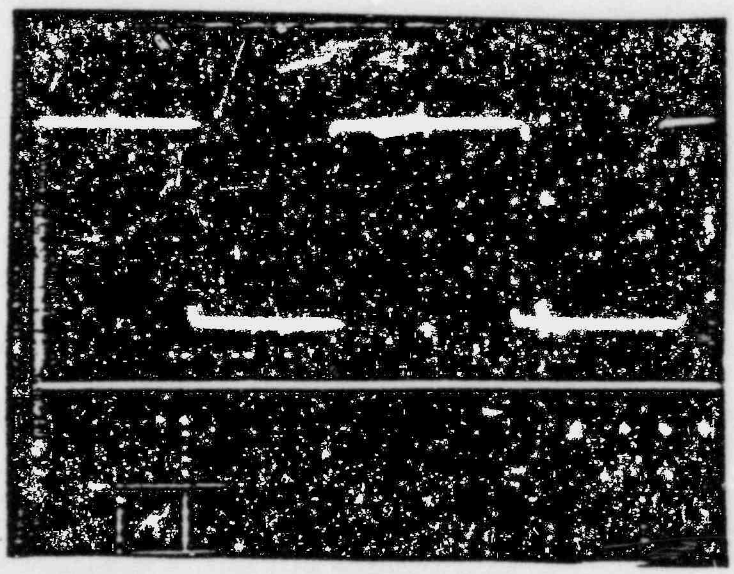
Input Signal

Ramping Wave Pattern

TIME

Ramping wave pattern of the F/V converter with the charge dispensing capacitor functioning properly.

AMPLITUDE



Input Signal

Output Signal

TIME

Constant voltage signal on the output of the failed open charge dispensing capacitor.

Attachment 3

TESTING AND RELIABILITY SUMMARY

All new and replacement circuit boards are visually inspected to insure proper component placement and workmanship. The printed circuit boards are also subjected to temperature cycles with soaks at both hot and cold extremes to search for any mechanical weaknesses in the hardware. Each circuit board must pass a complete functional test performed in accordance with formal test procedures. Other subsystems such as power supplies and monitoring panels are similarly tested. The electronics must also successfully complete a 200 hour burn-in test with all circuits energized and functioning prior to a final electronic test. The high reliability record of the MDT-20 control system indicates that this has been an adequate screening process for infant mortality of the electronic components.

Field experience has shown this to be an effective method for insuring maximum reliability of the components placed in-service. The accumulated operating service data obtained from the General Electric Power Makers Service Call System demonstrates the high reliability of the MDT 20 control system (refer to Attachment 5). This data indicates there have been no reported in-service failures of a F/V converter during the 837,712 service hours for 1981, 1982, and 1983. General Electric has informed Toledo Edison that they are aware of one in-service failure of a F/V converter which was not reported to the Power Makers Service Call System. A failure analysis was not performed on this component because it was not sent to General Electric for testing.

Teledyne Philbrick's published technical data on the F/V converter specifies a value of $\geq$ 400,000 hours Mean Time Between Failure per MIL Handbook 217A.

MDT-20

RELIABILITY DATA*

YEAR	SERVICE HOURS ON UNITS WITH MDT-20 CONTROL	CONTROL INCIDENTS	ELECTRONIC CONTROL BOX INCIDENTS	CONTROL FORCED OUTAGE HOURS	CONTROL FORCED OUTAGE RATE PER CENT
1981	222266	2	1	17	.00764
1982	308570	7	0	44	.01425
1983	306876	12	0	56.6	.01844
TOTAL	837712	21	1	117.6	.01403

*NOTE:

1. This data is summarized from information provided by utility companies for our Powermakers Service Call System.
2. No incidents reported in this data were related to failures of the F/V component.
3. Hours accumulated against controls also include hardware external of the MDT-20 control box. These include speed pickups, servomotors, LVDTs and panel components.
4. Greater than 70% of the MDT-20 population responded to the survey.

FINDINGS, CORRECTIVE ACTIONS AND GENERIC IMPLICATIONS REPORT

TITLE: TOLEDO EDISON - DAVIS-BESSE TURBINE BYPASS VALVE ACTUATOR FAILURE

REPORT BY: M. RAYNES (TED)
B. CARRICK (MPR)

PLAN NO. 9A/9B

REV	DATE	REASON FOR REVISION	WRITTEN BY	APPROVED BY
0	8/11/85	Initial Issue	M. Raynes	B. Beyer
1	8/17/85	Corrective Actions and Generic Implications	M. Raynes	L. Grime
2	8/29/85	Heading Change	M. Raynes	L. A. Grime

TABLE OF CONTENTS

I. ISSUE/CONCERN

This document:

- Describes the failure of the SP13A2 turbine bypass valve actuator which occurred during reactor cooldown to cold shutdown following the plant transient of June 9, 1985.

- Documents and describes the investigations and evaluations conducted to determine the cause of the failure.

Several hours after the June 9, 1985 transient at Davis-Besse, the actuator on one of the six turbine bypass valves failed. The failure occurred as plant operators attempted to realign the main steam piping valve line-up in order to cooldown the plant via the turbine bypass valves, which is the normal procedure. Until the realignment, plant cooldown was being controlled via the atmospheric vent valves. The turbine bypass valves are non-safety related equipment and not essential to cooldown of the plant. They are normally used to minimize loss of inventory from the steam and feedwater systems by venting to the main condenser rather than to the atmosphere. The turbine bypass valve actuator failure did not significantly affect plant operations or recovery from the plant trip. The main steam pressure boundary was not affected.

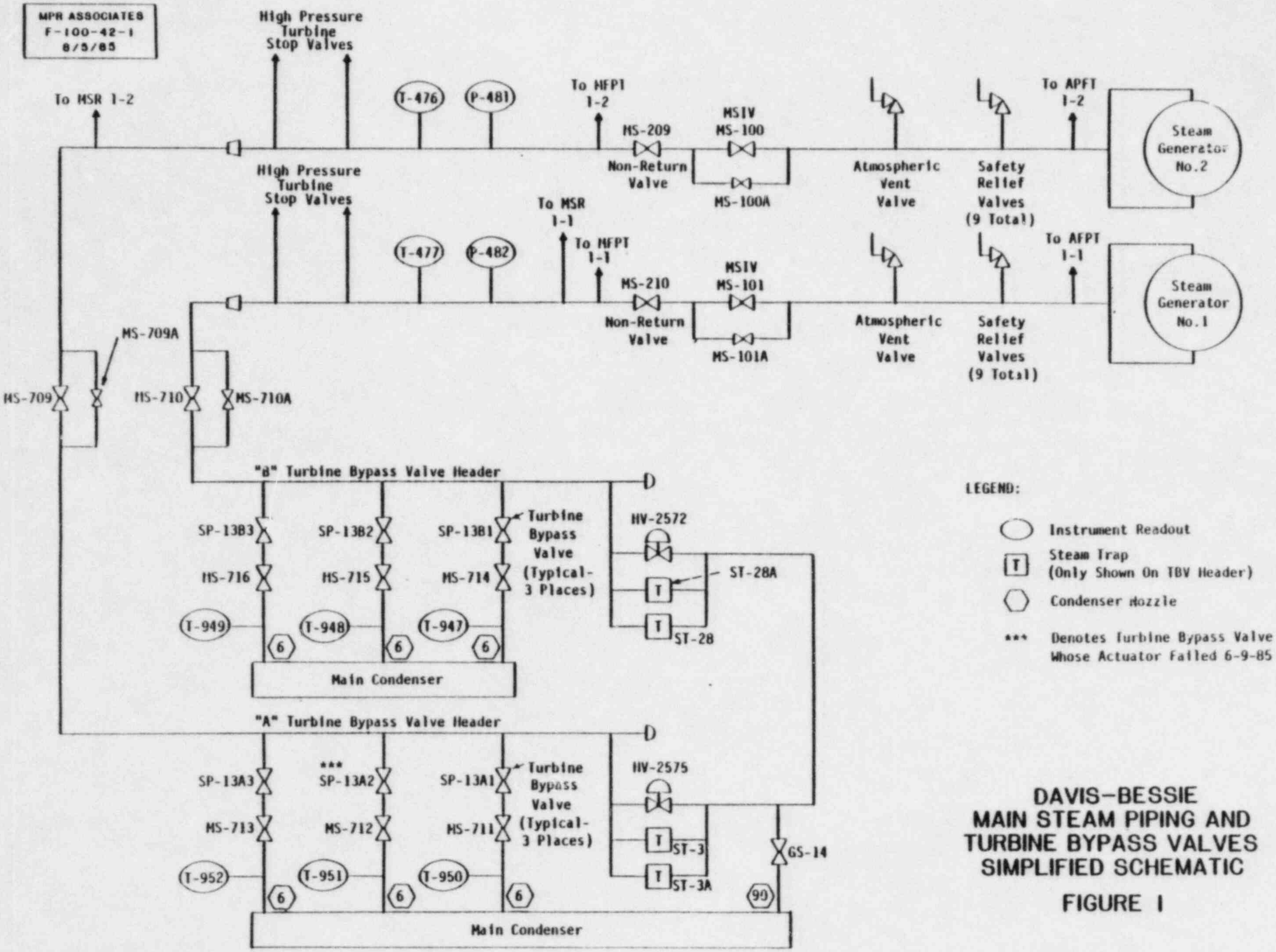
II. Basic Principles of Operation

The turbine bypass system is functionally part of the main steam system. It consists of six pneumatically operated control valves along with associated isolation and bypass valves and piping. There are three control valves on each of two headers off of the main steam lines to the turbine. The control valves are used to throttle the flow of main steam directly to the condenser as described below. Simplified schematic and isometric sketches of the portion of the main steam piping which includes the turbine bypass system are presented as Figures 1 and 2 respectively. Note from the sketches that the steam headers to the turbine bypass valves are equipped with drain valves and steam traps. Steam traps (see Figure 3) are intended to drain condensate preferentially, not steam, from the piping while it is pressurized.

The turbine bypass system functions along with the main steam safety valves and atmospheric vent valves to control main steam and steam generator shell side pressure during plant startup, cooldown, and following a turbine trip. The turbine bypass valves can be controlled either by the plant integrated control system to a selected pressure setpoint or manually by the operators in the control room.

The turbine bypass valves are Fisher Controls Company 6-inch valves; Type VFJ454BX Style C060WX (see Figures 4 and 5). They are ANSI 600-S valves rated for a maximum shutoff pressure of 1065 psia at 600°F. They are single port, cage-guided globe valves with an internal pilot valve to assist in positive shutoff against full

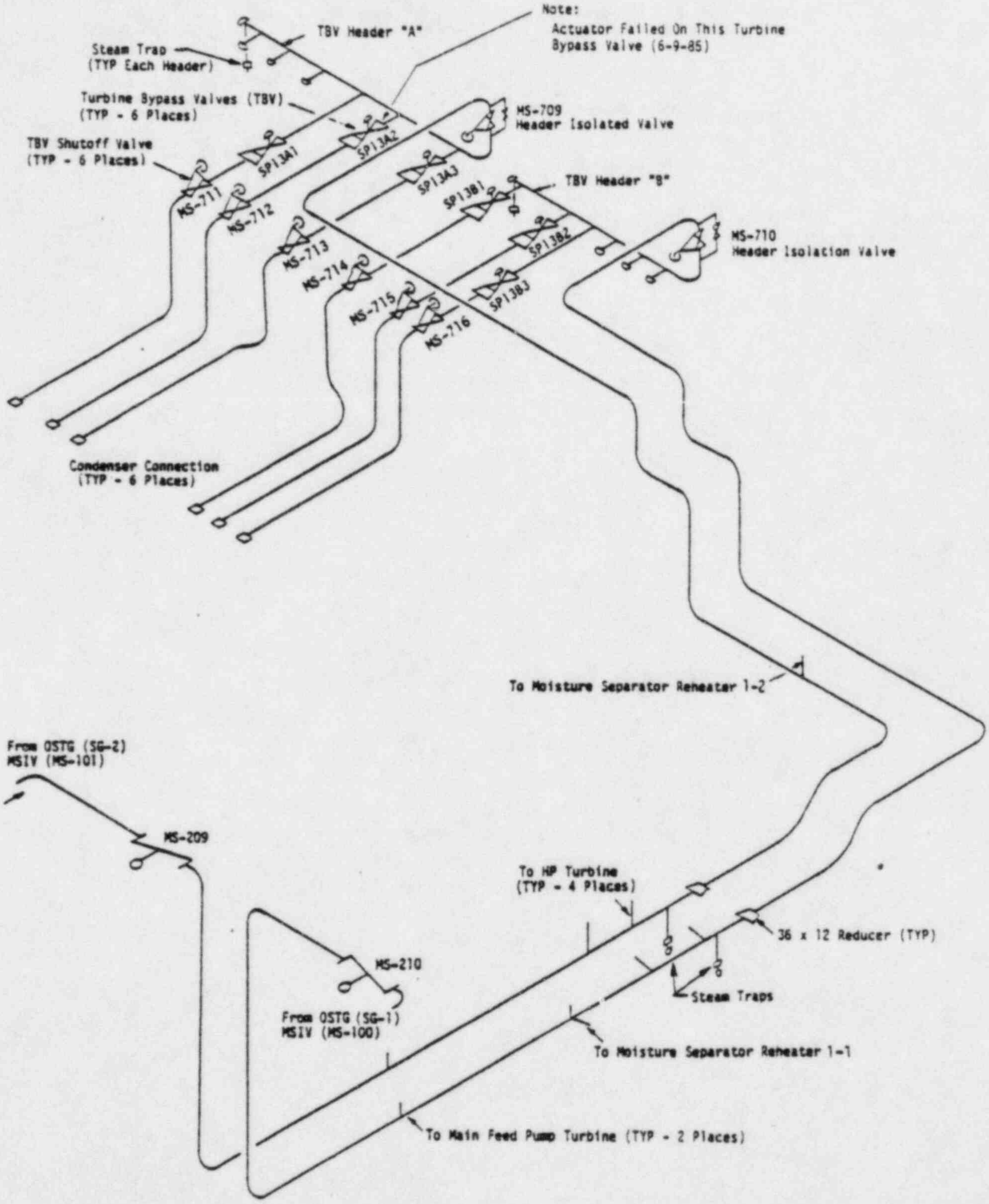
design pressure while minimizing operating forces required to unseat the valve disc. Except for the locking device used to secure the heavy hex nut threaded onto the bottom of the valve stem, all turbine bypass valves are the same design. As discussed in Section III.A.6 below, the design of this locking device was different on the SP13A2 valve (whose actuator failed) from that on the other turbine bypass valves. Each turbine bypass valve is equipped with a Fisher Controls pneumatic actuator; Type 476D Size 80 (see Figures 4 and 6). Each actuator is rated for 1.64 inches of travel.



DAVIS-BESSIE
MAIN STEAM PIPING AND
TURBINE BYPASS VALVES
SIMPLIFIED SCHEMATIC

FIGURE 1

MPR ASSOCIATES
F-100-42-2
8/5/85



DAVIS-BESSIE
MAIN STEAM PIPING AND TURBINE BYPASS VALVES
SIMPLIFIED SCHEMATIC

FIGURE 2

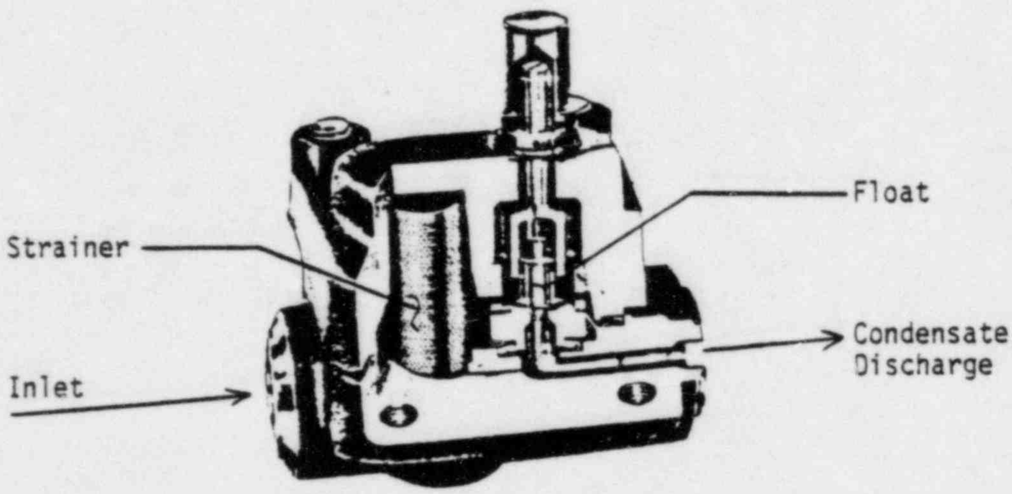


FIGURE 3

CUT-AWAY VIEW OF STEAM TRAP TYPICAL OF
THOSE USED ON MAIN STEAM PIPING AT DAVIS-BESSE

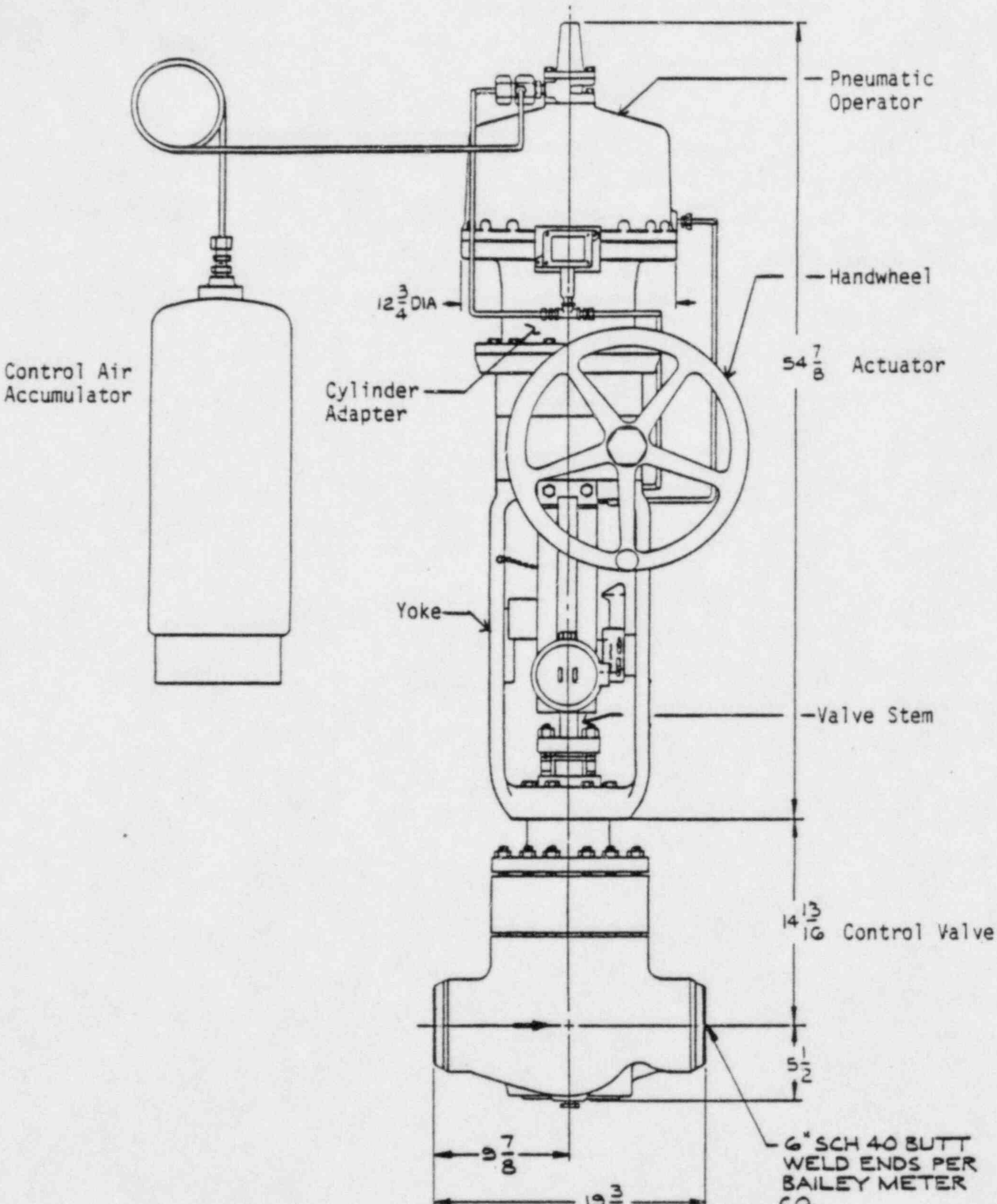
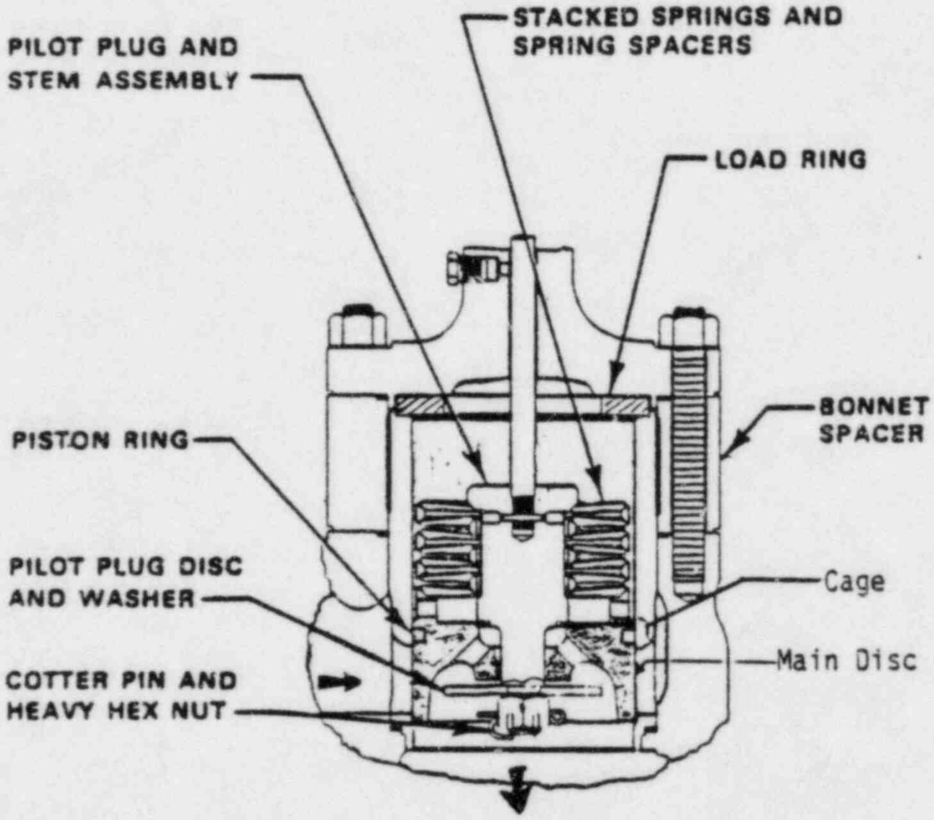


FIGURE 4

DAVIS-BESSE TURBINE BYPASS VALVE AND ACTUATOR



DETAIL OF 6-INCH DESIGN EAP BODY WITH CLOSED BELLEVILLE SPRING VALVE PLUG ASSEMBLY

FIGURE 5

DAVIS-BESSE TURBINE BYPASS VALVE INTERNALS

Note: Pin (Item 49) Shown Inserted For Handwheel (Manual) Operation. Normally Pin Not Inserted. Inspections Following 6-9-85 Transient Confirmed Pin Not Inserted At Time Of Failure.

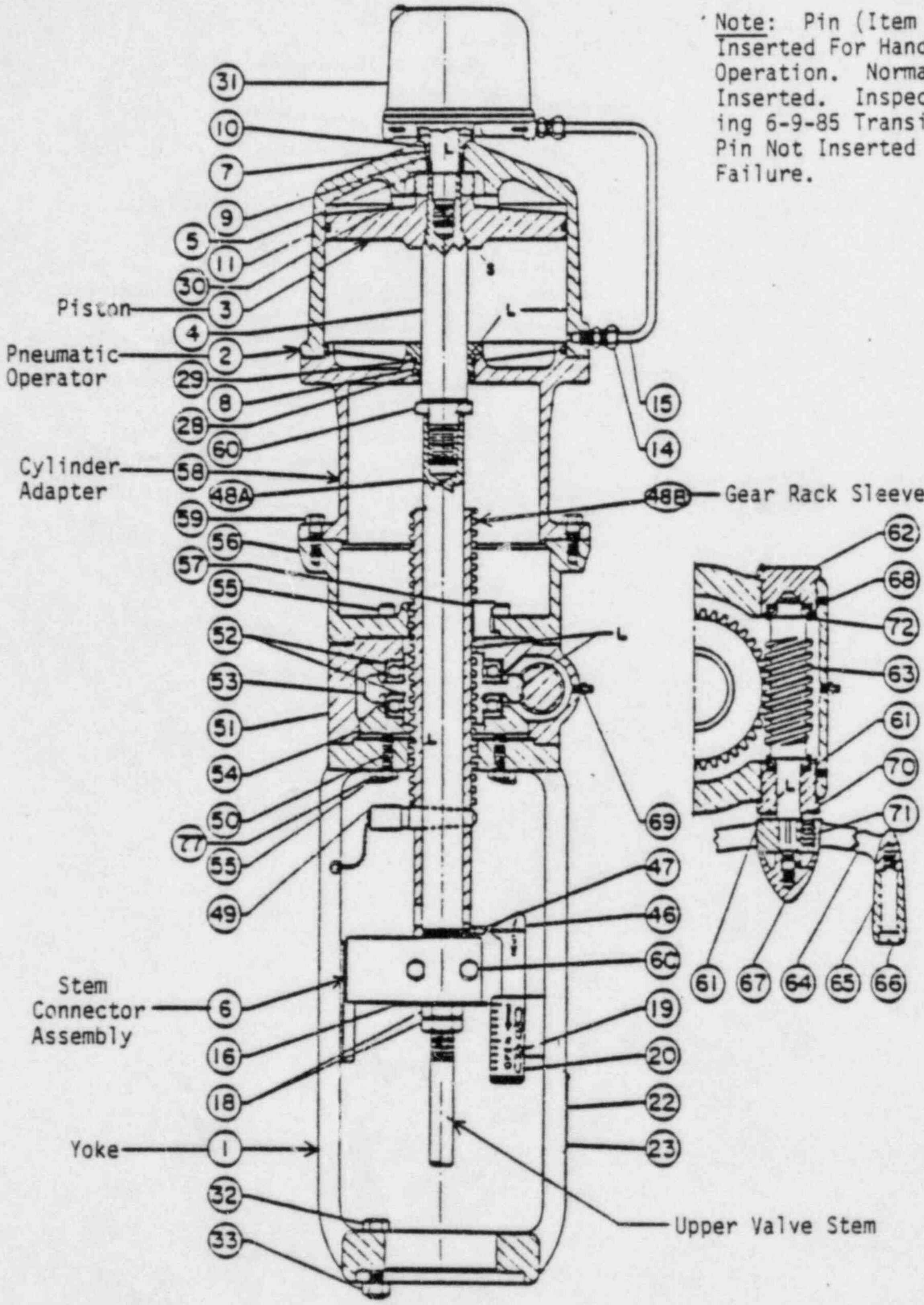


FIGURE 6

DAVIS-BESSE TURBINE BYPASS VALVE ACTUATOR

III. Summary of Troubleshooting and Investigations

A. Field Actions Performed

1. Sequence of Events Preceding Valve Actuator Failure

A detailed sequence of the events just prior to failure of the turbine bypass valve actuator failure was developed based on review of plant logs, instrument data, and discussions with plant personnel.

Following the initial plant transient of June 9, 1985, the reactor plant had been stabilized at hot shutdown conditions (Mode 3) with decay heat removed via the steam generators and the main steam atmospheric vent valves. The main steam isolation valves (MSIVs) were closed, isolating the main steam lines. The main steam lines downstream of the MSIVs had depressurized to less than 600 psi and were slowly cooling.

With the plant in a stable condition, operators began to realign the main steam system so that the plant could be cooled down following standard shutdown procedures. This required:

- Heating and pressurizing of the main steam line downstream of the MVISs
- Opening of the MSIVs
- Switching steam generator pressure control from the atmospheric vent valves to the turbine bypass valves

The plant operators proceeded as prescribed below in accordance with plant procedures for trip recovery (Reference 1). (Refer to Figures 1 and 2 for discussion below):

05:40 (Approx). Turbine bypass valve header isolation valves (MS-709 and MS-710) were closed along with the main steam line steam traps to minimize steam leakage and speed main steam line heatup. (Note that differences in heat loss and valve leakage had resulted in a difference in cooldown rate between the two lines and consequently a difference in measured temperature. This is not unexpected and did not affect valve actuator failure.)

05:43 The 1-inch MSIV bypass valves (MS-100A and MS-101A) were opened to heatup and begin pressurization of the main steam lines.

Exact Time Unknown)	Once temperature and pressure began to rise in the main steam lines, the 1-inch bypass valves around turbine bypass header isolation valves, (MS-709A and MS-710A) were opened to begin heatup and pressurization of the turbine bypass valve headers.
06:42	The MSIVs were opened to completely pressurize the main steam lines.
Exact Time Unknown)	Turbine bypass valve header isolation valves MS-709 and MS-710 were opened to pressurize the turbine bypass valve headers. Also, turbine bypass shutoff valves MS-711, MS-713, MS-714, and MS-716 were closed to isolate turbine bypass valves SP13A1, SP13A3, SP13B1, and SP13B3. The shutoff valves were closed at the request of the control room operators. Experience had shown that, for cooldown, more stable pressure control could be achieved using only one turbine bypass valve per header. At this time also, steam traps on the main steam line downstream of the MSIVs, including those on turbine bypass valve headers, should have been reopened. As discussed below, it appears that not all steam traps were operating and properly aligned at this time. <u>NOTE</u>: All of the above actions are manual operations which must be performed in the immediate vicinity of the turbine bypass valve actuator which eventually failed. The failure, when it did occur, was obvious by casual visual inspection. Hence, there is reasonable assurance that the valve had not failed prior to this time.
06:54	Turbine bypass valves on the "B" header (valves SP13B1, SP13B2 and SP13B3) were opened. With shutoff valve MS-714 and MS-716 closed, only turbine bypass valve SP13B2 was actually passing flow to the condenser. (This was as requested by the control room operators as discussed above.)
06:55:40	Turbine bypass valves on the "A" header (valves SP13A1, SP13A2, and SP13A3) were opened. With shutoff valves MS-711 and MS-713 closed, only turbine bypass valve SP13A2 was actually passing flow to the condenser. (This was as requested by the control room operators as discussed above.) Signals in the control room indicated that turbine bypass valve SP13A2

rapidly cycled open, closed, open, and finally closed. (Note that in the as-found condition, the position indicator was damaged and, therefore, the indicated position did not necessarily correspond to actual valve stem position.) At about the same time, several of the operators in the control room indicated that they heard a loud cracking sound which, they believed at the time, indicated waterhammer.

Exact Time Unknown)	Within about 10 minutes, a walkdown of the main steam line to look for waterhammer damage found the SP13A2 turbine bypass valve actuator damaged as described below. There was no evidence of steam leaks or of damage to the pressure boundary. The turbine bypass valve shutoff valve (MS-712) was closed to stop flow through the turbine bypass valve. Shutoff valve MS-716 was opened and cooldown proceeded normally using turbine bypass valves SP13B-2 and SP13B-3 on the "B" header.

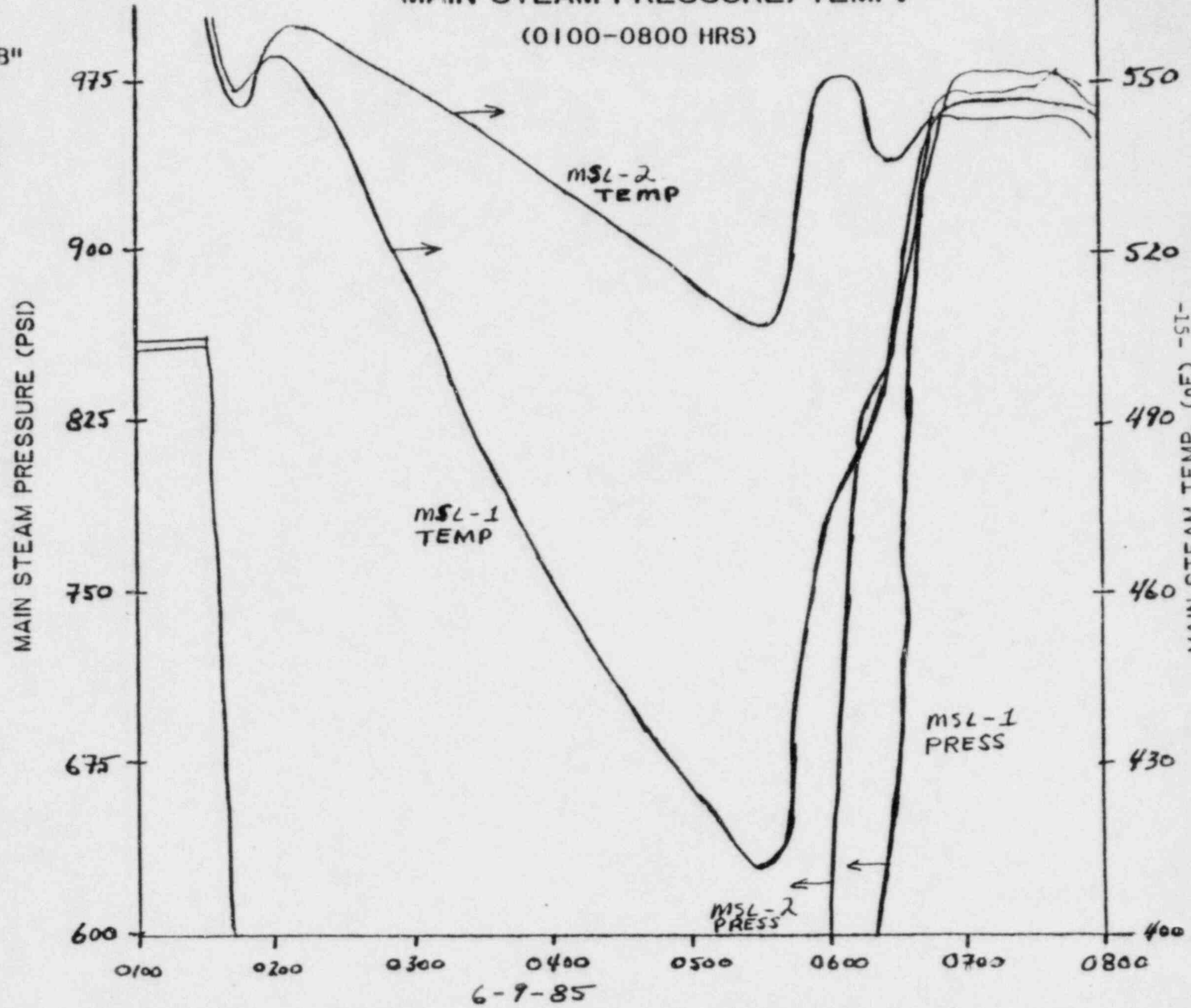
Plant instrument data for mainsteam pressure and temperature, and for turbine bypass valve discharge piping metal temperature, prior to the valve actuator failure, are shown in Figures 7 through 10.

NOTE TBV HEADER "A"
OFF OF MSL-2
TBV HEADER "B"
OFF OF MSL-1

FIGURE 7

MAIN STEAM PRESSURE/TEMP.

(0100-0800 HRS)



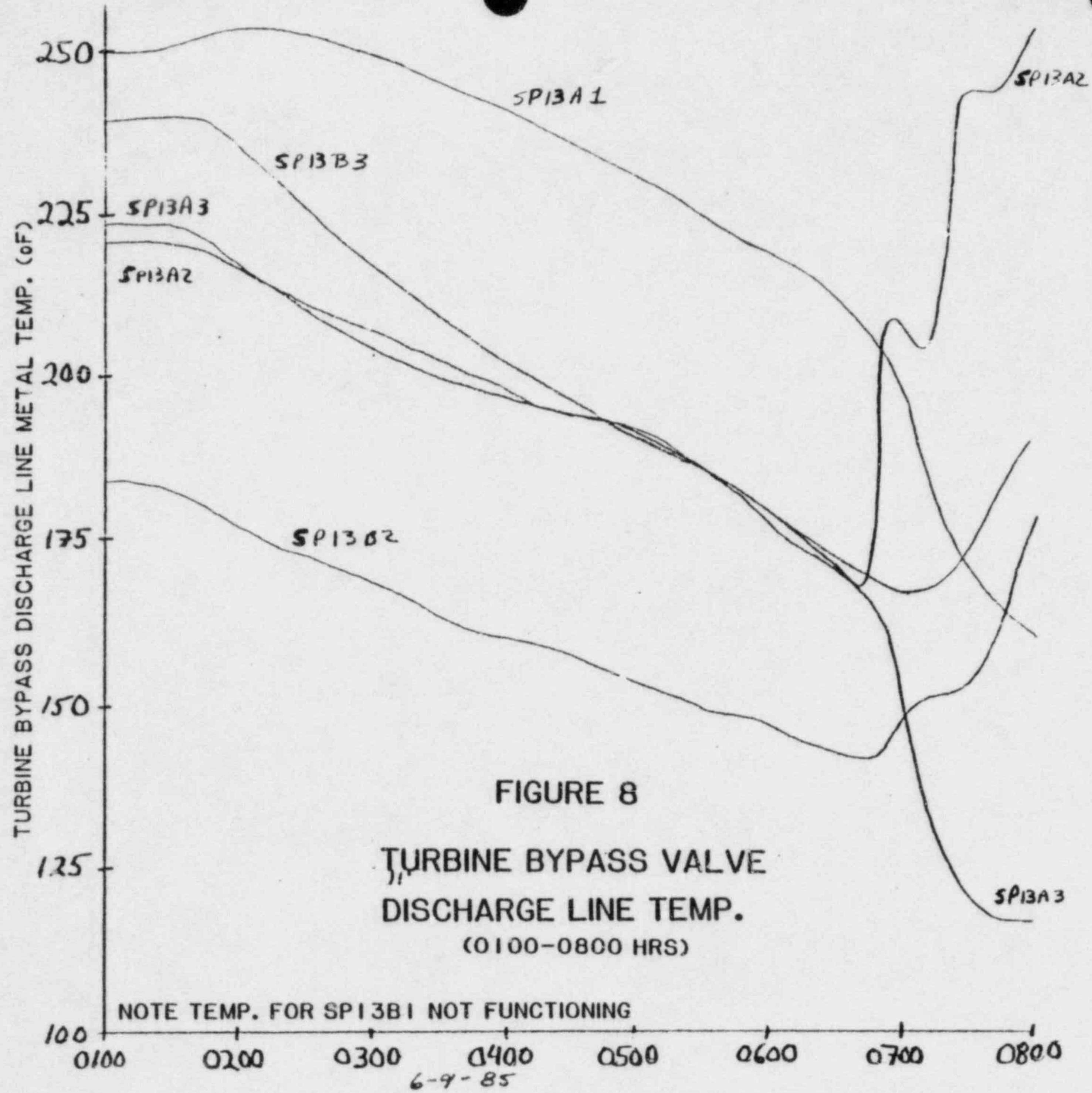


FIGURE 8

TURBINE BYPASS VALVE
DISCHARGE LINE TEMP.
(0100-0800 HRS)

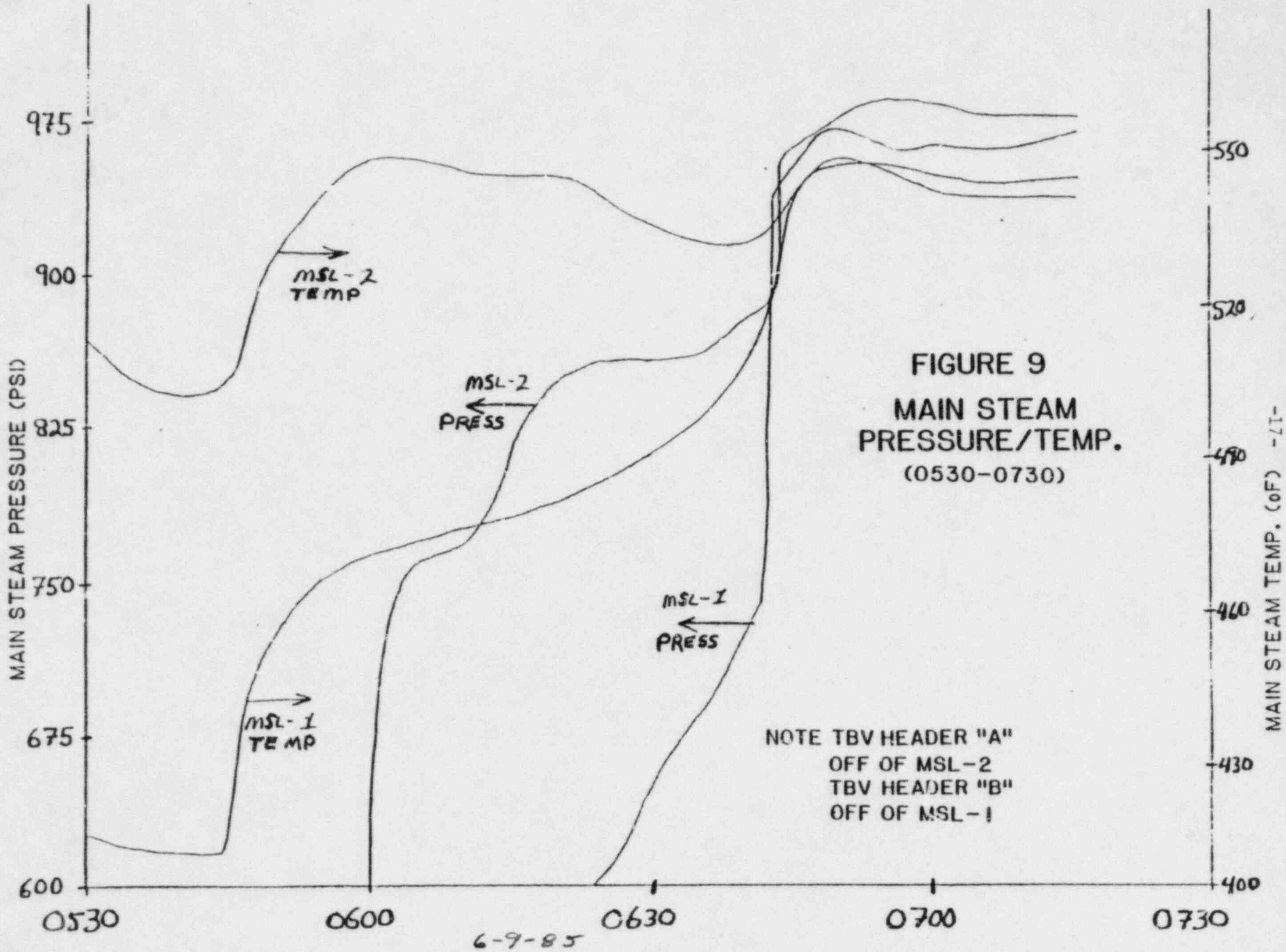


FIGURE 9
MAIN STEAM PRESSURE/TEMP.
(0530-0730)

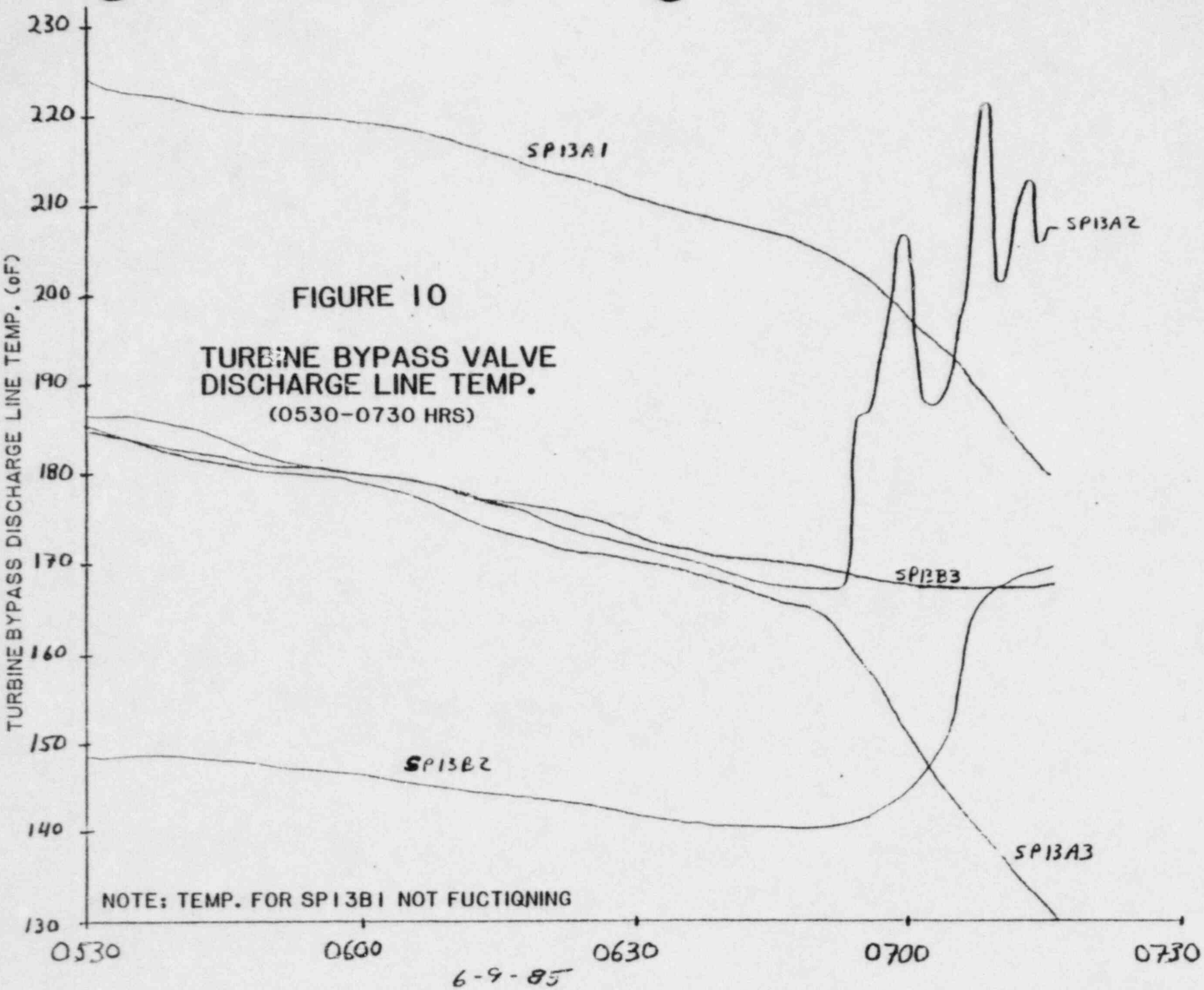


FIGURE 10
TURBINE BYPASS VALVE
DISCHARGE LINE TEMP.
(0530-0730 HRS)
TURBINE BYPASS DISCHARGE LINE TEMP. (oF)
230
220
210
200
190
180
170
160
150
140
130
SP13A1
SP13A2
SP13B3
SP13B2
SP13A3
NOTE: TEMP. FOR SP13B1 NOT FUCTIONING
0530
0600
0630
0700
0730
6-9-85

2. Initial Visual Examinations

Initial visual examinations (Reference 2) found that the SP13A2 turbine bypass valve actuator had failed in two places (see Figure 11):

- The cylinder adaptor had fractured through-wall, 360° around. The crack had propagated through the cap screw holes in the adaptor in two places so that the adaptor lower flange was in two pieces and separated from the rest of the adaptor.

