REPORT OF

ASSESSMENT OF ACTIONS AT DAVIS-BESSE RESULTING FROM JUNE 9, 1985 LOSS OF FEEDWATER EVENT

PREPARED BY:

BASIC ENERGY TECHNOLOGY ASSOCIATES, INC.

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I. EXECUTIVE SUMMARY

This report presents the results of an assessment, performed by Basic Energy Technology Associates (BETA), Inc., of Annandale, Virginia, of the complete loss of feed water event of June 9, 1985, at the Davis-Besse Nuclear Power Plant. The Davis-Besse plant is operated by the Toledo Edison Company (TED).

BETA was requested by TED to conduct an independent assessment of the actions taken or planned by TED as a result of the June 9 event. This assessment was to evaluate the appropriateness and completeness of TED's actions with respect to restart of the unit.

Immediately following the event both NRC and TED initiated investigations to determine factually what had happened and why. Based on their investigation, the NRC issued a report (NUREG 1154) which identified the results of the NRC fact finding effort. Based on the results of the TED investigation, TED created an Action Plan List of issues related to the event which require technical evaluation. BETA accepted the results of the NRC investigation, and began its assessment based on their findings. BETA also considered earlier NRC concerns related to the overall performance of the plant, e.g., SALP, since it is likely that these issues contributed to the June 9 event. During the assessment, BETA suggested that a task force be established by TED to conduct a broad review of the entire subject of decay heat removal at Davis-Besse. The Task Force Report was reviewed by BETA.

BETA concludes that the Davis-Besse Nuclear Plant should be permitted to return to operation subject to:

- Resolution of the recommendations contained in this report.

- Completion or resolution of the action planned for accomplishment prior to restart, as contained in the:

  - Restart Action Tracking Report

  - Decay Heat Removal Work Group Report

BETA bases this conclusion on the following:

a. TED's investigation and technical evaluation adequately address the equipment malfunctions noted during the June 9 event. Similarly, the corrective actions resulting from these evaluations are, with minor exceptions noted, reasonable and proper.

b. The analyses performed by the Decay Heat Removal Work Group have identified and addressed the matters of concern.

c. The broader generic issues or concerns expressed by the NRC involving management capability and program adequacy have been and are being aggressively pursued. Even though all corrective actions in these areas will not be in place at the time of restart, BETA considers the progress that will have been made will substantially upgrade TED's capability.

II. INTRODUCTION AND BACKGROUND

Following the June 9, 1985 loss of feed water event at the Davis-Besse Nuclear Power Plant, a number of actions were undertaken by the Toledo Edison Company (TED) and the Nuclear Regulatory Commission (NRC). These actions involved initiating plans and programs to investigate all facets of the event and those malfunctions that either contributed to, resulted from, or occurred at the time of the event. From these investigations a series of corrective actions have emerged. Also, because of a number of weaknesses known to exist prior to the event, certain other corrective actions, relevant to the event, were either already planned or underway prior to the event.

Basic Energy Technology Associates (BETA), Inc., was requested by Toledo Edison (Joe Williams, Jr.) to conduct an independent assessment of the June 9th event in order to determine whether or not, in BETA's opinion, the various investigations were appropriate to the event and that the corrective actions resulting from these investigations would be sufficient to permit restart of the unit.

This assessment was conducted by R. W. Bass, R. S. Brodsky, J. C. Grigg, and W. Wegner.

On the day following the June 9 event, an NRC Investigative Team was established consisting of a group of four technical experts. This NRC Team was dispatched to the site and began an intensive investigation of the actual event. It was tasked to: 1) find out what

happened, 2) identify the probable cause as to why it happened, 3) make appropriate findings and conclusions to form the basis for possible follow-on actions. The NRC Team interviewed personnel who were on duty at the time of the event and others, and reviewed documents related to the affected systems. The results of the NRC Team's investigation are reported in NUREG 1154 (Ref 3).

The assessment conducted by BETA did not attempt to duplicate the NRC Team effort. The sequence of events contained in Table 2.1 of NUREG 1154 and as described in narrative form in Section 3 of that report have been accepted by BETA as being accurate and complete.

Shortly after the event, Toledo Edison established its own team of technical experts to interact with the NRC Investigative Team and to conduct its own investigation. From that effort twenty-seven Action Plans were identified. The Action Plans outline the methods to be used to determine the causes of the problems and to identify proper corrective actions. Of those twenty-seven Action Plans, fifteen relate to equipment problems.

Reproduced in Table 1 below is the chronological sequence of events as described in Table 3 of NUREG 1154. Added to this sequence is the TED Action Plan Number that addresses the problem. The assessment conducted by BETA included reviewing a selected number of these Action Plans to determine if they: 1) represented the full scope of the problems encountered, 2) were reasonable in their approach to determining the cause, and 3) logically arrived at the cause. In

addition, BETA determined if a reasonable course of action had been identified to correct the problem.