- The yoke had fractured through both riser pieces very near to the upper flange plate.

Also, the valve positioner wire had broken loose from the stem connector assembly (Part 6 - Figure 6).

Visual examinations (Reference 3) of attached piping, piping supports, piping insulation, and the other turbine bypass valves indicated no other signs of damage. However, comparing the six turbine bypass valves; specifically comparing thread showing on the upper valve stem (Figure 6) indicated that almost twice the length of thread was visible on the failed turbine bypass valve as on the others. As a result, it was suspected that the failed valve might not have been assembled correctly. (Subsequent measurements by the valve original equipment manufacturer (Reference 1) indicated that there was only a minor deviation from design conditions.) Subsequent analysis, discussed below, confirmed that this did not significantly affect valve actuator failure.

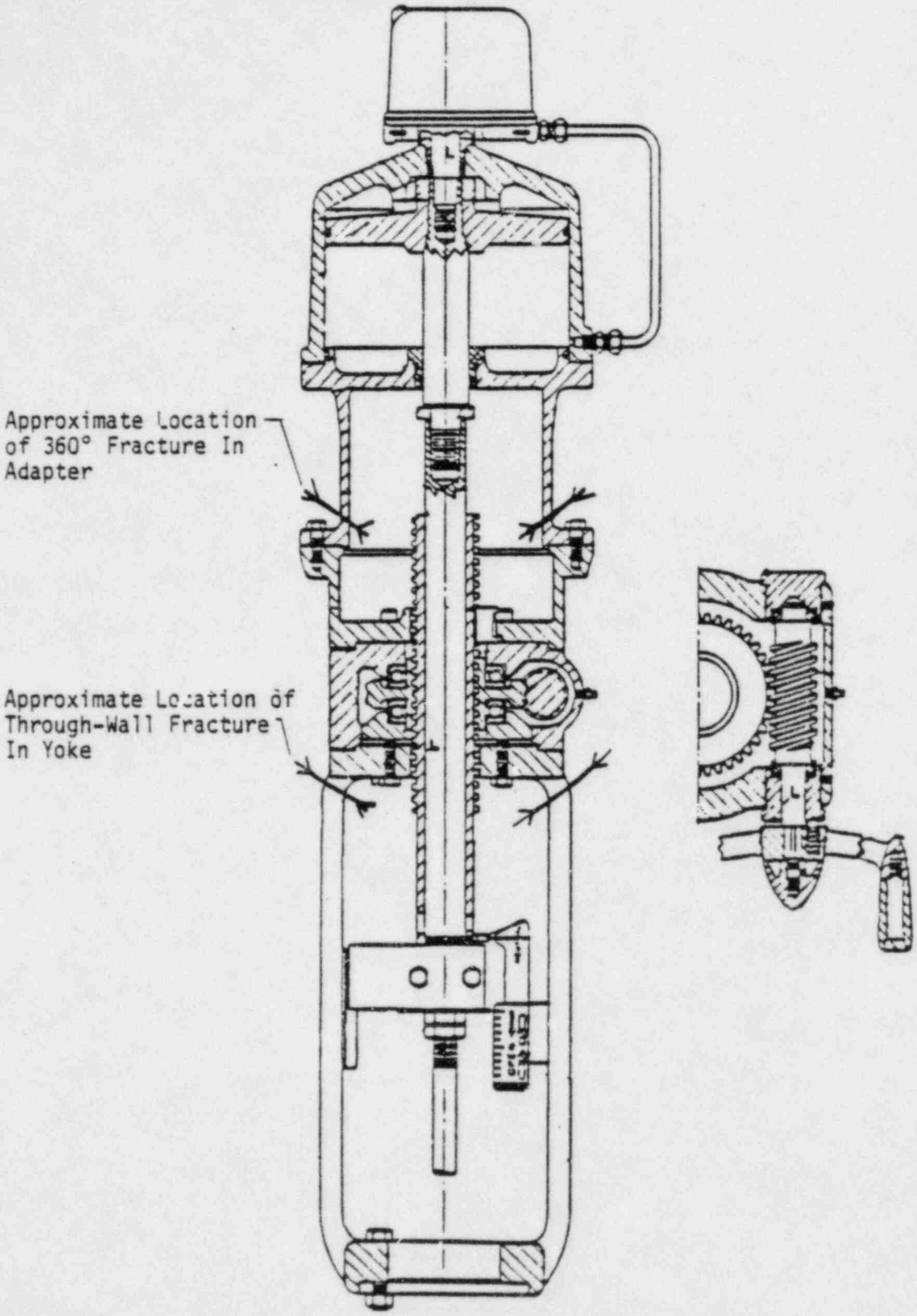


FIGURE 11

DAVIS-BESSE TURBINE BYPASS VALVE
ACTUATOR FRACTURE LOCATIONS

3. Action Plan

Based on initial visual examinations above. an Action Plan (#9A/9B) was developed (Reference 5) to determine the cause of the turbine bypass valve failure. The plan hypothesized that possible causes of the valve failure were:

1. Waterhammer

2. Valve internals not assembled in normal arrangement

3. Valve positioner malfunction

With the most likely cause being a combination of waterhammer and valve assembly problems. The plan set out the following action steps to test these hypotheses:

- Dissemble and inspect valve and actuator

- Test and/or calibrate positioner

The results of these action steps are documented in Reference 6 through 9 and are summarized below.

4. Valve and Actuator Disassembly and Internals Inspections

The valve and actuator were disassembled and inspected. The major findings were as follows:

- Travel of the valve stem was measured to be about 1-9/32 inches. Normal valve travel is 1.64 inches. (Note: Subsequent measurement by the valve manufacturer (Reference 9) indicated actual travel was about 1-1/2 inches.)

- The cause of the restricted travel (and also the atypical length of thread showing on the upper valve stem as noted above) was an old sheared-off positioner connecting rod piece which had been left in the stem connector assembly. The sheared-off rod piece fouled the inner threads and prevented proper seating of the upper valve stem in the connector assembly.

- Except for the fractured adaptor and yoke, actuator internals and parts were in satisfactory condition.

- Examination of the valve internals (see Figure 5) showed that the valve plug assembly had become disassembled in the valve. The pilot plug disc and washer, heavy hex nut, and cotter pin were all missing from the bottom of the pilot plug and stem assembly. Threads for the heavy hex nut on the

pilot plug and stem assembly were well-formed with no signs of distortion or abuse. As a result, it is concluded that the main valve disc was free of the shaft prior to failure of the actuator. The main disc was restrained laterally by the valve cage.

- The Belleville spring pack (stacked springs and spring spacers - Figure 5) was examined. A set of two washers and a spacer were tilted and lodged on the pilot plug and stem assembly. The other two sets were resting on the main disc. The upper, inner spacer ring for the spring pack was fractured.

- The valve's positioner was examined and found to be in satisfactory condition, although the connecting rod to the valve stem had apparently been overloaded and failed by the rapid stem motion that caused the failure of the valve actuator.

The valve and actuator were subsequently sent to Fisher Controls, the original equipment manufacturer, for closer examination and destructive metallurgical analysis. Their report (Reference 9) confirmed the above findings. Their metallurgical tests indicate that the cast aluminum adaptor was of lower strength than specified for the material (20 ksi vs. 30 ksi ultimate tensile stress) and very brittle, as is typical of this material. The analysis discovered no flaws in either the cast aluminum adaptor or the cast iron yoke. Their examination revealed some evidence that a cotter pin may have been installed.

5. <u>Examination of Associated Piping</u>

The piping associated with the turbine bypass valves was examined (References 3 and 4). No evidence of damage, distress, or overload was found. Insulation, hangers, and snubbers were all satisfactory with no signs of recent overload.

Steam traps on the turbine bypass valve headers were disassembled and examined. The results indicated that:

- On the "A" Header -- One steam trap was filled with debris (apparently leak sealant or valve packing material) and likely could not pass flow in service. The other trap had its internals distorted so that it was stuck open.

- Common Drain Line -- The isolation valve in the common drain line for all of the turbine bypass valve header steam traps was found in the closed position on 7/16/85. Based on conversations with station operators, it appears this valve may have

been closed at the time of the turbine bypass valve actuator failure. With this valve closed, condensate could not drain from the turbine bypass valve headers.

6. Examination of Other Turbine Bypass Valves

The five remaining turbine bypass valves were disassembled and examined. They were found in satisfactory condition. There were no indications of cracking in the actuator adaptor or yoke castings and no loose pieces. (The valve disc seating surfaces were worn from service. This is a common problem which can result in valve leakage. The undamaged valves will receive normal maintenance and refurbishment including reconditioning of their seating surfaces.)

Inspection of the remaining five turbine bypass valves identified that the design of the valve whose actuator failed was slightly different from that of the other turbine bypass valves. Specifically, the lower valve stem of the valve whose actuator failed had a small hole drilled through near the bottom for a cotter pin. The cotter pin was intended as a locking device for the heavy hex nut and pilot plug disc and washer which retain the main disc to the stem assembly, (see Figure 5). (As noted above, the cotter pin, nut, and disc washers were missing from the failed valve. Since the threads on the stem assembly showed no distress, the missing pieces apparently came loose prior to the valve failure possibly due to flow-induced vibration. As a result, it is concluded that the main disc was not attached to the valve stem assembly at the time of the actuator failure.) The other five turbine bypass valves were of an earlier design which used a star washer with deformable locking tabs as the locking device. As noted above, these valves were all in satisfactory condition. A review of valve maintenance histories confirmed that the lower valve stem of the valve whose actuator failed was replaced in June, 1982. The maintenance records indicate that lower valve stems for the other turbine bypass valves have not been replaced.

B. Analyses Performed

Analysis of the data gathered and discussed above indicates that the turbine valve actuator failed due to overload of non-ductile, cast valve actuator components. The overload was caused by an impact or impulse force imparted to the valve stem by fluid forces acting on the valve disc. The impulse force resulted from the condition of the valve plug internals; specifically from the fact that the main valve plug was not attached to the valve stem. Waterhammer in the header and piping upstream of the turbine bypass valves may also have

contributed to the failure. Details of the suspected failure sequence are discussed below:

1. Origin of Impulse Load

It appears that the cotter pin, heavy hex nut, and pilot plug disc and washer which normally cause the main valve plug to lift with the valve stem assembly were missing prior to valve actuator failure. When pressure in the header increased, the automatic controller started to open the valve to reduce pressure to the setpoint valve. The pilot valve opened causing some small steam flow. However, the main plug remained seated. Attempting to increase flow, the control system attempted to open the valve main disc i.e., it raised the valve stem by increasing air pressure below the actuator piston. However, the main disc remained seated since it was not attached to the stem assembly and no increased flow occurred. The valve stem was raised to the top of its travel while the main disc remained seated with a small differential pressure force due to the flow through the pilot vent holes. The position of the main disc was very unstable. Any leakage under the main disc seat, or any impulse which might partially unseat the main disc would allow upstream pressure to build up below the main disc. This high pressure would cause the main disc to lift rapidly, which apparently occurred. The main disc was accelerated upward through about 1½ inches of free travel until it collided with the pilot valve and valve stem assembly.

Analysis indicates that upstream pressure alone could impart a large impulse to the plug. It is estimated that the impact velocity of the main plug on the pilot valve/valve stem could have been on the order of 100 ft/sec, assuming only upstream pressure as the motive force. Moreover, the initial rush of steam flow through the suddenly opening valve could have caused condensate accumulated in the bottom of the upsteam header to build up a water slug in the piping immediately upstream of the valve. Because of the short time during which the header was pressurized and heated and because the surface layer of water in the stagnant header acts as an insulator, the bulk of this condensate would have been subcooled. The plug of subcooled water would rapidly decompress the volume upstream of the valve by condensing the steam in the space. The water plug would be accelerated rapidly down the pipe and collide with the opening valve main disc. The resulting waterhammer load could vary greatly depending upon the exact conditions in the pipe. However, scoping calculations indicate a short-lived impulse force with a peak pressure of 4000-7000 psi could have been applied to the valve main disc by such a waterhammer event.

2. Loading Sequence

With the valve stem assembly at the top of its travel, an upward impulse load on the valve stem due to impact by the main disc would be transferred to the actuator by bearing of the valve piston against the top of the pneumatic operator (see Figure 6). This would place the actuator assembly in tension. The cylinder adaptor is the weakest component in the actuator assembly. It has the thinnest wall and is cast aluminum; a brittle material with little energy absorbing capacity. Hence, upon impact of the main plug with the pilot valve/valve stem, the cylinder adaptor failed. With sufficient energy stored in the upward motion of the valve main disc, the valve stem assembly would move upward once the cylinder adaptor had failed since there would be no opposing restraining force. As the stem assembly moved upwards, the stem connector (Item 6 - Figure 6) would collide with the bottom of the gear rack sleeve (Item 48B - Figure 6) of the rack and pinion hand wheel assembly. Load would then be transferred through the rack and pinion gears and place the lower actuator assembly in tension again. The weakest member in the remaining actuator assembly under this tensile load is the valve yoke (Part 1 - Figure 6). The yoke is cast iron. Like the cast aluminum, the cast iron is a brittle material with little energy absorbing capacity. Hence, upon impact of the stem connector with the gear rack sleeve, the valve yoke failed. Estimates of the energy required to fail both the cylinder adaptor and yoke indicate that the initial impact velocity of the main disc with the pilot valve and stem assembly would have had to be on the order of 85-110 ft/sec. To accelerate the main valve disc to these velocities would require pressures acting on the plug on the order of 700-1100 psi for about 2.0 sec. These are comparable to those estimated based on the expected dynamic behavior of the valve main disc in the fluid flow as discussed above.

C. Significance of Findings

Based on the data accumulated and on the failure analysis described above, the following conditions appear to have directly or indirectly contributed to failure of the SP13A2 turbine bypass valve actuator.

1. Loss of Cotter Pin, Heavy Hex Nut, and Pilot Plug Disc and Washer from Bottom of Valve Stem

This allowed the main valve disc to move freely within the valve. As a result, the valve stem was moved to the top of its travel by the controller which was unsuccessfully attempting to lift the main valve disc. A large amount of kinetic energy, estimated to be sufficient to fail the actuator components, could be stored in the main

valve disc since its vertical motion was unrestrained. Finally, loss of these parts resulted in a sequence of events such that the valve opened suddenly and completely. This may have helped to induce a waterhammer event in the upstream piping. The parts could have been lost either because of improper assembly of the valve or because the modified locking design using a cotter pin is less satisfactory for the specific service condition than is the original locking design using a deformed star washer. Note, however, that the valve did function satisfactorily for three years prior to failure of its actuator.

2. <u>Poor Impact Properties of the Valve Actuator</u>

The components which failed are cast aluminum and cast iron. Both have extremely poor impact and energy absorbing properties. Hence, although the actuator is satisfactory for design statis loading, it has little tolerance for unexpected impact loadings. In contrast, the valve internals are of more ductile materials (stainless and cast steels). These suffered little damage.

3. <u>Condensate in the Turbine Bypass Header And/Or Main Steam Lines</u>

This may have resulted in waterhammer loading of the valve internals much greater than would be expected based only on upstream steam pressure. The presence of condensate in the piping upstream of the turbine bypass valves could have resulted from a combination of any of the following:

- The relatively long cooldown time prior to pressurization of the piping (about 4-5 hours) and the subsequent, relatively short pressurization and heatup time for the turbine bypass headers (less than 15 minutes).

- Possible misalignment of main steam piping steam traps and downstream isolation valves may have resulted in inadequate drainage of condensate from the piping and especially from the turbine bypass headers.

- The condition of the steam traps may have interfered with proper draining of condensate from the piping.

4. <u>Improper Assembly of Valve Limiting Stem Travel</u>

Although this condition should be corrected, it appears to have had little effect on the valve's failure. As discussed above, the controller would likely have moved the valve stem to the top of its travel in any case in its attempt to open the main valve disc. (The main disc

could not be opened by the controller since, at the time, it was disconnected from the valve stem.)

5. Positioner Operation

Inspection of the valve's positioner found no evidence that the positioner's operation had affected failure of the valve actuator.

IV. Results/Conclusions of Finds

A. Direct Causes

The SP13A2 turbine bypass valve actuator failure was caused by overload of cast aluminum and cast iron components of the actuator. The actuator was subjected to a large impulse load which resulted when the main valve disc, which had become disconnected from the valve stem, was accelerated upward from its seated position to its full-opened position.

B. Root Causes

1. Condition of Turbine Bypass Valve Internals Prior to Failure

Failure of the SP13A2 turbine bypass valve actuator can be traced to the condition of the valve internals just prior to the actuator failure i.e., the main valve disc had become disconnected from the valve stem. The valve internal's condition resulted from loss of the cotter pin locking device intended to keep the fastener assembly for the main disc in place. Of the six turbine bypasses, only the turbine bypass whose actuator failed employed a cotter pin as a locking device. Hence, it appears that loss of the cotter pin resulted either from mis-assembly of the valve internals or from the cotter pin locking device design being somewhat less durable under the demanding conditions of service to which it was exposed than the design used on the other turbine bypass valves. Note, however, that the valve did function properly for three years prior to the failure of its actuator.

2. Waterhammer

Estimates of the energy required to cause the actuator failure indicate that actuator failure could have been caused by the condition of the valve internals prior to actuator failure alone. However, there is some evidence that waterhammer in the piping upstream of the turbine bypass valves may have contributed to the failure of the actuator. Specifically, investigations indicate that condensate may have accumulated in the piping upstream of the turbine bypass valves because of the relatively short heatup time for the piping and the condition of the steam traps for the piping. However, there are no indications

of damage or abnormal pipe motion to confirm that waterhammer did occur.

C. Disproved Hypothesis

Reference 5 represents three hypotheses for failure of the SP13A2 turbine bypass valve failure. Two of these; (1) valve internals assembled in a fashion to inhibit proper operation and (2) waterhammer, are discussed above as root causes of the failure. The third; valve positioner malfunction, was disproved by the results of the investigations and analyses performed. Specifically, inspection of the positioner following failure of the actuator and analysis of the actuator failure indicate that the valve positioner did not malfunction to cause the valve actuator to fail. The positioner linkage apparently failed due to the violent motion of the valve stem when the main disc collided with the valve stem.

V. Technical Justification of Findings

Based on the investigation and analyses discussed herein, it is concluded that the SP13A2 turbine bypass valve actuator failed due to overload of the cast aluminum and cost iron components. Overload resulted from an impact load on the valve stem caused by the disconnected main valve plug and possibly made worse by waterhammer in the upstream piping. Data gathered from field inspection of the failed valve and actuator, of the remaining unaffected valve, and of the associated piping systems, as well as from the vendor's and destructive examination of the valve and actuator components, all support the above conclusion. Analyses of the actuator failure established the loading sequence for the failure and also indicated that acceleration of the main valve disc by the upstream pressure (and possibly waterhammer) could transfer sufficient energy to the main disc to fail the actuator. The investigations and analyses covered all associated equipment and components and suggest no other obvious failure mechanism. On this basis, it is concluded that the causes of the SP13A2 turbine bypass valve actuator failure of June 9, 1985, have been positively established. Therefore, the turbine bypass valve and actuator and associated valves (MS-737, MS-739, MS-2575, ST-3 and ST-3A) should be removed from the Equipment Freeze List.

VI. Specific Corrective Actions

1. Develop a Preventative Maintenance Program to Insure Proper Assembly of Valves

A Preventative Maintenance Program will be written to inspect all six turbine bypass valves during the next two refueling outages to insure they are assembled properly. The Preventative Maintenance Program may be modified based on the data

received from the first two inspections. All valve rework will be done by a vendor qualified by the valve manufacturer.

VII. Planned Additional Action

1. Repair Failed Valve Actuator

   The failed valve actuator and the associated turbine bypass valve will be repaired and returned to service. The valve vendor has identified the replacement parts that are required. Undamaged parts will be refurbished and reused. This will be done prior to plant startup.

2. Replace Steam Traps and Drain Valve Header

   Install new Steam traps at locations ST 3, ST 3A, and new drain valves at locations MS 737, MS 739, and MS 2575. This will be done prior to plant startup.

3. Revision of Plant Operating Procedures

   Revisions will be made to plant procedures to minimize the potential for waterhammer. The revisions include; insuring opening of GS 14 for proper drainage of turbine bypass valve headers, specifying a minimum of time for heatup between initial pressurization of the main steam line and turbine bypass header; and the opening of the turbine bypass valves. The revised procedure will also require documentation of changes made to steam trap valve alignments during the heatup period. Finally, the revised procedure will require that the turbine bypass header drains (Valves HV-2572 and HV-2575) be temporarily opened prior to use of the turbine bypass valves for plant startup or cooldown. This will be done prior to plant startup.

VIII. Generic Implications

Items VII-1 and VIII-3 apply to both turbine bypass valve headers. There are no other generic implications.

IV. References

1. Plant Procedure PP 1102-03 Trip Recovery.

2. Memo Dated June 11, 1985; Summary of 6/11/85 Walkdown of Turbine Bypass Valve PV-SP13A2; R. A. Ackerman, et. al.

3. Memo Dated June 13, 1985; SP13A2 and Associated Piping Walkdown 6/13/85 at 0930; M. Raynes, et. al.

4. Bechtel Inspection Report - Turbine Bypass Valve Failure From J. W. Fay to J. K. Wood (TED) Dated June 28, 1985.

5. Toledo Edison Corrective Action Plan 9A/9B; To Determine The Cause of Turbine Bypass Valve 2-2 (SP13A2) Failure.

6. Toledo Edison Maintenance Work Order 083-01-1942-03; Valve Actuator Disassembly.

7. Toledo Edison Maintenance Work Order 083-01-85-1942-04; Valve Disassembly.

8. Toledo Edison Maintenance Work Order 083-01-85-1942-02; Steam Trap and Header Drain Valve Disassembly.

9. Fisher Controls Report - Turbine Bypass Valve (SP13A2) From R. Micheel to M. Raynes (TED) Dated July 17, 1985.

PRELIMINARY FINDINGS, CORRECTIVE ACTIONS AND GENERIC IMPLICATIONS REPORT

Title: Toledo Edison - Main Steam Header Pressure

Report By: Larry Huston (TED)
Nick Moisidis (CYGNA)

Plan No. 16

REV	DATE	REASON FOR REVISION	WRITTEN BY	APPROVED BY
0	8/27/85	Initial Issue	N. Moisidis L. Huston	L. Grime
1	8/30/85	Incorporate Sections VI, VII and VIII and Revised Plan Additional Actions C and E	N. Moisidis L. Huston	L. A. Grime
2	9/6/85	Additional Findings & Trouble-shooting Results Incorporated	N. Moisidis L. Huston	D. Morrison

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I. ISSUE/CONCERN

Following the plant trip on June 9, 1985, there were several periods during which steam header pressure dropped below the expected control pressure of either the atmospheric vent valves (AVVs) or the main steam safety valves (MSSVs). At one point the pressure decreased by approximately 150 psi on Steam Generator one (SG-1) header. Such a large pressure swing is unexpected. More important, if pressure swings were the result of equipment malfunctions that could cause depressurization of the steam generators, they could cause a trip of the main feedwater pumps (MFPs), followed by a loss of steam generator inventory, and potentially loss of the ability to drive the steam-driven auxiliary feedwater pumps (AFPs).

An examination of the plant instrument pressure plots for both steam headers following the June 9th event revealed five instances when pressure decreased in an unexpected fashion. These are described below:

A. Issue No. 1:

During the period between 1:41:11 and 1:41:25, pressure in the header from SG-1 dropped from 942.4 psig to 924.5 psig while pressure in header from Steam Generator two (SG-2) dropped from 1001.0 psig to 973.2 psig.

B. Issue No. 2:

During the period between 1:50:13 and 1:51:55, pressure in the header from SG-1 dropped from 934.7 psig to 749.6 psig.

C. Issue No. 3:

During the period between 1:36:09 and 1:38:54, pressure in the header from SG-2 dropped from 994.6 psig to 960.3 psig.

D. Issue No. 4:

During the period between 1:48:44 and 1:49:27, pressure in the header from SG-2 dropped from 980.0 psig to 927.5 psig.

E. Issue No. 5:

The steam pressure trends in SG-1 between 1:48:33 and 1:50:13 and in SG-2 between 1:46:43 and 1:48:44 are considered abnormal.

F. Other Concerns:

Examination of the pressure plots for both steam headers also revealed several instances in which the MSSVs did not operate as expected. In some cases, the indicated pressure at which 2
the valves opened was as much as 3.7% below the expected set

pressure. Specifications for new valves call for a 1% tolerance on set pressure. In other cases, the steam pressure data indicate that blowdown following valve opening was possibly as little as 1.5% of the opening pressure. The expected blowdown is 3%. Finally, in SG-2 header there were some rapid pressure oscillations subsequent to valve closure. In all instances, 2
the MSSVs performed their required function in that they limited steam pressure to below system design pressure, and in all cases the MSSVs reclosed as required. In no case were these anomalies a cause of steam generator depressurization. Therefore, they were not potential threats to the operation of the main or auxiliary feedwater pumps. These unexpected trends are being investigated, and their significance to long-term operation will be assessed.

II. BASIC PRINCIPLE OF OPERATION

The basic purpose of the main steam system is to direct the steam produced by the once through steam generators to the turbine through the main steam piping. Steam produced in the steam generators removes heat from the reactor coolant system.

The main steam lines can be isolated (except for steam inlets to the auxiliary feedwater pump turbines) by closing the main steam isolation valves (MSIVs).

Following a turbine trip and closure of the MSIVs, eighteen spring loaded safety valves (nine per steam generator) will relieve steam to the atmosphere if steam pressure exceeds their setpoints. These valves are passive in that no automatic control functions nor operator actions are required for the valves to release steam and prevent overpressurization of the main steam system. The first bank of MSSVs is set to open at 1050 psig. Additional safety valve banks are set to open at pressures up to 1100 psig. The pressure relief capacity is such that the energy generated at the reactor high-power-level trip setting can be dissipated through this system.

The Integrated Control System (ICS) is a coordinated control system that develops parallel demands to the reactor, steam generator feedwater control, turbine control, and steam bypass system.

The steam bypass system automatically controls the steam to the condenser during startup while the turbine is being brought in service, and it provides dump capability to the condenser during minor steam transients at any power level. The steam bypass system is also capable of manual control at any load. The steam bypass system incorporates the turbine bypass valves and one AVV on each steam generator header.

Following a turbine trip or MSIV closure, header pressure control is maintained by modulation of either the AVVs if the MSIVs are closed or the turbine bypass valves if the MSIVs are open. The AVVs

relieve to the atmosphere and the turbine bypass valves relieve to the condenser.

The ICS is a combination of electric and electronically-operated devices designed to produce process variable outputs in accordance with desired or set point conditions. The system includes the following major components:

- Measuring element and signal conversion means
- Hand-automatic selector stations
- Action unit controllers
- Power operators
- Valve or drive positioning systems

The system uses a standard signal range of -10 to +10 volts DC throughout. All measuring elements and signal conversion means are local. The Hand-Automatic selector stations are on the operator's control board. Power operators are mounted at the valve or damper to be controlled. Signal converters to convert the -10 to +10 volt signal range to the pneumatic signal of the power operators are mounted near the pneumatic power operators. The controllers, signal manipulation devices, and alarm monitors are in the control cabinets.

The Hand-Automatic transfer station and its associated circuitry allows the operator to transfer either from "automatic to hand" or from "hand to automatic" at any time simply by depressing the

correct pushbutton on the selector station. No balancing of the selector station is required. However, when transferring to automatic control, it is necessary for the operator to insure that the automatic signal to which he is about to transfer is at the correct level since the automatic system will, as soon as the transfer is made, begin to correct the position of the final control element as directed by the automatic signal.

The controllers are of a modular design and are identified as action units capable of producing one of the following control actions: derivative, integral, proportional, summing, subtracting, etc. Each action unit is a plug-in device, which can be easily removed from the cabinet.

The electric-pneumatic converter is a force-balance device in which the electric signal moves a pressure sensitive vane by means of an electric coil. The resulting change in pressure is fed back through a booster relay to reposition the vane and change the output pressure signal of the electric-pneumatic converter. The pressure signal is then transmitted to a conventional pneumatic operator.

The ranging and biasing components provide, in addition to gain adjustment, changes to the ±10 volts DC signal range.

The AVVs are equipped with Fisher type electro-pneumatic transducers which receive a milliampere DC current electrical signal and transmit a proportional pneumatic output pressure to the AVV. An

increase in the DC milliampere signal to the transducer coils increases the output pressure to the AVV and vice versa.

The AVVs have also positioners equipped with an input capsule that serves as a force-balance member to match the valve/stem position to the control signal. An increase in the control pressure produces an increase in air pressure to the top of the actuator and a decrease of the pressure at the bottom of the actuator. This difference in pressure will drive the piston downward stretching a range spring until the spring tension opposes exactly the force resulting from the control pressure signal.

III. SUMMARY OF TROUBLESHOOTING AND INVESTIGATION

This section provides a summary of the troubleshooting and investigation of the large pressure swings experienced on both steam headers following the June 9, 1985 reactor trip.

Action Plan No. 16 provides some of the maintenance and surveillance and testing history of the AVVs and MSSVs prior to the June 9, 1985 trip. Also, included in this report are the hypotheses determined to be the probable causes of the large pressure swings of both steam headers during the June 9, 1985 trip.

A. Field Actions Performed

Of the eight steps listed in Action Plan No. 16 report, the following have been performed:

1. Step Number 4: Maintenance Work Orders 1-85-2190-00, 1-85-2344-00 and 1-85-2345-00 provided string checks of the Integrated Control System (ICS) modules which provide automatic control of the AVVs.

The testing was done in accordance with a specially developed guideline for testing of the AVV controls. This guideline closely simulates the actual conditions under which the AVVs operate. For the voltages specified on ICS Modules 4-3-8 (AVV-1) and 4-3-9 (AVV-2), all recorded voltages on the AVV control strings were as expected.

The operational check of the HS-SP12A and HS-SP12B hand/auto stations was performed by energizing and de-energizing the component modules and verifying the voltage difference across the pins. The results of this check indicated that the stations were functioning properly. Bench testing was performed on each module in the AVV ICS channel. All modules, except Module 4-3-4 sum-plus-integral, were found to function properly. Module 4-3-4 was found to give anomalous readings and had an improper gain. This module was sent to Bailey Controls for

further troubleshooting (see item 2 below). The remaining modules were reinstalled in the ICS.

Operability and calibration checks of the steam header pressure transmitters were performed in accordance with the instructions for Surveillance Test 5036.03 (Section 6.1 only) for steam generator outlet pressure instrument strings SP12A1 and SP12B1. The output from the current buffers and voltage buffers were found to exceed the required tolerances of ±30 mv and ±20 mv respectively. However, the actuation pressures from both the pressure indicators and the computer printout were within the tolerances for both instrument strings.

2. Step Number 8: As mentioned above, during the ICS module string test, Module 4-3-4 (Bailey Catalog Number 6624151A1C) was found to give anomalous readings and to have an improper gain and was sent to Bailey Controls Company for testing. The testing included checks of the following:

    a. Physical appearance
    b. Power supplies
    c. Calibration and adjustment
    d. Heat test

    The schematic of the Bailey module is illustrated in Figure 1.

The verification was performed in accordance with Bailey Product Instructions Section E92-60-2.

The findings were:

- The S3, S4, and S5 switches were corroded and very difficult to operate.

- Resistances of 1.5-2.0 ohms were found across the closed contacts of switches S3, S4 and S5. Contact resistance of 0.0 ohms was expected.

- Bias voltage was found to be at the saturation level of the amplifier (output = +15.1 V as compared to an expected value of 10.0 volts).

B. Analysis Performed

1. A review of the Data Acquisition Display System (DADS) and Sequence of Events Monitor (SEM) computer printouts for the operation of AVV's indicated that during the period following the June 9th trip, the AVV's were open as indicated in the table below:

	AVV-1		AVV-2	
Time	Position (Z961)	Pressure (P932)	Position (Z969)	Pressure (P936)
1:35:37	Open	1072.8		
1:40:18	Close	970.0		
1:40:23	Open	989.3		
1:41:04	Close	912.8		
1:46:29	Open	1033.3		
1:48:01	Close	945.3		
1:50:13	Open	934.7		
1:53:58			Open	976.4
1:58:28	Close	916.6		
1:59:35			Close	892.0
2:03:06			Open	970.5
2:03:15	Open	972.0		
2:03:23	Close	966.7	Close	973.5
2:03:31	Open	978.2	Open	981.4

The data above indicate that AVV-2 did not open prior to 1:53:58; however, there were indications from the steam pressure traces that AVV-2 did operate prior to this time. To verify this fact, data from the AVV exhaust stack temperature monitors were reviewed for the period immediately following the June 9 plant trip. These data clearly indicate that AVV-2 was open from approximately 1:48:20 to approximately 1:49:20 (data points were recorded only every 30 seconds). The data also indicate that AVV-2 was leaking from a point immediately following the trip (approximately 1:34:50) until the valve was opened at approximately 1:48:20. This fact is indicated by a slowly rising exhaust stack temperature on AVV-2 during this time period. It is also clear that the leakage through AVV-2 started as a result of the plant trip because the exhaust stack temperature data for both AVVs are essentially identical prior to the plant trip. It can be concluded 2

from the above information that the SEM limit switches intended to detect operating of AVV-2 did not operate 2 properly. This will be investigated.

In addition, a review of the computer data indicated that AFP turbine trip throttle valves were open as indicated below:

Time	AFP-1	AFP-2
1:46:27	Open	Close
1:52:15	Open	Open
1:58:33	Close	Open
1:58:56	Open	Open

Information from operators on shift on June 9th and the computer alarm logs indicate that all four AFP turbine steam admission valves (MS-106, MS-106A, MS-107, and MS-107A) were open throughout the time shown above. Therefore, steam to drive the AFP turbines was being taken from both steam generators after 1:46:27.

NOTE: The opening times in the table above are inferred from an indication of AFP speed; therefore, they may not be an exact measure of valve opening time. The closing time is based on indications from the "valve full open" limit switch on the AFP turbine trip throttle valve. Also, during periods when the valves were open, they were being controlled locally by the equipment operators.

Additionally, the transcripts from the interviews conducted by the NRC following the June 9th event, indicate that operators were at times manually controlling the AVVs.

2. The following data were extracted from the review of the sequence of events:

   At 1:41:11 the Steam and Feedwater Rupture Control System (SFRCS) Steam Generator No. 1 (SG-1) low level trip caused the Auxiliary Feedwater Pump (AFP) No. 1 to be aligned to draw steam from and provide feed to SG-1. Four seconds later the incorrect actuation of the SFRCS on low steam pressure isolated both Steam Generators preventing the auxiliary feed flow from reaching either Steam Generator. The immediate effect of steam flow to the AFPTs is a slight drop in header pressure. This was actually observed between 1:41:11 and 1:41:25 in both steam headers.

3. Calculations have been performed to explain the trend of the pressure transient from time 1:50:13 (AVV-1 open) to 1:58:28 (AVV-1 close). The calculations indicate that the pressure profile for SG-1 header can be obtained by considering that an AVV relief remained open (as indicated by the data in Section III B.1) while the steam generator was partially refilled by the Start Up Feedwater Pump (SUFP) (flow for approximately 3.5 minutes at a capacity of approximately 150 gpm). The secondary system operator

stated in his interview with the NRC that he reclosed AVV-1 when the steam generator pressure was dropping rather rapidly and unexpectedly during the time when SUFP flow was initially being added to SG-1. However, the SEM computer data indicate that the valve remained open until 1:58:28. This implies that the operator reduced the AVV-1 flow but did not completely close the valve. This action combined with the added flow from the SUFP would cause the repressurization of SG-1. After the SUFP flow stopped, the pressure in SG-1 started to decrease again until AVV-1 completely closed at 1:58:28.

4. The temperature downstream of the MSIV in steam line two was found to be consistently higher than the temperature downstream of the MSIV in steam line one. A comparison of temperature and pressure data in steam line two indicates that the steam in this line was superheated from approximately 1:45 a.m. until approximately 6:00 a.m. Therefore it can be concluded that there was some leakage through either the MSIV or the MSIV bypass valve from SG-2.

The magnitude of MSIV leakage is difficult to assess accurately. However, two actions were taken to determine if the leakage was significant. First, a nitrogen leak test of the valve was conducted according to Davis-Besse System Procedure SP-1106.08. The test indicated that valve leakage is within specifications with the valve in its current cold condition. Second, Davis-Besse piping 2

drawings were reviewed to determine if there are pathways
for large amounts of steam to be removed from steam line
number two downstream of the MSIV. Only a 3/8" sample line
and a supply line to the low pressure gland steam header 2
were found. The supply line to the gland steam header
contains a pressure reducing control valve which limits
flow to the low pressure header. The sample line is
normally isolated during operation.

5. The operation of the MSSVs is dependent on the piping
system natural frequency of vibration during a transient
event. Following the plant trip on June 9, 1985, the steam
headers can be expected to have experienced combined 2
acoustic and frictional pressure fluctuations caused by the
fast traveling waves. Preliminary evaluation indicates
that the fluid transient loads and the structural system
response and support reactions on the steam headers may 2
cause poor reseating of the MSSVs, valve opening pressures
lower than valve set pressures and lower steam blowdown
than expected. The analysis of the steam headers from both
steam generators shows the following:

   a. While the configuration of the steam headers is almost
   identical, the pipe support configuration between the
   two anchors enclosing the MSSVs and the MSIV is
   different. The header from SG-1 was provided with a
   lateral snubber (SR-47) as a result of an incorrect

stress intensification factor that had been used in
the seismic piping analysis for that header. The 2
header from SG-2 has lower seismic loading and does
not have this lateral snubber.

b. The Davis-Besse MSSV header design incorporates a
non-symmetrical arrangement of valve exhausts. In
addition, there are no supports provided to withstand
thrust loading on the exhaust elbow. The combined
effects of this design with the valve reaction forces
during operation may contribute to valve fluttering. 2

It should be noted that the team investigating operator
actions following the June 9th trip have indicated that
safety valve chattering has been noted as a problem by the
operators. Preliminary indications are that, in order to
assure proper reseating of the MSSVs, operators have 2
developed the practice of manually reducing header pressure
subsequent to trips by using the AVVs.

C. Significance of Findings

1. Issue No. 1:

The findings relative to the drop in steam pressure in
SG-1 & 2 headers at 1:41:11 indicate that this pressure
drop was the result of steam flow out of SG-1 & 2 to the

AFPs following the SFRCS actuation. The pressure drop lasted only for fourteen seconds and is thought to represent the time required to pressurize the AFP steam supply line. A detailed thermal-hydraulic analysis indicates that the pressure drop in the AFPT steam supply lines last approximately 15 to 16 seconds when both admission lines are opened.

2. Issue No. 2:

The findings relative to the drop in header pressure from SG-1 during the period between 1:50:13 and 1:51:55 indicate that this pressure drop was the result of:

a. Prolonged manual control of the AVV-1 by the reactor operator;

b. To a small degree to the steam flow being provided to AFP turbines subsequent to 1:46:27.

The repressurization beginning at 1:51:55 was due to water being added to SG-1 by the SUFP, as well as a manual reduction of AVV flow by the operator. After SUFP flow was stopped, pressure in SG-1 header once again began to decrease because the AVV was still open. The decrease in header pressure ended at 1:58:28 when the AVV was closed.

3. <u>Issue No. 3</u>:

Steam leakage through either the MSIV or the MSIV bypass valve from SG-2 would contribute to the pressure drop during the period between 1:36:09 and 1:38:54 as well as during other time periods. However, this effect is thought to be small since there are no significant steam leakage paths downstream of MSIV-2, and the pressure in the steam line dropped and stayed below 600 psig for several hours after the plant trip. Additional, performance testing indicates that valve leakage is currently within specifications, and the valve has not been operated since it was tripped closed on June 9. 2

The bypass valves around both MSIVs were opened several hours after the June 9 trip in order to heat the steam lines and operate the turbine bypass valves. The rapid increase in steam line pressure when these valves were opened provides further indication that leakage through MSIV-2 or its bypass valve was small. The bypass valves are 1" valves and are installed in 3/4" lines around each MSIV. Therefore, the flow through these lines is small. However, the steam pressure data indicate that when the valves were opened, pressure downstream of the MSIVs increased at rates of 15-20 psi/min. Since pressure in steam line two had remained below 600 psig for several hours prior to opening of the bypass valves, it can be

concluded that leakage through either MSIV-2 or its bypass was very much smaller than flow through the 3/4" bypass 2
lines when the bypass valves were opened.

In addition, the anomalous readings found from Module 4-3-4 appeared to be the result of switch corrosion. As seen from Figure 1, corrosion on Switches S3, S4 and S5 could lead to both improper gain and unstable integration by the amplifier. These effects could have produced poor modulation of the AVV on SG-2 header and could have contributed to the pressure drop during the period between 1:36:09 and 1:38:54. Further ICS tests will be performed.

Finally, leakage through AVV-2, as indicated by rising temperature in the exhaust stack, would have contributed to decreasing pressure in SG-2 header during this time period. Because the AVV was not leaking before the plant trip, the leakage is judged to be the result of poor reseating of the valve following its initial operation in response to the plant trip.

2

The small out-of-tolerance conditions of the current and voltage buffers in the steam header pressure transducers were judged to have an insignificant effect on AVV pressure modulation since the actuation pressures from both pressure indicators and the computer printout were found to be

within the tolerances for both instrument strings (SP12A and SP12B1).

4. Issue No. 5:

The opening times of both the AVVs and the AFPT trip throttle valves indicate that the pressure trends in SG-1 header between 1:48:33 and 1:50:13 and in SG-2 header between 1:46:43 and 1:48:44 were a result of steam flow being provided to the AFP turbines. The trip throttle valve to AFP-1 was opened at 1:46:27 and steam from both steam generators was supplied to AFPT-1. At this time AVV-1 was also open and pressure in SG-1 header was decreasing. At 1:48:01 the AVV was closed; however, AFP-1 continued to run and take steam from both SGs. The combined effects of steam flow to the AFP turbine and the decreasing water inventory in SG-1 caused the observed pressure trend in SG-1. A similar effect can be seen in the pressure trend in SG-2 header. The only difference is that AVV-2 was not open when AFP-1 was started, and therefore, the effects of the steam flow on SG-2 pressure can be observed very shortly after AFP-1 was started ($\cong$ 16 sec.).

IV. RESULTS/CONCLUSION OF FINDINGS

A. Direct Causes

1. Issue No. 1:

The direct cause of the drop in steam header pressure, on both steam generators, between 1:41:11 and 1:41:25 was the result of steam flow from both steam generators to the AFP turbines following SFRCS actuation. The drop in pressure and subsequent recovery are attributed to the transient pressurization of the AFP turbine steam lines.

2. Issue No. 2:

The direct causes of the large pressure swing between 1:50:13 and 1:58:28 are:

a. Prolonged relief through AVV-1 due to operator action;

b. To a lesser degree the effects of steam being provided to the AFP turbine;

c. To the water supplied to the SG-1 by the SUFP which caused the repressurization starting at 1:51:55.

d. Action by the operator at about 1:51:30 to reduce AVV-1 flow.

3. <u>Issue No. 3</u>:

The direct cause of the pressure drop in the SG-2 header
between 1:36:09 and 1:38:54 is still being investigated.
However, preliminary results indicate that this is due to
the effects of poor automatic control of the AVVs by the
ICS, leakage through AVV-2 immediately after the plant 2
trip, and possibly due to either MSIV or MSIV bypass valve
leakage. It still remains to be determined why the comput-
er alarm points do not indicate operation of AVV-2 prior to
1:53:58.

4. <u>Issue No. 4</u>:

The pressure drop in SG-2 header between 1:48:44 and
1:49:27 was due to operation of AVV-2. Temperatures in the
exhaust stack confirm this. However, computer logs from
the limit switches that indicate AVV-2 position did not 2
show the valve to be opened during this time. Therefore,
further investigation of the ICS and limit switch indica-
tions will be performed to determine the cause of this
discrepancy.

5. Issue No. 5:

The direct cause of the unexpected pressure response of SG-1 header between 1:48:33 and 1:50:13 and SG-2 header between 1:46:43 and 1:48:44 are due to steam flow being provided to the AFP turbines.

6. Other Concerns:

The direct causes of the set pressure variations, steam blowdown variations and rapid pressure oscillations associated with the MSSVs are as yet unknown. However, the structural evaluation performed on the MSSV headers indicate that these pressure oscillations could be the result of MSSV flutter. Additionally, poor automatic control of the AVVs by the ICS could contribute to the rapid pressure oscillations.

B. Root Causes

The root causes for issues number 1, 2, 4 and 5 are the same as
the direct causes indicated above. Root causes for other issues 2
are still under investigation.

C. Disapproved Hypotheses

Action Plan No. 16 dismissed the hypothesis that pressure drops in the steam headers were due to steam flow past the MSIVs (Hypothesis No. 4). At present there are data which indicate that there is MSIV leakage. Therefore this hypothesis deserves further investigation.

D. New Hypotheses

1. Hypothesis No. 4 from Action Plan No. 16 report has been revised as follows:

   Pressure drops in the steam headers are due to MSIV leakage.

2. Some of the unexpected pressure trends in the steam headers following the June 9th trip were the result of steam flow to the AFP turbines.

V. Planned Additional Actions

The following additional actions are planned in order to continue the direct/root cause determination.

A. Issue No. 1:

No further actions are planned.

B. Issue No. 2:

No further actious are planned.

C. Issues No. 3 and 4:

1. Proper functioning of the alarm points Z961 and Z969 that provide position status of AVV's will be ensured. Other limit switches which may affect AVV operation will be determined. To ascertain proper operation of this equipment, investigation and troubleshooting will be performed, including disassembly if required (see Step No. 3 from Action Plan No. 16 report).

2. A string check of the following ICS modules which provide automatic control of the AVVs will be performed:

   a. E/I converter (modules 4-4-3 and 4-4-12).
   b. Hand/auto stations ICS 11A-MCS and ICS 11B-MCS.
   c. I/P converters PY-ICS11A and PY-ICS11B.

3. An investigation is presently underway at NALCO Chemicals to determine the cause of the corrosion of the switches in Module 4-3-4. If the results of the investigation indicate that the corrosion process of the switches cannot be alleviated, a minimum time for the replacement of the switches will be established and documented in a preventive Maintenance Work Order (MWO).

4. If necessary, further evaluation of MISV or MSIV bypass 2
valve leakage will be performed.

D. Issue No. 5:

No further actions are planned.

E. Other Concerns:

1. The four MSSVs set to actuate at 1050 psig and the four 2
MSSVs set to actuate at 1070 psig will be removed from their headers and sent to an outside laboratory for testing. These valves were selected because they experience the most demanding operational duty, i.e., their lower setpoints cause them to be opened more often and to stay open longer than valves with higher set pressures. There- 2
fore, these valves are expected to provide conservative indication of any valve degradation that may have occurred.

The valves will be subjected to full flow steam testing in order to determine the following:

a. Actual Valve Setpoint

b. Steam Blowdown

c. Steam Leakage Before Opening and After Reseating

These determinations will be made for at least three 2
consecutive lifts of each valve with a minimum waiting time of ten minutes between lifts. The test results will be corrected to appropriate Davis-Besse system conditions as 2
necessary. All valves will be inspected externally for any damage that might occur during testing and the results recorded in the final report.

2. Toledo Edison will select MSSVs for internal inspection based on the test results from Item 1 above. The testing laboratory will perform the internal inspection. Inspection will be done in the presence of representatives from both Toledo Edison and Dresser and will include visual inspection dimensional check and adjustment of parts. Any necessary repairs will include correction or replacement of deteriorated parts. Final adjustments will include setpoint, ring settings and valve blowdown. The need to test additional valves will be determined based on the results of these inspections.

3. Proper settings of setpoint pressures of the remaining MSSVs will be confirmed by performing Surveillance Test Procedure ST 0570.01 during the next plant startup. 2

2

4. A review of the fluid transient loads following a turbine trip event and the structural system response and support reactions will be performed. The effects of piping feedback forces on main steam safety valve operability during valve actuation will be assessed. For this review, both reports (thermal-hydraulics and steam line piping analyses) and additional material such as piping modeling, assumptions made and fluid transient and structural dynamics computer analyses will be needed. This review may also 2 identify causes for MSIV leakage from SG-2 header.

5. A review of the operability data of spring-loaded self-actuating MSSVs used for overpressure protection in other nuclear plants will be conducted. The review will focus on:

   a. set pressure tolerance
   b. blowdown
   c. leakage

F. If the actions noted above indicate a need for additional information, a program for monitoring and analyzing operating 2 conditions which could contribute to degradation of the ICS and

MSSVs will be developed (See Step No. 7 from Action Plan No. 16 report).

In addition, if necessary, a transient thermal-hydraulic analy- 2
sis for the secondary system (up to the main steam non-return valves) will be performed. This analysis will simulate the conditions that occurred during the June 9, 1985, reactor trip as closely as possible. The details about system modeling, boundary conditions, sequence of events, components operability, and transient duration will be established later should this
analysis be done. 2

VI. Technical Justification of Findings

A. Issue No. 1

Steam flow to the AFPTs is physically similar to operation of a pressure control device such as an AVV or MSSV. Steam exiting the SGs to pressurize the AFPT steam lines and drive the turbines will cause pressure in the SGs to decrease. This is particularly true when the SG water level is low and limits the amount of steam that can be generated via energy extraction from the reactor coolant system. Thermal-hydraulic calculations using detailed computer models indicate that startup of a Davis-Besse AFPT in the configuration that occurred on June 9 should cause a pressure decrease lasting approximately 15-16 seconds. This decrease is followed by a pressure recovery as

the AFPT lines pressurize and the AFPT comes up to speed. The actual time seen in the pressure trends on June 9 was approximately 14 seconds. Therefore, it can be concluded that this trend is the transient effect of AFPT startup.

B. Issue No. 2:

The interviews with the operator that were held immediately following the June 9 trip revealed that AVVs were being controlled manually during the period between 1:50:13 and 1:51:55. Moreover, the computer logs indicate that AVV-1 was open from 1:50:13 until 1:58:28. The operator on shift also stated that he closed AVV-1 when he saw SG-1 pressure dropping very low. While these actions were occurring, the water level in SG-1 was very low indicating a dry or nearly dry unit. Additionally, during this period flow from the SUFP was added to SG-1. Calculations confirm that the water added to a dry or nearly dry steam generator in conjunction with reduction in flow through AVV-1 can account for the repressurization of SG-1 that occurred at approximately 1:51:30. Thus, it may be concluded that the combined effects of AVV operation under manual control and the addition of water to a dry or nearly dry SG explains the large pressure swing in SG-1 header from 1:50:13 until 1:58:28.

C. Issue No. 4

As noted above, operators were manually controlling the AVVs shortly after the plant trip on June 9. Although limit switch position indication on AVV-2 did not show AVV-2 to be open between 1:48:44 and 1:49:27, the exhaust stack temperature clearly indicates the valve was relieving significant amounts of steam during this time. Additionally, the pressure trend shows characteristics that are essentially identical to other periods of decreasing steam pressure when the AVVs are clearly indicated as being open both by exhaust stack temperature and limit switch position indication. Thus, it may be concluded that this pressure trend was the result of manual operation of AVV-2 by the operators. 2

D. Issue No. 5

Information compiled about operation of the AFPTs following the June 9 trip indicates that steam was supplied to the AFPTs from both SGs starting at 1:46:27. Subsequent to this time, the measured water level in each SG indicated that the units were dry or nearly so. Thus, there was limited capability to maintain steam pressure in either unit at any time when steam was being extracted. The trends between 1:48:33 and 1:50:13 in SG-1 header and between 1:46:43 and 1:48:44 in SG-2 header illustrate this effect as a result of steam being supplied to the AFPTs.

The causes for several of the steam header pressure anomalies observed on June 9 have been positively established. Others remain to be resolved.

VII. Specific Corrective Actions

A. Required Corrective Actions

1. Issue No. 1

No corrective action is necessary. The steam header pressure trends between 1:41:11 and 1:41:25 are normal for the conditions that existed during that time.

2. Issue No. 2

No corrective action is necessary. However, operator practices relative to manual AVV control following plant trips are being reviewed. Operator training will reinforce the proper actions and acceptability of manual pressure control post-trip. This is being done as part of Action Plan 3.

3. Issue No. 3

Module 4-3-4 in the ICS string controlling AVV-2 will be replaced.

Other corrective actions are not yet determined.

4. Issue No. 4

No corrective action is necessary. However, operator practices relative to manual AVV control following plant trips are being reviewed. Operator training will reinforce the proper actions and acceptability of manual pressure control post-trip. This is being done as part of Action Plan 3. 2

5. Issue No. 5

No corrective actions are necessary. The steam header pressure trends between 1:48:33 and 1:50:13 in SG-1 and between 1:46:43 and 1:48:44 in SG-2 are normal for the conditions existing during those times.

6. Other Issues

Corrective actions, if needed, will be defined after the evaluations described in Section V.E. are completed.

B. Additional Planned Actions

Preventive maintenance procedures or corrective actions to control corrosion of components in the AVV control strings will

be established based on the results of investigations to define the cause of this corrosion.

Other planned actions will be determined as other root-cause findings are completed.

VIII. Generic Implications

A. Significance

Contact corrosion, as was found in Module 4-3-4 of the AVV controls, may also effect other control modules.

B. Planned Actions

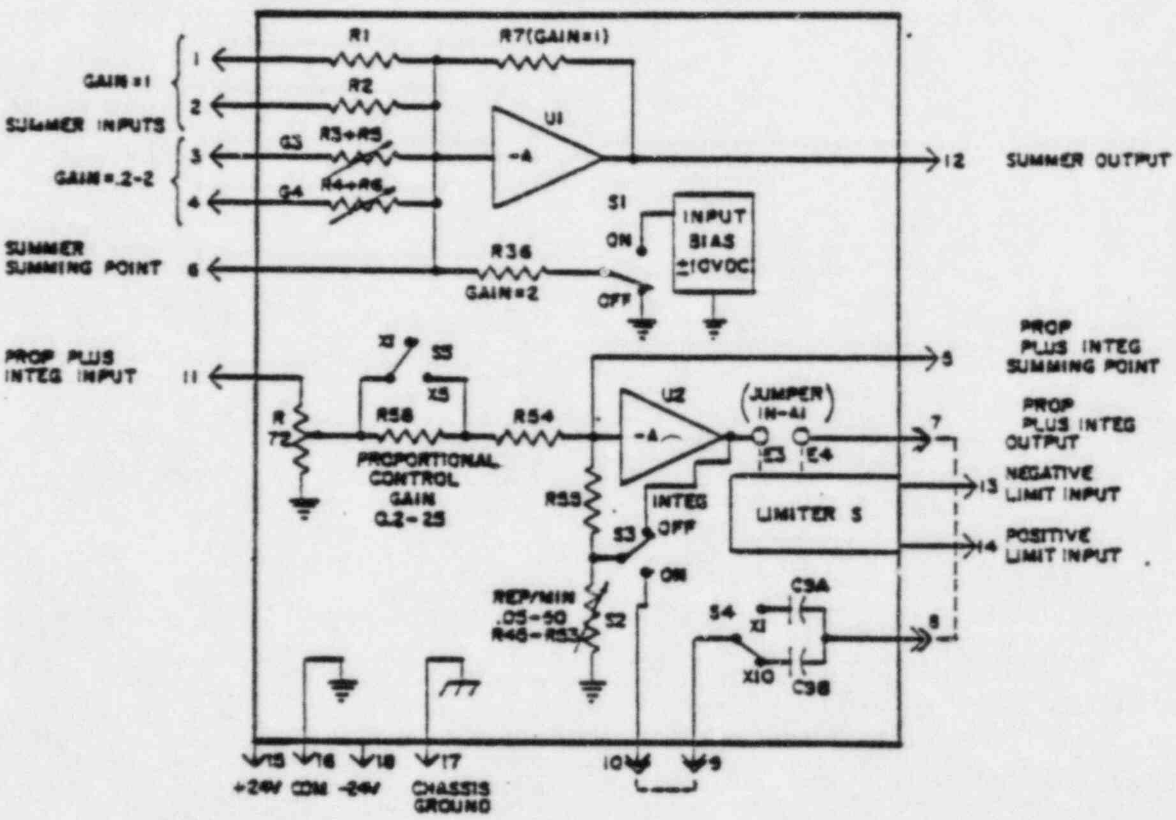
The results of the investigation of the contact corrosion will be evaluated to determine if corrective actions or preventive maintenance procedures should be applied to other control equipment.

Other generic implications will be defined as the remaining root-cause evaluations are completed.

Figure 1

MODULE

BAILEY CATALOG NO. 6624151A1C



Simplified Schematic of Module 4-3-4

FINDINGS, CORRECTIVE ACTIONS AND GENERIC IMPLICATIONS REPORT

Title: Toledo Edison - Startup Feedwater Valve SP-7A Problem Analysis

Report By: Tom Gulvas, James Tabbert

Plan: 18

REV	DATE	REASON FOR REVISION	WRITTEN BY	APPROVED BY
0	8/17/85	Initial Issue	J. Tabbert T. Gulvas	L. Grime
1	8/24/85	Revision to Section VI.A	T. Gulvas	D. Mominee
2	8/29/85	Heading Change Revised Para. VI A.	T. Gulvas	S. A. Jeimn

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I. Issue/Concern:

To investigate and evaluate indicated malfunctions of SP-7A and SP-7A controls during the June 9 transient.

During the June 9 transient, the startup feedwater valve SP-7A for #2 OTSG was closed automatically by the activation of Steam and Feedwater Rupture Control System (SFRCS) trip. After SP-7A was closed, the operator blocked the SFRCS signal to SP-7A and reset SP-7A, to return control of SP-7A to the control room hand/auto station. Channel 4 of SFRCS did not indicate SP-7A reset. The operator requested the bulb in the reset indicator be checked. A technician, to save time, removed a bulb from a SFRCS Channel 1 reset indicator and installed the bulb in Channel 4 reset indicator for SP-7A. The bulb failed immediately.

During the investigation of SP-7A, data was discovered that indicated flow through SP-7A when SP-7A was indicated closed. The indicated flow was approximately 1 percent of the normal startup feedwater flow to #2 OTSG. The data also shows that the indicated values did not hold steady but instead showed a decreasing trend with respect to time.

II. Basic Principle of Operation

The startup feedwater valves, SP-7A and SP-7B are used to control feedwater flow from 0 to 15 percent reactor power. Above 15% the startup feedwater valves are full open. The startup feedwater valves are closed automatically by SFRCS actuation. The SFRCS signal to the startup feedwater valves can be blocked and the logic reset to allow control of the startup feedwater valves from their hand/auto stations.

SFRCS consists of two identical, redundant, and independent actuation channels. Each actuation channel consists of one AC supplied logic train and one DC supplied logic train. Logic trains commonly referred to as SFRCS channels 1 and 2 are AC supplied. Logic trains commonly

referred to as SFRCS channels 3 and 4 are DC supplied. SFRCS Channels 1 and 3 make up actuation channel 1 and SFRCS channels 2 and 4 make up actuation channel 2.

III. Summary of Troubleshooting and Investigation:

A. Field Actions Performed

Initial investigation on June 9 revealed that the bulb used in SFRCS Channel 1 reset indicator for SP-7A is rated at 6 volts, and the bulb in SFRCS Channel 4 reset indicator for SP-7A is rated at 120 volts. The use of the 6 volt bulb in a 120 volt application was the direct cause of the replacement bulb failure. The correct rated bulbs were installed in both Channel 1 and 4 reset indicators.

To verify the operation of SP-7A, MWO 1-85-2113-00 was implemented in conjunction with MWO 1-85-2235-01, SFRCS Response Time Testing.

SP-7A was opened from the hand/auto station in the Control Room. Channels 2 and 4 of SFRCS were tripped. SP-7A closed as per design. The operator blocked the SFRCS signal to SP-7A and reset the SFRCS logic for SP-7A. The Channel 4 reset light came on and SP-7A opened to the set demand as per design. The power to the reset light in Channel 4 was monitored for voltage surges. The preceding sequence was repeated. SP-7A and the logic reset indication responded as per design. No voltage spikes at the reset indicators were found.

Investigation of the Data Acquisition and Display System (DADS) printout and the alarms printout showed that SP-7A responded as per design during the June 9 transient. It also can be assured that SFRCS channel 4 logic for SP-7A had reset (by voltage at the reset indicator) shown by the immediate failure of the replacement bulb.

Inspection of SP-7A valve and actuator revealed an air leak between the top of the actuator cover and the actuation cylinder. MWO 1-85-2228-01 was implemented to investigate the effects of the air leak on the operation of SP-7A.

A pressure gage was installed to measure the pressure at the top of the actuator piston. SP-7A was closed. The pressure at the top of the actuator piston was equal to the plant air system pressure and hence, the air leak had no effect on the operation of SP-7A. The actuator on SP-7A was able to provide sufficient downward force to provide tight shutoff of SP-7A.

To investigate the controls of SP-7A, MWO 1-85-2112-00 and 1-85-2228-00 were implemented. MWO 1-85-2112-00 checked the instrumentation string that controls SP-7A. MWO 1-85-2228-00 checked SP-7A positioner and position indicator. SP-7A valve positioner and SP-7A position indicator were in tolerance with no significant findings. The remaining part of the instrument string, the flow transmitter FT-SP3A, was found to be slightly out of tolerance by approximately +0.36% of full scale. FT-SP3A was recalibrated to within ±0.25%.

MWO 1-85-2411-00 was written to investigate the possibility of an internal valve anomaly in SP-7A. SP-7A was disassembled. The valve internals were inspected by Toledo Edison Quality Control and a Fisher Valve factory representative. The inspection found no evidence that SP-7A valve interals would prevent a tight shutoff.

MWO 1-85-2476-00 checked the instrument lines which supply FT-SP3A. FT-SP3A provides the SP-7A flow indication. There were no indications of blockage or obstructions in the instrument lines.

MWO 1-85-2488-00 investigated the ambient temperature effects on FT-SP3A. FT-SP3A was heated by a portable heater and the output was monitored. It was found that FT-SP3A was effected by heating by indicating a higher output. A consultant from Quality Services International estimated the effects of heating FT-SP3A to be approximately +0.13% of full scale for approximately 20°F rise of the flow transmitter and hence, well within the tolerance of the instrument.

B. Analysis Performed

It has also been determined from the DADS printout that during the time that SP-7A was closed and a small indication of flow was present on FT-SP3A, the steam generator pressure was much greater than the output pressure of the feedwater system. Therefore, no possible flow through SP-7A could occur.

C. Significance of Findings

The finding of a failed bulb in SFRCS channel 4 logic reset indicator for SP-7A has been attributed to normal or random end of service life of the bulb. The reset indication informs the operator that the SFRCS signal has been blocked, the trip logic for SP-7A has been reset, and control of SP-7A has been returned to the hand/auto station. With the bulb failure of the reset indication, the operator was unable to determine if SP-7A trip logic had been reset at SFRCS Channel 4.

From the findings of MWOs 1-85-2488-00, 1-85-2411-00 and 1-85-2476, it has been determined that there was no flow through SP-7A when SP-7A was closed. The indicated flow was within the tolerance of the instrument. The out of calibration and the ambient temperature effects biased the readings high. The temperature effects due to the cooldown of the nearby plant equipment explains the decreasing flow readings with respect to time. Additionally, the feedwater system did not develop enough pressure to provide flow to the steam generator.

IV. Results/Conclusions of Findings:

A. Direct Causes

The direct cause of the failure of the reset indication for SP-7A in Channel 4 of SFRCS was a failed bulb in the reset indicator. It has been shown by field investigation that there was no system anomaly which caused the failure (i.e., it was a random or normal end of service life failure of the bulb).

B. Root Cause

The direct and root cause are the same.

C. Disproved Hypotheses

Hypothesis 1 is:

Startup feed value SP-7A did function properly. The operator had no indication of proper reset function due to the reset indicating lamp failure. The lamp failure was due to random or normal end of bulb life, or to a voltage spike in the reset circuit.

It has been shown that the bulb failure was not due to a voltage spike in the Channel 4 reset indication. However, the rest of hypothesis one is true.

Hypothesis 2 is:

SP-7A did not respond correctly.

Hypothesis 2 has been disproved by field investigation and June 9 transient computer data reduction. SP-7A did respond to the SFRCS trip, logic reset, and control functions as designed. It has been shown that the indicated flow through SP-7A was due to out of calibration and ambient temperature effects on the flow

transmitter. The combined effects of these two errors were estimated to represent approximately 80% of the magnitude of the anomalous flow indication seen on June 9, 1985. There was no flow through SP-7A when it was closed.

Hypothesis 3 is:

SP-7A did not close fully due to an air leak between the actuator cylinder and the cylinder cover.

Hypothesis 3 has been disproved by field investigation. There was sufficient air pressure on the actuator piston to provide the closing force required for SP-7A.

Hypothesis 4 is:

FT-SP3A including sensing lines, did not respond correctly.

Hypothesis 4 has been disproved by field investigation. When tested, FT-SP3A responded as per design.

V. Technical Justification of Finding

Action Plan 18 addresses the concerns of: 1) no reset indication on SFRCS channel 4 for SP-7A after the SFRCS signal was blocked and the logic reset and 2) an indicated flow through SP-7A when SP-7A indicated closed.

It has been shown that the failed SFRCS channel 4 reset indication for SP-7A was due to a random or normal end of service life of the bulb and not to a system anomaly.

It has been shown by a valve internals inspection and verifying the operability of the valve actuator that SP-7A was capable of providing a tight shutoff during the June 9 transient.

It has been shown by field testing and investigation that SP-7A responded as per design to the June 9 transient.

The causes for the anomaly observed on June 9, 1985 associated with the Startup Feedwater Valve SP-7A have been positively established. SP-7A should be removed from the freeze list.

VI. Specific Corrective Action

A. Required Corrective Action

None, the failed bulb has been replaced and the start-up
2 feedwater valve, control system, and instruments functioned
properly during the event.

B. Additional Planned Action

Information concerning the different power supplies to the SFRCS will be provided to operators and technicians to insure that they are aware of the varying bulb and indicator requirements of the system.

VII. Generic Implications

None - there were no significant findings.

nm d/4

PRELIMINARY FINDINGS, CORRECTIVE ACTIONS AND GENERIC IMPLICATIONS REPORT

TITLE: TOLEDO EDISON - SERVICE WATER TRANSFER

REPORT BY: TIMOTHY CZUBA (TED)
BRUCE HICKMAN (TED)
JAMES TABBERT (TED)

PLAN NO. 26

REV	DATE	REASON FOR REVISION	WRITTEN BY	APPROVED BY
0	8/17/85	Initial Issue	Tabbert Czuba B. Hickman	L. Grime
1	8/23/85	Corrective Actions Added	Tabbert Czuba B. Hickman	L. Grime
2	8/29/85	Testing Clarification	Tabbert Czuba B. Hickman	L. Grime
3	9/9/85	Updated Root Cause and Technical Justification	L. Grime	D Mominee

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I. ISSUES/CONCERN:

During the June 9 transient, an inadvertent automatic transfer of the suction of Auxiliary Feed Pump 1-1 (AFP 1-1) from the condensate storage tanks to the service water system was actuated.

The automatic transfer of auxiliary feed pump suction from the condensate storage tanks to the service water system occurred prior to the actual loss or low water level in the condensate storage tanks. Service water will allow the auxiliary feed water pumps to perform their safety function. Service water is chlorinated lake water which is chemically undesirable for use in the steam generator.

II. BASIC PRINCIPLES OF OPERATION

In the event of loss of the water supply from the condensate storage tanks, an automatic backup is provided from the service water system. Two independent low pressure switches provided on the auxiliary feedwater pump suction line, upon both sensing low pressure, will automatically close the valve from the condensate storage tanks and open the valve from the service water system. Each auxiliary feedwater pump has an independent set of pressure switches, supply valve from the condensate storage tank, and supply valve from the service water system. These components function independently with their respective auxiliary feed pumps. See Figure 1.

III. SUMMARY OF TROUBLESHOOTING AND INVESTIGATION

A. Field Actions Performed

MWO 1-85-2130-00 and 1-85-2133-00 checked the time response, calibration, condition of the switch, and wiring of PSL 4928A, PSL 4928B, PSL 503, PSL 4929A, PSL 4929B, and PSL 507.

PSL 507 was found to actuate at 9.36 PSIG. The setpoint for PSL 507 is 11 PSIG. PSL 507 monitors the auxiliary feed pump 1-2 suction pressure downstream from the strainer S206. PSL 507 provides an alarm indication in the control room, but no control function.

PSL 4928A was found to have a loose terminal connection. It was determined the connection was making contact and had no effect on the operation of PSL 4928A. Review of the circuit diagram shows the loose wire would not affect the actuation of the automatic transfer.

MWO 1-85-2146-00 verified there were no obstructions in strainers S201, S206, or S257. The strainers were disassembled and no obstructions were found.

MWO 1-85-2144-00 verified that upon sensing low pressure at PSL 4928A and PSL 4928B, the suction to auxiliary feedwater pump 1-1 would transfer from the condensate storage tanks to the service

water system. Low pressure was applied to PSL 4928A and PSL 4928B simultaneously and the suction transferred correctly.

B. Analysis Performed

The effects of vibration on PSL 4928A and PSL 4928B was investigated. The evaluation concluded that vibration was not a credible cause of inadvertent actuation of PSL 4928A and PSL 4928B. The conclusion was based on vibration analysis of the supports and switches.

Another study investigated the cause of the automatic transfer of auxiliary feed pump suction from the condensate storage tanks to the service water system. The study concluded the conical strainer S257 may be responsible for the automatic transfer.
Calculations show that conical strainer, S257, is expected to 3
have a higher pressure drop than originally specified. This will reduce the steady state suction pressure thus increasing the probability of a suction pressure fluctuation dropping below the setpoints of the pressure switches PSL 4928A and PSL 4928B,
activating the automatic transfer. 3

A study was conducted to verify the circuitry for the automatic transfer of the auxiliary feedwater pump suction was of correct design and logic configuration. The study concluded:

- The circuitry will provide the automatic transfer of the auxiliary feedwater pump suction upon sensing low pressure at both low pressure switches. (i.e., PSL 4928A and PSL 4928B for AFP 1-1. PSL 4929A and PSL 4929B for AFP 1-2.)

- No single failure or inadvertent actuation of any single device will cause the automatic transfer of the auxiliary feedwater pump suction. The automatic transfer requires two (2) out of two (2) actuation of the low pressure switches.

- Barring the supposition of multiple or common mode failure of the pressure switches, actuation of the automatic transfer of the auxiliary feedwater pump 1-1 suction was caused by a real or artificial sensing of low pressure by PSL 4928A and PSL 4928B.

Investigation of June 9 and previous documented auxiliary feed pump suction automatic transfer from condensate storage tanks to the service water system has shown:

- The automatic transfer has occurred four (4) times. Three (3) times on train 1 and once on train 2.
- All transfers occurred after the addition of strainer S257.
- All transfers occurred during or shortly after a large auxiliary feedwater flow or auxiliary feedwater pump turbine speed change.

C. Significance of Findings

Investigations have shown that the automatic transfer of the auxiliary feedwater pump suction was not due to a mechanical or electrical malfunction of PSL 4928A or PSL 4928B. PSL 4928A and PSL 4928B are mechanically and electrically independent. An automatic transfer of the auxiliary feedwater pump suction caused by a malfunction of PSL 4928A and PSL 4928B would require both to fail at the same time. Therefore, a transfer of the auxiliary feedwater pump suction by a malfunction of PSL 4928A and PSL 4928B is not credible.

Review of historical data has shown the automatic transfers of auxiliary feedwater pump suction have occurred after the installation of strainer S257.

Review of June 9 transient and historical data has shown the automatic transfer of the auxiliary feedwater pump suction has occurred during or shortly after large flow changes in the auxiliary feedwater pump suction header.

Analyses have been performed which indicate that the larger than 3
originally specified pressure drop across strainer S257 results
in a lower suction pressure such that the system responds to
momentary pressure fluctuations (e.g., due to pump speed changes)
that would not have occurred prior to the strainer installation.

IV. RESULTS/CONCLUSIONS OF FINDINGS

A. Direct and Root Causes

Investigation and analysis have found evidence that automatic transfer of the auxiliary feedwater pump suction resulted 3
because the available suction pressure in the auxiliary feedwater pump suction header is less than intended by design.

B. Disproved Hypotheses

Hypothesis #1: Suction header pressure switches PSL 4928A and PSL 4928B setpoints are out of specification. Hypothesis 1 was disproved by MWO 1-85-2130-00. Both PSL 4928A and PSL 9428B setpoints were found to be within tolerance.

Hypothesis #2: The low suction pressure alarm pressure switch PSL 503 is out of specification and failed to alarm on an actual low suction pressure condition. Hypothesis 2 was disproved by MWO 1-85-2130-00. PSL 503 setpoint was found to be within tolerance.

Hypothesis #3: Pressure switches PSL 4928A and PSL 4928B were inadvertently actuated by vibration. Hypothesis 3 was disproved by vibration analysis. Actuation by vibration is not credible due to the indepen-

dent mounting of the switches, and both switches are required for the automatic transfer.

Hypothesis #4: Momentary loss of power to motor operated valves AF 786 and SW 1382 and their control circuits. Hypothesis 4 was disproved by review of the control circuit diagram. Upon loss of power to AF 786 and SW 1382 or their controls, the valves will not automatically open or close, but remain in their initial position.

Hypothesis #5: Operators may have manually transferred suction supply to service water after seeing the low suction pressure alarm. Hypothesis 5 was disproved by discussions with the operator on duty and reviewing log entries. There is no evidence to support this hypothesis. Also inadvertent manual actuation of the valves would not cause the automatic transfer alarms to occur.

Hypothesis #6: Inlet strainer S201 was clogged during the transient and caused inadvertent transfer of auxiliary feedpump #1 suction transfer. Hypothesis 6 was disproved by MWO 1-85-2146-00 and by review of the piping isometrics. MWO 1-85-2146-00 checked the strainer and found it clear. The piping isometrics show that PSL 4928A

and PSL 4928B are located upstream of the strainer S201 and would not respond to the pressure drop caused by a clogged strainer.

C. New Hypotheses

Based on investigation, the following hypothesis has been developed.

Hypothesis 7: Hydraulic characteristics of the auxiliary feedwater pump suction header may cause a momentary suction pressure drop below the setpoint of PSL 4928A and PSL 4928B, causing the automatic transfer of the auxiliary feedwater pump suction from the condensate storage tank to the service water system.

V. PLANNED ADDITIONAL ACTIONS

Hypothesis 7 is to be investigated.

VI. TECHNICAL JUSTIFICATION OF FINDINGS

A review of data associated with the June 9, 1985 automatic transfer and previous transfers revealed that: 3

1. They all occurred after the installation of strainer S257.

2. They occurred during or shortly after large flow changes in the auxiliary feedwater pump suction header. 3

Analyses have been performed which indicate that the larger than originally specified pressure drop across strainer S257 results in a lower suction pressure such that the system responds to momentary pressure fluctuations (e.g., due to pump speed changes) that would not have occurred prior to the strainer installation.

The pressure switches PSL 4928A and PSL 4928B can respond to short duration low pressure conditions.

The conclusion that the transfer is cuased by the less than intended suction pressure available in the auxiliary feedwater pump suction header is justified.

VII. <u>SPECIFIC CORRECTIVE ACTION</u>

A. <u>Required Corrective Action</u>

<u>The following are the proposed corrective actions</u>. One, all, or a combination thereof are expected to be required to correct this automatic suction transfer issue 3

- Lower the current setpoints for PSL 4928A, PSL 4928B, PSL 4929A and PSL 4929B. The actual setpoint is to be determined by Mode 3 testing. Analysis has shown pressure drops

associated with the strainer S257 may be making the pressure switches respond to suction pressure fluctuations. 3
Lowering the setpoint would increase the margin between the actuation of the transfer of the auxiliary feedwater pump suction and system hydraulic characteristics.

- Install a time delay in the circuit for the automatic transfer of the auxiliary feedwater pump suction. The time delay would prevent the automatic transfer of the auxiliary feedwater pump suction due to short term pressure fluctuations, but would provide the transfer upon authentic loss of suction supply.

- Provide a coarser mesh strainer in S257. All automatic transfers of the auxiliary feedwater pumps have occurred after the installation of S257. Analysis has shown, S257 produces a sizeable pressure drop. Making the strainer coarser will reduce the pressure drop on the suction of the auxiliary feedwater pumps, making the switches less susceptible to pressure fluctuations.

- Remove the strainers S201 and S206. The strainers may not be required due to strainer S257.

B. <u>Additional Planned Action</u>

None at this time.

VIII. GENERIC IMPLICATIONS AND CORRECTIVE ACTIONS

At this time, generic implications are under investigation and will be reported at a later date.

sm e/17

AUXILIARY FEEDWATER PUMP SUCTION

SCHEMATIC

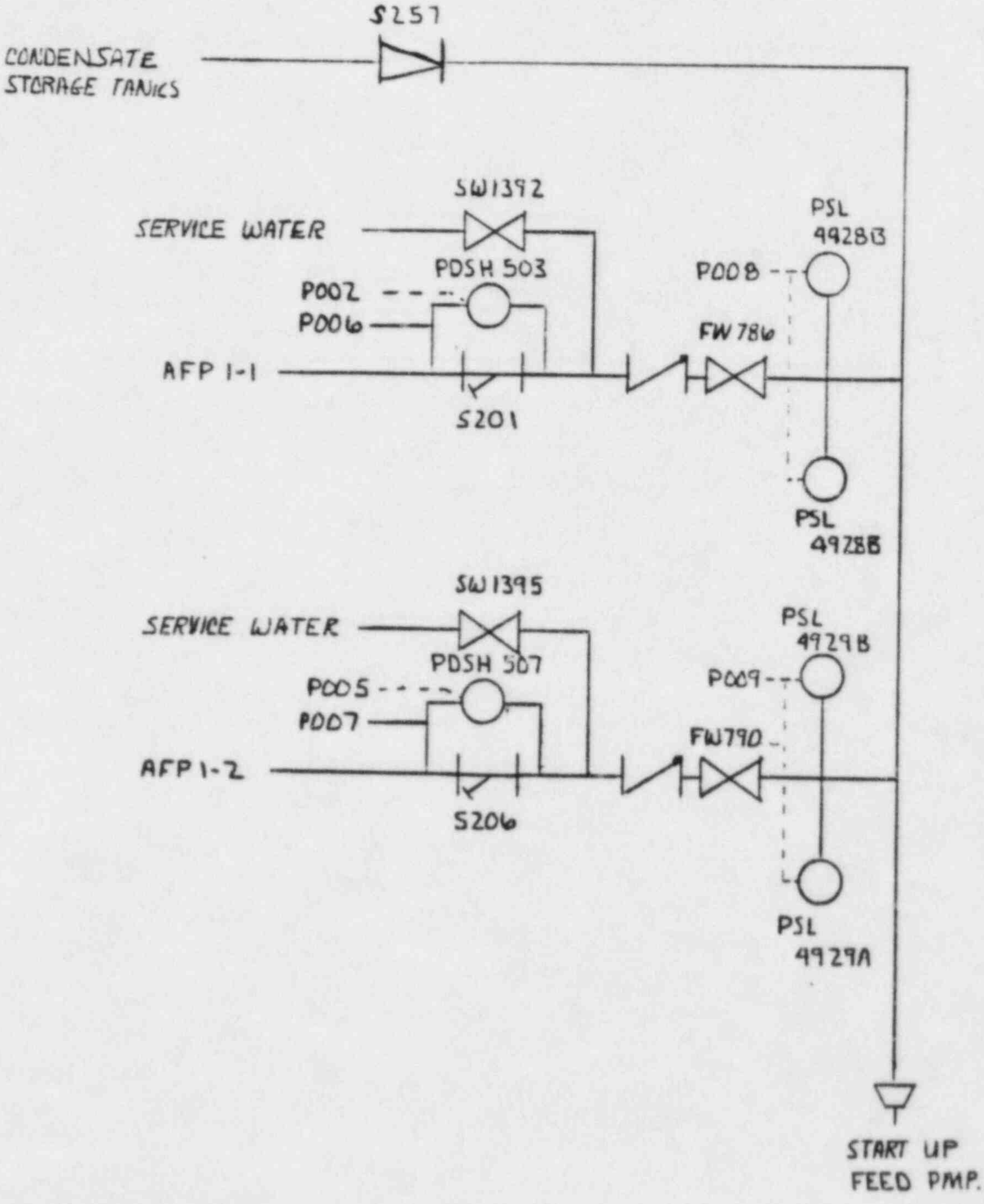

FIGURE 1

PRELIMINARY FINDINGS, CORRECTIVE ACTIONS AND GENERIC IMPLICATIONS REPORT

TITLE: TOLEDO EDISON - MAIN STEAM SYSTEM VALVE MS-106

REPORT BY: NEAL BONNER (TED)
ROBERT C. ELFSTROM (BABCOCK & WILCOX)

PLAN NO. 27

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE
0	8/15/85	Initial Issue	N. Bonner R. Elfstrom	L. Grime
1	8/20/85	Preliminary Corrective Actions Added	N. Bonner R. Elfstrom	L. Grime
2	8/29/85	Testing Clarification and Heading Change	N. Bonner R. Elfstrom	L. Grime
3	9/9/85	General Update	J. Wood	B. Beyer [handwritten initials]

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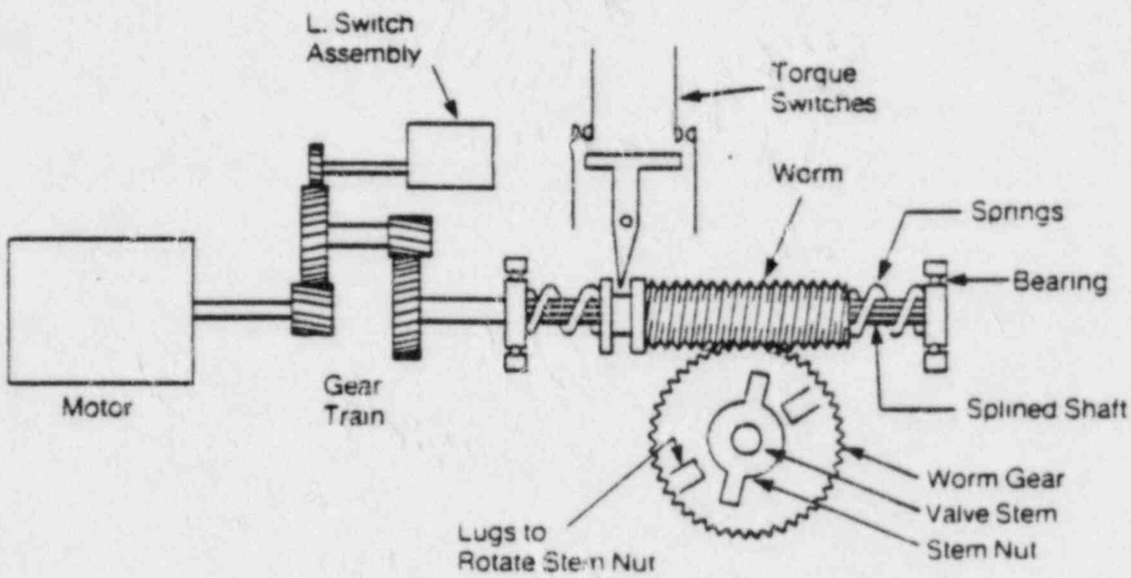
I. ISSUE/CONCERN

During the June 9, 1985 reactor trip, the Main Steam Isolation Valve MS-106 to turbine driven Auxiliary Feed Pump Turbine (AFPT) 1-1 received an open signal from the Steam and Feedwater Rupture Control System (SFRCS). Subsequently, Control Room operator action replaced the open signal to MS-106 with a close signal. The proper response of MS-106 to this initiation sequence would have been to go fully open; and once fully open, to return to the closed position.

The indicated operation, however, was for the valve to leave its closed position, indicate it was mid-positioned, then return closed. Position indicating data shows that the open/close sequence occurred in approximately 30% of the time expected for the valve to stroke full open, then stroke full closed.

II. BASIC PRINCIPLES OF OPERATION OF MOTOR ACTUATOR



The motor rotates the worm through a gear train. The worm gear rotates the stem nut, which raises or lowers the threaded valve stem. When the worm gear can no longer turn (valve closed, open, or obstructed), the worm then moves axially along its splined shaft compressing a Belleville spring pack. The axial movement operates the torque switch and stops the motor. The torque setting is related directly to the amount of spring pack compression. When the motor is reversed, a loss of motion must be taken up until the worm gear lugs engage the stem nut. This motion permits the motor to reach full speed while unloaded, and then apply a hammer blow to the valve stem

to unseat the valve. The limit assembly is directly driven by the gear train and can be adjusted to operate at any point of valve travel.

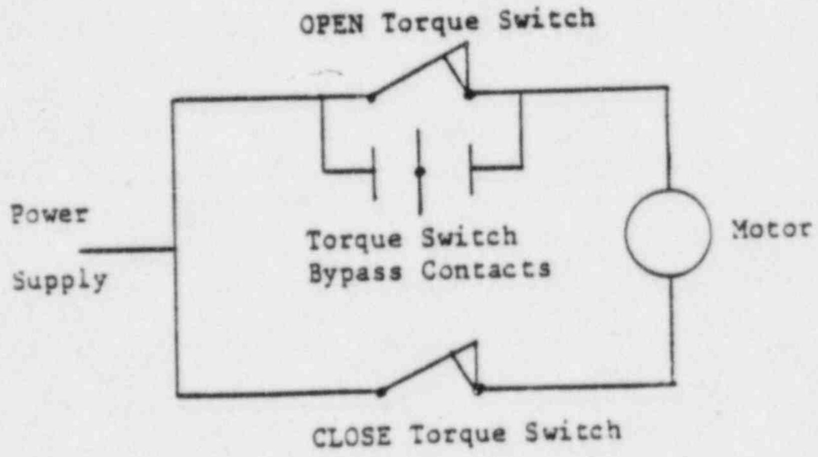
The torque switch assembly basically performs the following functions:

1. It deenergizes the motor in rising stem valves when the valve seats in the closing direction.

2. It protects against mechanical overloads anywhere between full open and full closed position of the valve, except when bypassed in the opening direction.

3. In the opening direction, the torque switch is wired in series with the geared limit switch, and as such, acts as backup to prevent damage to the valve's back seat.

A simplified electrical schematic of the torque switch contacts is shown below:



During the opening sequence of wedge type gate or globe valves, such as MS-106, a high torque is required to unseat the valve disc. Typically, this high torque is required for 50 to 2000 milliseconds, after which torque requirements to continue opening the valve drop by 60% to 80%. Contacts on the geared limit switch bypass the "open" torque switch during this "high torque" period to prevent torque switch actuation from stopping valve motion. After the valve is unseated, this bypass opens, returning the torque switch to the circuit. This sequence allows the actuator to deliver the high torque necessary to unseat the valve, while providing conservative mechanical overload protection during the majority of the valve travel.

III. SUMMARY OF TROUBLESHOOTING AND INVESTIGATION

A. Field Actions Performed

1. Maintenance Work Order 1-85-2105-00 was written to test and inspect the valve MS-106 and its starter D135.

2. A visual inspection was made of the MS-106 valve and operator. There were no significant deficiencies noted.

3. The torque switch was verified to be set in accordance with Drawing E-15.

4. The wiring of the electrical compartment for MS-106 was checked against the associated drawing. Several deficiencies were noted:

   - The wire designated as CL1 of limit switch contact #7 was loose. This wire provides connection for the computer indication for valve closed/not closed alarm. This connection was "wiggled" to determine if it would have given a false indication to the computer. The alarm did not come and go as this was done.

   - Connection jumpers for the compartment space heaters were not connected in accordance with the wiring diagram. The manner in which the heaters were connected was electrically correct and would not have interfered with the operation of the valve or the heaters.

5. A wiring check of the starter D135 in Motor Control Center D1NA was performed using the associated wiring drawings. Several deficiencies were noted:

   - The line side interconnecting jumpers for the open and close motor contactors were not installed in accordance with the Westinghouse internal wiring drawings. Comparing the wiring with the Bechtel elementary diagram, it was determined that the starter contactors would still electrically operate properly.

   - The wiring check of the coil connections to the starter contactors revealed interconnecting jumpers not installed in accordance with the Westinghouse internal wiring diagrams. Comparing the wiring with the Bechtel elementary diagram, it was determined that the starter contactors would still electrically operate properly.

   - Westinghouse internal wiring connections to terminal block points 28, 29, 30, and 31 were lifted. These wires were traced to unused auxiliary contacts on one of the starter contactors. These internal wires were

apparently lifted to accommodate external wiring required by the Bechtel wiring diagram. No drawing update was performed to reflect this change. Since these auxiliary contacts are not required for the electrical operation of this starter, there was no impact on the operation of this starter.

- The four (4) control circuit fuses were checked for proper amperage rating. One (1) of the four was found to have a 15 amp rating. The remaining three (3) fuses were of the proper rating of 10 amps. This would not have affected the opening or closing time of the valve.

- One set of unused (spare) auxiliary contacts on one of the starter contactors was mislabeled. This was determined by tracing out the wires to the respective terminal block points. Since the contacts were spare, this would not have affected the operation of this starter.

6. A wiring check, calibration, and functional operation check of PSL4930A was performed. PSL4930A is a loss of suction pressure switch (for Auxiliary Feed Pump 1) which provides an interlock with the valve control circuit for MS-106. These checks revealed no discrepancies either in the way the pressure switch was wired or the way the switch operated. This would not have affected the operation of the valve during the June 9, 1985 transient.

7. A wiring check of cable 1CD135G in C5762A was performed. This cable provides SFRCS contacts to the control circuit of MS-106. No discrepancies were found between the cable wiring and the connection diagram.

8. Testing of MS-106 was performed utilizing Davis-Besse procedures and MOVATS (Motor Operated Valve Analysis and Test System). This equipment is a totally portable system designed for field use. This system is capable of acquiring, storing, and analyzing the following critical valve, operator, control circuit, and motor parameters during actual valve operation:

   Actual valve stem thrust
   Time of actuation of all control switches
   Dynamic motor current
   Actual operator output torque

   The following testing was performed:

   a. With no differential pressure across the valve seat, MS-106 opened successfully. However, the limit switch bypass opened prior to valve fully unseating. Additionally, a gap in the spring pack caused the torque |3

switch to trip in the closing direction at a lower thrust value than its setting would normally produce.

b. Based on analysis of the first MOVATS testing, there were indications that MS-106 never fully unseated. To test this hypothesis, MOVATS testing was again performed under the following conditions: |3

To prevent the valve from unseating, a temporary restraint was located in such a manner as to limit stem movement. Restraint was such that the limit switch would trip but the valve would not be fully unseated.

Upon initiation of the open signal, the valve operator opened the limit switch contacts placing the torque switch in the circuit and sending a valve "not closed" signal to the computer. Upon encountering the restraint, the valve operator deenergized due to torque switch actuation. The spring pack then relaxed allowing the torque switch contacts to reclose and reenergize the operator, which deenergized again as the torque switch actuated. This evolution continued until at 4.0 seconds after the original open signal, a closed signal was initiated.