In addition to the Toledo Edison Task Force on Action Plans, a team of technical experts was formed specifically to review the design of systems utilized for removal of decay heat at the Davis-Besse Nuclear Power Station. This team was led by Toledo Edison, and included representatives from the nuclear steam system supplier, Babcock & Wilcox, the engineering firms MPR Associates and CYGNA, and was assisted by representatives from the architect-engineer, Bechtel. This group, which was called the Decay Heat Removal Work Group, was formed at the request of BETA as a means of concentrating attention on the overall problem of decay heat removal rather than the individual and sometimes isolated events which occurred on June 9. BETA reviewed the scope of the Work Group effort and the resultant recommendations as contained in Reference 7.

Finally, BETA has reviewed the total list of action items identified by Toledo Edison as being necessary for restart of the unit or requiring correction at some later date. This list contains over 500 line items and is reported in Reference 10. The BETA review was intended to determine the completeness of the list and whether BETA would agree that after accomplishment or resolution of the items on the pre-restart list, the plant should be allowed to restart.

TABLE 1

Chronological Sequence of Events

Initial Conditions

- Unit operating at 90% power
- Number One Main Feedpump (MFP) in automatic control
- Number Two Main Feedpump in manual control
- One Source Range Nuclear Instrumentation Channel inoperable 15
- Safety Parameter Display System (SPDS) inoperable, both channels 17

Transient Initiator

*01:35:00 #1 MFP Trips
Control system causes MFP flow increases; MFP turbine trips on overspeed. 8

Systems Response/Operator Actions to Partial Loss Main Feedwater

01:35:01 Unit runback initiated toward 55% at 50%/min.

01:35:21 Operator increases the speed of #2 MFP turbine. Pressurizer (Prz) spray valve manually opened to 100%.

01:35:30 Reactor Trip & Turbine Trip - RCS High Pressure (2300 psig) from 80% power.**

*01:35:31 Computer recorded Steam and Feedwater Rupture Control System (SFRCS), full trip on low level, actuation channel 2. 5/6

*01:35:31 Both Main Steam Isolation Valves (MSIVs) start to close. 7

01:35:34 SFRCS actuation signal automatically clears.

*01:35:36 MSIV #2 has closed. 7

*01:35:37 MSIV #1 has closed.
With both MSIVs closed, the source of steam for #2 MFP turbine is isolated. Steam from main steam piping and moisture separator reheaters allowed #2 MFP to provide adequate flow for about 4½ minutes.

01:35:45 Pressurizer spray valve closed.

01:35:56 Once Through Steam Generator (OTSG) levels at normal post-trip level (35 inches).

*01:40:00 OTSG levels begin to fall from the normal post-trip level. 7

*Unexpected or off-normal response.

**As part of normal reactor trip procedure, operator isolated RCS letdown and started second RCS makeup pump, to maintain pressurizer level.

System Response/Operator Actions to Complete Loss of Main Feedwater

01:41:04 SFRCS OTSG #1 low level (26.5 in.) full trip, actuation channel 1; this actuation causes Auxiliary Feedwater Pump (AFP) #1 to be aligned to draw steam from, and provide feed to, OTSG #1.

*01:41:08 The control room operator attempted to manually initiate SFRCS; however, he incorrectly actuated the SFRCS on low steam pressure instead of the desired low steam generator level. He performed the manual actuation by depressing the top switch in each column of manual actuation switches for the two SFRCS actuation channels. 3/14

Therefore, each SFRCS actuation channel sensed that its associated steam generator was inoperable and that the opposite OTSG was intact. SFRCS actuation channel 1 then attempted to align its associated AFW train (#1) to draw steam from only, and to provide feed only to, OTSG #2. SFRCS actuation channel 2 attempted to align its associated AFW train (#2) to draw steam from only, and to provide feed only to, OTSG #1. Both SFRCS actuation channels also closed their associated OTSG/AFW containment isolation valves. That is, SFRCS actuation channel 1 isolated OTSG #1 by closing valve AF-608; actuation channel 2 isolated OTSG #2 by closing valve AF-599. These OTSG/AFW isolation actions prevented any auxiliary feed flow from reaching either OTSG.

Per the SFRCS design, valves that had been positioned by the low level trip on SFRCS channel 1 were repositioned by the higher priority low pressure trip. The AFP 1 steam supply valve from OTSG #1, MS-106 had started open in response to the SFRCS actuation channel 1 low level trip. Following the low pressure trip, the valve should have continued opening to its full open position before it cycled closed. The entire open/close stroke time should have been about 50 seconds. *MS-106, however, returned to its closed position in about 18 seconds. 27

01:41:13 SFRCS actuation channel 2 tripped on OTSG #2 low level. Since the low pressure trip already present had priority, no change in component actuation occurred.