The next torque switch trip in the open direction allowed the closed circuit to energize, and the valve attempted to reverse the direction of the stem. The gap in the spring pack, resulting in a low closed thrust value, allowed the torque switch to trip prior to the limit switch sending a "closed" signal, so the closed signal was sealed in. When the spring pack relaxed, the operator reenergized in the closed direction and continued this cycle until the stem moved enough to allow the limit switch to reset and send a "valve closed" signal to the computer. This sequence took approximately 9 seconds from open initiation to valve closed indication.

B. Analysis Performed

Calculations have been performed to verify that the motor horsepower and the actuator sizes are correct.

Stem stresses have been checked to verify that they do not exceed ASME design values.

C. Significance of Findings

1. The second phase of MOVATS testing demonstrated the conditions that show the sequence of events which could give indications of MS-106 stroking open and closed in 19 seconds versus its normal 50 second stroke time. Since this

testing was accomplished with no differential pressure across the valve, the normal operating differential pressure of 1000 psig would increase the seating forces to be overcome and increase the time this sequence would required.

2. A correctly adjusted limit switch bypass contact allows sufficient torque to be applied to the valve to unseat it. With this contact misadjusted, the torque switch was put in the circuit before the valve fully unseated. Successful operation of the valve on previous occasions with normal operating differential pressure across the valve seat indicates that a condition increasing the amount of closing thrust occurred between these previous operations and its response during the June 9, 1985 event.

   The condition of increased closing thrust would result in
   higher unseating forces required which would cause the
   torque switch to actuate, preventing initially the valve 3
   from fully opening on June 9, 1985. The valve later in the
   event was opened successfully, however, this occurred
   with MS 106A already open which could have decreased the
   differential pressure across MS 106. This would have
   reduced the torque requirements and thus would have allowed
   MS 106 to open even with the torque switch in the circuit.

3. This mode of failure of Limitorque operators applies only to wedge-seating gate or globe valves.

IV. RESULTS/CONCLUSIONS OF FINDINGS

A. Direct Cause

1. The limit switch bypass contacts opened prior to the valve unseating. This placed the torque switch back in the circuit during the period when the torque being generated was greater than the torque switch setpoint. This coupled with SFRCS "seal in" signals produced the anomalous indication of a 19 second stroke time.

2. An undetermined event caused the valve to require more unseating force than was previously required during performance of the surveillance procedure. The most probable cause of this increased force would be due to manual closure of the valve. Another probable cause would be foreign material trapped between the disc and seat (rust, scale, etc.). However, if the limit switch bypass contacts had been adjusted correctly, the unseating force would have had to be greater than the unseating force generated by the motor in the locked rotor condition versus unseating force required to activate the torque switch. This would have greatly increased the probability of the valve opening.

B. Root Causes

1. Ambiguous Torrey Pines Information

The procedure, as supplied by Torrey Pines Technology, for setting the position of the bypass contacts gave ambiguous instructions. The procedure called for setting the contacts based on a percentage of valve stem movement. The intent, as indicated by Torrey Pines representatives, of the procedure was to set the contacts based on a percentage of valve disc movement.

C. Disapproved Hypotheses

1. An open in the field circuit to the compound wound dc motor driving the operator of MS-106.

A check of the motor revealed no open field circuit.

2. An open or misoperation in the 42a/0 contact seal in circuit.

A detailed examination of electrical wiring and circuitry revealed no deficiencies that would affect the operation of the seal in circuit. This was further verified during operation of the valve during MOVATS testing.

3. Improper operation of MS-106 valve operator open and close circuitry due to possible wiring errors of SFRCS contacts into valve control circuitry.

A wiring check of cabling from the SFRCS contacts to the control circuitry of MS-106 revealed no discrepancies.

4. Improper operation of pressure switch PSL4930A and/or its auxiliary relay PSL4930X1 which provides a permissive for both the SFRCS open initiation and the 42a/0 seal in contact.

A wiring check, calibration, and functional operation check of PSL4930A were performed. All checks were satisfactory.

5. Improper operation (opening) of the torque switch due to improper setting of the torque switch 33/t0.

The torque switch was found to be set properly in accordance with Drawing E-15.

D. Planned Actions

All other hypotheses have been disproved. Further troubleshooting is planned to provide further substantiation of the hypothesis.

V. TECHNICAL JUSTIFICATION OF FINDINGS

The troubleshooting and investigation evaluated the valve and the operator in detail for causes that would have produced the anomaly observed on June 9, 1985. The Action Plan was developed to investigate any component in the operator that could have caused the observed anomaly. The failure mode of the valve was reproduced by simulation of the conditions using MOVATS testing. The assumption that seating force was increased by either manual operation or foreign material is valid based on all testing and inspections. These activities substantiate that the cause for failure has been correctly identified.

VI. SPECIFIC CORRECTIVE ACTION

Although additional testing and inspections will be performed on 3
MS-106 enough information exists to warrant stating corrective actions and generic implications at this time. Additional corrective action or generic implications subsequently brought to light will be included in the final issue of this report.

A. Required Corrective Action

The following actions have been identified to correct existing deficiencies and prevent future problems with the Limitorque operator on MS-106.

1. Maintenance Procedures

   Issue Maintenance Procedures (MP) to provide proper instructions for corrective maintenance, setting limit and torque switches on type SMB Limitorque valve operators, and to test Limitorque operators using the Motor Operated Valve Analysis and Testing System (MOVATS).

   This action completed on August 7, 1985 upon issue of MP 1410.32, Rev. 3 and MP 1411.05, Rev. 0.

2. Limit Switch Bypass Contacts Setpoint

   Adjust the limit switch bypass setting (closed rotor) of MS-106 to a value of 20% of full stroke in the open direction as measured from the point of valve disc movement. This will ensure the torque switch is not placed in the open circuit prior to the valve fully unseating. Adjustments to be performed per the current revision of MP 1410.32 and MP 1411.05.

   This item to be completed prior to plant start-up.

3. Torque Switch Setpoint

   Adjust the torque switch setpoint in the open direction to the maximum value that will still preclude valve damage,

per FCR 85-134. This setting will act as a back-up to the bypass setting and will give increased confidence of proper valve operation. Adjustments to be performed per the current revision of MP 1410.32 and MP 1411.05.

This item to be completed prior to plant start-up.

B. Additional Planned Action

1. Preventive Maintenance Procedures (PM)

Prepare and issue procedures to provide instruction for preventive maintenance on Limitorque operated valves.

2. Training

Institute a formal training program for personnel performing maintenance on Limitorque valve operators and personnel operating and analyzing data from MOVATS test equipment.

VII. GENERIC IMPLICATIONS

A. Significance

There are 232 Limitorque operated valves at Davis-Besse. Not all of these are wedge-seating. There are generic implications specifically for wedge-seating valves and generic implications that apply to all Limitorque operated valves. The significance and planned actions are separated into these categories.

1. Limitorque Operators on Wedge-Seating Valves

   a. Based on procedures existing at the time, all of these valves can be assumed to need readjustment of the limit switch bypass contacts to ensure proper operation.

   b. Increase the torque switch setpoint to maximum for the open cycle, on all safety-related valves.

2. All Limitorque Operators at Davis-Besse

   a. Adequate procedures for corrective and preventive maintenance apply to all Limitorque operators at Davis-Besse.

   b. All Limitorque valve operators at Davis-Besse require trained personnel for corrective maintenance and testing.

3. There may be other types of valve actuators using the same basic principles as Limitorque operators whose torque-sensing protection could cause similar problems.

B. Planned Actions

1. Limitorque Operators on Wedge-Seating Valves

   a. Adjust the limit switch bypass contacts to a value of 20% of full open stroke as measured from the point of valve disc movement.

   b. For all safety-related valves, set the torque switch to the maximum in the open direction.

2. All Limitorque Operators at Davis-Besse

   a. Issue maintenance procedures to provide instruction for corrective maintenance and testing of Limitorque operators.

   b. Review the preventive maintenance program for Limitorque operated valves.

   c. Institute a formal training program for personnel performing maintenance and testing on Limitorque operated valves.

   d. Provide training to operations personnel on the operating principles and actual operation of Limitorque operators.

3. Investigate other types of valve actuators at Davis-Besse to ascertain whether similar problems could exist.

APPENDIX C.1.2 - RELIABILITY OF SAFETY RELATED VALVES

Presented on the following pages is the Findings, Corrective Actions and Generic Implications Report related to Action Plan Number 12, Auxiliary Feedwater System Valves AF599 and AF608. This report is presented separately, rather than being included in Appendix C.1.1, because it reports actions related to a specific concern identified in the enclosure to NRC's letter of August 14, 1985 (Item II.A.5.).

FINDINGS, CORRECTIVE ACTIONS AND GENERIC IMPLICATIONS REPORT

TITLE: Toledo Edison - Auxiliary Feedwater System Valves AF 599 and AF 608

REPORT BY: James W. Long (TED) PLAN NO.: 12
Robert C. Elfstrom (Babcock & Wilcox)

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE
0	8/11/85	Initial Issue	R. C. Elfstrom J. W. Long	B. R. Beyer
1	8/19/85	Added Corrective Actions	R. C. Elfstrom J. W. Long	L. A. Grime
2	8/29/85	Heading and Title Change	R. C. Elfstrom J. W. Long	L. A. Grime

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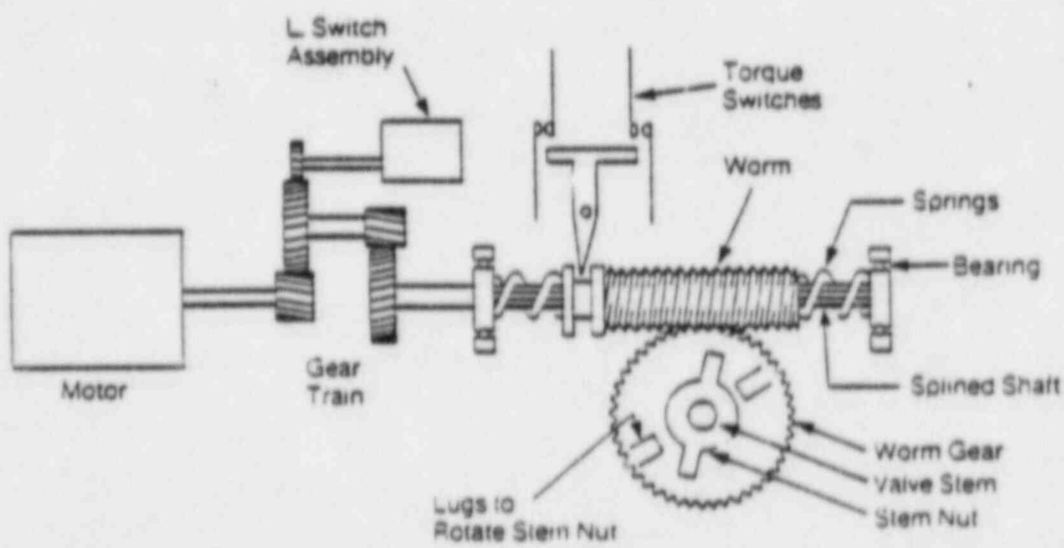
I. Issue/Concern

During the June 9, 1985 reactor trip, Auxiliary Feedwater (AFW) to Steam Generator (SG) motor operated isolation valves, AF 599 and AF 608, closed on a demand from Steam Feedwater Rupture Control System (SFRCS). However, when the SFRCS was reset, both valves failed to re-open on demand. The cause of the failure of the motor operated valves to re-open was determined to be a combination of a high differential pressure and an improperly set torque switch bypass limit switch. This finding was based upon actual tests following the plant transient. An action plan (Plan #12) was formulated to confirm these findings and also to determine any other possible cause which may have contributed to the failure of the valves to re-open. This report provides the summary of troubleshooting and investigations.

II. Basic Principle of Operation of Motor Actuator



The motor rotates the worm through a gear train. The worm gear rotates the stem nut, which raises or lowers the threaded valve stem. When the worm gear can no longer turn (valve closed, open, or

obstructed) the worm then moves axially along its splined shaft compressing a Belleville spring pack. This axial movement operates the torque switch and stops the motor. The torque setting is related directly to the amount of spring pack compression. When the motor is reversed, a loss of motion must be taken up until the worm gear lugs engage the stem nut. This motion permits the motor to reach full speed while unloaded and then apply a hammer blow to the valve stem to unseat the valve. The limit assembly is directly driven by the gear train and can be adjusted to operate at any point of valve travel.

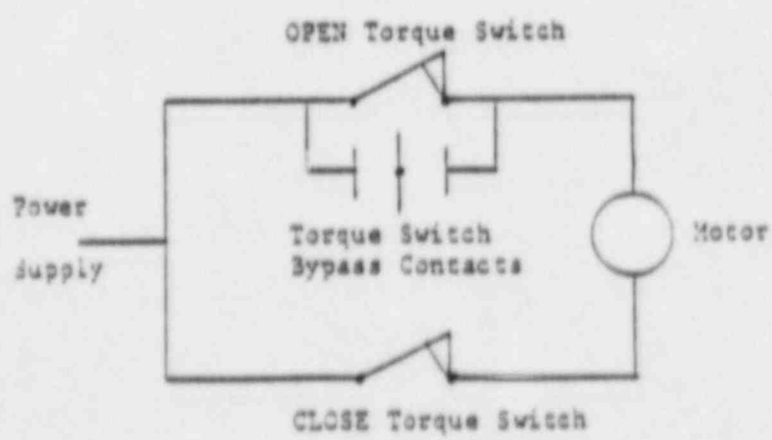
The torque switch assembly basically performs the following functions:

i) It de-energizes the motor in rising stem valves when the valve seats in the closing direction.

ii) It protects against mechanical overloads anywhere between full open and full closed position of the valve, except when bypassed in the opening direction.

iii) In the opening direction the torque switch is wired in series with the geared limit switch and as such acts as backup to prevent damage to the valve's back seat.

A simplified electrical schematic of the torque switch contacts is shown below:



During the opening sequence of wedge type gate or globe valves, such as AF 599 and AF 608, a high torque is required to unseat the valve disc. Typically, this high torque is required for 50 to 2000 milliseconds, after which torque requirements to continue opening the valve drop by 60% to 80%. Contacts on the geared limit switch bypass the "open" torque switch during this "high torque" period, to prevent torque switch actuation from stopping valve motion. After the valve is unseated, this bypass opens, returning the torque switch to the circuit. This sequence allows the actuator to deliver the high torque necessary to unseat the valve while providing conservative mechanical overload protection during the majority of the valve travel.

III. Summary of Troubleshooting and Investigation

A. Field Actions Performed

1. Maintenance Work Orders 1-85-1941-01 & 02 and 1-185-1945-01 & 02 were written calling for inspection and testing of valves AF 599 and AF 608, respectively.

2. A visual inspection was made of the valves and operators. There were no significant deficiencies noted.

3. The torque switch settings were verified to be as specified per FCR No. 84-039 and Torrey Pines Technology study of all Davis-Besse Motor Operated Valves (MOV).

4. Testing of AF 599 and AF 608 was performed utilizing Davis-Besse procedures to examine and analyze valve operability. Additionally, these valves were also tested using MOVATs (Motor Operated Valve Analysis and Test System). This equipment is a totally portable system designed for field use. This system is capable of acquiring, storing, and analyzing the following critical valve, operator, control circuit and motor parameters during actual valve operation:

Actual valve stem thrust
Time of actuation of all control switches
Dynamic motor current
Actual operator output torque

The following tests were performed:

i) Both valves were tested without differential pressure across the valve disc using MOVATS. The results indicated that the "open" torque switch bypass contacts opened prior to actual unseating of the valve. This allowed the torque switch to be re-enabled prematurely, but since the torque switch setting was above the torque required to unseat the valves, they operated satisfactorily.

ii) Both valves were again tested with a differential pressure of 1050 psi across the valve disc without utilizing MOVATS. Each valve was operated three times. Valve AF 599 failed to open in all three operations. In every operation it was observed that the "open" torque switch bypass contacts opened prior to actual unseating of the valve and caused premature torque switch trip. Valve AF 608 failed to open one time out of three tests using 1050 psi differential pressure across the valve disc. Again it was observed that the "open" torques switch bypass contacts opened and placed the torque switch in the circuit prior to the unseating of the valve.

iii) The valves were retested with differential pressure across the valve using MOVATS.

A. AF 599 was tested three times with a differential pressure of 1050 psig across the valve. The valve actuator was de-energized by the torque

switch prior to the valve unseating in all three tests.

B. AF 608 was tested two times with a differential pressure of 1050 psig across the valve. The valve opened successfully in both tests. However, the torque switch trip setting was very close to its trip point.

Two additional tests were performed with a differential pressure of 1095 and 1100 psig, respectively, across the valve. In both tests, the valve actuator was de-energized by the torque switch prior to the valve unseating.

C. As in previous tests, the open limit switch bypass contacts opened and placed the torque switch back in the circuit prior to the valve unseating.

5. The valves were operated manually to determine the setting of the bypass contacts. The contacts on both valves opened prior to the stem moving 5% of the full travel as specified in procedure MP 1410.32 which reflected the information contained in the Torrey Pines study.

6. The spring packs were inspected. The locknut on AF 599 was found to be installed backward and without a setscrew. This discrepancy did not affect operation of the valve. When AF 608 was tested, the preload on the spring pack was found to be slightly lower than expected. This would have caused the valve to torque out at a slightly lower value.

B. Analysis Performed

1. Calculations have been performed to verify that the motor horse power and the actuator sizes are correct.

2. Stem stresses have been checked to verify that they do not exceed ASME design values.

3. The present torque switch settings of both valves were checked and were found to be in accordance with settings required per FCR No. 84-039 dated March 4, 1984 and are reproduced below:

   open dial torque switch = 1.5
   close dial torque switch = 1.0

   The FCR was issued to change the torque switch setting in the closed direction because AF 599 torqued out while attempting to open during an earlier plant shutdown. The new setting was based on design information from a Torrey Pines Technology study of Davis-Besse MOVs.

   A subsequent review of the March 1984 Installation of FCR No. 84-039 discovered that the stem diameter, thread pitch and thread lead information given to Torrey Pines for valves 599 and 608 was incorrect. Field measurements of these dimensions made in June 1984, indicate that the "open" torque switch should have been set at 2.0, using the procedures defined in the Torrey Pines study.

4. Calculations have been performed based on the plant conditions during the event of June 9, 1985, and indicate the actual differential pressure across the valve for AF 599 and AF 608 was higher than 1050 psig.

C. Significance of Findings

1. A correctly adjusted limit switch bypass contact allows sufficient torque to be applied to the valve to unseat it. With this contact misadjusted, the torque switch was put in the circuit before the valve fully unseated. This prematurely tripped the motor on June 9, 1985. With the existing torque switch setting, the valve operator was not allowed to deliver required thrust.

2. Post maintenance and surveillance testing were performed with 0 psig differential pressure across the valve which required much lower unseating torque than required with the differential pressure existing on June 9, 1985. This testing was inadequate to reveal the fact that the limit switch bypass was set improperly and put the torque switch in the circuit prior to valve unseating.

3. This mode of failure of Limitorque operators applies only to wedge-seating gate or glove valves.

IV. Results/Conclusions of Findings

A. Direct Cause

The limit switch bypass contacts opened prior to the valves unseating. This placed the torque switch back in the circuit during the period when the torque generated by the actuator was higher than the torque switch setpoint, causing the actuator to de-energize prior to unseating the valves.

Proper setting of the torque switch trip point and correct adjustment of spring pack pre-load can increase the probability of the valves opening with a misadjusted limit switch bypass, however, this does not appear to have been the case during the June 9, 1985 event.

B. Root Causes

There are several factors that contributed to the failure of valves AF 599 and AF 608 to re-open.

1. Ambiguous Torrey Pines Information

   The procedure as supplied by Torrey Pines Technology for setting the position of the bypass contacts gave ambiguous instructions. The procedure called for setting the contacts based on a percentage of valve stem movement. The intent, as indicated by Torrey Pines representatives, of the procedure was to set the contacts based on a percentage of valve disc movement.

2. Incorrect Dimensional Information Supplied to Torrey Pines

   Torrey Pines Technology conducted a study of Davis-Besse MOVs. They used design information from vendor valve drawings to calculate torque switch settings. The actual measured dimensions were different than the design information supplied to Torrey Pines.

3. Inadequate Test Procedures

   Incorrect adjustment of bypass limit switch was not discovered during post maintenance or surveillance testing due to the lack of any differential pressure across the valve during this testing.

C. Disproved Hypotheses

1. Improper Torque Switch Setting - The torque switches were set correctly in that they were set per the directions of FCR No. 84-039 and the Torrey Pines study. However, these

settings were not correct for the actual dimensions of valves AF 599 and AF 608.

2. Wrong or Improperly Adjusted Spring Pack - Both spring packs were verified to have the correct size and number of washers. The spring pack shoulder nut installed backwards on AF 599 did not contribute to the failure of AF 599. The spring pack on AF 608 was slightly out of adjustment, but was not a direct cause of the failure of the valve to open.

3. Failure of Motor Brake to Release When Energized or Engage When Deenergized - Brake operation was observed on both valves and both brakes were found to be operating correctly.

4. Improper Torque Switch Installation - Both torque switches were verified to be installed correctly.

5. Valve Operator Capability to Handle High Differential Pressure - As stated earlier, both valves were tested with a differential pressure of 1050 psi across the valve seat. Even though they failed to open against this differential pressure, the reason for the failure was found to be incorrect setting of the limit switch bypass contact. With the proper switch settings, the valve operators are capable of handling 1050 psi differential pressure.

V. Technical Justification of Findings

The troubleshooting and investigation evaluated the valve and operator in detail for causes that would have prevented the valves from opening. Reports from the Equipment Operators that were dispatched to manually open the valves, indicated that the valves torqued out. The Action Plan was developed to investigate any component in the operator that could have caused the observed anomaly.

The failure of the valves was reproduced by simulating the transient conditions. MOVATS testing and the inspection of the valve operators substantiate that the cause of failure has been correctly identified.

The causes for the anomaly observed on June 9, 1985 associated with AF 599 and AF 608 have been positively established. The equipment should be removed from the freeze list.

VI. Specific Corrective Action

A. Required Corrective Action

The following actions have been identified to correct existing deficiencies and prevent future problems with the Limitorque operators on AF-599 and AF-608.

1. Maintenance Procedures

Issue Maintenance Procedures (MP) to provide proper instructions for corrective maintenance, for setting limit and torque switches on type SMB Limitorque valve operators, and to test Limitorque operators using the Motor Operated Valve Analysis and Testing System (MOVATS).

This action was completed on August 7, 1985 upon issue of MP 1410.32, Rev. 3 and MP 1411.05, Rev. 0.

2. Limit Switch Bypass Contacts Setpoint

Adjust the limit switch bypass setting (closed rotor) of AF 599 and AF 608 to a value of 20% of full stroke in the open direction as measured from the point of valve disc movement. This will ensure the torque switch is not placed in the open circuit prior to the valve fully unseating. Adjustments to be performed per the current revision of MP 1410.32 and MP 1411.05.

This item to be complete prior to plant Mode 3.

3. Torque Switch Setpoint

Adjust the torque switch setpoint in the open direction to the maximum value that will still preclude valve damage, per FCR 85-134. This setting will act as a back-up to the bypass setting and will give increased confidence of proper valve operation. Adjustments to be performed per the current revision of MP 1410.32 and MP 1411.05.

This item to be completed prior to plant Mode 3.

4. Verification of Valve Data Used for Stress Calculations

Verify that valve data and measurements used for stress and unseating torque calculations are correct based on field measurements of valve dimensions used in calculations.

This action was completed July 7, 1985.

5. Valve Operator Testing

Verify the adequacy of limit switch and torque switch adjustments during valve operation. This will be accomplished by testing AF 599 and AF 608 with a differential pressure of 1050 psig across the valve, using the current revision of MP 1410.32 testing of Limitorque motor operated valves using MOVATS.

This item to be completed prior to plant Mode 3.

6. Differential Pressure

Review system design and operating parameters to ensure that a design differential pressure of 1050 psig is

adequate to ensure proper operation of AF 599 and AF 608 upon activation by a Steam Feedwater Rupture Control System (SFRCS) signal.

This item to be completed prior to plant Mode 3.

B. Additional Planned Action

1. Preventive Maintenance Procedures (PM)

   Prepare and issue procedures to provide instructions for preventive maintenance on Limitorque operated valves.

2. Review of Surveillance and Post-Maintenance Testing Procedures

   Review surveillance and post-maintenance test procedures to determine if this testing or portions thereof can be performed at expected operational differential pressures.

3. Training

   Institute a formal training program for personnel performing maintenance on Limitorque valve operators and personnel operating and analyzing data from MOVATS test equipment.

4. Maintenance Procedures

   Issue corrective maintenance procedures for type SMC Limitorque operators.

VII. Generic Implications

A. Significance

There are 232 Limitorque operated valves at Davis-Besse. Not all of these are wedge-seating. There are generic implications specifically for wedge-seating valves and generic implications that apply to all Limitorque operated valves. The significance and planned actions are separated into these categories.

1. Limitorque Operators on Wedge-Seating Valves

   a. Based on procedures existing at the time, all of these valves can be assumed to need readjustment of the limit switch bypass contacts to ensure proper operation.

   b. All safety-related valves need to have the torque switch setpoint increased to maximum for the open cycle.

2. All Limitorque Operators at Davis-Besse

   a. There may be additional cases of vendor drawings not reflecting as-built dimension which can produce incorrect values for settings of torque switches.

   b. Adequate procedures for corrective and preventive maintenance apply to all Limitorque operators at Davis-Besse.

   c. There may be other cases where post maintenance and surveillance testing does not adequately ensure proper valve operation under operating conditions.

d. There may be other cases where a review of design differential pressure versus operating pressure may be required.

e. Adequate training for personnel engaged in maintenance and testing of Limitorque operators is required for all Limitorque operators at Davis-Besse.

3. There may be other types of valve actuators using the same basic principles as Limitorque operators whose torque-sensing protection could cause similar problems.

B. Planned Actions

1. Limitorque Operators on Wedge-Seating Valves

a. Adjust the limit switch bypass contacts to a value of 20% of full open stroke as measured from the point of valve disc movement.

b. For all safety-related valves, set the torque switch to the maximum in the open direction.

2. All Limitorque Operated Valves at Davis-Besse

a. Issue maintenance procedures to provide instructions for corrective maintenance and testing of all Limitorque operators at Davis-Besse.

b. Verify that calculations used in adjusting Limitorque operator torque switches are correct based on field measurements of valve dimensions used in calculations.

c. Review the preventive maintenance program for Limitorque operated valves.

d. Review post-maintenance testing and surveillance testing procedures to ensure they reflect the operational requirements of the operator where possible.

e. Institute a formal training program for personnel performing maintenance and testing on Limitorque operated valves.

3. Investigate other types of valve actuators at Davis-Besse to ascertain whether similar problems could exist.

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APPENDIX C.1.3 - RELIABILITY OF THE PORV

Presented on the following pages is the Findings, Corrective Actions and Generic Implications Report related to Action Plan Number 10, Pilot Operated Relief Valve (PORV) Operation. This report is presented separately, rather than being included in Appendix C.1.1, because it reports actions related to a specific concern identified in the enclosure to NRC's letter of August 14, 1985 (Item II.A.8.)

FINDINGS, CORRECTIVE ACTIONS AND GENERIC IMPLICATIONS

TITLE: TOLEDO EDISON - PILOT OPERATED RELIEF VALVE (PORV) OPERATION-

REPORT BY: TOM ISLEY (TED)
WM. McCURDY (MPR ASSOC.)

PLAN NO. 10

REV	DATE	REASON FOR REVISION	WRITTEN BY	APPROVED BY
0	8/6/85	Initial Issue	T. Isley W. McCurdy	B. Beyer
1	8/17/85	Added Corrective Actions	T. Isley W. McCurdy	L. Grime
2	8/23 85	Failure of PORV to Pass Leakage Test	M. Foust	L. O. Grime

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FIGURES

I. ISSUE/CONCERN

During the transient on 6/9/85, the PORV cycled three (3) times. The first time the PORV opened for 3 seconds and then closed at the proper setpoint. The second time the PORV opened at the proper setpoint for 3 seconds and then closed approximately 25 psi below the required setpoint. The third time the valve opened at the proper setpoint but did not reseat at the proper pressure. The operator manually closed the PORV block valve. RCS pressure stopped decreasing at approximately 2075 PSIG. The block valve was reopened 2 min. 13 sec. later and the PORV appeared to hold RC pressure. When the PORV failed to close, the operator noticed that the close light was lit indicating the control circuit worked properly, deenergizing the PORV solenoid.

It should be noted the PORV block valve stroke time is approximately nine (9) seconds. The acoustical monitor indicated that flow stopped in approximately seven (7) seconds after the block valve started to move to the close position. The exact time at which flow stopped is uncertain because the acoustical monitors are not designed to indicate accurately at low flow rates. Therefore, it cannot be positively identified if the PORV reset (at approximately 300 psi below the required setpoint) or the block valve closed which stopped the flow through the PORV.

II. BASIC PRINCIPLE OF OPERATION

A. PORV Location and Function

The pilot-operated relief valve (PORV) and its associated upstream block valve are connected to the top of the reactor coolant system pressurizer by way of a section of inlet piping. This inlet piping is configured such that it provides a loop seal which contains water (at a temperature of approximately 450°F) during normal reactor operation.

The PORV is a Crosby Style HPV-SN pressure relief valve which is opened or closed by a solenoid-actuated pilot valve. The controls for the PORV provide for automatic or manual operation of the valve. To open the PORV, a control relay is energized which in turn energizes the PORV solenoid. In automatic operation, the bistable in the reactor coolant pressure channel closes one set of contacts above the high pressure setpoint (2425 psig) and closes another set of contacts below the low pressure setpoint (2375 psig). When the high pressure setpoint is reached, the control relay is energized and an electrical seal-in circuit is energized. When the low pressure setpoint is reached, an auxiliary relay is actuated which in turn interrupts the seal-in circuit.

An acoustic monitor is provided to give an indication of the flow rate through the PORV. This monitor consists of redundant accelerometer transducers which provide signals to drive the PORV position meter on the post-accident monitoring (PAM) panel and to drive the PORV open/closed lights on the PAM panel. This latter circuit is adjusted such that the PORV open light is energized if the signal magnitude is greater than 22% of the signal magnitude at full valve flow. In addition, an indication of PORV solenoid position is provided by open/closed lights on the PORV control panel. These lights are controlled by a limit switch which is mounted on the PORV solenoid and senses the position of the solenoid plunger.

B. Valve Construction

1. Figure 1 is an illustration of the Crosby Style HPV-SN Pressure Relief Valve. Part numbers in parenthesis in the following refer to parts in Figure 1.

2. Inside the main valve body (1) is housed the lower portion of the nozzle (2), disc (3), guide (5) and spring (4).

3. The pilot valve body is a part of the main valve body (1). The nozzle (15) is retained between the pilot valve body (1) and the bonnet (20) by the bonnet studs (12) and nuts (13).

4. Housed in the nozzle (15) and bonnet (20) is the disc (14), spring (21), spring washer (23) and retaining ring (22). Also contained within the bonnet by the bellows top adapter (18) is the bellows (17) and the disc actuator (19).

5. Attached to the main valve body (1) by the bracket studs (27) and nuts (26) is the solenoid bracket (28), to which the solenoid (35) and solenoid cover (38) is attached.

6. The adjusting bolt (31) is threaded into the lever (33) and held in place by the adjusting bolt lock nut (32). The link (29) connects the lever (33) and solenoid (35).

C. <u>Valve Operation (See Figure 1)</u>

1. Under normal operating conditions, the Inlet Port "A", the Cavities "B" and "C", and the Pilot Valve Connecting Cavity "D" are at the same fluid pressure. The disc (main valve) (3) seats against the nozzle (2) seat since the pressure in Cavity "C" is greater than the pressure in Discharge Port "E". The disc (pilot valve) (14) seats against the nozzle (pilot valve) (15) seat since the pressure in the Connecting Cavity "D" is greater than the pressure in the Pilot Valve Discharge Port "F".

   1.1 When the solenoid (35) is energized, the solenoid plunger actuates the lever (solenoid) (33) causing the adjusting bolt (31) to strike the end of the disc actuator (pilot valve) (19). This action unseats the disc (pilot valve) (14) and allows steam to pass

through the vent holes in the nozzle (pilot valve) (15) to the Pilot Valve Discharge Port "F".

1.2 When the pilot valve opens, pressure in Cavity "C" is reduced and the greater pressure in Cavity "B" causes the disc (main valve) (3) to open.

1.3 When the solenoid (35) is deenergized, the solenoid plunger returns to the original free position. The pilot valve closes causing pressure to again build up in Cavities "D" and "C", thereby closing the disc (main valve) (3).

III. SUMMARY OF TROUBLESHOOTING AND INVESTIGATION

A. Field Actions Performed

1. Valve Inspections (MWO No. 1-85-2049-00) A visual inspection of the PORV and associated linkage was performed in order to check for broken or missing parts, boric acid buildup, or other abnormalities. This inspection was performed by Davis-Besse Maintenance and Crosby Field Service personnel. The results of this inspection are as follows. None of the inspection results indicated any abnormalities which could have any effect on the operability of the PORV.

   a. Three (3) of the eight (8) nuts on the PORV inlet flange were found to be hand-tight (not torqued to the specified preload). However, no evidence of leakage was found from a visual examination. Also, the valve is adequately supported with no pre-load on the inlet flange nuts, and the lack of pre-load would have no effect on valve operability.

b. The adjusting bolt locking nut was found to be loose (Item 32 in Figure 1). However, the cotter pin holding the adjusting bolt (Item 40 in Figure 1) was in place such that no movement of the adjusting bolt could have occurred.

c. All other inspection results indicated nominal condition.

The PORV was then disassembled and a complete visual, functional, and dimensional inspection of the internal parts was performed using a detailed checklist which was prepared by Crosby personnel. Again, the inspection was performed by Davis-Besse and Crosby Field personnel. The results of this inspection are as follows:

a. Minor steam cutting had occurred on the pilot seat and disc.

b. There were minor wear marks on the guide lands for the main disc.

c. A brown substance (possibly boric acid) was found on the valve body in the vicinity of the pilot valve..

d. A sliver of metal (from flexitallic gasket) and a small gouge was found on the outside edge of the bellows housing gasket surface.

e. All other inspection results indicated normal condition.

2. The PORV failed to pass its leakage test specified in Corrective Action Plan #10-1. Demineralized water was then 2
flushed through the PORV's pilot valve while moving the solenoid lever. The discharge contained foreign material.

The PORV then successfully passed its leakage test. A new hypothesis has been developed to address this failure 2

3. Actuation Circuit Inspections (MWO No. 1-85-2049-01) An inspection of the PORV actuation circuitry was performed by Davis-Besse Maintenance personnel using a detailed check-list. Results of this inspection are as follows. None of the inspection results indicated any abnormalities which could have any effect on the operability of the PORV.

   a. All checks showed proper performance of the control circuits. When checking the actuation circuits, it was noted that the PORV solenoid was actuated before the bistable indicated a trip. However, the difference between energizing the solenoid and the trip indication is only 4 psi, which is not significant.

   b. All other inspection results indicated nominal condition and function of the actuation circuitry.

B. Analysis Performed

Based on a review of the conditions during the PORV actuation transient and discussion with Crosby and Babcock & Wilcox engineering personnel, it was identified that differential expansion of the valve internal parts might occur such that free motion of the pilot and main discs could be impeded. Therefore, an analysis was performed to determine the amount of clearance required between the discs and their guiding surfaces in order to prevent interference from resulting. Note that a valve temperature increase from an initial value of approximately 470°F to close to 650°F could have occurred during the transient. This analysis determined the maximum relative thermal expansion by assuming the temperature of the discs (main or pilot) increased to 650°F while the temperature of the guides was maintained at the initial temperature of 470°F. This

calculation indicated that the measured clearances between the valve disks and their guides were sufficient to accommodate the differential expansions which could have occurred during the valve actuation transient. The measured clearances would be adequate for loop seal temperatures as low as about 300°F. Therefore, it is concluded that sticking of the valve parts as a result of differential thermal expansion did not occur during the actuation transient.

C. Significance Of Findings

Based on the results of the inspections and analyses discussed in Sections III.A. and III.B. above, it is concluded that no mechanical or electrical abnormalities or off-nominal conditions existed in the PORV or its actuation circuitry that would explain its failure to reclose during the June 9, 1985 transient.

IV. RESULTS/CONCLUSIONS OF FINDINGS

A. Direct Cause

Based on the results of the inspections and analyses which were performed of the PORV and its actuation circuitry, it is concluded that the direct cause for the PORV maloperation (failure to reclose) has not been identified. However, it is possible that the following sequence of events occurred:

1. During the extended period since the last valve actuation (on September 1, 1982), foreign material could have accumulated within the internal chambers of the valve. During the PORV actuations in the June 9, 1985 transient, the foreign material could have been transported under the action of the fluid hydraulic forces to critical locations within the valve.

For example, a piece of foreign material could become lodged between the pilot disk and its guiding surfaces or between the pilot disc and its seat, thereby preventing the pilot disc from reseating properly. As a result, the build-up of pressure in the region under the main disc (Cavity "C" in Figure 1) required to seat the main disc would not occur.

2. Eventually, this foreign material could be dislodged as a result of the internal valve fluid forces, permitting the pilot and main valve discs to move to the closed position.

B. Root Cause

Again, the root cause for the PORV maloperation has not been identified.

C. Disproved Hypotheses

Hypotheses listed in the Investigation and Troubleshooting Report which have been disproved by the inspections and analyses are as follows:

1. Hypothesis

The PORV stuck open due to differential expansion of the valve disc and body which caused the valve to fail to close as a result of interference between internal parts.

Finding

Differential thermal expansion of the valve parts could have occurred as a result of non-uniform heating. However, the clearances between the internal moving parts (e.g., between the main disc and its guide and between the pilot disc and its guide) were adequate to accommodate the

maximum differential expansion that could have occurred during the June 9, 1985 transient.

It is noted that in the EPRI Safety and Relief Valve Test Program, two of the PORVs (Dresser and Target Rock) failed to close during a test transient which imposed a large thermal transient on the valves. In both of these cases, interference of internal valve parts as a result of differential thermal expansion was suspected, but post-test examination was not conclusive in identifying this as the cause. However, the Crosby test valve (similar in design to the Davis-Besse PORV) opened and closed on demand during a similar EPRI test.

2. Hypothesis

The valve mechanically malfunctioned causing it to not close during the transient.

Finding

The results of the valve inspection discussed in Section III.A. above indicate the mechanical function of the valve and the condition of the valve parts were nominal.

3. Hypothesis

The solenoid coil linkage could be broken or have corrosion build-up causing faulty operation.

Finding

The results of the valve inspection indicate that the condition of the solenoid coil linkage is normal.

4. Hypothesis

A control circuit malfunction caused the PORV to remain open.

Finding

The results of the PORV actuation circuitry checks discussed in Section III.A. indicate that the function of the actuation circuit is normal.

D. New Hypotheses

The following hypotheses is presented to suggest a reason for the inability of the PORV to pass the criteria of MP 1402.08 (Rev. 3) for leakage: 2

Foreign material was lodged on the seating area of the pilot valve, preventing good seating contact and allowing the valve to leak.

V. TECHNICAL JUSTIFICATION OF FINDINGS

Detailed inspections of the condition and function of the PORV parts and actuation circuitry have been completed. The results of these inspections indicate that the PORV and its actuation circuitry are in normal condition.

As discussed in Section IV.A. above, it is possible that the failure of the PORV to reclose during its third actuation in the June 9, 1985 transient was a result of interference between internal parts caused by the presence of a foreign substance. If this happened, this substance was subsequently dislodged by the fluid hydraulic forces thereby allowing the valve to later reclose. It is noted that relatively close clearances between moving parts is an inherent feature of a valve of this type and that occasional service failures

are expected. Also, it is noted that the failure rate experienced to date with the Davis-Besse PORV (3 failures in 111 actuations) is consistent with the industry-wide failure rate of 0.02 per challenge for this type of valve (see NUREG-0560, Pg. 3-14). Further, it is noted that a block valve is provided upstream of the PORV to permit isolation in the event of a failure of the PORV to close on demand. This block valve was properly used by plant operators to provide isolation of the PORV during the June 9, 1985 transient as well as during previous plant transients (as required).

Therefore, it is concluded that all appropriate troubleshooting and investigative activities necessary to confirm the structural, mechanical, and electrical integrity of the PORV and its actuating circuit are complete. Confirmatory testing to verify the operability of the PORV will be performed prior to startup of Davis-Besse. The nature of these tests as well as future corrective actions to be taken are to be covered in a corrective actions report. Based on completed investigations and planned operability testing, we recommend the PORV be removed from the equipment freeze list, the valve be refurbished as necessary, and reinstalled on the pressurizer.

VI. SPECIFIC CORRECTIVE ACTIONS

A. REQUIRED CORRECTIVE ACTIONS

1. Change in PORV Position Indication

Currently, an acoustic monitor is used to provide indication of the PORV flow rate. This flow indication is provided by PORV open/closed lights and position/flow meter on the PAM panel. The open light is energized if the signal magnitude is greater than 22% of the signal magnitude at full valve flow. In addition, an indication of PORV solenoid position is provided by open/closed lights on the PORV control panel. The concern is that the PORV solenoid could be in the closed position while there is

flow through the PORV as indicated by the acoustic monitor (as occurred during the June 9, 1985 transient). As a result, the plant operator is provided with an ambiguous indication of PORV position. To eliminate this concern, the following modifications will be made.

- Acoustic monitor PORV flow indication lights will be added to the PORV control panel and will be identified as PORV position.

- The PORV solenoid position indicator will be identified as PORV solenoid position indication. 2

- The PORV annunciator will be changed from white to red lighted.

2. Confirmation of Valve Operability

Confirmation of PORV oper-ability will be accomplished by actuating it at reduced and full reactor coolant system pressure. These actuations are identified as follows:

- At Reduced Pressure (Nominally 700 psig) 2

  With a loop seal temperature of about 450-500°F, actuate the PORV eight (8) times. The valve should remain open approximately five (5) seconds during each actuation and the time between actuations should be about thirty (30) seconds.

- At Full Pressure (Nominally 2155 psig)

  With a loop seal temperature of 450-500°F, actuate the PORV three (3) times. The valve should remain open approximately five (5) seconds during each actuation

and the time between actuations should be approximately thirty (30) seconds.

During future plant operation, the PORV will be exercised as follows:

- The PORV will be exercised at reduced pressure during plant shutdowns at the following frequency:

  -- For operating intervals of three (3) months or longer, exercise during each shutdown.

  -- For intervals less than three (3) months, exercising of the PORV is not required unless three (3) months have passed since last shutdown exercise.

  -- If the PORV was actuated in the course of plant operation at a frequency which satisfies the above requirements, additional exercising during plant shutdown is not required.

- The PORV disk movement will be confirmed by exercising the valve while observing the PORV solenoid position and flow indicators.

3. <u>PORV Control Circuit Repair</u>

During the troubleshooting inspections, it was found that the PORV solenoid was actuated before the bistable indicated a trip. To correct this problem, the signal monitor in the PORV control circuit will be replaced.

4. Loose Nuts on the PORV Inlet Flange

The procedure used in torquing the PORV's inlet flange nuts will be reviewed to determine if it is adequate. 2

B. ADDITIONAL PLANNED ACTIONS

A program will be pursued to identify, procure, and evaluate the potential benefits of an alternative PORV. This program will include the following activities:

1. Procurement of Alternative PORV

Candidate alternative PORVs are as follows:

- Crosby HPV-SN

  These PORVs were tested in the EPRI Safety and Relief Valve Test Program and found to perform without failure to open or close on demand under steam and water flow conditions.

- Target Rock Pilot-Operated

  A version of this PORV design was tested in the EPRI Program and found to perform without failure under saturated steam and water flow conditions.

- Garrett Pilot-Operated

  A version of this PORV design was tested in the EPRI Program and found to perform without failure under steam and water flow conditions.

2. Qualification Testing of Alternative PORV

Alternative PORVs will be qualified by testing them under steam and water flow conditions. Test facilities which could be utilized for this testing are as follows:

- Marshall (Duke Power) Facility

  This is one of the facilities which was used in the EPRI Program. Capabilities of this facility are:

  - Repeated valve actuations (unlimited number) with saturated steam flow at 2400 psia.

  - Maximum flow capacity of about 250,000 LB/HR.

- Wyle (NORCO) Facility

  Again, this is one of the facilities which was used in the EPRI Program. Capabilities of this facility are:

  - Few valve actuations with saturated or subcooled water at 2000 - 2400 psia.

  - Maximum flow capacity of about 250,000 LB/HR.

  This facility uses accumulators which are charged prior to a test. As the test proceeds, the accumulator pressures drop from their initial values. Accordingly, the total test duration is dependent on the valve flow capacity.

3. Other Modifications

Investigate other modifications to the PORV or associated piping which could improve the operability of the valve.

VII. GENERIC IMPLICATIONS

There is only a single PORV installed on the pressurizer and there are no valves of similar design in any other Davis-Besse plant systems. Therefore, there are no generic implications resulting from the PORV troubleshooting and investigation findings.

VIII. GENERIC CORRECTIVE ACTIONS

Since there are no generic implications of the PORV troubleshooting and investigation findings as discussed in Section II above, no generic corrective actions are required.

FIGURE 1
ASSEMBLY OF PRESSURMATIC
VALVE STYLE HPV-SN

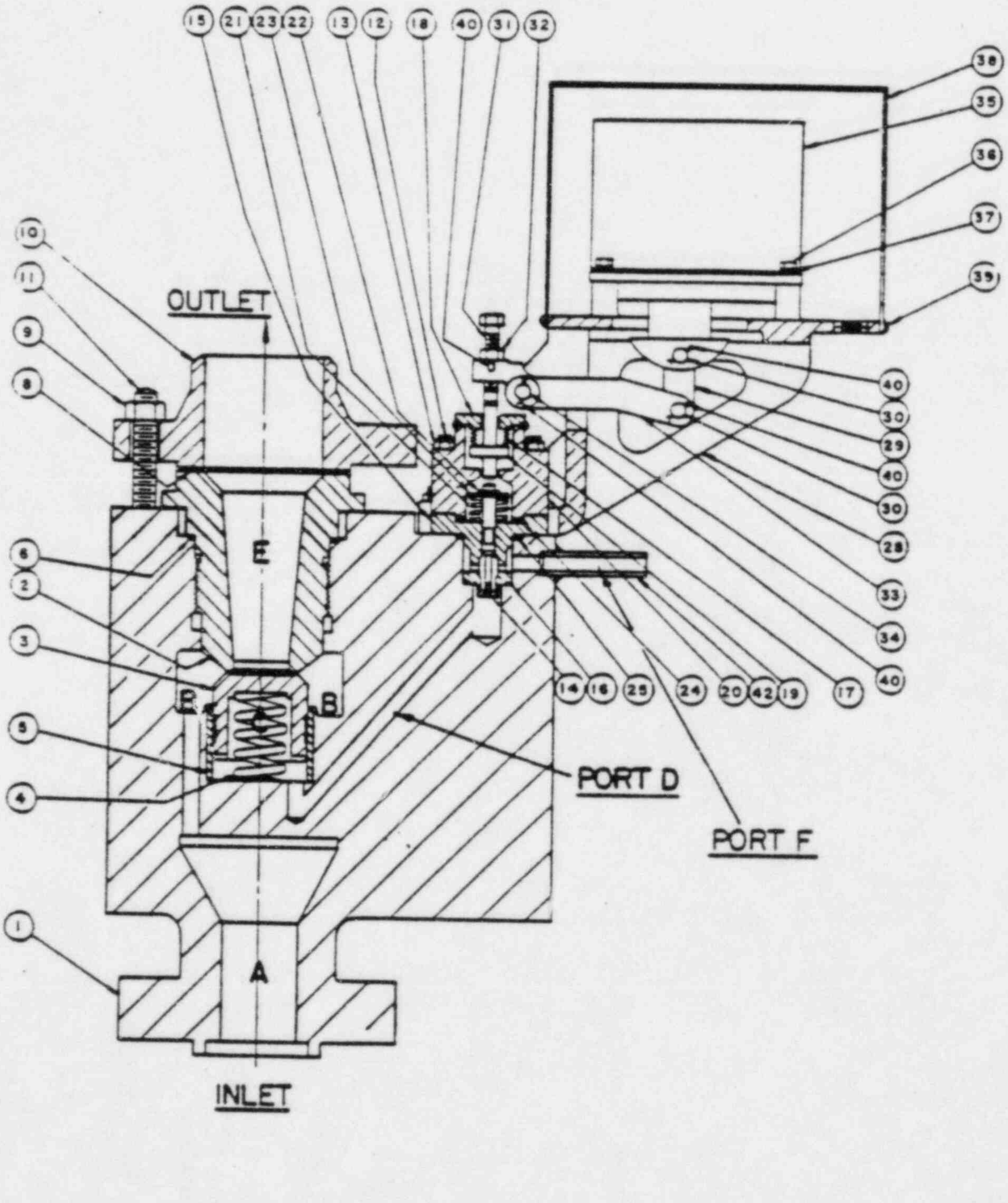


FIG. 1
ASSEMBLY OF PRESSURMATIC
VALVE STYLE HPV-SN

FIGURE 2
LIST OF MATERIALS
STYLE HPV-SN

Pc. No.	Name of Part	Pc. No.	Name of Part
1	Body	22	Retaining Ring
2	Nozzle	23	Spring Washer
3	Disc (Main Valve)	24	Gasket (Pilot Valve Adapter Flange)
4	Disc Spring (Main Valve)		
5	Guide (Main Valve)	25	Gasket (Pilot Valve Nozzle)
6	Seal Ring	26	Nut (Solenoid Bracket)
7	Gasket (Nozzle)	27	Stud (Solenoid Bracket)
8	Outlet Flange Gasket (Not Furnished)	28	Solenoid Bracket
		29	Link (Solenoid)
9	Outlet Flange Nuts	30	Link Pins (Solenoid)
10	Outlet Flange (Not Furnished)	31	Adjusting Bolt
		32	Adjusting Bolt Locknut
11	Outlet Flange Studs	33	Lever (Solenoid)
12	Stud (Pilot Valve)	34	Lever Pin (Solenoid)
13	Nut (Pilot Valve)	35	Solenoid
14	Disc (Pilot Valve)	36	Bolt
15	Nozzle (Pilot Valve)	37	Lockwasher
16	Seal Ring (Pilot Valve)	38	Solenoid Cover
17	Bellows (Pilot Valve)	39	Cover Screw
		40	Cotter Pins
18	Bellows Top Adapter (Pilot Valve)	41	Drain (Main Valve)
19	Disc Actuator (Pilot Valve)	42	Drain & Vent (Pilot Valve)
20	Bonnet (Pilot Valve)	43	Name Plate and Data Plate
21	Spring (Pilot Valve)	44	Drive Screws

APPENDIX C.1.4 - CONFIRMATORY TESTING

Toledo Edison will perform confirmatory testing to demonstrate the successful performance of all equipment which was subjected to corrective actions as a result of TED's investigation of the June 9 event. This testing will be performed as part of the startup from the current outage. The testing in some cases requires the plant at full temperature and pressure (Mode 3), and would involve normal surveillance tests to document operability. In certain cases, however, TED has decided to perform special confirmatory tests in addition to the normal surveillance tests. The specific equipment which will be subjected to special confirmatory testing is listed below:

- Auxiliary Feedwater System Pump Turbines
- Pilot Operated Relief Valve
- Selected Motor Operated Valves
- Atmospheric Vent Valves

In addition to the testing identified above, at power (Mode 1) the Main Feedwater Pump turbines and controls will also be tested.

TED had previously planned Mode 3 testing to determine root-cause failures. This position has changed based upon the success of TED's root-cause finding investigation and corrective action program. This is particularly true for the overspeed of the Auxiliary Feedwater Pump Turbines. Results of our investigation clearly show that condensation in

the cold pipeline and its subsequent passage through the turbine is the primary cause of the overspeed problem. This conclusion is based on other industry experience as well as Davis-Besse specific experience and analytical calculations related to the problem. The number of factors affecting our ability to reproduce the conditions which led to the overspeed conditions makes it likely that reproducing the failure during testing could not be reliably accomplished. In addition, intentionally driving large slugs of condensate at high velocities through the steam piping could result in further hanger piping and component damage. For these reasons, the earlier planned testing will not be performed.

APPENDIX C.2.1 ACTIONS TO IMPROVE DECAY HEAT REMOVAL RELIABILITY

The Decay Heat Removal Task Force review described in section II.C.2 of the Course of Action report resulted in a number of recommended improvements. These recommendations are being evaluated individually to determine whether there are additional factors which must be addressed prior to implementation. Described below are the recommendations which are in the process of being implemented. Detailed confirmatory analyses are being performed where required and will be completed prior to modifying the systems. Approved recommendations which reflect changes to be made to the Steam Feedwater Rupture Control System (SFRCS) are described separately in Appendix C.2.2.

Additional upgrades to the Decay Heat removal capability will continue to be evaluated. Among them are:

- PORV reliability improvements.
- Augmented High Pressure Injection capability, e.g. installation of a high head HPI pump.
- Alternative RCS Pressure reduction devices, e.g. installation of additional PORVs off of the pressurizer code safety valve nozzles.

As viable Decay Heat Removal improvements are identified, they will be implemented.

Actions Relating to Auxiliary Feedwater System Which Will Be Accomplished Prior to Startup

1. Keep the Steam Inlet Lines to the Auxiliary Feedwater Pump Turbines at a Hot and Pressurized Condition

The steam inlet lines to the auxiliary feedwater pump turbines need to be kept hot and pressurized to preclude formation of large amounts of condensate. This condensate is considered to be the cause of the overspeed trips of both auxiliary feedwater pump turbines on June 9, 1985 and of the steam piping hanger support damage experienced previously. Two parallel approaches to maintaining these steam lines hot and pressurized are being pursued in the short term. Both are considered technically achievable; however, the first is the preferred approach. The latter approach would be utilized only if the preferred approach cannot be implemented in the short term. Both of these approaches are summarized below:

a. Install One Remotely Operable Valve in the Steam Inlet Line Near Each Auxiliary Feedwater Pump Turbine with Additional Condensate Drains as necessary

These valves would be opened on a signal from the SFRCS. All four of the existing steam admission valves (MS106, MS106A,

MS107 and MS107A) which are located at a distance from the turbine, would be maintained open during normal plant operation. This will ensure that all steam supply piping is hot and pressurized. The ability to automatically close the appropriate existing steam admission valves individually in the event of a steam line break would be maintained.

b. Continuously Run both Auxiliary Feedwater Pump Turbines

The turbine and pump vendors (Terry Turbine and Byron Jackson, respectively) have concurred that continuous operation of the auxiliary feedwater pump turbines is acceptable from an equipment standpoint. Continuous operation of the auxiliary feedwater pump turbines represents the alternative approach to preventing the rapid formation of condensate during a cold startup.

In both approaches, analyses of the steam inlet lines to the auxiliary feedwater pump turbines to demonstrate acceptability as high energy lines is required. This analysis is in process and necessary changes including pipe whip restraints and jet impingement barriers and environmental qualification upgrades are being identified for implementation prior to restart. Design and material procurement are in process.

2. Replace the Woodward PG-PL Governor on Auxiliary Feedwater Pump Turbine No. 1 with a Woodward PGG Governor

The PG-PL Governor has proven insufficiently reliable in operation. The PGG governor, one of which is currently installed on Auxiliary Feedwater Pump Turbine No. 2 is an improved design and has shown favorable results from test data supplied by Woodward.

3. Revise the Pressure Switch Setpoints for Auto-Transfer to Service Water From The Condensate Storage Tank

The current setpoint of the auxiliary feedwater pumps' suction line pressure switches has resulted in several spurious transfers of the suction source from the condensate storage tank to the service water system. Calculations indicate that the current setpoint (2 psig) is close to the nominal minimum operating pressure in the suction portion of the system. The pressure setpoint needs to be reduced to as low as practical. In addition, a time delay relay will be utilized to further minimize occurrence of a spurious auto-transfer.

4. Remove Control Power From Auxiliary Feedwater Pump Suction Valves FW 786 and FW 790

This modification will preclude spurious closure of these valves which would lead to loss of the preferred water source (condensate storage tank) to the auxiliary feedwater pumps, and could prevent transfer to the safety grade service water source.

5. <u>Provide Coarser Mesh Strainer (S257) in the Suction Line from the Condensate Storage Tank to the Auxiliary Feedwater Pumps</u>

The existing strainer in the common condensate storage tank supply line to the auxiliary feedwater pumps (AFP) creates pressure differentials that contribute to spurious switchovers to the service water supply. The intent of this strainer is to remove debris from the non-safety grade, non-seismic condensate storage tank supply. In consultation with the pump vendor, a coarse strainer size will be determined and the existing strainer will be replaced with this coarser mesh strainer.

6. <u>Procedurally Direct Manual Control of Steam Generator Level Once Automatic Control Has Established a Suitable Level Using Auxiliary Feedwater</u>

This action will formalize by procedure what is generally current practice. The existing water level control system results in intermittent flow to the steam generators and large level swings. Placing the system into manual control state should prevent the intermittent flow to the steam generator which can result in fatigue cycles on the steam generator, and erratic reactor coolant pressure control water supply.

7. <u>Remove AFP Suction Strainer Baskets (S201 and S206)</u>

The strainers in the suction of each Auxiliary Feedwater Pump have the potential to cause unnecessary pump trips. These strainers are redundant to strainers in the condensate storage tank suction line and the service water system. The strainer baskets will be removed following confirmation from the pump vendor that the strainers at the service water pumps are an acceptable size.

8. <u>Align AFP Normal Discharge Valves AF3870 and AF3872 to be Normally Open</u>

These valves currently open on demand for auxiliary feedwater. Maintaining the valves open will reduce the number of automatic actuations required to initiate auxiliary feedwater. Currently installed and redundant check valves will ensure against steam binding of the auxiliary feedwater pumps. This modification will be completed prior to beginning of Cycle 6.

Actions Relating to Auxiliary Feedwater System Which Are Longer Term

1. Remove Interlock on Steam Inlet Valve to the Auxiliary Feedwater Pump Turbine Which Secures Turbine on Low Suction Pressure

Automatically securing an auxiliary feedwater pump turbine on low pump suction pressure is overly protective and may result in unnecessary loss of auxiliary feedwater. Prolonged loss of suction (a few minutes) is acceptable based on vendor (Byron Jackson) correspondence. A low suction pressure alarm will continue to be available to the operator and operator action to secure the pump is considered to be acceptable.

A Technical Specification change will be required to implement this item. A change request will be submitted to NRC in time to support making this change prior to beginning of Cycle 6.

2. Delete Automatic Operation of Steam Generator Auxiliary Feedwater Isolation Valves AF599 and AF608 from the SFRCS

The automatic closure signals for valves AF599 and AF608 will be removed from the SFRCS. This will minimize the probability of complete isolation of AFW from a steam generator. Confirming analyses are in progress to demonstrate that automatic closure of these two valves is not necessary for containment over-pressure protection or for core protection. An open signal from the valve control circuitry will be provided to these valves

to prevent inadvertent closure. Remote manual operation of these valves will be retained in the event a control room operator must close these valves. The change, if found acceptable by the analyses, will be implemented prior to the beginning of Cycle 6.

Action Related to the Auxiliary Steam System:

Provide Turbine Gland Seal and Air Ejector Motive Steam from Both Main Steam Headers

This change will preclude the loss of condenser vacuum and resultant loss of both main feed pumps, in the event of closure of one Main Steam Isolation Valve. This modification will be installed prior to the beginning of Cycle 6.

Actions Related to the Motor-Driven Feed Pump (MDFP)

A new motor-driven feed pump will be installed. Installation of this pump was a previous commitment and is a condition of the Davis-Besse operating license which must be accomplished prior to the beginning of Cycle 6. This activity will be accelerated, and the pump will be installed prior to startup from the present outage. (Note: the existing startup feedwater pump will be retired in place following installation of the MOFP). The new pump will provide flow to the steam generator equal to the flow provided by one of the present steam-driven Auxiliary Feedwater Pumps. The new pump will be located outside the

Auxiliary Feedwater Pump rooms and will be capable of being supplied by either Emergency Diesel Generator following a loss of offsite power. The restrictions which made it impossible to remotely start the present Startup Feedwater Pump (SUFP) from the control room during the June 9 event will therefore not be necessary. The new pump will be capable of being started remotely from the control room, and the concern expressed in item II.A.10 of the enclosure to NRC's August 14, 1985 letter will thus be alleviated. The following specific features and lineups will apply to the new motor-driven feed pump:

1. <u>The Normal Alignment Will Be From the Condensate Storage Tank to the Auxiliary Feedwater System</u>

This will permit the Motor Driven Feed Pump to act as a "backup," diversely powered Auxiliary Feedwater Pump that can be started from the control room. It will thus provide an additional auxiliary feedwater source in the event that the steam driven Auxiliary Feedwater Pumps are not available.

During operation at low power levels (less than approximately 30% full power) the pump discharge will be aligned to the main feedwater system, taking suction from the deaerator storage tanks. At these power levels, steam generator level is maintained at a low level (35") and therefore challenges to AFWS are more frequent. The use of the Motor Driven Feed Pump will provide an improved ability to control level and should reduce the number of actuations of the steam

turbine driven Auxiliary Feedwater Pumps during such operation. Following start-up operations, at approximately 30% power, the MDFP will be re-aligned to feed the Auxiliary Feedwater header, taking suction from the condensate storage tank.

In the event auxiliary feedwater is not available from the current steam turbine driven pumps when operating at less than 30% power and when aligned to the main feedwater system, the MDFP will be capable of being locally realigned to provide feedwater from the condensate storage tank or deaerator storage tank to the auxiliary feedwater nozzles of either steam generator.

2. <u>The Common Suction Line Strainer will be Eliminated</u>

The strainer will be used for initial testing of the motor driven pump train, but subsequently removed. This filter is considered an unnecessary potential obstruction to flow.

3. <u>Quality, Seismic, and Environmental Aspects</u>

TED has undertaken an effort to provide a subsystem which is as near to safety grade as practicable, and to clearly define areas where requirements for a safety-related system are not met. The only practical location for the new system is in the turbine building - a building which was not required to be designed to

withstand the extremely low probability seismic disturbances required by NRC standards for safety-grade buildings and systems. This is not to say that the system in the chosen location would not survive a severe earthquake. The Motor Driven Feed Pump will provide a reliable source of feedwater under all probable conditions of operation. These conditions include the survival of the system in plausible earthquakes of limited magnitude, and other plausible off-normal situations in which it may be required to function (such as a fluid system line break in its vicinity).

TED intends to perform engineering analyses which will consider seismic and other safety-grade related requirements. While the intent is not to fully qualify the system as safety grade, reasonable and cost-effective upgrades will be considered for implementation in the longer-term.

4. <u>The following longer-term changes are planned for the Motor-Driven Feed Pump train:</u>

   a. Capability to remotely operate the pump discharge valves to the Auxiliary Feedwater Pump headers from the Control Room will be provided prior to the beginning of Cycle 6. This will permit realignment when below 30% power, if necessary, to be accomplished remotely from the control room.

   b. To enhance reliability during loss of offsite power events, a DC lube oil pump which will be installed as a backup to

the AC lube oil pump or, as an alternative, the AC lube oil pump will be supplied by an Emergency Diesel Generator following a loss of offsite power. The selected alternatives will be completed prior to the beginning of Cycle 6.

Long Term Action Related To Existing Startup Feedwater Pump (SUFP)

Because of a lack of spare 4160V electrical switchgear to be used for the new Motor Driven Feed Pump, the existing startup feedwater pump is being electrically disabled. Hardware modifications will be provided in the longer term to restore the power supply to the SUFP. This is intended to facilitate manual initiation in the event of a loss of all feedwater from the main feedwater system, steam turbine driven auxiliary feedwater system and the Motor Driven Feed Pump. The restrictions presently contained in the Davis-Besse Operating License related to operation of the SUFP will continue to be observed. These restrictions will have minimal impact on operations since the new Motor Driven Feed Pump will be used for all routine operations which presently utilize the SUFP.

APPENDIX C.2.2 ACTIONS RELATED TO SFRCS

Item II.A.2 of the enclosure to the NRC's letter to Toledo Edison of August 14, 1985 identified as a concern:

> "The adequacy of the design and operation of the SFRCS, including spurious actuations, seal-in features for SFRCS-actuated equipment, and single failures."

The Steam Feedwater Rupture Control System (SFRCS) was considered as part of the Decay Heat Removal Task Force review. The changes to be made to SFRCS as a result of this review are described in this section. Additional Task Force recommendations are under consideration and may result in additional changes being made.

1 Filter Existing Steam Generator Water Level Signals

This filtering will minimize spurious responses of the SFRCS due to transient pressure impulses (e.g., due to turbine trips; water level manometer effects) which are not indicative of inventory changes. This problem occurred during the June 9 event and resulted in MSIV closure with the consequential loss of main feedwater. Filtering will thus improve the reliability of main feedwater. Filtering will be provided prior to restart.

2. Provide Seal-In and Manual Reset for the SFRCS Full Trip Annunciator Alarm

Short duration SFRCS trips which may actuate or isolate plant equipment may not be detectable by the operator via the existing alarm. The system presently seals in the full trip alarm for two seconds, after which the alarm is automatically reset. A seal-in feature with manual reset will be provided prior to plant startup.

3. Correct SFRCS Power Supply Problems

Long-standing problems with overheating, and AC ripple on the 125 VDC bus can lead to malfunction of the electronic power supplies and spurious operation of the SFRCS. Additional cooling will be provided for the SFRCS cabinets prior to restart. Additional corrective actions, if necessary, will be identified following completion of investigative activities.

4. Increase the Margin Between the SFRCS Low Level Trip Setpoint and the Integrated Control System (ICS) Low Level Limit

This will minimize inadvertent SFRCS trips during operation at the ICS steam generator low level limit (normal low power operation, reactor trip, or unit runbacks) and thus improve main feedwater availability. Confirmatory analyses to justify lowering the SFRCS low level trip setpoint are being performed. Those analyses will be completed and changes, if found acceptable, will be implemented prior to the beginning of Cycle 6.

5. <u>Modify SFRCS Low Steam Generator Level Trip Logic to Delete the Isolation of Main Steam and Main Feedwater Flow Paths</u>

On low steam generator level, no isolation of the main steam or main feedwater lines should occur. This will permit continued main feedwater flow to the steam generators and heat removal via the condenser. Confirming analyses are in progress to verify adequate steam inventory and compliance with accident analysis acceptance criteria for loss of feedwater and loss of offsite power events. These analyses will be completed, and if found acceptable, logic changes will be made prior to restart.

6. <u>Modify SFRCS Low Steam Generator Pressure Trip Logic to Prevent Isolation of Auxiliary Feedwater to Both Steam Generators</u>

For low pressure in one steam generator, both Auxiliary Feedwater Pumps are aligned to feed the second steam generator. If pressure in the second steam generator subsequently falls below the trip setpoint, the logic change will assure that both AFP's continue to feed the second steam generator. The existing SFRCS low pressure logic isolates auxiliary feedwater flow to both steam generators in this event. This logic change will be accomplished prior to restart.

7. <u>Delete the Pneumatic Relays in the Main Steam Isolation Valves Control Circuits</u>

These relays are not testable and their failure is not readily detectable. These relays will be removed and the existing solenoid valves will be replaced with larger solenoid valves containing position switches. This modification will be completed prior to beginning Cycle 6.

APPENDIX C.2.3 - PROBABILISTIC EVALUATION OF AFWS RELIABILITY

This evaluation is in progress. Results will be included in this Appendix, by revision, when the evaluation is completed.

APPENDIX C.3.1 - TRANSIENT ANALYSIS PROGRAM RESULTS

To calculate a "best estimate" response for a LOFW event, the RELAP5/MOD2 computer program was used for all ECCS analyses. These analyses were performed by Babcock & Wilcox. The RELAP5 model developed for Davis-Besse is shown in Figure C.3.1.1. The acceptability of using the RELAP5/MOD2 program and of the modeling techniques utilized for the ECCS analyses was established by successfully benchmarking RELAP5 results to Integral System Test (IST) Program experimental results from Once Through Integrated System (OTIS) Test 230299.

It is noted that the use of systems to support the makeup/HPI cooling mode depends upon the use of RCS code safety valves, the PORV, and high point and pressurizer vents. These systems are safety related except for the PORV (the PORV block valve is safety related). For injection capability at RCS operating pressure, the makeup system is utilized. Although not originally classified as a safety grade system, the quality attributes of the system and its support systems compare well with other safety grade systems. The required continuous service of one pump at all times, coupled with the procedural immediate action of starting the second pump following a reactor trip results in a high system reliability. The operability of both makeup pumps is required in the Technical Specifications.

All analyses performed incorporated the following set of assumptions. These analyses confirm that the June 9 conditions would not have resulted in core uncovery given initiation of feed and bleed within the first 30 minutes.

- Reactor at 102% of full power prior to LOFW
- LOFW initiated by 5 second ramp down to main feedwater flow
- Realistic decay heat based upon 1979 ANS 5.1 Standard
- Reactor trips on high RCS pressure of 2300 psig by RPS. Turbine trips 1 second after Reactor trip
- Main Steam Line pressure controlled at 1050 psig by safety valves.
- PORV capacity of 226,000 lb/hr steam @2500 psia based upon EPRI test data.
- No PORV actuation prior to operator action
- No Make-Up Pump flow prior to operator action
- RCS Pumps trip on loss of sub-cooled margin
- Letdown flow isolated throughout the transient
- AFW System unavailable throughout the transient
- Start-Up Feed Pump unavailable throughout the transient

Additionally, based upon the present Davis-Besse ATOG Procedures, all analyses assume the following operator actions upon determination that both lack of heat transfer and lack of of feedwater conditions exist.

- Open PORV and PORV block Valve
- Open pressurizer and hot leg high point vent lines
- Actuate both Make-Up Pumps
- Align HPI Pumps in piggyback mode

These assumptions conservatively bound the actual plant response to a total loss of feedwater. In particular, they provide for no decay heat removal other than that provided by operator actions. For example, letdown flow would probably not be isolated and would provide some heat removal capability.

The following cases were analyzed to investigate the effect that the time of operator manual actuation has upon the transient response of the Reactor Coolant System (RCS):

Case A - Operator action 5 minutes after RCS hot leg temperature reaches 610°F

Case B - Operator action 10 minutes after RCS hot leg temperature reaches 610°F

Case C - Operator action 20 minutes after Reactor Trip

Case D - June 9 transient with no recovery of Secondary Feedwater. Makeup/HPI cooling is initiated 30 minutes after Reactor Trip.

The results for the four cases are summarized on the following pages and are reflected in "collapsed" water level above the core. This level determination is therefore conservative in core cooling considerations.

SUMMARY OF RESULTS FOR CASE A

CASE DESCRIPTION (Refer to Figures C.3.1.2 to C.3.1.5)

TITLE: 100% Power with New Procedures

Loss of Feedwater. No Auxiliary Feedwater. No startup Feedwater. Operator initiation of makeup/HPI cooling 5 minutes after RCS Hot leg temperature reaches 610°F.

INITIAL CONDITION: Power = 102% of 2772 MW_t

KEY ASSUMPTIONS:
- Decay heat = 1.0 x 1979 ANS
- High point vents, PORV and make up flow initiated 5 minutes after T_{hot} = 610°F

PORV: I.D. = 1.54 in., flow set to 226,000 lb/hr steam @ 2500 psia

MU: 2 pumps

HPI: 2 trains in piggy-back

SEQUENCE

Time:

0 sec	LOFW
512 sec (8.5 min)	Operator initiated makeup/HPI cooling. Hot leg reactor coolant system temperature ~630°F. Reactor coolant system pressurizes.
1700 sec (28.5 min)	Reactor Coolant System Pressurizes to 2400-2500 psi.
2700 sec (45 min)	Depressurization of the Reactor Coolant System begins.
3500 sec (58 min)	Minimum Reactor Vessel collapsed water level reached is 1.5 feet above the top of the core.

RESULTS: No core uncovery.

SUMMARY OF RESULTS FOR CASE B

CASE DESCRIPTION (Refer to Figures C.3.1.6 to C.3.1.9)

TITLE: 100% power. Loss of Feedwater. Operator initiation 10 minutes after hot leg reactor coolant system temperature reaches 610°F.

INITIAL CONDITION: 102% of 2772 MW_t

KEY ASSUMPTIONS:

- Decay heat = 1.0 x 1979 ANS
- High point vents, PORV, and make up flow initiated 10 minutes after T_{hot} = 610°F

PORV: I.D. = 1.54 in., flow set to 226,000 lb/hr steam @ 2500 psia

MU: 2 pumps

HPI: 2 trains in piggy-back

SEQUENCE

Time:	
0 sec	LOFW
812 sec (13.5 min.)	Operator initiated makeup/HPI cooling.
2700 sec (45 min.)	Depressurization of the Reactor Coolant System begins.
3492 sec (58.2 min)	Minimum Reactor Vessel collapsed water level reached is .10 ft. above the top of the core.

RESULTS: No core uncovery

SUMMARY OF RESULTS FOR CASE C

CASE DESCRIPTION (Refer to Figures C.3.1.10 to C.3.1.13)

TITLE: 100% Power Case

Loss of Feedwater, No Auxiliary Feedwater. Operator Initiation of makeup/HPI cooling at 20 minutes after reactor trip.

INITIAL CONDITION: 102% of 2772 MW_t

KEY ASSUMPTIONS:
- Decay heat = 1.0 x 1979 ANS
- High point vents, PORV and make up flow initiated 20 minutes after reactor trip.

PORV: I.D. = 1.54 in., flow set to 226,000 lb/hr steam @ 2500 psia

MU: 2 pumps at 20 minutes

HPI: 2 trains in piggy-back

SEQUENCE

Time:	
0 sec	LOFW
1200 sec (20 min)	Operator initiates makeup/HPI cooling.
2400 sec (40 min)	Reactor coolant system depressurization begins.
3200 sec (53.3 min)	Minimum Reactor Vessel level occurs at 1/2 foot below the top of the core.
3600 sec (60 min.)	Reactor coolant system pressure 2050 psia and decreasing.

COMMENTS:

Collapsed core liquid level only 1/2 foot below top of core. Minor acceptable fuel temperature excursion projected.

SUMMARY OF RESULTS FOR CASE D

CASE DESCRIPTION (Refer to Figures C.3.1.14 to C.3.1.17)

TITLE: June 9, 1985 Transient without Recovery of Secondary Side Feedwater

INITIAL CONDITION: Power - 90% of 2772 MW_t

KEY ASSUMPTIONS:

- DECAY HEAT = 0.9 x 1979 ANS
- Main Feedwater available for 4½ minutes
- ICS controls SG Water Level @35" for 4½ minutes
- 2 Make-up pumps on until pressurizer level reaches 200"
- PORV actuates 3 times
- After 3rd actuation PORV closed when RCS Pressures reaches 2080 psia
- Pressurizer Spray actuates @2200 psia
- No AFW
- No Start-Up Feed Pump
- Operators open PORV, highpoint vents and initiate make-up flow @ 30 minutes.

PORV: I.D. = 1.54 in., flow set to 226,000 lb/hr steam @ 2500 psig
Open @ 30 minutes.

MU: 2 pumps @ 30 minutes

HPI: 2 trains in piggy-back @30 minutes

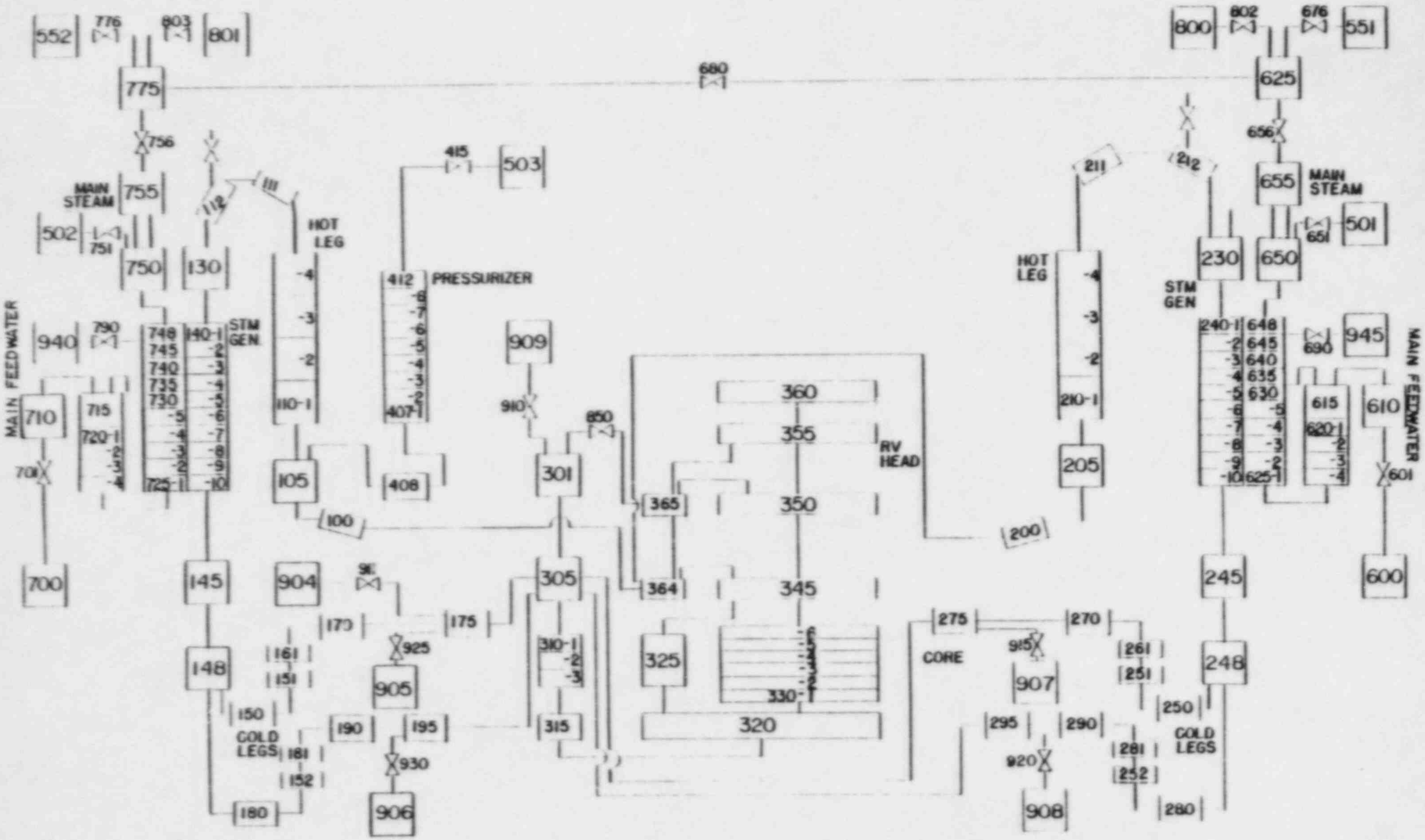
SEQUENCE:

TIME	
0-30 min	Sequence as experienced June 9 without restoration of startup or auxiliary feedwater.
1800sec (30 min)	Operator initiates makeup/HPI cooling.
3200 sec	Minimum reactor vessel water level at 3 feet above the (53.3 min) core.
4000 sec (66.7 min)	Reactor coolant system maximum pressure of 2340 psi starting to depressurize.
6200 sec (103.3min)	Reactor coolant system pressure 1900 psi and declining

RESULTS: No core uncovery

Key RCS parameters are shown in figures C.3.1.2 through C.3.1.17 for each of the cases analyzed. The parameters shown are:

- Collapsed Liquid Level in Core
- Loop A Hot and Cold Leg Temperature
- Loop B Hot and Cold Leg Temperature
- Hot Leg Pressure in Loop with Pressurizer



RELAP5 MODEL

FIGURE C.3.1.1

CASE A

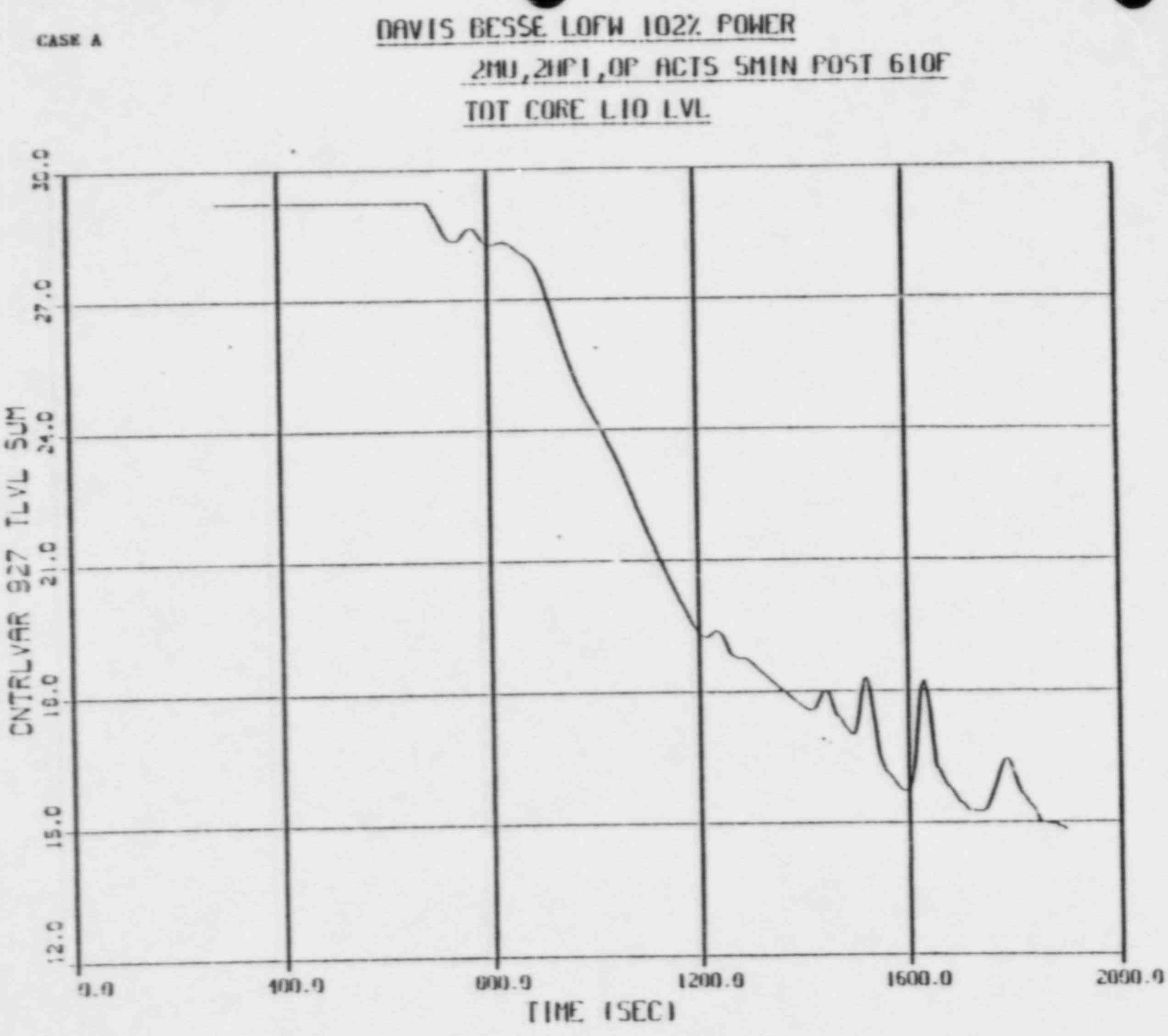


FIGURE C.3.1.2

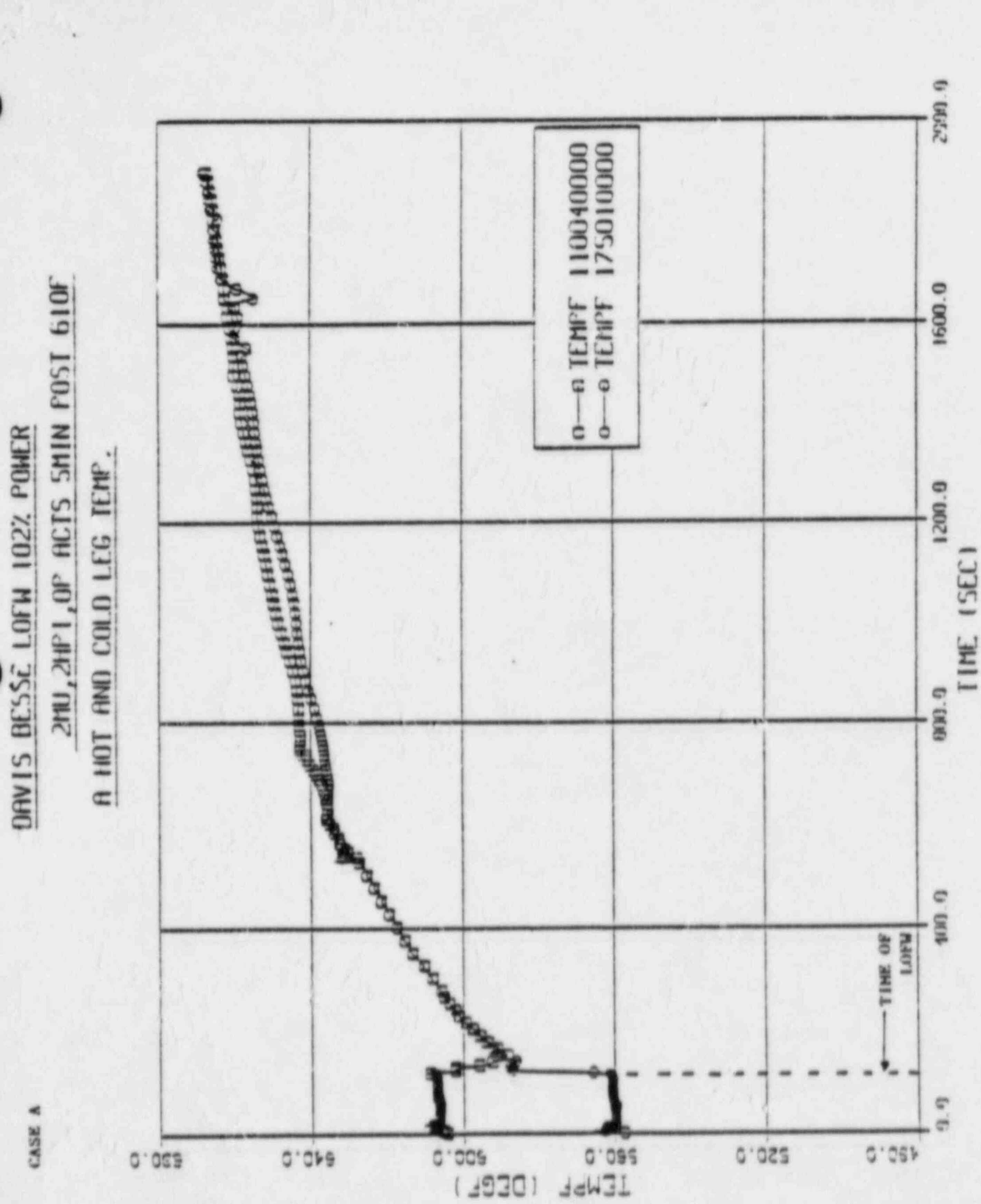

CASE A
DAVIS BESSE LOFW 102% POWER
2MU,2HPI,OP ACTS 5MIN POST 610F
A HOT AND COLD LEG TEMP.
TEMPF 110040000
TEMPF 175010000
TEMPF (DEGF)
680.0
640.0
600.0
560.0
520.0
480.0
0.0
400.0
800.0
1200.0
1600.0
2000.0
TIME (SEC)
TIME OF LOFW

FIGURE C.3.1.3

CASE A

DAVIS BESSE LOFW 102% POWER

2MU,2HPI,OF ACTS 5MIN POST 610F

B HOT AND COLD LEG TEMP.

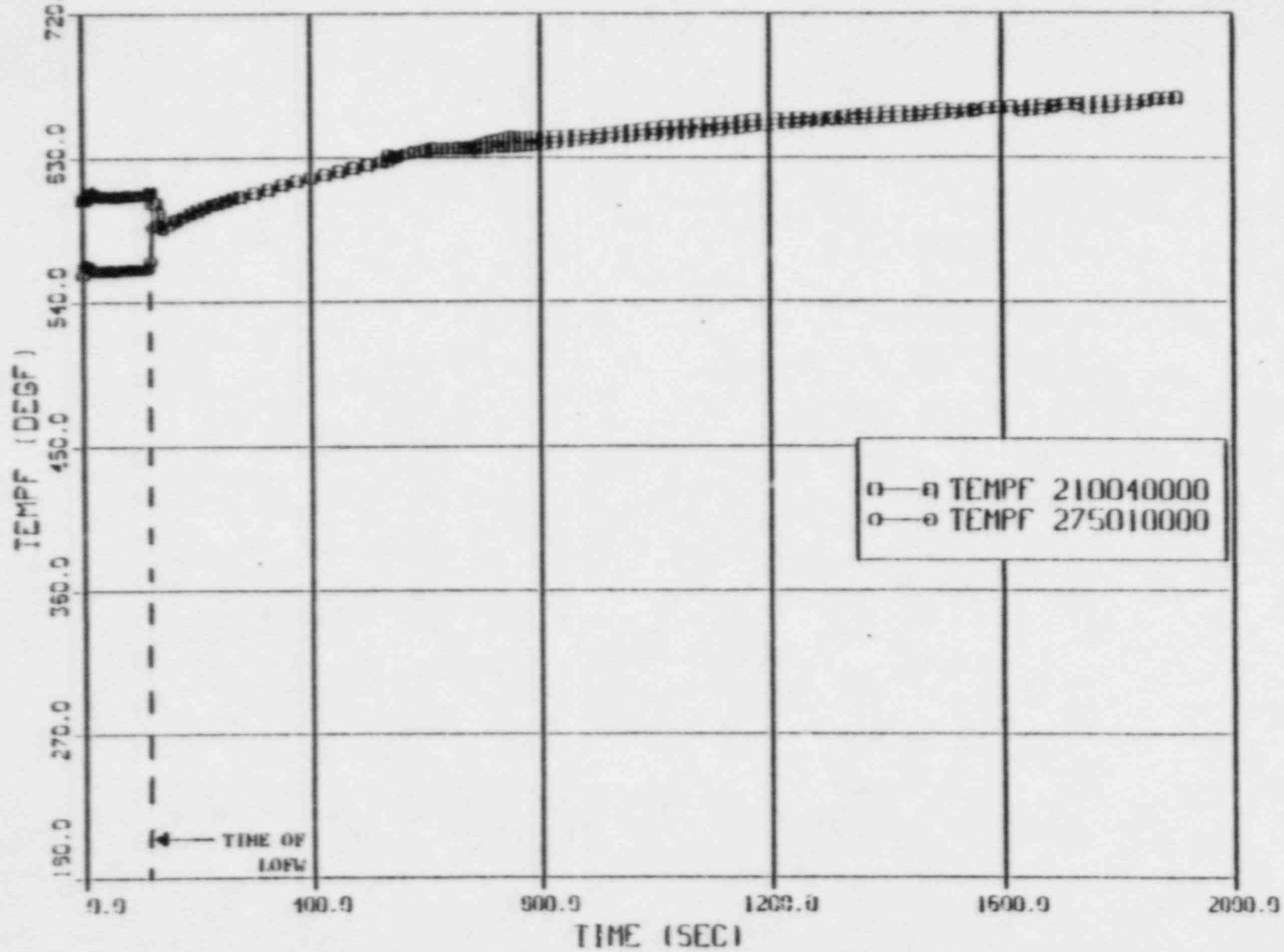


FIGURE C.3.1.4

CASE A

DAVIS BESSE LOFW 102% POWER

2MU,2HPI,OP ACTS 5MIN POST 610F

HOT LEG PRESSURE

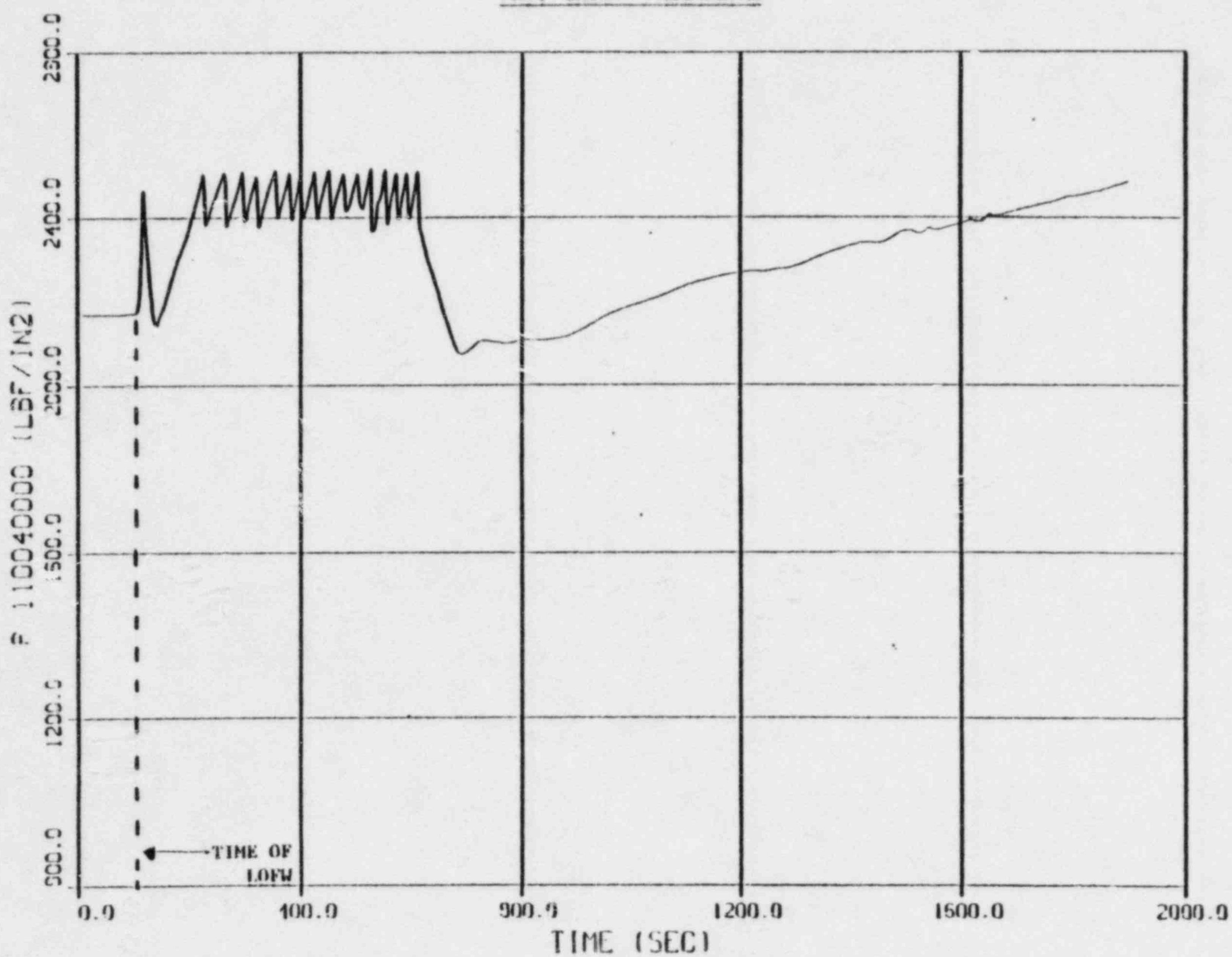


FIGURE C.3.1.5

CASE B

DAVIS BESSE LOFW 102% POWER

PORV, 2 MAKE-UPS, VENTS, AT 912 SEC

TOT CORE LIQ LVL

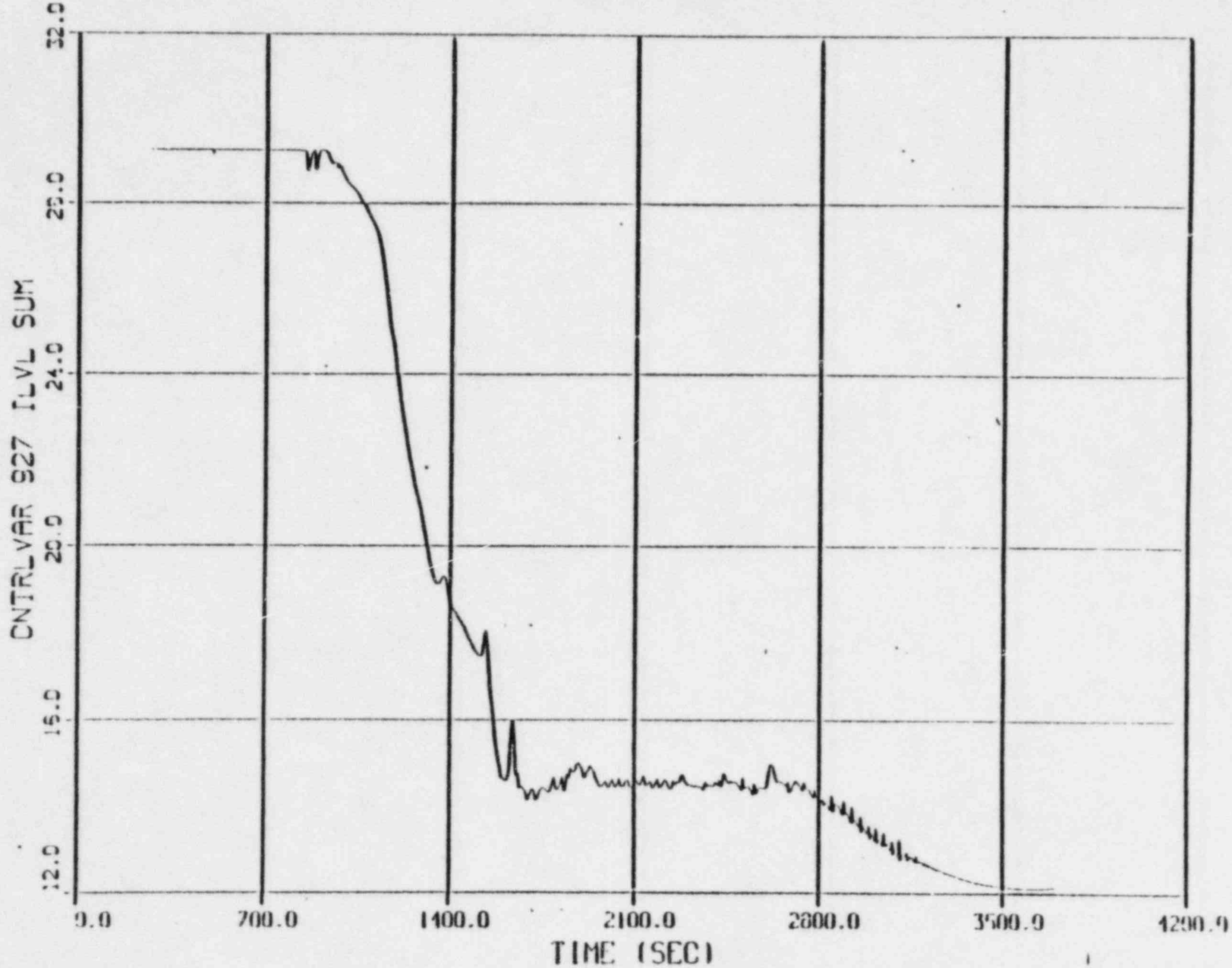
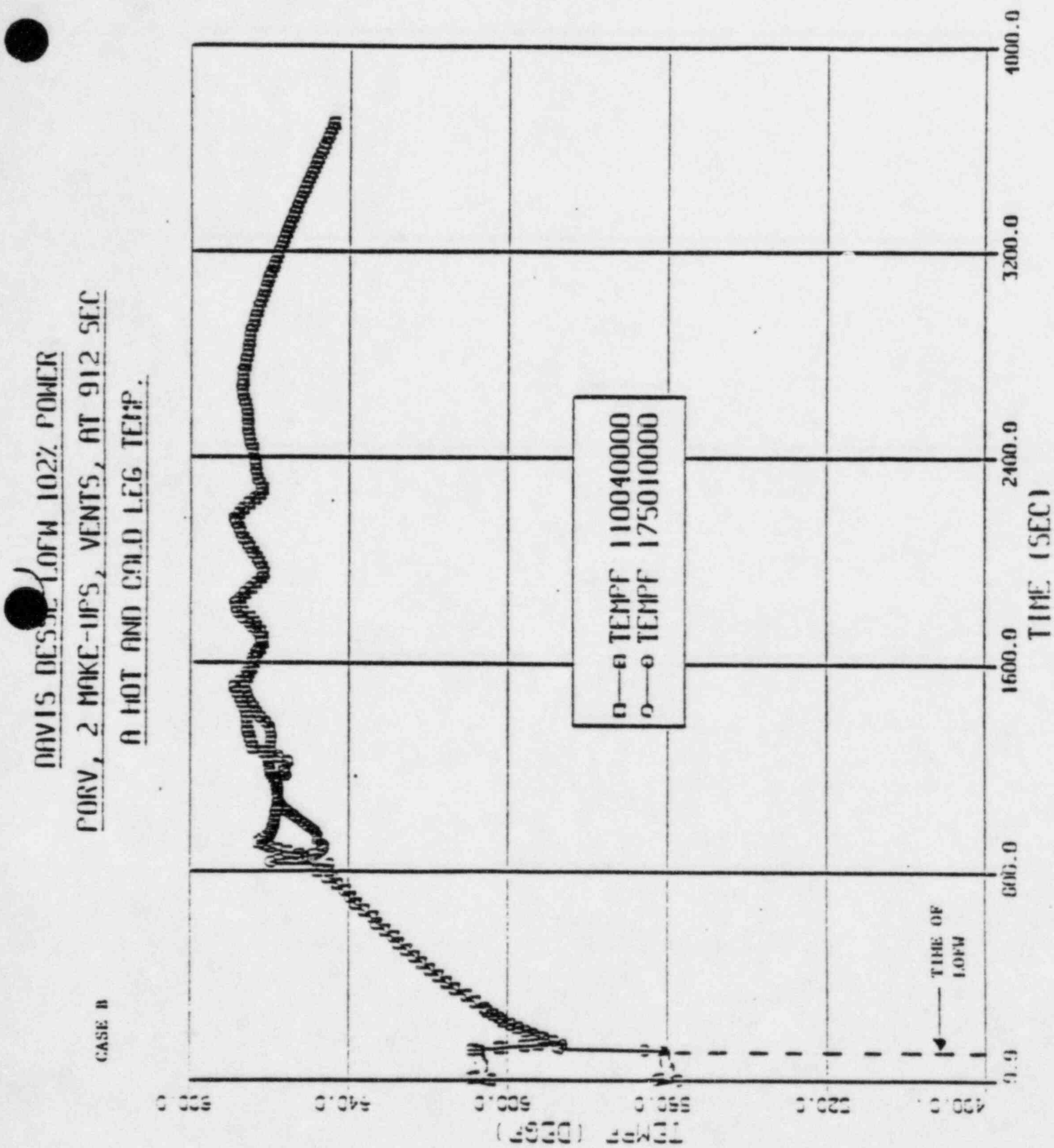


FIGURE C.3.1.6



CASE B
DAVIS BESSE LOFW 102% POWER
PORV, 2 MAKE-UPS, VENTS, AT 912 SEC
A HOT AND COLD LEG TEMP.
TEMPF 110040000
TEMPF 175010000
TIME OF LOFW
TIME (SEC)
TEMPF (DEGF)
0.0
800.0
1600.0
2400.0
3200.0
4000.0
480.0
520.0
560.0
600.0
640.0
680.0

FIGURE C.3.1.7

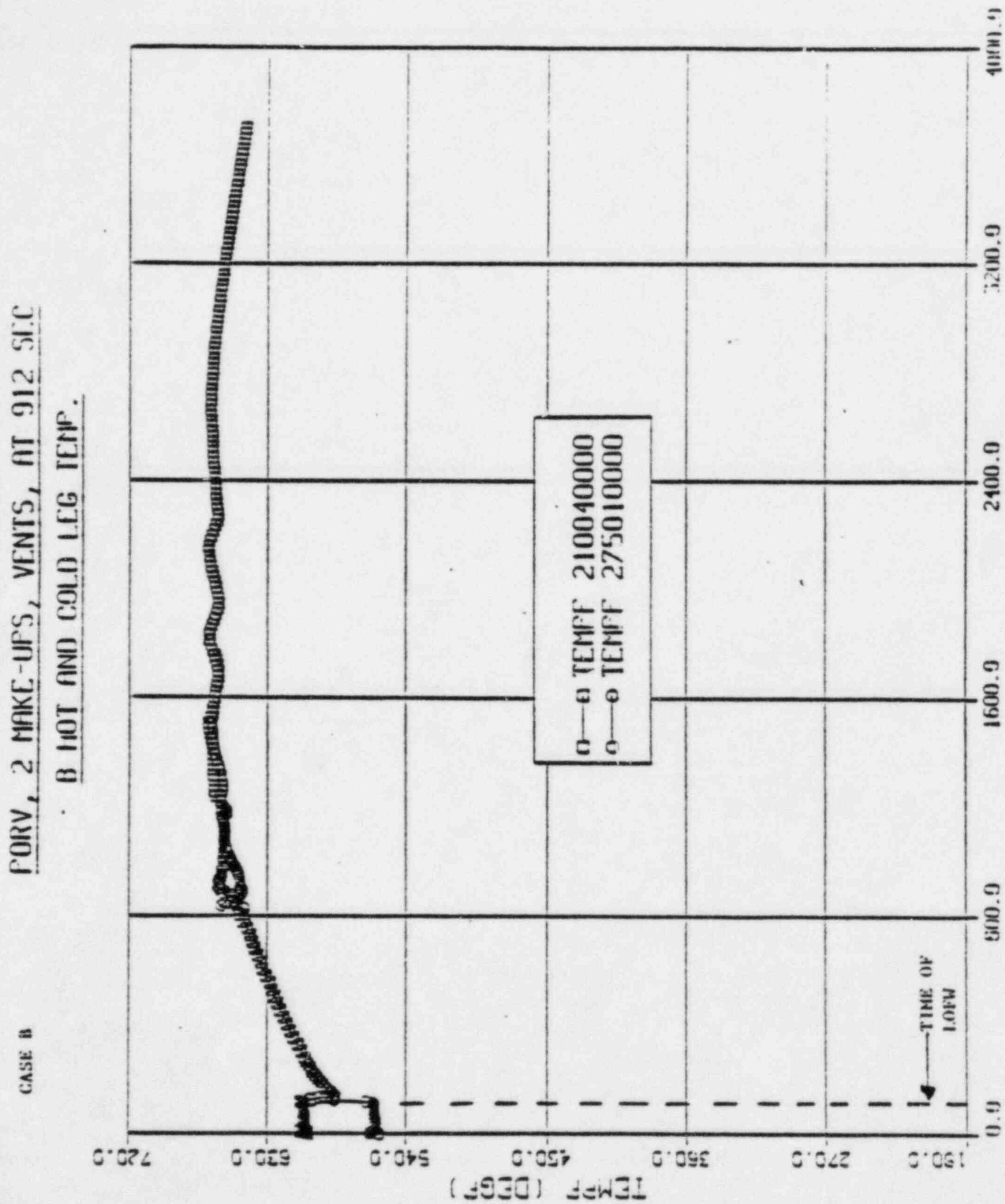
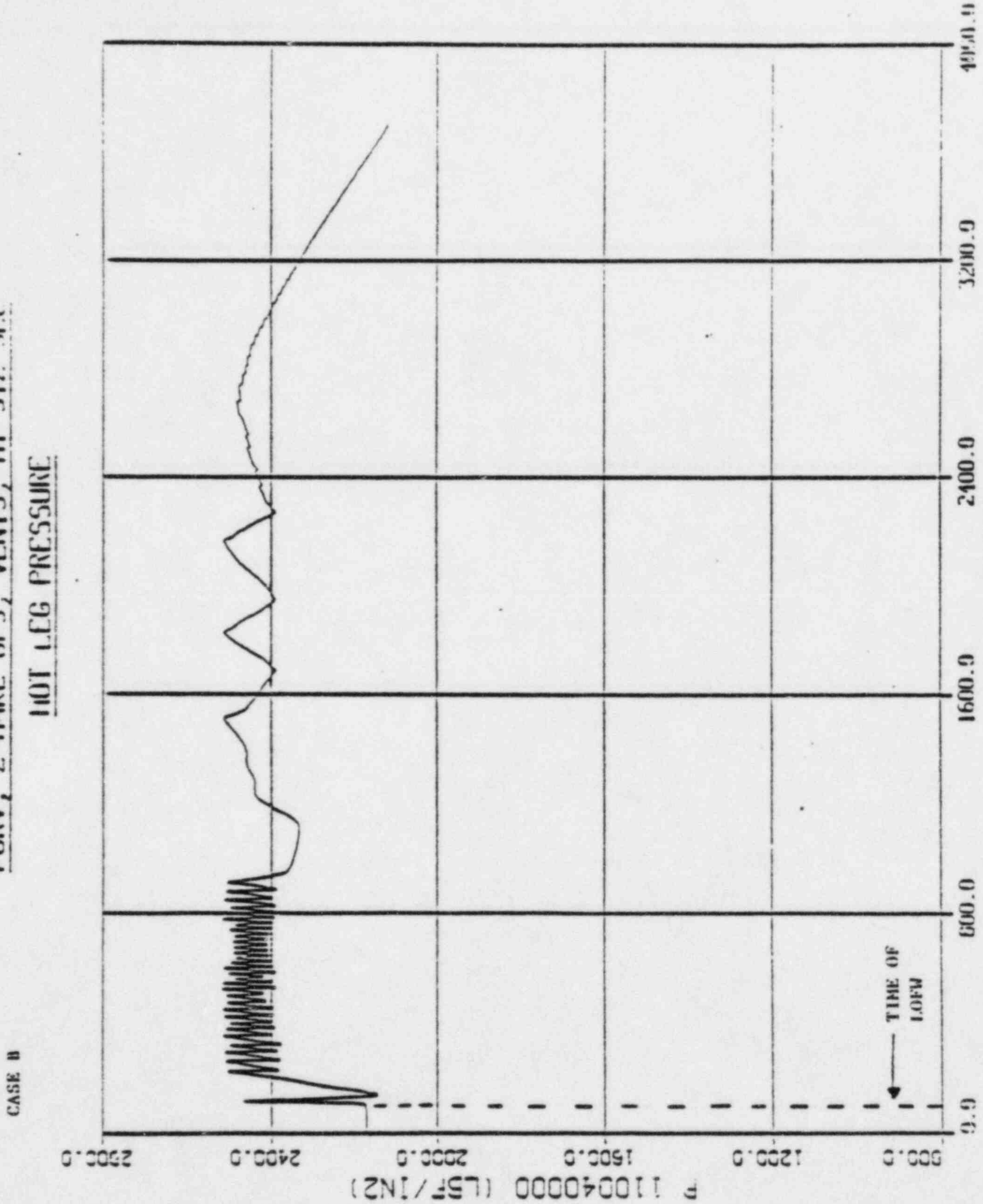

DAVIS BESSE LOFW 102% POWER
PORV, 2 MAKE-UPS, VENTS, AT 912 SEC
B HOT AND COLD LEG TEMP.
CASE B
TEMPF 210040000
TEMPF 275010000
TIME OF LOFW
0.0
800.0
1600.0
2400.0
3200.0
4000.0
TIME (SEC)
180.0
270.0
360.0
450.0
540.0
630.0
720.0
TEMPF (DEGF)

FIGURE c.3.1.8



DAVIS BESSE LOFW 102% POWER
PORV, 2 MAKE-UPS, VENTS, AT 912 SEC
HOT LEG PRESSURE
CASE B
TIME OF LOFW
TIME (SEC)
0.0
800.0
1600.0
2400.0
3200.0
4000.0
P 110040000 (LBF/IN2)
800.0
1200.0
1600.0
2000.0
2400.0
2800.0

FIGURE C.3.1.9

CASE C

DAVIS BESSE LOFW 102% POWER

OP ACTS @ 20 MIN, 2 MU, PORV

TOT CORE LIQ LVL

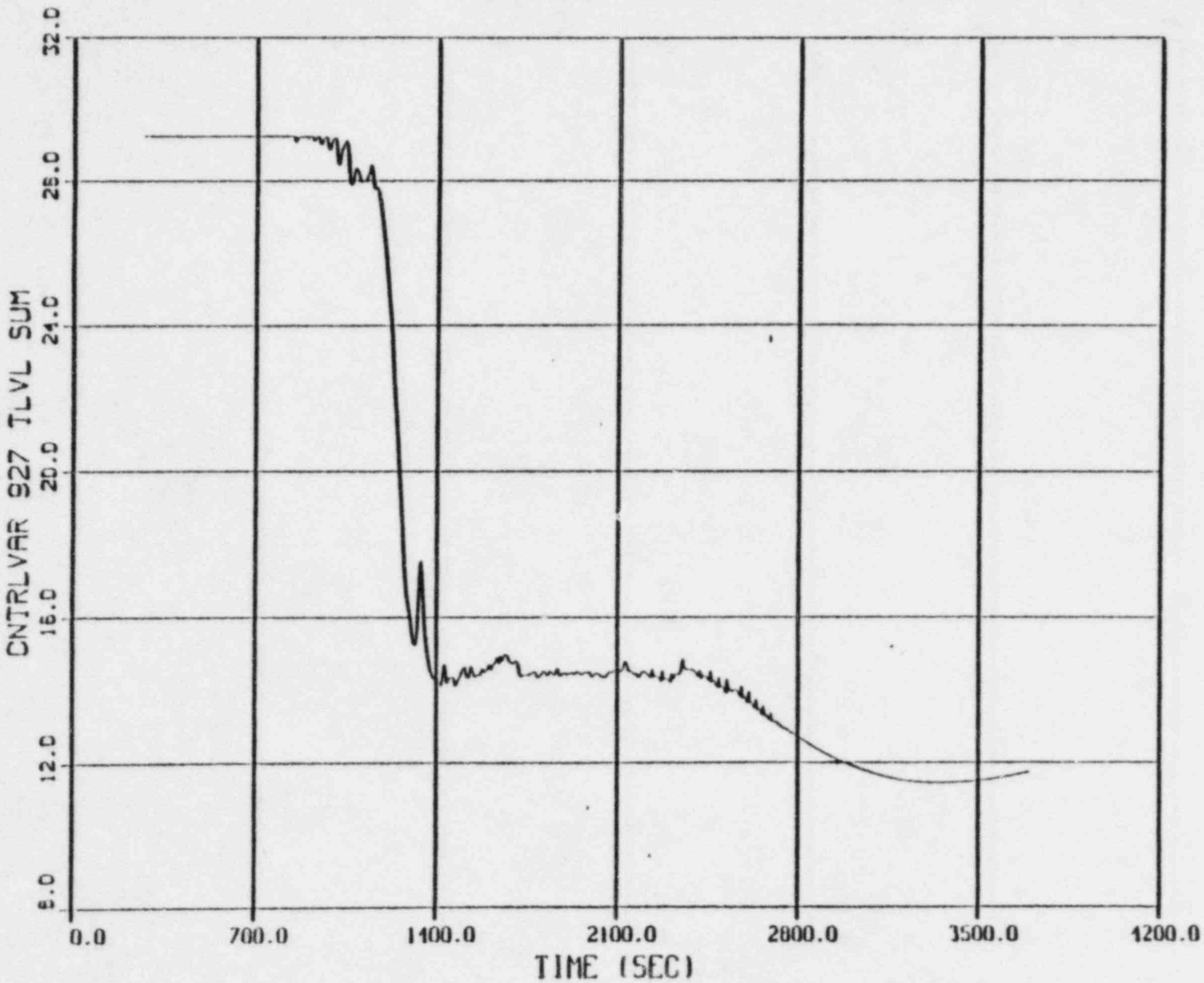


FIGURE C.3.1.10

CASE C

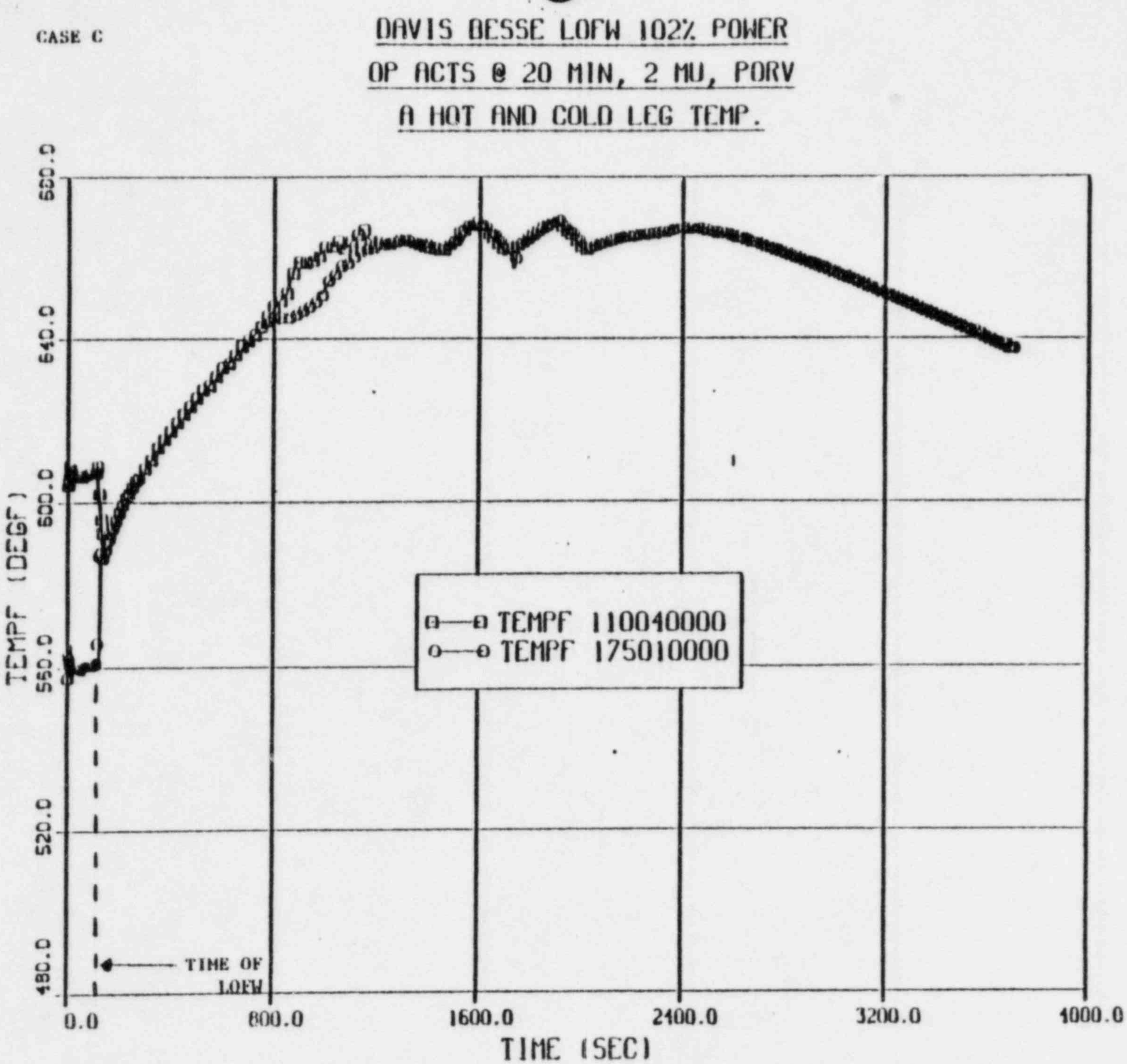


FIGURE C.3.1.11

CASE C

DAVIS BESSE LOFW 102% POWER

OP ACTS @ 20 MIN, 2 MU, PORV

B HOT AND COLD LEG TEMP.

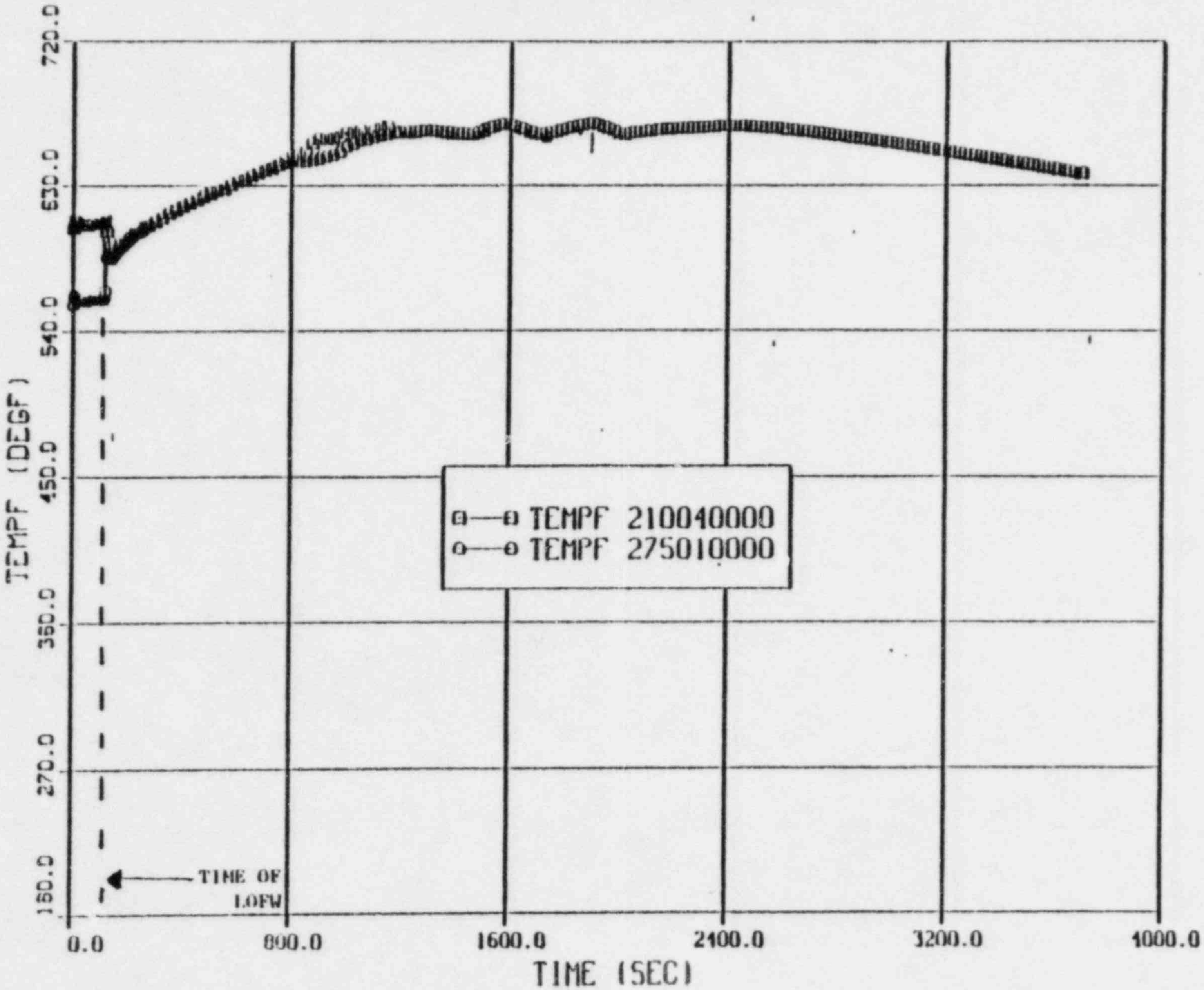


FIGURE C.3.1.12

CASE C

DAVIS BESSE LOFW 102% POWER

OP ACTS @ 20 MIN, 2 MU, PORV

HOT LEG PRESSURE

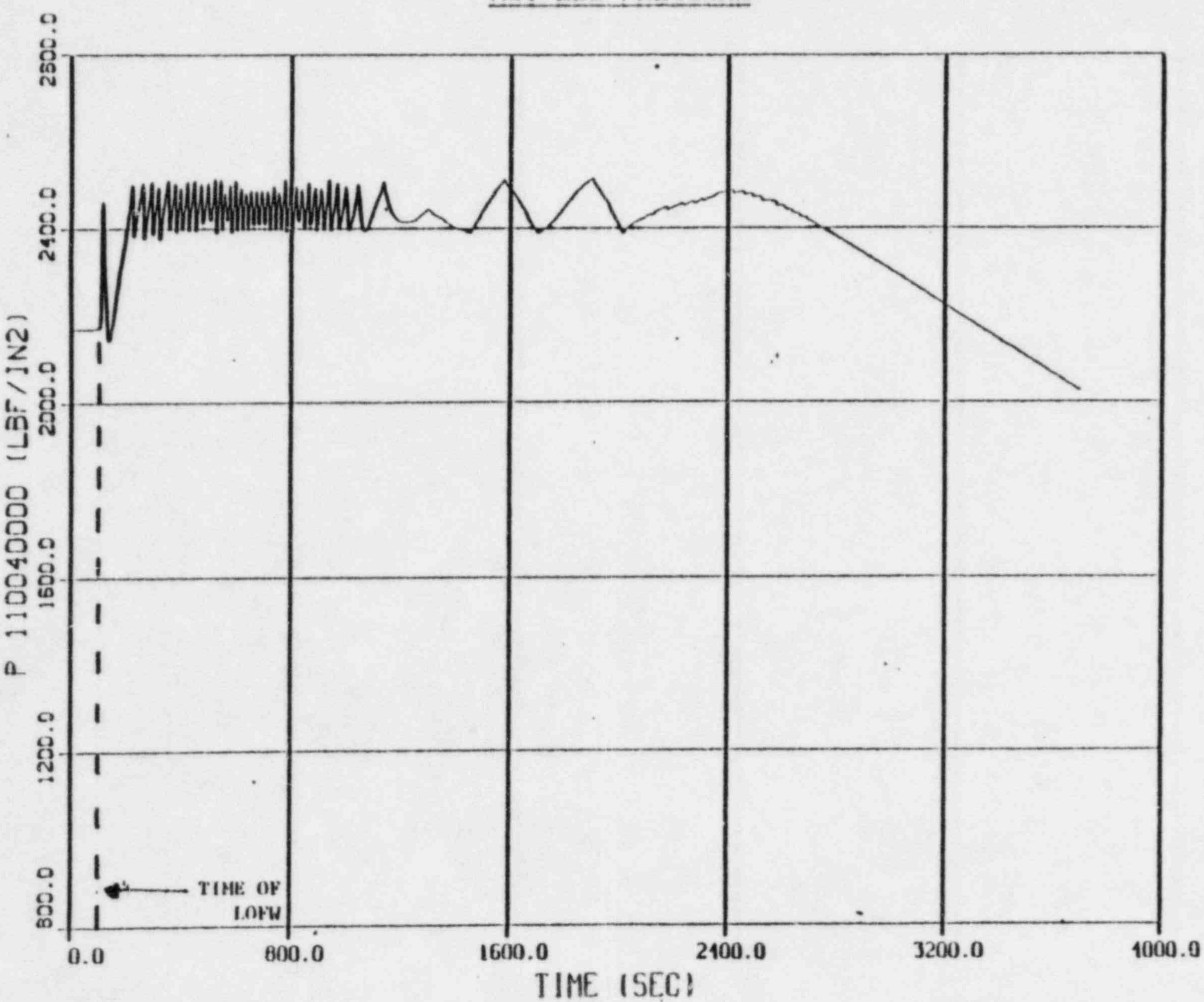


FIGURE C.3.1.13

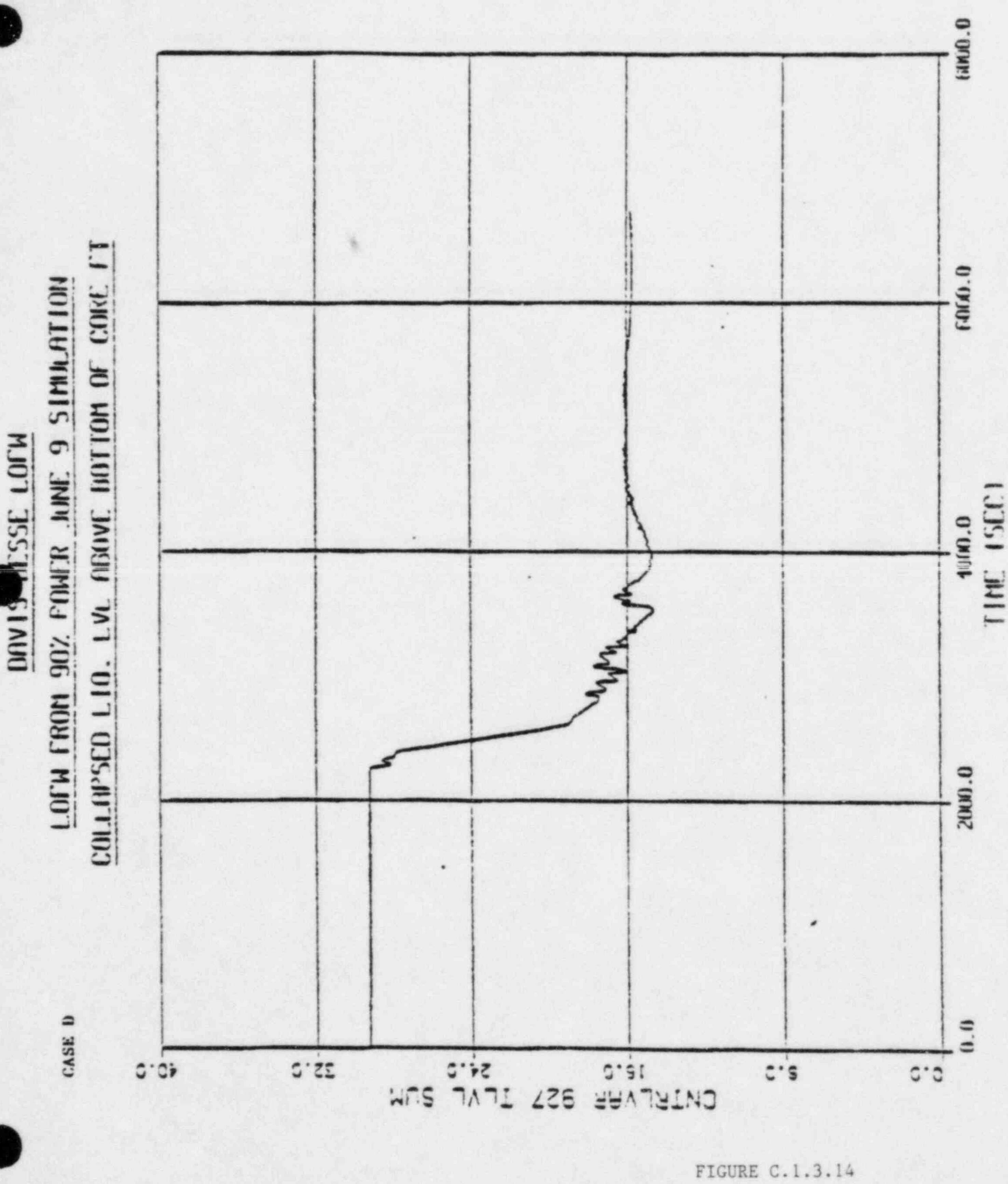


FIGURE C.1.3.14

DAVIS BESSE LOFW

LOFW FROM 90% POWER JUNE 9 SIMULATION

A HOT AND COLD LEG TEMP.

CASE D

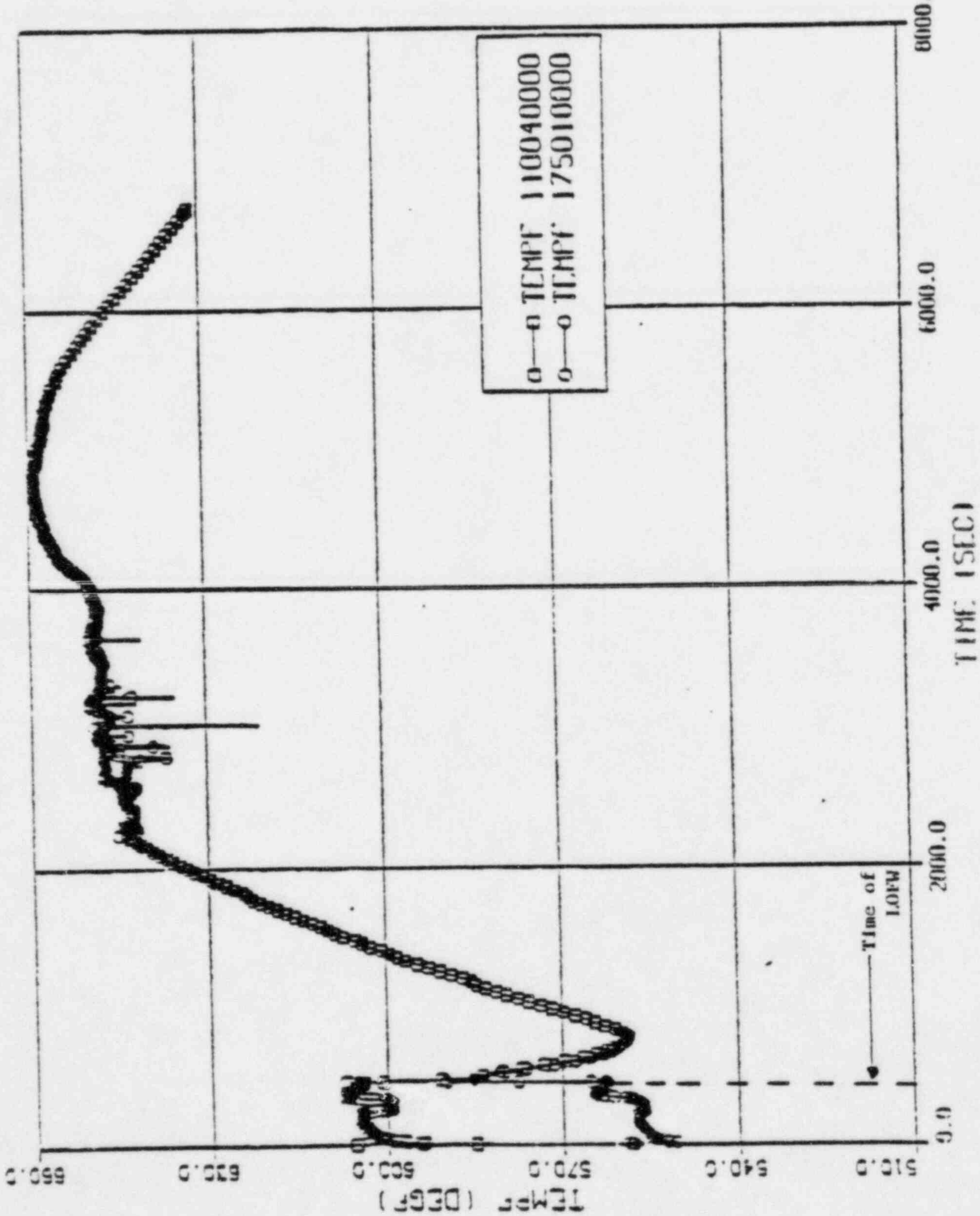


FIGURE C.3.1.15

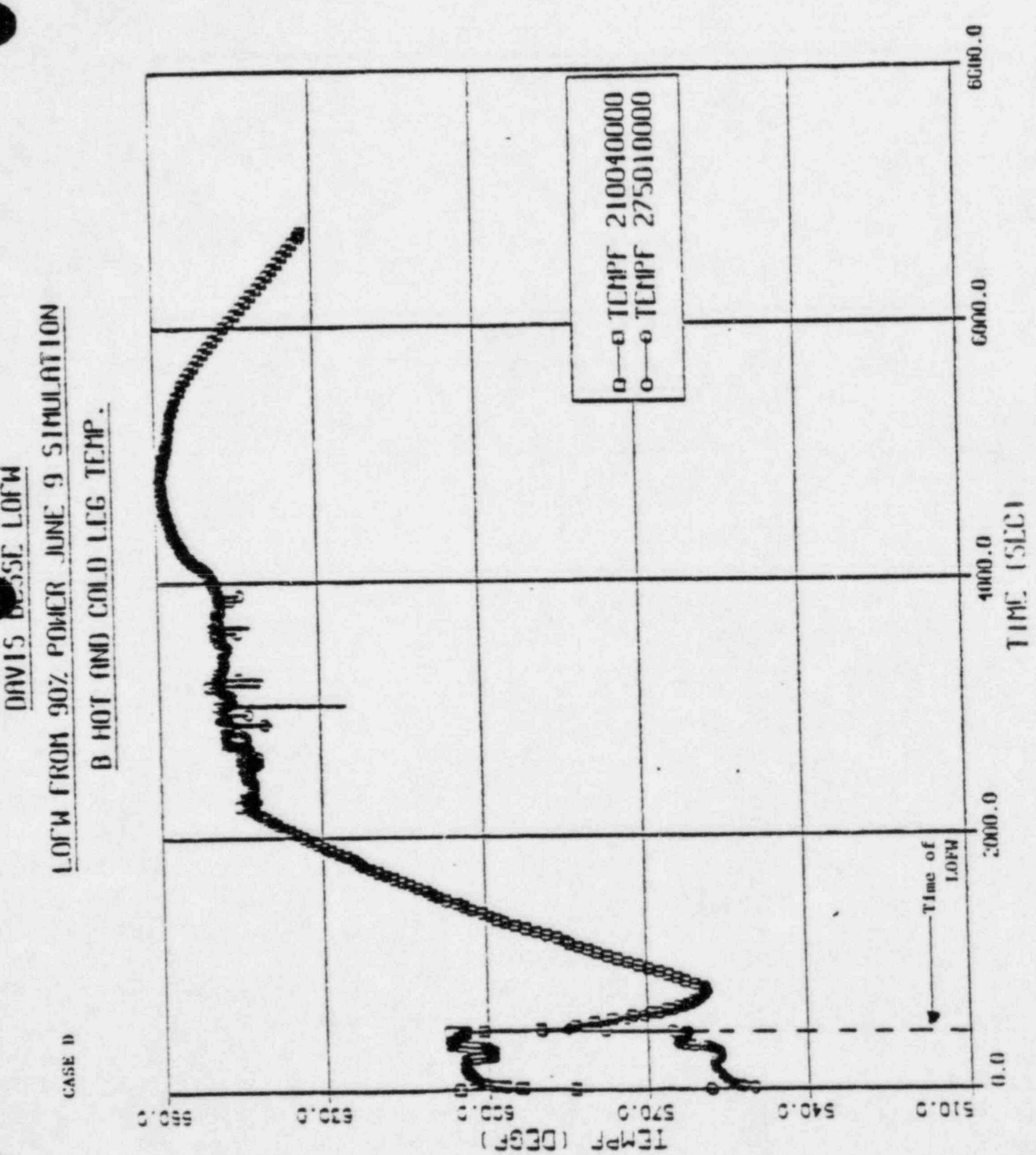


FIGURE C.3.1.16

CASE D

DAVIS BESSE LOFW

LOFW FROM 90% POWER JUNE 9 SIMULATION

HOT LEG PRESSURE

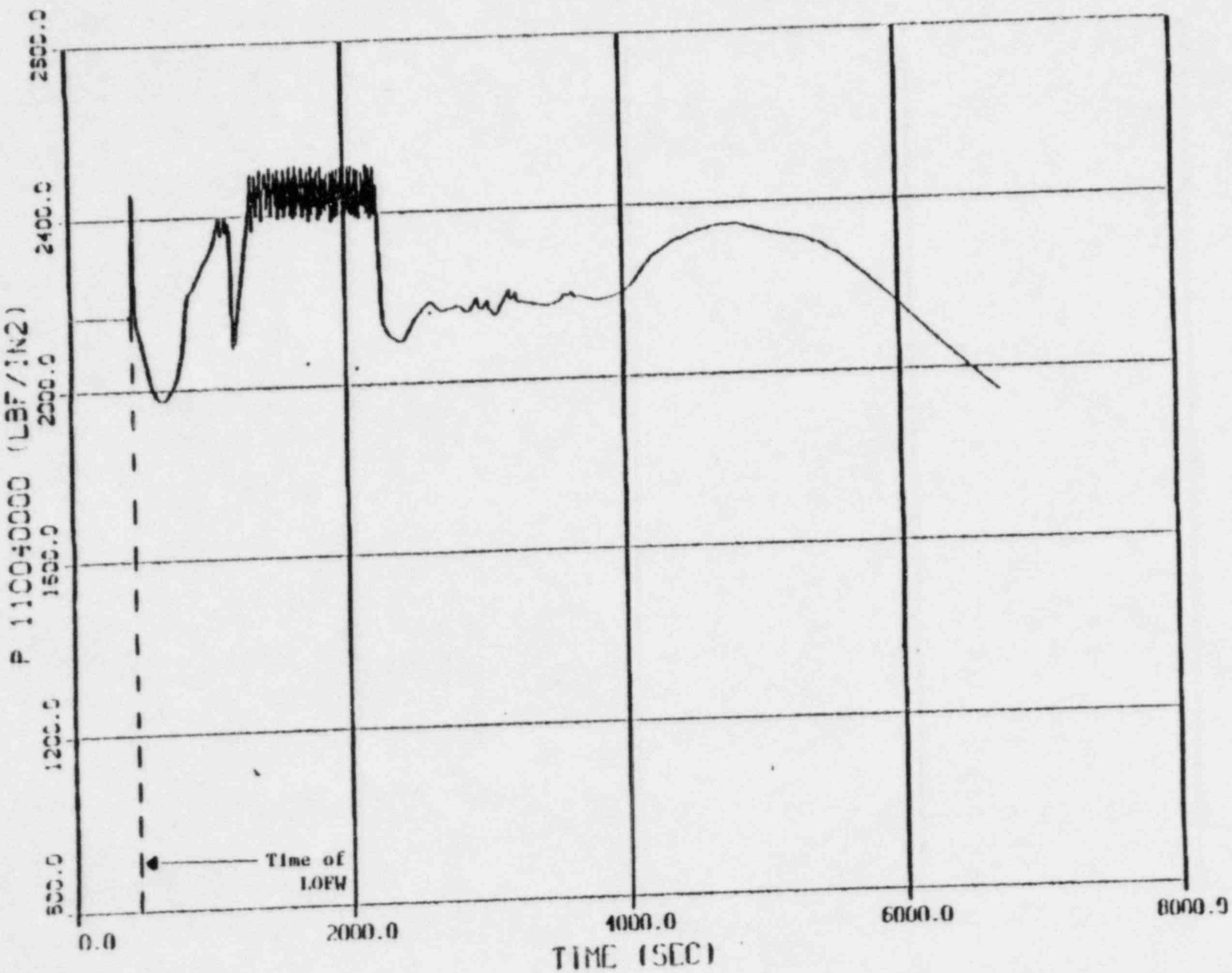


FIGURE C.3.1.17

APPENDIX C.3.2 - ANALYSES OF EVENT EFFECTS ON EQUIPMENT

Presented on the following pages is the report of the Babcock & Wilcox evaluation of the effect of the June 9, 1985 event on the Once Through Steam Generators.

An evaluation of the effects of the June 9 event on the Reactor Vessel is currently in process and will be completed prior to restart. The results of this evaluation will be included in this Appendix following completion.

Babcock & Wilcox

a McDermott company

Nuclear Power Division
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July 16, 1985
SGBM-85-531

Mr. Frank Y. Chen
Nuclear Systems & Analysis
Toledo Edison Company
Edison Plaza
300 Madison Avenue
Toledo, OH 43652

Subject: Transmittal of Revised B&W Document Number 32-1158583-00 Entitled "Davis-Besse Transient (6/85) - OTSG Structural Integrity"

Reference: T. E. Smith to F. Y. Chen, "Engineering Evaluation of the Davis-Besse Steam Generators Following the June 9, 1985, Loss of Feedwater Transient," dated June 20, 1985.

Dear Mr. Chen:

The attached Engineering Document has been prepared by Babcock & Wilcox to evaluate the effect of the 6/85 transient on the Davis-Besse steam generators. This document originally stamped "Preliminary" and submitted to you as an attachment to the above referenced letter has now been finalized. Conclusions and recommendations as noted in the above referenced letter remain unchanged.

Please feel free to call either myself (804) 847-3741 or Mr. J. C. Brown (804) 847-3358 if you have any questions on the analysis or if we can be of some further assistance.

Technical Concurrence: J. C. Brown
J. C. Brown
Steam Generator Engineering

Sincerely,

T. E. Smith
T. E. Smith
Product Manager

css/11-5

Attachment

cc JR Albert
EJ Domaleski
WR Smith
JK Wood

CALCULATION DATA/TRANSMITTAL SHEET

DOCUMENT IDENTIFIER — CALC. 32 - 1158583 - 00   C.C. 308

TRANS. 86 - ____ - ____   REF. PG(s) 85

TYPE: __ RESEARCH & DEVELOPMENT __ SAFETY ANALYSIS REPORT __ DOC. SERV. INPUT __ DESIGN REQT. X DESIGN VERIF. __ OTHER

TITLE Davis Besse Transient (6/85) - OTSG Structural Integrity HTH

PREPARED BY D.E. COSTA/H.T. HARRISON   REVIEWED BY J.F. SHEPARD

TITLE ENGR II / ENGR III DATE 7-16-85   TITLE J.F. Shepard   DATE 7/16/85

PURPOSE:

To investigate the effects of the Davis Besse I transient of June 9, 1985 on the structural integrity of the OTSG.

SUMMARY OF RESULTS (INCLUDE DOC. ID'S OF PREVIOUS TRANSMITTALS & SOURCE CALCULATIONAL PACKAGES FOR THIS TRANSMITTAL)

1) The structural integrity of the OTSG has not been impaired as a result of the June 9, 1985 transient.

2) It is recommended that the outer tubes of OTSG #2 be inspected during the next scheduled inspection of OTSG #2 for any indications near the 1st or 15th tube support plate.

Note: Pages 34-85 (Attachments 1 & 2) consists of References 9 & 10. These documents contain proprietary information and are not for release outside the Babcock & Wilcox Co.

DISTRIBUTION

TABLE OF CONTENTS

Introduction

On June 9, 1985, a loss of feedwater event occurred at Toledo Edison's Davis Besse 1 plant. The purpose of this report is to document the investigations undertaken regarding the possible effect of this transient on the structural adequacy of the Once Through Steam Generators (OTSG).

The loads on the following portions of the OTSG were investigated.

- Auxiliary Feedwater Nozzle
- Main Feedwater Nozzle
- AFW Jet Impingement Tube Stress
- Thermal Shock on Lower Tubesheet
- Axial Compressive Load in Tubes Due to Shell to Tube Temperature Difference

Conclusion

The results of this evaluation show that the June 9, 1985 transient had no adverse structural effect on the steam generators.

The following pages provide a summary of each of the investigations conducted. These are followed by detailed discussions.

Auxiliary Feedwater Nozzle

The stresses in this nozzle have been reviewed because of the large temperature difference imposed on the nozzle by AFW initiation.

The stress and fatigue analysis of the nozzle is contained in Document 32-1134736-00, "Auxiliary Feedwater Bolted Nozzle Analysis" (Ref. 3). A review of this analysis shows that the analyzed transient is more severe (ΔT between shell and AFW = 530°F) than the transient experienced on June 9, 1985, (ΔT = 501°F). From the report, the fatigue usage factor is 0.55 (<1.0 allowable); this covers all specified design transients, but is in fact due solely to AFW initiation.

Due to the high stresses that result from the injection of cold AFW into the hot nozzle, the fatigue life of the AFW Nozzle is limited to 875 AFW initiations; this is specified in Field Change Authorizations 04-3783-05 and 04-3784-05 (Ref. 2).

PDS-21036-3 (9-84)

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GENERAL CALCULATIONS

DOC. I.D. 32-1158553-00

Main Feedwater Nozzle

The stresses in this nozzle have been reviewed because of the large temperature difference imposed on the nozzle by feedwater activation.

The stress and fatigue analysis is contained in the original stress report, Stress Report # 7, Contract 620-0014-55, "Stress Analysis of Feedwater Nozzle."

In the original stress report a case was considered where 90°F feedwater is injected into a nozzle at 535°F; the Δ T is therefore 535 - 90 = 445°F. The fatigue usage factor for the nozzle is 0.4, which is less than the allowable value of 1.0.

Based on data from the event of June 9, 1985, the shell temperature prior to MFW initiation is conservatively assumed to be 572.5°F; the nozzle temperature is assumed to be equal to the shell temperature. The feedwater temperature at initiation is 411°F. The Δ T for this case is then 572.5 - 411 = 162°F.

Since the analyzed ΔT (445°F) is greater than the actual Δ T (162°F), it is concluded that the event of June 9, 1985 is conservatively covered by the stress report. The effect of this transient on the fatigue usage factor is negligible.

PREPARED BY Je DATE 6/20/85

REVIEWED BY JFS DATE 6/20/85

Impingement of Auxiliary FW on OTSG Tubes

Stresses resulting from impingement of cold AFW on hot OTSG tubes have been reviewed because of the large ΔT involved.

These stresses are calculated in the document 32-1147666-00, "TECO AFW Jet Impingement Tube Stress" (Ref. 5).

In the calculation, it was assumed that 40°F auxiliary feedwater impinges on a tube at 626°F. Based on 29,400 cycles, a fatigue usage factor equal to 0.33 was calculated for AFW impingement alone. The combined usage factor for all transients is 0.39, which is well below the allowable value of 1.0.

During the event on June 9, 1985, the primary fluid temperature prior to AFW initiation was 592.5°F (Ref. 1). Based on thermocouple data, the AFW temperature was about 70°F (Ref. 1). The ΔT was therefore 522.5°F, which is less than the ΔT analyzed.

Axial Compressive Load in Tubes

Due to the axial restraint imposed on the OTSG tubes by the two tubesheets, a temperature difference between the tubes and the shell induces an axial load in the tubes. This load is tensile when the shell temperature is greater than the tube temperature and compressive when the tubes are hotter than the shell. A ΔP across the tubesheet and tubes also induces axial loads inthe tubes. Both ΔT and ΔP must be considered when evaluating the final tube load.

Temperature data from the event of June 9, 1985 (Ref. 1) shows that in this case, the tube temperature (assumed equal to the average reactor coolant temperature) is higher than the average shell temperature (based on thermocouple readings). The shell and tube temperatures for the two generators are:

	SG 1	SG 2
T(shell)	533°F	521°F
T(tube)	593°F	593.5°F

Based on these temperatures and the corresponding pressures, the compressive tube loads for SG 1 and SG 2 are 751 lbs. and 994 lbs., respectively.

The effect on the usage factor of the load discussed above is zero.

Thermal Shock On Tubesheet

The stress analysis of the tubesheet is contained in the document, "Stress Analysis of Upper and Lower Tubesheets," contract 620-0014-55, Report # 4.

The analysis resulted in a fatigue usage factor in the tubesheet of 0.13, which is considerably below the allowable value of 1.0.

Because of the modest ΔT involved and the fact that only one stress cycle is involved, the effect on the usage factor will be zero.

AFW NOZZLE EVALUATION

THIS SECTION WILL EVALUATE THE EFFECTS OF THE JUNE 9, 1985 TRANSIENT (REF 1) ON THE AFW BOLTED NOZZLE.

TRANSIENT CONDITIONS ANALYZED (REF 3)

THE FOLLOWING IS A SUMMARY OF THE AFW TRANSIENT EVALUATED IN REF [3], "AFW BOLTED NOZZLE ANALYSIS".

TRANSIENT CONDITION -

570° NOZZLE & SHELL SUDDENLY HIT WITH 175 GPM (PER NOZZLE) 40° AFW FLOW. THE FLOW CONTINUES FOR 425 SEC TO REACH A STEADY STATE CONDITION AND IS THEN TURNED OFF. 570° STEAM

IS THEN ASSUMED TO FILL THE NOZZLE.

∴ MAXIMUM $\Delta T = 570° - 40° = 530°$
AFW FLOW = 175 GPM / NOZZLE
AFW TEMP = 40°

FATIGUE USAGE FACTOR FOR THE NOZZLE IS .547 FOR A 5 YEAR DESIGN LIFE. SEE REF [3] PAGE 124. THIS IS BASED ON 875 AFW ACTUATIONS. SEE REF [2] & [3].

ACTUAL TRANSIENT CONDITIONS (REF 1)

AFW FLOW TEMP - ASSUMED TO BE ~ 70°
AFW FLOW RATE - MAXIMUM = 1088.7 GPM TOTAL
= 136 GPM / NOZZLE

THE AFW FLOW IS MUCH LESS THAN THE MAX DURING MOST OF THE TRANSIENT. FLOW IS INITIATED 3 TIMES FOR OTSG 2 AND 2 TIMES FOR OTSG 1.

MAX SHELL TEMP PRIOR TO AFW INITIATION IS BASED ON THERMOCOUPLE TEMPERATURES

MAX TEMP = 571.7° @ TIME 1:54, OTSG 1

∴ MAXIMUM ΔT = 571.7° − 70° = 501.7°
AFW FLOW = 136 GPM / NOZZLE
AFW TEMP = 70° (ASSUMED)

IT IS CONCLUDED THAT THIS TRANSIENT HAS BEEN CONSERVATIVELY COVERED IN REF [3]. A FATIGUE USAGE VALUE WILL BE CALCULATED FOR THIS TRANSIENT BASED ON REF [3] STRESSES.

\# CYCLES = 3 (AFW INITIATIONS)

ALLOWABLE CYCLES FOR COMPARABLE TRANSIENT OF REF [3] IS 1600 (pg 122)

$\mu = \frac{3}{1600} = .002$ NEGLIGIBLE

CONCLUSION: THE TRANSIENT OF REF [1] DOES NOT AFFECT THE STRUCTURAL INTEGRITY OF THE AFW BOLTED NOZZLE.

MAIN FEEDWATER NOZZLE EVALUATION

THIS SECTION CONTAINS THE EVALUATION OF THE MFW NOZZLE FOR THE TRANSIENT DESCRIBED IN REF [1]

TRANSIENT CONDITIONS ANALYZED (REF 4)

THE FOLLOWING IS A SUMMARY OF THE MFW TRANSIENTS EVALUATED IN THE ORIGINAL STRESS REPORT, REF [4].

TRANSIENT CONDITION -

FROM REF [4], PG B-1-1 THE RESULTING STRESS FROM LOSS OF FW FLOW IS SMALL. THE CASE OF HOT SHELL & NOZZLE BEING HIT WITH COLD FW IS COVERED BY THE [illegible] POWER CASE (4.62 HR AFTER HU START). FROM PAGE B-1-4 OF

REF [4], THE NOZZLE IS AT 535° AND THEN SUDDENLY HIT BY 9500 GPM (32 NOZZLES) 90° FEEDWATER FLOW.

∴ MAXIMUM $\Delta T = 535° - 90° = 445°$
MF FLOW = 9500/32 = 297 gpm/NOZZLE
= 139,650 LB/HR REF[4], pg B-3-4
MF TEMP = 90°

FATIGUE USAGE FACTOR FOR THE NOZZLE IS .40 (REF [4], pg B-17-3).

ACTUAL TRANSIENT CONDITIONS (REF 1)

MAIN FEEDWATER TEMP = 410.83° (time 1:51.26)
MAIN FEEDWATER FLOW = 137,000 LB/HR MAX

THE MFW FLOW IS MUCH LESS THAN THE MAXIMUM DURING MOST OF THE TRANSIENT. MFW FLOW IS INITIATED ONLY ONCE. NOTE THAT THE MFW INFORMATION IS FOR OTSG #1 AND IS ASSUMED TO APPLY TO OTSG #2.

MAXIMUM SHELL TEMP PRIOR TO MFW INITIATION IS BASED ON THERMOCOUPLE TEMPERATURES

MAX TEMP = 572.5° TIME 1:50.52

$\therefore$ MAXIMUM $\Delta T = 572.5 - 410.83 \approx 162°$
MFW FLOW = 137,000 LB/HR
MFW TEMP $\approx$ 411°

IT IS CONCLUDED THAT THIS TRANSIENT HAS BEEN CONSERVATIVELY COVERED IN REF[4]. THE EFFECT OF THIS TRANSIENT ON THE FATIGUE USAGE FACTOR IS INSIGNIFICANT.

CONCLUSION: THE TRANSIENT OF REF[1] DOES NOT AFFECT THE STRUCTURAL INTEGRITY OF THE MAIN FEEDWATER BOLTED NOZZLE.

NOTE: A STEP CHANGE IN TEMP FROM 573° TO 411° IS MORE SEVERE THAN A RAMP CHANGE FROM 411° TO 320°. BOTH 411° FW & 320° FW CASES ARE COVERED BY THE EXISTING ANALYSIS (535° STEP CHANGE TO 95°).

AFW JET IMPINGEMENT TUBE STRESS

THIS SECTION WILL EVALUATE THE EFFECTS OF THE AFW FLOW ON THE OTSG TUBES FOR THE TRANSIENT OF REF [1].

TRANSIENT CONDITIONS ANALYZED (REF 5)

THE FOLLOWING IS A SUMMARY OF THE CONDITIONS ANALYZED IN REF [5].

PRIMARY FLUID TEMP = 626°
AFW FLUID TEMP = 90°

TUBE USAGE FACTOR IS .390 FOR 29400 CYCLES OF AFW

ACTUAL TRANSIENT CONDITIONS (REF 1)

PRIMARY FLUID TEMP = 592.5° (TIME 1:53.20)*
AFW FLUID TEMP = 70° ASSUMED

* AT AFW INITIATION

3 CYCLES OF AFW (AFW INITIATED 3 TIMES, OTSG 2)

IT IS CONCLUDED THAT THIS TRANSIENT HAS BEEN CONSERVATIVELY COVERED IN REF [5]. THE EFFECT OF THIS TRANSIENT ON THE FATIGUE USAGE FACTOR IS INSIGNIFICANT.

CONCLUSION: THE AFW FLOW OF THIS TRANSIENT DOES NOT AFFECT THE STRUCTURAL INTEGRITY OF THE OTSG TUBES.

PDS-21036-3 (9-84)

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DOC. I.D. 32-1158583-00

OTSG Tube Loads

In this section, the compressive axial loads in the OTSG tubes are investigated.

After determining the ΔT between tubes and shell and the corresponding primary and secondary pressures for each Steam Generator, the compressive loads in the tubes are determined and show to be acceptable.

PREPARED BY [illegible] DATE [illegible]

REVIEWED BY [illegible] DATE 6/20/85

TUBE-SHELL ΔT (Data from Ref. 1)

OTSG #1

TUBE TEMP: USE AVERAGE OF HTL + CLG TEMPS.

AT APPROX. 1:53 AVE TEMP = 593°

SHELL TEMP: AT THE TIME OF THE MAX. TUBE TEMP THE AVERAGE SHELL TEMP IS APPROX 533°.

$\Delta T = 593° - 533° = 60°$

ΔP: AT THE TIME OF PEAK TUBE TEMP (AND PEAK TUBE-SHELL ΔT) THE PRIMARY PRESSURE IS APPROX. 2000 PSI AND THE SECONDARY PRESSURE IS APPROX. 800 PSI. SINCE THE SECONDARY PRESSURE CURVE IS SO STEEP DURING THIS PORTION OF THE TRANSIENT AND A SMALL ΔP IS CONSERVATIVE FOR CALCULATING COMPRESSIVE TUBE LOADS A SECONDARY PRESSURE OF 950 PSI WILL BE USED.

$\Delta P = 2000 - 950 = \underline{1050 \text{ PSI}}$

TUBE-SHELL ΔT CONT.

OTSG #2

TUBE TEMP: 593.5°

SHELL TEMP: 521°

$$\Delta T = 593.5 - 521 = 72.5^\circ$$

ΔP: PRIMARY PRESSURE = 2300 [illegible]

SECONDARY PRESSURE = [illegible] PSI

$\Delta P =$ 2300 - [illegible] = [illegible] PSI

TUBE LOADS

DATA FROM REF 7 WILL BE USED TO DETERMINE THE TUBE LOADS CORRESPONDING TO THE CALCULATED TEMPERATURE AND PRESSURE DIFFERENTIALS.

FROM REF. 7, TABLE 5-7 :

TRANS.	ΔP	MECH. TUBE LOAD
1A	1300	419#
1B	0	65#

$$\text{TUBE LOAD FROM } \Delta P = \frac{419-65}{1300} = .2723\ \#/\text{PSI } \Delta P$$

FROM REF 7, TABLE 5-4 :

TRANSIENT 1A TOTAL TUBE LOAD = -775#

THERMAL TUBE LOAD = -775 - 419 = -1194#

FROM REF 7, TABLE 5-2 : ΔT FOR TRANS. 1A = 65°

$$\text{TUBE LOAD FROM } \Delta T = \frac{-1194}{65} = -18.369\ \#/{}^\circ F\ \Delta T$$

$$\text{TUBE LD} = 65 + .2723(\Delta P_i) - 18.369\,\Delta T_i$$

THE MAXIMUM COMPRESSIVE TUBE LOADS ARE:

OTSG #1 : $65 + (.2723)(1050) - 18.369(60) = -751\#$

OTSG #2 : $65 + (.2723)(1000) - 18.369(72.5) = -994\#$

THE CRITERIA FOR EVALUATING THESE TUBE LOADS WILL BE DISCUSSED IN THE FOLLOWING SECTION.

ALLOWABLE TUBE LOAD

Reference 9 summarizes tests made on a single OTSG tube. In addition to measurements of the natural frequencies under various conditions, lateral tube deflections as a function of axial compressive load were measured up to a load of 700 lbs. The load was also increased to about 1200 lbs, but no deflections were measured; it was noted, however, that the tube came in contact with at least one of the 1/4 inch clearance tube stops.

Reference 10 reports on tests made on several OTSG tubes with tube spans corresponding to the TVA design. Lateral tube deflections were measured for various compressive loads and it was determined that elastic buckling occurs at about 700 lbs; this is in agreement with Reference 9. In this test, deflections were also measured up to a load of 1300 lbs. Also, the lateral permanent set was measured after the load was removed. In this test, the tubes were loaded above 700 lbs by heating the tubes (displacement controlled test), which is realistic; in Reference 9, the load was applied with a hydraulic cylinder (load controlled test), which does not correspond to the actual loading conditions in an OTSG.

Since Reference 10 contains considerably more data than Reference 9, it would be desirable to use the former to draw conclusions concerning tube behavior in the Davis-Besse OTSG. Before this can be done, however, the question of the longer tube spans at Davis-Besse must be discussed.

The tube spans adjacent to the tubesheets are about 46" in the Davis-Besse OTSG; the corresponding spans used in the tests reported on in Reference 10 are 22 3/4 and 29 1/2. With these exceptions, the Davis-Besse tubes spans agree closely with those reported in Reference 10 (mostly in the 38"-40" range). Since the maximum tube deflections occur in the intermediate spans near the midpoint of the tube where the effect of the end conditions is minimal the test results of Reference 10 can reasonably be applied to Davis-Besse intermediate tube spans. End span differences can be resolved as follows:

For analytical purposes, the tubes spans between tube support plates are assumed to be hinged at each end, i.e., it is assumed that the support plates do not inhibit rotation of the tube. Test data indicate that this is a reasonable assumption, at least until cocking of the tube overcomes the clearance between the tube and the edges of the hole in the support plate. In an end span, however, the tube is attached at one end to the primary face of the tubesheet and extends through the hole in the tubesheet before reaching the secondary face. Since the clearances between tube and tubesheet and tube and support plate are the same (0.015") and since the tubesheet is much thicker than a tube support plate (24" vs. 1.5" respectively), the tube rotation that can occur before a tube comes in contact with the edge of the hole on the secondary face of the tubesheet is less than one-tenth of the possible rotation at a support plate. This means that the end spans behave more like a hinged-fixed span than hinged-hinged. Ideally, this would reduce the effective length from 46" to 0.7 x 46" = 32"; this is perhaps a bit too optimistic in practice, but the effective length certainly lies in the 35"-40" range, which corresponds to the tests described in Reference 10.

In Reference 10, it is stated that the tubes are able to withstand a compressive load of 1100 lbs. without gross structural damage, although some local yielding might occur. Also, the lateral deflections are large enough to permit tube-to-tube contact. Reference 10 also summarizes the measurements made of the local deformations of the tubes at the support plates; the maximum value reported is 2.5 mils. Since the tube-thinning investigation Ref. 7 showed that much larger defects were tolerable, the local deformations to be expected at a load of 1100 lbs. would not be a concern.

There remains a question whether the 1100 lbs. should be adjusted downward to account for the tube temperature. Since the tube load in the test was imposed by heating the tubes, they were obviously at an elevated temperature; this temperature is unfortunately not reported in Reference 10. If we assume that the 1100 lbs were applied at room temperature, the adjustment for temperature (E-shift) would reduce the load to about 1020 lbs., which is still above the calculated value of 994 lbs.

TUBE FATIGUE DAMAGE

STRESS RANGE / LOAD RANGE

6-9-85 TRANSIENT	-994 #	
NORMAL COOLDOWN (18)	+1107 #	(REF. 7 TABLE 5-4)
RANGE	2101 #	

STRESS RANGE $\frac{2101^{\#}}{.063} = 33.35$ KSI

A REVIEW OF THE FATIGUE CALCULATIONS IN REF. 7, SECTION 6 SHOWS THAT A SINGLE OCCURANCE OF THIS TRANSIENT HAS A NEGLIGIBLE EFFECT ON THE USAGE FACTOR.

TUBE YIELD STRESS

THE MAX. TUBE LOAD DURING THE TRANSIENT IS -994 #

$\sigma = \frac{994}{.063} = 15.8$ KSI < TUBE YIELD STRESS = 27.9 KSI @ 600°

TUBESHEET STRESSES

THIS SECTION CONTAINS THE EVALUATION OF THE LOWER TUBESHEET FOR THE TRANSIENT DESCRIBED IN REF [1].

TWO CONDITIONS ARE LOOKED AT:

1) PRIMARY + SECONDARY STRESS DUE TO SHELL TO TUBESHEET ΔT
2) PEAK STRESS DUE TO THERMAL SHOCK.

THE TRANSIENT DESCRIBED IN REF [1] WAS NOT EVALUATED FOR IN REF [6]. A REVIEW OF REF [1] AND REF [6] SHOWS THAT THE TEMPERATURE DIFFERENCES USED IN REF [6] EVALUATIONS ARE GREATER THAN THOSE EXPERIENCED BY THE TRANSIENT OF REF [1]

PRIMARY + SECONDARY STRESS

TRANSIENT CONDITIONS: (REF [1], OTSG #1)

T_{SHELL} = TEMP OF SHELL AT LOWER THERMOCOUPLE (T 887)

$T_{TUBESHEET}$ = ASSUMED TO BE THE PRIMARY FLUID DISCHARGE TEMPERATURE.

T_{SAT} = SATURATION TEMPERATURE OF FEEDWATER ON TUBESHEET

T_{FW} = FEEDWATER TEMPERATURE

	AT LOSS OF FW FLOW TIME 1.40.02	AT RETURN OF FW FLOW TIME 1.51.26
T_{SHELL}	533.9°	540.3°
$T_{TUBESHEET}$	554.3°	587.6°
T_{SAT}	541.5°	515.7°
T_{FW}	436.3°	410.3°

THE ΔT WHICH CAUSES THE MAJORITY OF PRIMARY + SECONDARY STRESS IS THE $T_{SHELL} - T_{TUBESHEET}$ ΔT. ($T_{TUBESHEET} \approx T_{TUBE}$)

ΔT AT FW FLOW LOSS = 554.3 − 533.9 = 20.4°

ΔT AT FLOW RETURN = 587.6 − 540.3 = 47.3°

A REVIEW OF REF [6] SHOWS THAT THE ΔT BETWEEN SHELL AND TUBESHEET ARE GREATER THAN THOSE GIVEN ABOVE.

IT IS CONCLUDED THAT THE TRANSIENT STRESSES DO NOT AFFECT THE STRUCTURAL INTEGRITY OF THE TUBESHEET

THERMAL SKIN STRESS (Tubesheet)

FROM REF [9], APPENDIX A (A-8152)

THE MAXIMUM THERMAL SKIN STRESS IS:

$$\sigma_{SKIN} = K_{SKIN} Y_{max} \left(\frac{P}{h}\right)\left(\frac{E\alpha}{1-\nu}\right)(T_m - T_e) \quad \text{eq } 23$$

WHERE E, α, ν = UNMODIFIED MATERIAL PROPERTIES

Y_{max} = STRESS MULTIPLIER

T_m = MEAN PLATE TEMP

T_s = SURFACE TEMP

P = PITCH

h = LIGAMENT WIDTH

FROM REF [6], pg 172

(P) PITCH = .875

HOLE DIA = .635

(t) PLATE THICKNESS = 24"

PLATE O.R. = 57.47"

FROM REF [8], SA 508 CL 2

$E_{600°} = 25.4 \times 10^6$ psi

$\alpha_{600°} = 7.42 \times 10^{-6}$ in/in/°F

$\nu = .30$

h = LIGAMENT WIDTH = .875 - .635 = .240"

η = LIGAMENT EFFICIENCY = h/P
= .240/.875 = .274

Y_{MAX} = 1.2 (FIG A-8142-2)

K_{SKIN} = .24 (FIG A-8153-1)

T_{MEAN} = USE PRIMARY FLUID DISCHARGE TEMPERATURE (REF 1), OTSG #1
= 587.6° F (PRIOR TO FW FLOW BEING TURNED ON, TIME = 1.51.26)

T_S = USE SATURATION TEMPERATURE OF FW (REF 1, PG 10) OTSG #1
= 515.7° F (TIME = 1.51.26)

$$\sigma_{SKIN} = .24(1.2)\left(\frac{.875}{.240}\right)\left(\frac{25.4(7.42)}{(1-.3)}\right)(587.6 - 515.7)$$

σ_{SKIN} = 20,326 psi

S_{ALT} = S_{PEAK} RANGE ÷ 2

= 20,326/2 = 10,163 psi WHICH IS ADDED TO PREVIOUS S_{ALT} FOR 1 FATIGUE CYCLE.

PDS-21036-3 (9-84)

Babcock & Wilcox
a McDermott company
Nuclear Power Division

GENERAL CALCULATIONS

DOC. I.D. 32-1158583-00

IT IS CONCLUDED THAT THIS ADDITIONAL STRESS WILL NOT AFFECT THE FATIGUE USAGE FACTOR GIVEN IN REF [6].

THE FATIGUE USAGE FACTOR OF REF [6] (PAGE A1) IS .11 FOR THE SHELL AND .13 FOR THE TUBESHEET.

PREPARED BY DEC DATE 6/20/85
REVIEWED BY JFS DATE 6/20/85

References

1. B&W Document 32-1158582-00, "Plant Parameter Data for 6/85 Davis Besse-1 Transient." (NSS 14)

2. PE Certification Sheets, Field Change Authorization (FCA) Nos. 04-3783-05 & 04-3784-05. (NSS 14)

3. B&W Document 32-1134736-00, "Auxiliary Feedwater Bolted Nozzle Analysis. (NSS 14)

4. B&W Stress Report of OTSG Toledo Edison Co., Contract 610-0014-55, Vol. 1-3, Report No. 7, NPGD Microfilm Roll Nos. 80-15 & 80-16. Feedwater Nozzle (NSS 14)

5. B&W Document 32-1147666-00, "TECO AFW Jet Impingement Stress." (NSS 14)

6. B&W Stress Report, Vol. 1-3, Report #4, NPGD Microfilm Roll Nos. 7-80-15 & 80-16. Tubesheet Analysis (NSS 14)

7. B&W Topical Report BAW-1588, Determination of Minimum Required Wall Thickness of 177-FA Once Through Steam Generator, April, 1980.

8. ASME Boiler & Pressure Vessel Code, Section III, Appendices, 1980 Edition.

9. B&W Research Report No. 6830, "Vibration and Buckling Characteristics of a Sample Tube from the Once Through Steam Generator", February 16, 1968 (B&W Proprietary Information).

10. B&W Letter Report LR:74:2162-70:01 "OTSG Tube Buckling Test," May 10, 1974 (B&W Proprietary Information).

Attachment 1

Research Report No. 6830

"Vibration & Buckling Characteristics of a Sample Tube from the Once Through Steam Generator"

February 16, 1968

Note: Attachment 1 (pages 34-65) contains proprietary information and is not for release outside B&W

Attachment 2

Letter Report LR:74:2162-70:01

" OTSG Tube Buckling Test"

May 10, 1974

Note: Attachment 2 (pages 66-85) contains proprietary information and is not for release outside B&W

APPENDIX C.3.3 - ENGINEERED SAFEGUARD SYSTEM

Evaluations of the Reactor Protection System (RPS) and Engineered Safety Features Actuation System (ESFAS) are in progress. The results of these evaluations will be included in this Appendix following completion.

APPENDIX C.4.1 - ACTIONS RELATED TO OPERATING PROCEDURES AND TRAINING

As discussed in Section II.C.4 of the Course of Action report, a review of operational implications of the June 9, 1985 event was conducted. The review was made by an action plan committee chaired by the Operations Superintendent and including representation from Operations, the Technical Section, and the Training Department. The committee identified "Findings" which defined the operational-related problems experienced during the event. An overall assessment also identified findings related generically to Operations activities.

This Appendix reports those findings and the conclusions reached in evaluating each problem. The conclusions include the corrective actions to be taken and their schedule. The findings are discussed in two groupings:

- Overall Findings - Relating to management of the operations function and general procedural issues.

- Specific Findings - Relating to specific problems encountered during this event.

Separate from the Action Plan committee review, an assessment was also made into the circumstances involved in classifying and reporting this event. The results of this assessment are reported at the end of this section.

Overall Findings

1. Manual vs. Automatic Safety System Actuation

During the June 9 event, operators anticipated automatic operation of the Steam Feedwater Rupture Control System (SFRCS) and manually actuated the system. The desirability of such manual initiation was evaluated.

Finding:

Manual actuation of the SFRCS played a key role in the June 9 event. An operator error in carrying out this actuation ultimately caused the loss of all feedwater. The operators were responding to the apparently inadvertent closure of the main steam isolation valves and the resulting coastdown of the remaining main feedpump. It was their intent to manually actuate the system in anticipation of the forthcoming low level and the realization that the MSIVs were closed. The Reactor Operator (RO) consulted with the Shift Supervisor and received his concurrence prior to the manual actuation.

Conclusion:

The licensed operators have a responsibility to manually actuate safety systems. Some procedures also direct manual actuation during deteriorating plant conditions; e.g., loss of instrument air. The committee did not consider it prudent to attempt to provide specific

case-by-case guidance for when it is appropriate to manually actuate the various safety systems. The operators must evaluate all conditions present at the moment, then make the decision for manual actuation. The Reactor Operator should not be required to obtain specific permission from the Control Room Senior Reactor Operator (SRO) prior to taking manual actions if he deems them necessary. However, if the SRO is in the Control Room panel area at the time, the RO must commun-icate his intent to manually actuate a safety system. At that point, the SRO may choose to direct that the action not be taken. All operations personnel will be advised of this conclusion prior to startup. The simulator training program has been revised to incorporate this philosophy.

2. <u>SRO's Absence from Control Room during Emergency Procedure Use</u>

Both SRO Licensed Operators were outside Control Room Panel Area while Emergency Procedure EP 1202.01, "RPS, SFAS, SFRCS Trip or Steam Generator Tube Rupture Emergency Procedure" was in use.

Finding:

For a very brief period during the event, both SRO licensed personnel left the Control Room panel area. The Assistant Shift Supervisor left to lineup the startup feedpump; the Shift Supervisor left to obtain keys. This condition caused a delay in assessing the course of action in EP 1202.01 since the Shift Supervisor had to backtrack

through the procedure to ensure all required actions had been completed.

Conclusion:

Once EP 1202.01 has been entered and the control room SRO has assumed the duties of procedure director, the SRO will be required to remain in the Control Room directing the Reactor Operators until properly relieved by another SRO. The emergency procedure was developed and training was conducted based upon a team concept, with the SRO directing the actions of the reactor operators. The procedure was written and structured with this team effort in mind and the June 9, 1985 event demonstrates the need to maintain this structure. (It should also be noted that the provision of an emergency key locker in the Control Room, as discussed in Appendix C.4.2 directly address the reason the Shift Supervisor left the Control Room during this event).

3. Role of Interim Emergency Duty Officer (EDO)

The Shift Supervisor is procedurally required to assume the responsibilities of the Emergency Duty Officer whenever an Emergency situation exists. His ability to fulfill these responsibilities, in addition to his primary interest in directing the activities of Operations personnel, was reviewed.

Finding:

Although the Shift Supervisor is capable of performing his plant responsibilities and those of Interim EDO, it is difficult to assume both roles simultaneously. During the event, conditions existed for a short period of time (approximately 12 minutes) which would constitute a Site Area Emergency. The Shift Supervisor was heavily involved in resolving the numerous equipment malfunctions to mitigate the loss of feedwater. Although it was recognized that Emergency Action Level (EAL) conditions existed for which it was appropriate to declare a Site Area Emergency, immediate efforts were appropriately directed towards stabilizing the plant. Implementing the emergency plan was of secondary priority. This is consistent with guidance and training provided in the Emergency Plan.

Conclusion:

The current STAs are in training to assume the role as Interim EDO (see Section II.C.6 of the Course of Action Report). This training will be completed prior to returning the unit to power operation so that the STA will be able to advise the Shift Supervisor on Emergency Action Levels. The STA will assist the Shift Supervisor in making Emergency Plan determinations. The Shift Supervisor will maintain ultimate responsibility for event classification.

4. Operator Performance of "Drastic Actions"

Item II.A.12 of the enclosure to NRC's August 14, 1985 to Toledo Edison identified, in part, a concern regarding whether plant procedures requiring "drastic" action are sufficiently precise and clear to assure timely implementation.

Finding:

A reluctance to initiate drastic actions, by itself, is not considered inappropriate. Operations personnel are expected to be aware of the potential consequences of their actions. On the other hand, knowingly exceeding strict procedural action points because of a perception that more margin actually exists would be unacceptable. The review committee determined that the latter case did not occur in this event. Key decision points are defined in emergency procedures based upon much analysis and forethought by the preparer of the procedure. The operator must not assume anything beyond the defined conditions set forth in the procedure.

Conclusion:

The Operations Superintendent will reinforce to all plant operators the philosophy that actions explicitly required by procedures must be taken when called for by the procedure. In particular, it will be noted that it is imperative that the operators perform the actions outlined in EP 1202.01 without question. The analysis and decision

steps are all based on these actions. In addition, EP 1202.01 will be reviewed to assure that all cases where drastic actions are called for are explicit and clear and that plant parameters used to initiate these actions are clearly distinguished to the operators. These actions will be completed prior to startup.

5. Other Infrequent, Difficult or Critical Operator Actions

Several of the operator actions which were required to be performed during the June 9, 1985 event were actions performed by operators only infrequently. In some cases, difficulties were experienced.

Finding:

The Training Department has utilized an INPO Training Systematic Development Process to support of Toledo Edison's program to obtain INPO accreditation of training programs. This process is being used to identify critical and difficult tasks that require training.

Conclusion:

Specific operator tasks involving infrequent operations will be reviewed to identify those of "highest priority" in terms of difficulty, frequency of performance, and importance of proper performance to safety. These tasks will be compared to the plant

emergency/alarmed procedures for required actions. Specific training will be conducted for all operators on these tasks prior to restart. In the longer term, the performance-based training process will provide assurance that high priority tasks are included in the training program.

6. Lack of a Complete Understanding of the loss of Feedwater Event Analysis.

Proper actions were taken by Operations personnel to recover auxiliary feedwater flow as rapidly as possible. Interviews following the June 9 event, however, raised some questions regarding the understanding of the loss of feedwater analyses.

Finding:

The prompt actions of operations personnel during the June 9 event demonstrated an understanding of the severity of a total loss of feedwater. Some confusion exists, however, over what specific time frames and equipment configurations were assumed in the analysis.

Conclusion:

All licensed and non-licensed operators will receive training on the results of the loss of feedwater analyses presently being conducted by B&W (see Section II.C.3 of the Course of Action Report.) The

training will include assumptions, specific results, and how the analysis relates to EP 1202.01, especially that section dealing with the lack of heat transfer. EP 1202.01 may be revised as a result of the new analyses and training will include any changes. This training will be completed prior to startup.

Specific Findings

1. Resetting of Auxiliary Feedpump Turbine Trip Throttle Valve

Investigations into the causes of the inability to restart and control the Auxiliary Feedwater Turbines after the overspeed trips identified that equipment operators had not properly reset the overspeed trip mechanism.

Finding:

The Equipment Operators were not fully aware of the correct actions required to reset both the Trip Throttle Valve and the associated turbine overspeed mechanism. Training previously conducted, along with procedural guidance, placed the primary emphasis on the trip hook mechanism and not the overspeed mechanism tappet. In addition, operators rarely would have had to reset an actual overspeed trip, which is not exactly the same as a manual trip. Large steam differential pressures exist during an actual overspeed condition. This causes difficulty in handwheel operation not normally encountered by the operator during routine surveillance testing.

Conclusion:

Each plant operator, licensed and non-licensed, along with non-shift staff licensed personnel, will be required to reset the trip throttle valve and turbine overspeed mechanism from a tripped condition. In order to best simulate the differential steam pressure conditions as close as possible to an actual event, this training session will be done with full hot standby steam pressure available at the trip throttle valve and the auxiliary feedpump lined up for full flow on the test header. During this training, the overspeed trip mechanism tappet operation will be discussed as this cannot be simulated without an actual overspeed trip. This training will be conducted after any hardware modifications which might be required are completed (as may be identified as part of Action Plan 1d). The training will be completed prior to startup.

2. AF-599/608, Auxiliary Feedwater Containment Isolation Valves Operating Logic

During the June 9 event, operators experienced difficulty in taking the actions necessary to reopen AF 599 and AF 608 from the Control Room. Operation of these valves is different from other plant valves.

Finding:

Without regard to the equipment failure associated with AF-599/608, the operator interviews show confusion existed associated with the

logic circuitry and control room switches for these valves. The Control Room operators attempted to reposition the valves following failure of the automatic signals from the SFRCS. In addition, unnecessary actions were taken to place the SFRCS in the blocked condition for low steam pressure by using the "Initial Bypass" and "Block" pushbuttons. Although this action did not prevent or hinder proper valve response, it demonstrated a lack of understanding of the logic schemes by the operators.

Conclusion:

Operators will receive training regarding the specific control logic for AF-599/608. This training will include not only the specific control switch functions, but also the dual electrical controllers associated with the valves. The training will not be conducted until after any physical changes which may be made as a result of the investigation are implemented to ensure the operators are instructed on the system actually in place when the unit is restarted. This training will be completed prior to restart.

3. Improper Manual SFRCS Actuation

The principal operator error involved in the June 9 event was the improper manual actuation of SFRCS. In addition to the generic issues regarding manual actuation (discussed above), the circumstances involved in this specific error were evaluated.

Finding:

In reviewing the event leading up to the improper SFRCS actuation, several factors have been identified as the root causes for the operator error.

- A human engineering design deficiency related to the control switch layout.

- Insufficient training regarding potential consequences of improper manual actuation of the SFRCS.

- Infrequent opportunities to actually perform the operation and inability to perform the operation on the simulator.

The operator did, in fact, initiate the SFRCS improperly by manually depressing the wrong buttons; however, the operator quickly recognized his error based upon unexpected response of the AFW system. Prompt action was taken to remedy the error by the operator, however, an equipment malfunction prevented proper system realignment. These actions indicate the ability of the operators to analyze abnormal conditions, thus indicating a good understanding of the system. The improper control switch selection indicates a need to practice in a simulated emergency situation and a need to change the switch configuration.

Conclusion:

SFRCS has been reviewed as part of the Decay Heat Removal Task Force efforts (see Section II.C.2 of the Course of Action Report). In addition to the changes which may result from the review, the following actions will be completed:

- Licensed personnel will receive training regarding manual actuation of the SFRCS. All combinations of actuations will be addressed in this training, including the negative consequences of improper actuation. This training will be completed prior to startup.

- Simulator training, which began August 26, 1985, will include use of the magnetic Control Room mock-up switches for SFRCS.

4. <u>Performance of Manual Pressure-Temperature Plotting when the SPDS is not Functioning</u>

Plant procedures require that operators manually plot reactor coolant system pressure and temperature when SPDS is not functioning during transients. That action was not taken on June 9. The need for such action was reevaluated.

Finding:

During normal station operation, the SPDS provides the Control Room operator a graphic display and trend of key parameters. This plot

allows the operator to readily determine the key symptom which must be remedied to stabilize the plant. The plant symptom-based emergency procedure, EP 1201.01, was developed with the premise that operators are able to recognize Lack of Heat Transfer, Excessive Heat Transfer, and Loss of Subcooling Margin based upon Pressure-Temperature (P-T) displays or plots. For this event, the operators were correctly able to recognize the appropriate symptom without the P-T display. The operators did not perform manual plotting, as they were trained to do, during the the June 9, 1985 event.

Conclusion:

The events of June 9, were recognized to be extremely serious and the pace of the events was quite fast to mitigate the abnormal heat transfer symptom. However, during events of longer duration involving multiple symptoms, it is important to track the event for changing symptoms and correlation to the procedure. The SPDS may not always be available to the operator. The following actions will be taken:

- During the 1985 simulator training at least one day of the training will include an inoperable SPDS display screen. This will require manual P-T plotting. The plot should be performed by the primary side Reactor Operator since the parameters are most readily available at that location.

- A laminated or plastic covered P-T graph and writing device (e.g., a grease pencil) will be provided on the operator console in the control room to be used in the event that the SPDS is unavailable.

5. Premature Operator Actions to Control Header Pressure on a Reactor Trip

Davis-Besse operators manually reduce steam header pressure after most reactor trips. During the June 9 event, difficulties were experienced in controlling header pressure. The efficiency of the standard practice was evaluated.

Finding:

Davis-Besse Operations personnel have developed a normal practice of manually reducing steam header pressure following most reactor trips. This practice results from experienced problems with steam generator safety valve operation including a failure of one valve to reseat on March 2, 1984. Reducing header pressure serves to help assure that the safety valves reseat.

Conclusion:

Training of the operators prior to startup will reinforce that it is not necessary to immediately lower the header pressure setpoint.

This training will include calculations correlating the effects of reducing secondary side pressure prematurely to reactor coolant inventory and subsequent loss of pressurizer level. Training will also reinforce the acceptability to take actions if a valve is truly malfunctioning.

6. Recognition of Steam Generator Dryout Conditions

Steam Generator dryout conditions existed on June 9 for which Emergency Procedure EP 1202.01 required initiation of feed and bleed cooling. Such actions were not taken. The reasons for not taking these actions were evaluated.

Finding:

EP 1202.01 specifies conditions defining steam generator dryout after a lack of primary to secondary heat transfer exists. The specified conditions are both steam generator pressures less than 960 psig or both SG levels less than 8 inches indicated level. When both SGs are "dry" the procedure directs establishing MU/HPI cooling (feed and bleed). At the time dryout conditions were reached during the June 9, 1985 event, no one in the control room had the procedure open to the page where these conditions are defined. The Assistant Shift Supervisor, who had initially been reading EP 1202.01 to the Reactor Operators, had left the Control Room prior to dryout conditions being reached to line up the startup feedpump. The Shift Supervisor left at the same time, momentarily, to obtain a set of locked valve keys

to give to the equipment operators for opening AF-599/608. Upon returning to the Control Room, the Shift Supervisor backtracked to an earlier procedure section to verify conditions. As a result, there was a delay in identifying the steam generator dryout.

Conclusion:

- If the SRO performing the task of reading the steps of EP 1202.01 must leave the Control Room, he will be required to clearly explain to his relief what step in the procedure the operators are currently performing.

- Turnover of this task will be practiced during 1985 simulator exercises.

- EP 1202.01 will be modified based on the new B&W loss of feedwater analysis to provide definitive criteria for lack of heat transfer requiring initiation of MU/HPI cooling. This criteria will be added to the Actions side of the page.

NOTE: The need for keys which caused the Shift Supervisor to leave the Control Room is being directly addressed by installation of an emergency key locker in the Control Room (see Appendix C.4.2)

7. SFRCS Table in EP 1202.01 Contained Errors

During review of EP 1202.01, errors were found in the table the operators use to verify SFRCS response.

Finding:

The table used to verify proper SFRCS response during a trip condition was not correct. The table included the steam generator drain valves under the respective channel half trip conditions but not under the full trip conditions, and the startup feedwater valves were not properly designated as closing from a full trip in either actuation channel.

Conclusion:

The procedure will reflect the actual SFRCS response prior to startup. Procedure revisions will be made, as necessary, whenever changes to SFRCS are implemented.

8. Adequacy of Control Room Instruments to Support Decision Steps in EP 1202.01

The operators failure to identify steam generator dryout conditions (6. above) was also reviewed from the perspective of adequacy of available instrumentation.

Finding:

A decision step to initiate feed and bleed cooling was missed by the plant operators. Although the root cause was not specifically found to be the instrumentation, the committee determined a generic concern that sections of EP 1202.01 and plant abnormal procedures require use of instrumentation that may not be able to be read to the required accuracy to support the decision step of the procedure. It should be noted that the DCRDR previously identified many of these concerns.

Conclusion:

- EP 1202.01 and all Abnormal Procedures (ABs) will be reviewed and compared to existing Control Room instruments prior to restart.

- If deemed necessary, instruments will be color coded to denote very important values to support significant actions of EP 1202.01 and other abnormal procedures (ABs).

9. <u>Operation of AF-599/608 not in System Procedure</u>

As noted in Specific Finding No. 2 above, the operation of AF599 and AF608 is different than other plant valves. System procedures were reviewed to determine if this difference was adequately described.

Finding:

The operation of AF-599/608 open/close/reset pushbuttons are not

similar to other valves in the plant. These have a unique logic and operation. A review of the system operating procedure, SP 1106.06, revealed no guidance on the specific operation of these valves.

Conclusion:

The discussion section in the procedure will be revised to include an explanation of AF 599/608. Procedural changes will not be made until changes to the operating logic, presently under consideration as a result of the review of SFRCS, are implemented. At the time of startup, however, the procedure will discuss the system then in place.

10. <u>Realignment of Auxiliary Feedpump Minimum Recirculation Flowpath</u>

Closure of the Auxiliary Feedwater Containment Isolation Valves meant that all AFW was via a recirculation flowpath to floor drains. The need for this lineup, considering the resulting loss in available inventory, was evaluated.

Finding:

During the June 9 Event, the Condensate Storage Tanks (CST) reached a minimum level of approximately 25 feet. One contribut-ing factor was that the minimum recirculation flowpath for the auxiliary feedpump is normally aligned to the CST overflow line and floor drain. This

prevents inadvertent contamination of the CST, however, the lineup also allows a significant amount of available water to be dumped needlessly down the floor drains.

Conclusion:

A step will be added to EP 1202.01 in the section for response to SFRCS actuations to provide for realignment of the mini-recirculation line to the CST. This will be completed prior to restart.

11. <u>Auxiliary Feedpump Suction Transfer to Service Water</u>

During the June 9 event, Auxiliary Feedwater Pump #1 automatically transferred its suction source from the Condensate Storage Tank to Service Water as a result of low suction pressure. The procedural implications of this occurrence were evaluated.

Finding:

No procedural guidance exists to provide instructions as to when it is appropriate to transfer the AFP suction back to the CST from Service Water.

Conclusion

Procedure changes will be made to include specific criteria to be satisfied prior to allowing suction transfer from Service Water to the CST. These changes will be in place prior to startup.

12. MSIV Status

MSIVs closed during the June 9 event resulting in the loss of both main feedwater pumps.

Finding:

The operators did not recognize the closure of the MSIVs until several minutes into the event. There are no specific procedure requirements to verify MSIV status as one of the supplementary operator actions.

Conclusion:

MSIV status verification will be added to EP 1202.01 Supplementary Actions, prior to startup.

13. Piggyback Operations of HPI

High Pressure Injection at Davis-Besse has a shutoff head of 1600 psi. Under certain conditions, however, a "piggyback" lineup is

used in which the discharge of LPI is directed to the suction of the High Pressure Injection (HPI) pumps to produce a lineup which can inject against a pressure of 1730 psi. This lineup was used during the June 9 event.

Finding:

During both the June 9, 1985 and June 2, 1985 events, the operators used the option to piggyback LPI to HPI. EP 1202.01, Specific Rules, allows the operator this option if deemed necessary to control inventory in the reactor coolant system. During the June 9, 1985 event, with the pressurizer nearly full and a large reduction in inventory forthcoming from the restoration of feedwater to the steam generators, it was appropriate to line up the system for piggyback. On the other hand, the actions taken by the operators on the June 2, 1985 reactor trip were found to be premature and not appropriate. The specific rule was not intended to allow indiscriminate use of HPI piggyback operation since excessive use will cause unnecessary stress on the thermal sleeves because it is common after a reactor trip for RCS pressure to drop below the shutoff head of a piggyback HPI pump.

Conclusion:

- The Operations Superintendent will reinforce to the licensed operators the specific rule and basis for its use prior to restart.

- Annual simulator training will emphasize that indiscriminate HPI piggyback operations is not permitted.

Classification and Reporting of Events

Separate from the Committee review of operations during the event, the classification of the event in accordance with the Emergency Plan was reviewed. Total loss of feedwater is an event which should clearly be classified as a Site Area Emergency. The Emergency Plan does not directly address, however, classification of dynamic events in which conditions change rapidly.

Davis-Besse procedures specify that actions which are necessary for safety (i.e., to return the plant to a stable condition) should be taken immediately. Classification of the event is performed after plant stabilization, followed by reporting to NRC.

During the June 9 event, the immediate actions taken restored auxiliary feedwater flow and returned the plant to a stable condition, which would no longer be classified as a Site Area Emergency. Thus, at the point when formal classification was made, the plant conditions no longer corresponded to an emergency event classification. An Unusual Event was declared as a precaution and to assure that additional personnel would be made available at the plant to aid in evaluating the event and to maintain stable conditions. It is therefore concluded that the classification of the June 9 event was appropriate and not inconsistent with procedures.

Reporting of the event to NRC, however, was incomplete. The person making the initial notification to the NRC Operations Center was not familiar with the information which would be required by the NRC duty officer. To preclude this problem from recurring, the following actions will be taken:

- A checklist covering the information which must be provided during emergency notifications will be located near the red phone in the Control Room. This checklist will be in place prior to startup.

- Personnel who may make emergency notification calls will receive training to assure they are familiar with the information which must be provided. This training will also emphasize that the person making a notification must be familiar with the current plant status and with the major events which have occurred. This training will be completed prior to startup.

APPENDIX C.4.2 EFFECT OF PHYSICAL SECURITY PROVISIONS ON OPERATIONS

Introduction

Item II.A.3 of the enclosure to NRC's letter to Toledo Edison of August 15, 1985 detailed a concern regarding

> "The potential adverse effect of plant physical security and administrative features (locked doors, locked equipment, etc.) on the operator's ability to gain timely access to equipment to mitigate accidents."

Toledo Edison has completed an evaluation of the specific physical security provisions which were of concern during the June 9, 1985 event. A general assessment to identify other specific provisions where action should be taken to assure timely access has been initiated. These efforts are described in this Appendix.

Background

During the June 9 event, Operations personnel were dispatched to several locations to reset, recover and locally operate equipment. The equipment involved included the two Auxiliary Feedwater Pumps, the Auxiliary Feedwater Isolation Valves and the motor-driven Startup Feedwater pump. In getting to and operating this equipment, personnel had to pass through security doors controlled by key card

access and a hatchway locked with a padlock. To manually operate the AFW isolation valves, they also had to unlock padlocks which were used to chain the handwheels in position to prevent undesired repositioning of the valves.

All security doors and locks involved in the event were successfully opened, and operator actions were not delayed. Nevertheless, the potential consequences of not being able to operate the equipment, had difficulties been experienced, highlighted the need to assess these and other security provisions.

<u>Padlock on Auxiliary Feedwater Pump Room Hatch</u>

The hatch leading to the AFW pump room is a sliding grate, secured by a padlock. If operators are unable to open the padlock, access to the room could be prevented. To assure that this will not occur, several actions have been taken:

- The requirement to have this entrance locked has been reviewed by security personnel. It was determined that this entrance must remain locked.

- The possibility of replacing the present padlock with a key card reader lock will be evaluated for possible long-term implementation. Interim measures to assure access have been implemented. These measures will be detailed in a separate submittal under the appropriate safeguards procedures.

- The possibility of alternate access to the Auxiliary Feedpump rooms is being evaluated by security and engineering.

In addition to these actions, a general review of padlocked areas will be conducted. This review will entail: 1) identification of all areas secured with padlocks, 2) an assessment of the equipment in these areas to determine whether access might be required to mitigate an operational event, and 3) implementation of changes similar to those described above for areas which might require emergency access. This review will be completed prior to startup.

Availability of Keys

During the June 9 event, the Shift Supervisor had to leave the Control Room to obtain keys. To prevent the need for personnel to leave the Control Room during a transient to obtain keys, an emergency key locker will be provided in the Control Room. This locker will contain keys which are determined to be necessary by Operations' personnel. The cabinet will be used only in emergency situations. The locker will be in place prior to startup.

Locked Valves

Numerous valves throughout Davis-Besse are locked in their desired position using chains and padlocks. This action was taken to comply with a TED NUREG 0737 commitment to prevent unauthorized operation which could render systems unable to perform their emergency function. As demonstrated by the experience gained during the June 9 event, however, this need must be balanced against the possibility that valves may have to be manually repositioned quickly in emergency situations. To assure both needs are met, the method of securing valves at Davis-Besse will be changed. Alternate locking devices will be used in place of chains and locks. Administrative controls for routine operation of these valves will remain in effect. Unauthorized operation of valves will be detected by the broken locking device, and it will be possible to readily operate the valves in an emergency. All valve padlocks will be replaced prior to startup.

Security Door Access to Vital Areas

Vital areas within Davis-Besse are secured using key card readers controlled by a central security computer. Problems have been experienced with card readers in the past. To prevent these problems from precluding emergency access, several actions have been evaluated. and implemented. The results of these evaluations and details of implementation will be submitted as they are completed in accordance with applicable safeguards procedures.

APPENDIX C.5.1 - SPECIFIC ACTIONS RELATED TO CONTROL ROOM DEFICIENCIES

This appendix will be provided later, by revision. It will identify the Human Engineering Deficiencies (HEDs) which will be corrected prior to startup.

APPENDIX C.7.1 - SYSTEM REVIEW AND TEST PROGRAM RESULTS

This Appendix will be provided later, by revision. It will report the major conclusions of the System Review and Test Program.

APPENDIX III-1 ACTIONS TO BE IMPLEMENTED BY TOLEDO EDISON

Presented on the following pages is a detailed list of the actions Toledo Edison intends to implement in carrying to this Course of Action. The schedule for long term actions, i.e. those to be implemented following restart, is included where it has been definitively determined. The schedule for the remaining long term actions will be provided by revision to this Appendix.

I.A INSTRUMENTATION OR ELECTRICAL CHANGES
PRE-START UP

ITEM NO.	COA SECTION	ITEM	TARGET COMPLETION PRE/POST	JUSTIFICATION 50.59/UNREVIEWED SAFETY QUESTION	TECH SPEC NEW/CHANGE	STAFF PRODUCT REQ'D - NONE SER/LIC AMEND.	COMMENTS
1.	App C.2.1	Disconnect Power to AFP AFP Suction Valve from CSTS	PRE	50.59	NONE	NONE	
2.	App C.2.2	Provide Electronic Filtering to Steam Generator Level Transmitters	PRE	50.59	NONE	NONE	
3.	App C.2.2	Clarify SFRCS Lo Level trip setpoint	PRE	50.59	NONE	NONE	May be desirable to clarify DB Tech Specs for consistency with other B&W Plants
4.	APP C.2.2	Seal-in Manual Reset for Full SFRCS Trip Alarm	PRE	50.59	NONE	NONE	
5.	App C.2.1	Provide Time Delay for Transfer of AFP Suction to S.W.	PRE	50.59	NONE	NONE	
6.	App C.2.2	Provide "Disable" to Isolation of Second S/G When First S/G depressurizes below 600 psig	PRE	50.59	NONE	NONE	
7.	II.C.5	Install PORV Position Indication Lights on Panel Next to PORV Controls	PRE	50.59	NONE	NONE	
8.	CAGIR	Complete Torque Switch Bypass Settings on Safety Related Valves (Includes AF 599, 608 & MS106)	PRE	50.59	NONE	NONE	

I.A INSTRUMENTATION OR ELECTRICAL CHANGES
PRE-START UP

ITEM NO.	COA SECTION	ITEM	TARGET COMPLETION PRE/POST	JUSTIFICATION 50.59/UNREVIEWED SAFETY QUESTION	TECH SPEC NEW/CHANGE	STAFF PRODUCT REQ'D - NONE SER/LIC AMEND.	COMMENTS
9.	App C.2.1	Lower Suction Pressure Setpoint on the Switches that Transfer Suction of AFP's From CST's to S.W.	PRE	50.59	NONE	NONE	
10.	CAGIR	Repair NI 1 and 2 As Necessary to Accomplish Operability	PRE	50.59	NONE	NONE	
11.	II.C.2	Rearrange SFRCS Manual Initiation Switches and Provide Switch Covers for Less Frequently Needed Switches	PRE	50.59	NONE	NONE	
12.	IV.C.2.2	Delete the isolation of main steam and main feedwater flow paths on Low Steam Generator Level	PRE	50.59	NONE	NONE	
13	IV.C.2.2	Replace the pneumatic relays in the the main steam isolation valves control circuits with larger solenoid valves containing pressure switches.	PRE	50.59	NONE	NONE	

I.B INSTRUMENTATION OR ELECTRICAL CHANGES
POST-START UP

ITEM NO.	COA SECTION	ITEM	TARGET COMPLETION PRE/POST	JUSTIFICATION 50.59/UNREVIEWED SAFETY QUESTION	TECH SPEC NEW/CHANGE	STAFF PRODUCT REQ'D - NONE SER/LIC AMEND.	COMMENTS
1.	IV.C.2.1	Remove interlock on steam inlet to the auxiliary feedwater pump turbine which secures turbine on low suction pressure.	POST	50.59	4.7.1.2(d)	Lic. Amend	
2.	IV.C.2.1	A non-SFRCS open signal will be provided to the AFW isolation valves AF599 & AF608 to prevent inadvertent closure. If found acceptable, will be implemented prior to Cycle 6.	POST	TO BE DETERMINED	NONE	TO BE DETERMINED	
3.	IV.C.2.1	The Automatic Closure Signals for valves AF599 & AF608 will be removed from SFRCS	POST	TO BE DETERMINED	NONE	TO BE DETERMINED	
4.	IV.C.2.1	Capability to remotely operate the MDFP discharge valves to the Aux Feedwater pump headers will be provided	POST	NONE	NONE	NONE	

II.A HARDWARE CHANGES
PRE-START UP

ITEM NO.	COA SECTION	ITEM	TARGET COMPLETION PRE/POST	JUSTIFICATION 50.59/UNREVIEWED SAFETY QUESTION	TECH SPEC NEW/CHANGE	STAFF PRODUCT REQ'D - NONE SER/LIC AMEND.	COMMENTS
1.	App II.B.1 C.2.1	Install Motordriven Feed Pump	PRE	50.59	NEW	LIC. AMEND	Lic Amendment not required prior to Startup
2.	App C.2.1	Change out of #1 AFPT Governor to a Woodword PGG	PRE	50.59	NONE	NONE	
3.	IV.C.2.1	Install Stm Admission Valves on the AFPT Inlet Lines	PRE	50.59	NONE	NONE	
4.	CAGIR	Drain PORV loop seal	PRE	50.59	NONE	NONE	
5.	IV.C.2.1	Remove strainer baskets in AFP Suction Lines	PRE	50.59	NONE	NONE	
6.	IV.C.2.1	Install a Coarser Mesh Strainer in the Common Suction Line to the AFP's from CST	PRE	50.59	NONE	NONE	
7.	CAGIR	Repair Damage to Turbine Bypass Valves	PRE	NONE	NONE	NONE	
8	IV.C.2.2	Improved ventilation provided for SFRCS cabinets	PRE	50.59	NONE	NONE	
9.	IV.C.2.1	Remove startup strainer basket in each AFPT suction	PRE	50.59	NONE	NONE	

II.B HARDWARE CHANGES
POST START UP

ITEM NO.	COA SECTION	ITEM	TARGET COMPLETION PRE/POST	JUSTIFICATION 50.59/UNREVIEWED SAFETY QUESTION	TECH SPEC NEW/CHANGE	STAFF PRODUCT REQ'D - NONE SER/LIC AMEND.	COMMENTS
1.	IV.C.2.1	Motor Driven Feed Pump will be provided with alternatively powered lube oil pump.	POST	NONE	NONE	NONE	

III.A MAJOR PROCEDURAL CHANGES
PRE-START UP

ITEM NO.	COA SECTION	ITEM	TARGET COMPLETION PRE/POST	JUSTIFICATION 50.59/UNREVIEWED SAFETY QUESTION	TECH SPEC NEW/CHANGE	STAFF PRODUCT REQ'D - NONE SER/LIC AMEND.	COMMENTS
1.	C.4.1	Modify Procedure to Require SRO to be in Panel Area of Control Room after Entry into EP1202.01	PRE	50.59	NONE	NONE	
2.	IV.C.4.1	Modify EP1202.02 to Require HPI/MU Cooling when RCS Reaches 610° Post Trip	PRE	50.59	NONE	NONE	
3.	II.B.3	Put in Place a Conduct of Maintenance Procedure	PRE	NONE	NONE	NONE	
4.	II.B.3	Put in Place a Procedure to Document Maintenance Requests For Engineering Assistance	PRE	NONE	NONE	NONE	

IV.A PROGRAMMATIC CHANGES
PRE-START UP

ITEM NO.	COA SECTION	ITEM	TARGET COMPLETION PRE/POST	JUSTIFICATION 50.59/UNREVIEWED SAFETY QUESTION	TECH SPEC NEW/CHANGE	STAFF PRODUCT REQ'D - NONE SER/LIC AMEND.	COMMENTS
1.	IV.C.4.2	Modify Locking Mechanisms on Locked Valves to Allow Emergency Disabling of Locking Mechanisms Without Keys	PRE	50.59	NONE	NONE	
2.	II.B.3	Decrease the Ratio of Supervisors to Craft Personnel to a Level Acceptable to the Assistant Plant Manager, Maintenance	PRE	NONE	NONE	NONE	
3.	IV.C.4.1	Provide Manual P.T. Plotting Capability in CR	PRE	NONE	NONE	NONE	
4.	II.B.3	Put in Place a Program that Improves the Interface Between Maintenance & Training	PRE	NONE	NONE	NONE	
5.	II.B.3	Eliminate Backlog of Preventive Maintenance Work	PRE	NONE	NONE	NONE	
6.	II.B.3	Institute a Plant Cleanliness Program	PRE	NONE	NONE	NONE	
7.	CAGIR	Arrange for PORV Testing at Testing Facility	PRE	NONE	NONE	NONE	
8.	IV.C.1.4	Complete Atmoshperic Vent Valve Testing	PRE	NONE	NONE	NONE	

APPENDIX III-2 - SCHEDULE OF ACTION TO BE IMPLEMENTED PRIOR TO RESTART

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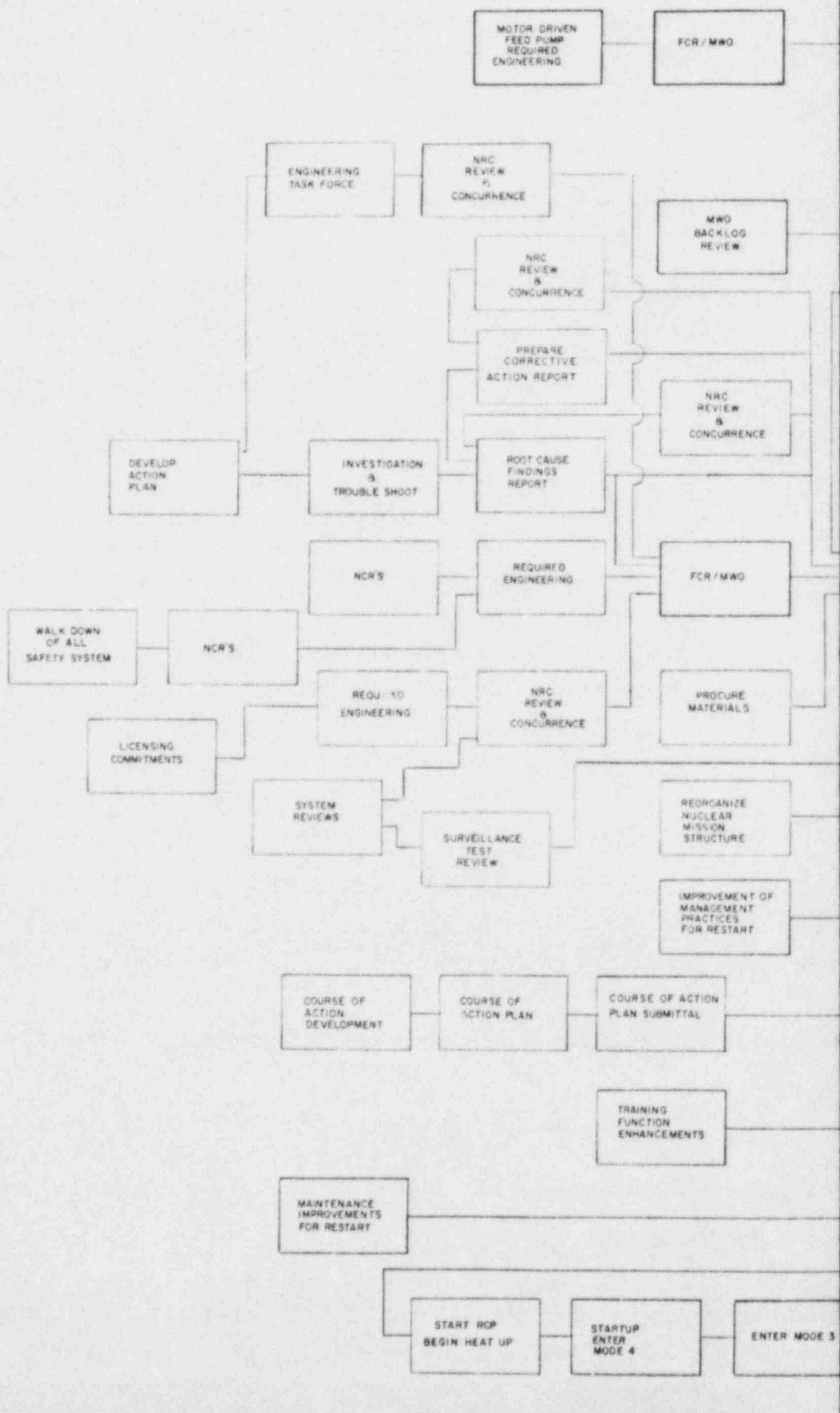
COURSE OF ACTION
SUMMARY SCHE



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ESTART
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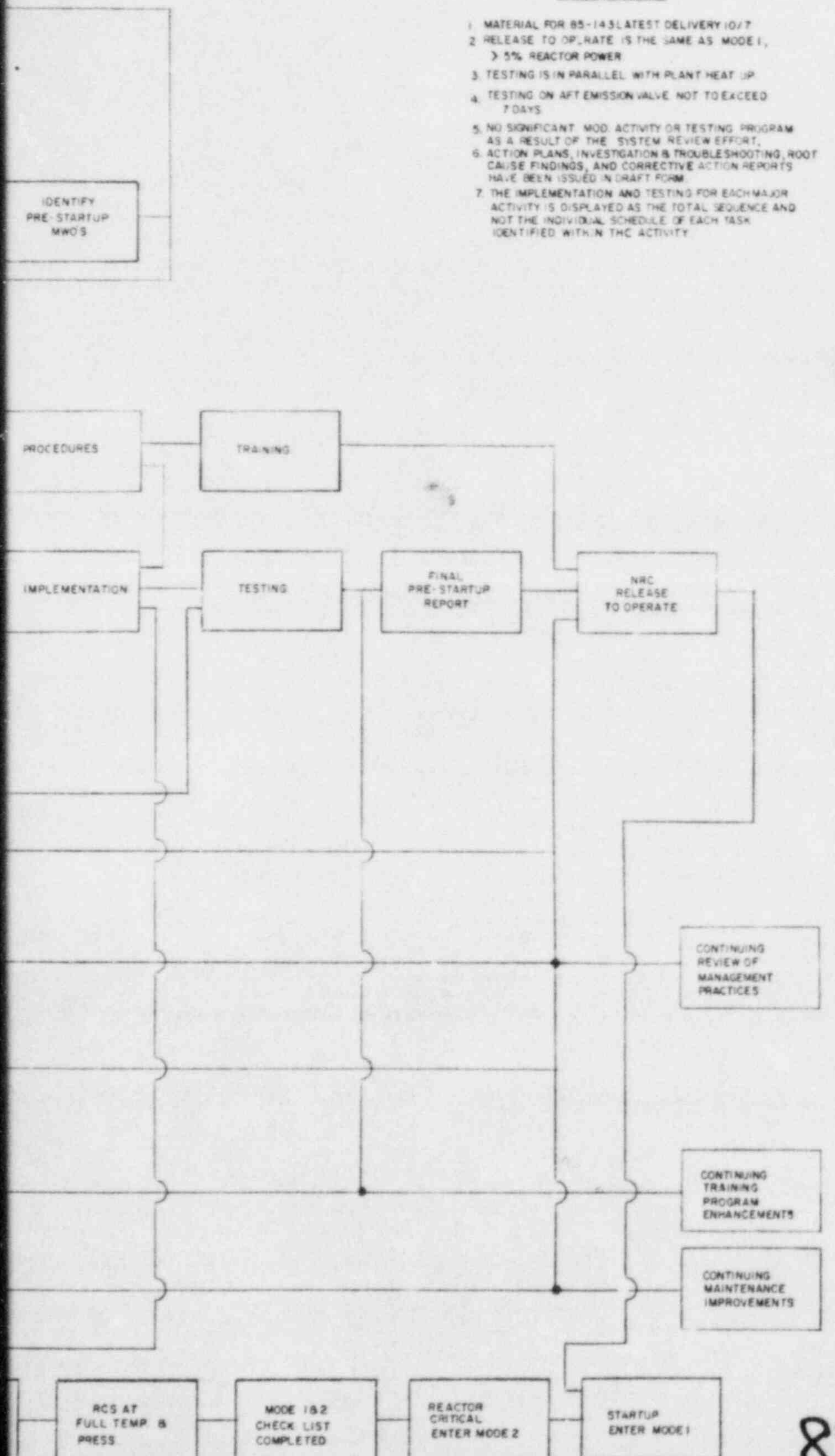
ASSUMPTIONS

1. MATERIAL FOR 85-143 LATEST DELIVERY 10/7
2. RELEASE TO OPERATE IS THE SAME AS MODE 1, > 5% REACTOR POWER
3. TESTING IS IN PARALLEL WITH PLANT HEAT UP
4. TESTING ON AFT EMISSION VALVE NOT TO EXCEED 7 DAYS
5. NO SIGNIFICANT MOD. ACTIVITY OR TESTING PROGRAM AS A RESULT OF THE SYSTEM REVIEW EFFORT.
6. ACTION PLANS, INVESTIGATION & TROUBLESHOOTING, ROOT CAUSE FINDINGS, AND CORRECTIVE ACTION REPORTS HAVE BEEN ISSUED IN DRAFT FORM.
7. THE IMPLEMENTATION AND TESTING FOR EACH MAJOR ACTIVITY IS DISPLAYED AS THE TOTAL SEQUENCE AND NOT THE INDIVIDUAL SCHEDULE OF EACH TASK IDENTIFIED WITHIN THE ACTIVITY.



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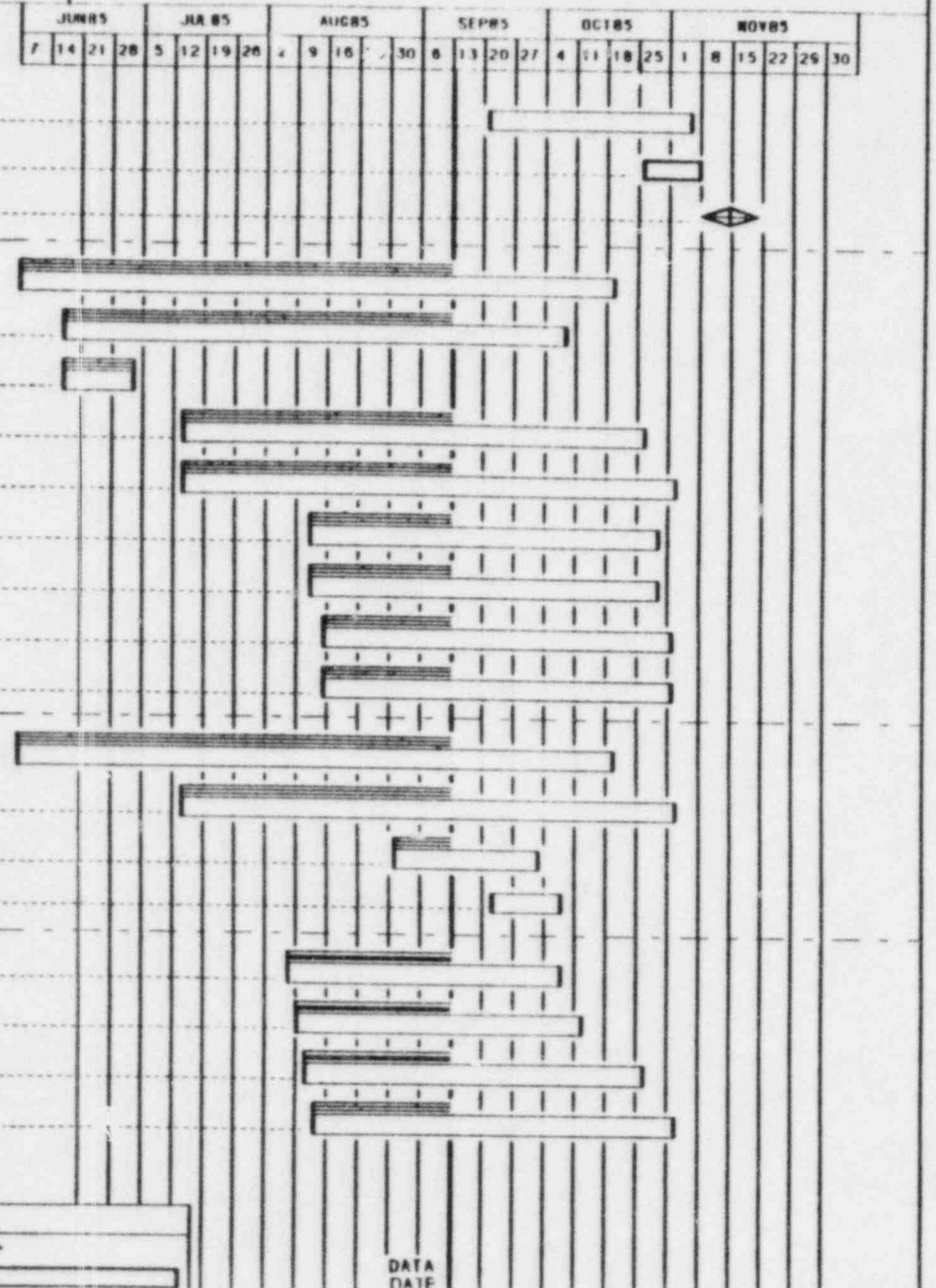
PROJECT 850UTSUM PLOT 850UT UM RUN DATE 23SEP85 START 1JUN85 FINISH 1NOV85 DATA DATE 6SEP85	COURSE OF ACTION SUMMARY SCHEDULE WORKING SCHEDULE SORT START	MODE C/FE INTERVAL: 1 WEEK(S)	PROJECT/2 8481 BAR CHART GRAPHICS PAGE 1 SHEET 1

	Activity	SD	FD
FINAL REPORT AND RELEASE TO OPERATE	FINAL PRE-STARTUP REPORT	13SEP85	30OCT85
	HEAT UP CYCLE	20OCT85	1NOV85
	NRC RELEASE TO OPERATE		1NOV85
ACTION PLANS	FIELD CHANGE REQUESTS / MAINTENANCE WORK ORDERS	1JUN85	13OCT85
	INVESTIGATION & TROUBLE SHOOT	11JUN85	2OCT85
	DEVELOP ACTION PLANS	11JUN85	26JUN85
	IMPLEMENTATION FOR THE ACTION PLANS	8JUL85	20OCT85
	TESTING AND TURNOVER FOR THE ACTION PLANS	8JUL85	27OCT85
	ROOT CAUSE FINDINGS REPORT	6AUG85	23OCT85
	PREPARE CORRECTIVE ACTION REPORT	6AUG85	23OCT85
	NRC REVIEW OF ROOT CAUSE FINDING REPORT	9AUG85	26OCT85
	NRC REVIEW OF CORRECTIVE ACTION REPORT	9AUG85	26OCT85
SYSTEM REVIEWS	FIELD CHANGE REQUESTS / MAINTENANCE WORK ORDERS	1JUN85	13OCT85
	TESTING AND TURNOVER FOR SURVEILLANCE TEST	8JUL85	27OCT85
	SYSTEM REVIEWS	25AUG85	26SEP85
	SURVEILLANCE TEST REVIEW	16SEP85	1OCT85
MAINTENANCE WORK ORDER REVIEW	MAINTENANCE WORK ORDER BACKLOG REVIEW	1AUG85	1OCT85
	IDENTIFY PRE-STARTUP MAINTENANCE WORK ORDERS	3AUG85	6OCT85
	IMPLEMENTATION FOR MAINTENANCE WORK ORDERS	5AUG85	20OCT85
	TESTING AND TURNOVER FOR MAINTENANCE WORK ORDERS	7AUG85	27OCT85



LEGEND

REPORTED PROGRESS — MILESTONE

WORKING SCHEDULE — CRITICAL

PROJECT 85OUTSUM
PLOT 85OUTSUM
RUN DATE 09SEP85

PROJECT/2 8481
BAR CHART GRAPHICS
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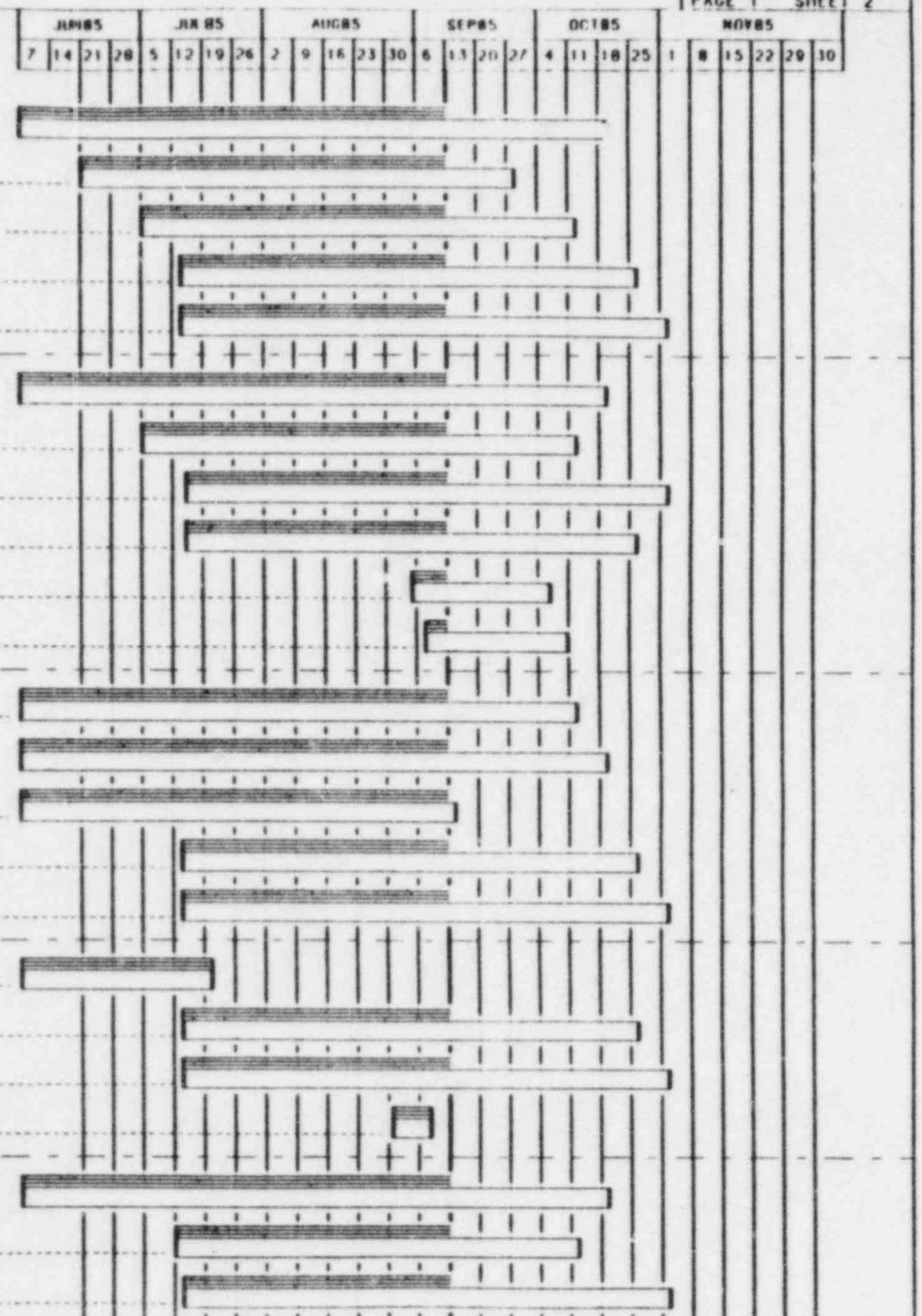
	Activity	SD	FD
NON CONFORMANCE REPORTS	FIELD CHANGE REQUESTS / MAINTENANCE WORK ORDERS	1JUN85	13OCT85
	NON CONFORMANCE REPORTS	15JUN85	22SEP85
	REQUIRED ENGINEERING FOR NON CONFORMANCE REPORTS	29JUN85	6OCT85
	IMPLEMENTATION FOR NON CONFORMANCE REPORTS	8JUL85	20OCT85
	TESTING AND TURNOVER FOR NCR'S	8JUL85	27OCT85
WALKDOWN OF ALL SAFETY SYSTEMS	FIELD CHANGE REQUESTS / MAINTENANCE WORK ORDERS	1JUN85	13OCT85
	REQUIRED ENGINEERING	29JUN85	6OCT85
	TESTING AND TURNOVER	9JUL85	27OCT85
	IMPLEMENTATION	9JUL85	20OCT85
	WALKDOWN OF ALL SAFETY SYSTEMS	30AUG85	30SEP85
	NON CONFORMANCE REPORTS	2SEP85	4OCT85
LICENSING COMMITMENTS	REQUIRED ENGINEERING	1JUN85	6OCT85
	FIELD CHANGE REQUESTS / MAINTENANCE WORK ORDERS	1JUN85	13OCT85
	LICENSING COMMITMENTS	1JUN85	8SEP85
	IMPLEMENTATION FOR LICENSING COMMITMENTS	8JUL85	20OCT85
	TESTING AND TURNOVER FOR LICENSING COMMITMENTS	8JUL85	27OCT85
MOTOR DRIVEN FEED PUMP	MOTOR DRIVEN FEEDPUMP REQUIRED ENGINEERING	1JUN85	14JUL85
	IMPLEMENTATION OF MOTOR DRIVEN FEEDPUMP	8JUL85	20OCT85
	TESTING AND TURNOVER	8JUL85	27OCT85
	FIELD CHANGE REQUESTS / MAINTENANCE WORK ORDERS	25AUG85	2SEP85
ENGINEERING TASK FORCE	FIELD CHANGE REQUESTS / MAINTENANCE WORK ORDERS	1JUN85	13OCT85
	ENGINEERING TASK FORCE	6JUL85	6OCT85
	TESTING AND TURNOVER FOR ENGINEERING TASK FORCE	8JUL85	27OCT85



PROJECT 85OUTSUM
PLOT 85OUTSUM
RUN DATE 09SEP85

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BAR CHART GRAPHICS
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	SD	FD
ENGINEERING TASK FORCE		
IMPLEMENTATION FOR ENGINEERING TASK FORCE	8JUL85	20OCT85
NRC REVIEW AND CONCURRENCE	1SEP85	9OCT85
SUPPORT ACTIVITIES FOR MODIFICATIONS		
PROCURE MATERIAL	1JUN85	8OCT85
PROCEDURES	16SEP85	20OCT85
TRAINING	1OCT85	31OCT85
MANAGEMENT AND PROGRAM CHANGES		
IMPROVEMENT OF MANAGEMENT PRACTICES FOR RESTART - POSITION DESCRIPTIONS - SALARY REVIEW - TRAINING - INPO ACCREDITATION - MATERIAL MANAGEMENT SYSTEM - MAINTENANCE MANAGEMENT - ENGINEERING ROLE - CONFIGURATION MANAGEMENT PROGRAM	1JUL85	1NOV85
MAINTENANCE IMPROVEMENTS - ORGANIZATION AND STAFFING - TRAINING - ADMINISTRATIVE AND TECHNICAL PROCEDURES (9/1/85 - 12/1/86) - PREVENTIVE MAINTENANCE (9/1/85 - ?) - SPARE PARTS AND MATERIALS CONTROL (7/1/85 - 9/1/85) - ENGINEERING INTERFACE AND SUPPORT (7/1/85 - 9/30/85) - PLANT CLEANLINESS AND MATERIAL READINESS (7/1/85 - 9/1/85) - NEW FACILITY (9/4/85 - 12/1/85)	1JUL85	1NOV85
TRAINING FUNCTION - ON SITE, PLANT SPECIFIC SIMULATOR (8/1/85 - 12/15/88) - EVALUATE AND IMPROVE PROGRAMS - INCREASE STAFFING LEVELS (7/1/85 - ?) - UPGRADE FACILITIES	1JUL85	1NOV85
REORGANIZE NUCLEAR MISSION STRUCTURE - CENTRALIZED PLANNING DEPARTMENT - MAINTENANCE DEPARTMENT - NUCLEAR ENGINEERING DIVISION	1JUL85	27AUG85
COURSE OF ACTION DEVELOPMENT	20JUL85	28AUG85
COURSE OF ACTION PLAN	31AUG85	4SEP85
COURSE OF ACTION PLAN SUBMITTAL	7SEP85	11SEP85
CONTINUING TRAINING PROGRAM ENHANCEMENTS		1NOV85
CONTINUING REVIEW OF MANAGEMENT PRACTICES		1NOV85
CONTINUING MAINTENANCE IMPROVEMENTS		1NOV85