*01:41:31 Auxiliary Feedwater Pump Turbine (AFPT) #1 tripped on overspeed. 1

*01:41:44 AFPT #2 tripped on overspeed.

System Response/Operator Actions to Complete Loss of All Feedwater

01:42:00 Manual reset of SFRCS OTSG low pressure actuation.

*AF-599, AF-608 should have reopened automatically, but did not. 12

*An attempt was made to reopen AF-599 and AF-608 from the main control panel, but the valves did not respond.

01:42:00 Pzr. Spray valve opened.

01:43:55 Assistant Shift Supervisor went to SFRCS cabinets (behind the control room area), opened the doors, and operated the "operating bypass" for the SFRCS ("Initiate Reset and Block," used for normal plant cooldowns) in an attempt to reset any automatic safety signals to AF-599 and AF-608.

*The valves remained closed. 12

*01:44 Equipment Operators were dispatched into the plant to operate the following equipment:

(1) Two Equipment Operators were sent to the Auxiliary Feedwater Pump turbines to manually restore the AFW pumps to service. 1

(2) The Assistant Shift Supervisor left the control room to make the startup feed pump available for service. This required opening the pump suction valve, the pump discharge valve, and two cooling water valves. In addition, the control fuses for the 4160-volt pump motor circuit breaker were required to be installed.

(3) Two equipment operators were sent to open OTSG Auxiliary Feedwater Isolation Valves AF-599 and AF-608. These valves are the containment isolation valves for the AFW system. The operators manually moved the valves from the closed position, and the motor operators opened the valves. 12

01:44:50 RCS Makeup flow decreases as the makeup flow control valve, MU-32, modulates closed based on pressurizer level being above setpoint (200 inches).

01:45:50 AFPT #2 overspeed trip reset locally.

01:46:29 OTSG #1 Atmospheric Vent Valve opened.

01:46:30 AFPT #1 trip throttle valve relatched and valve opened (overspeed trip not cleared). Speed controlled locally throughout event.

01:47:33 OTSG #1 below 960 psig and decreasing.

01:47:48 OTSG #2/AFW isolation valve, AF-599, opened locally.

01:48:08 OTSG #1 atmospheric vent valve closed.

01:48:49 PORV opens (first time) at 2433 psig (2425 setpoint).

*01:48:51 OTSG #2 below 960 psig and decreasing. (Both OTSGs now "dried out," according to criteria in plant emergency procedures related to MU/HPI cooling.) 7/12

01:48:52 PORV closed at 2377 psig (2375 setpoint).

01:49:28 OTSG #1/AFW isolation valve, AF-608, opened locally.

01:50:09 PORV opens (second time) at 2434 psig.

01:50:12 PORV closed at 2369 psig.

01:50:13 OTSG #1 Atmospheric Vent Valve opened; OTSG #1 pressure decreases rapidly toward about 750 psig.

01:51:17 OTSG #1 level falls below eight inches (MU/HPI cooling criterion).

*01:51:18 PORV opens (third time) at 2435 psig; did not close. 10

01:51:23 Startup feed pump motor started.

01:51:30 Obtained flow from startup feed pump to OTSG #1.

01:51:42 Operator started to close PORV block valve as RCS pressure fell through 2140 psig.

01:51:42 RCS Loop #1 reaches a minimum pressure of 2081 psig.
Loop #1: T-hot = 588.6°F; Tave = 587.5°F.

01:51:43 Pressurizer spray valve closed.

01:51:49 Acoustic monitor indicates less than 20% flow through PORV/block valves.

01:53:00 RCS loop #1 T-hot reaches peak value of 593.5°F.

01:53:22 AFW Train #2 has significant flow, with control locally via the trip-throttle valve.

01:53:25 RCS Tave reaches peak value of 592.3°F.

01:53:35 OTSG #2 returns to above 960 psig.

01:53:56 PORV Block Valve reopened by operator.

01:54:45 OTSG #1 returns to above 960 psig.

01:54:46 AFW Train #1 has significant flow, with control locally via the trip throttle valve.

01:56:58 OTSG #2 Atmospheric vent open; OTSG #2 below 960 psig and decreasing.

01:57:05 OTSG #1 below 960 psig and decreasing.

*01:57:53 Low suction pressure developed on AFP #1; 34 seconds later (01:58:27), suction pressure was recovered. 26

01:58 Tave passed through the normal post-trip temperature. The cooldown had lowered RCS pressure to about 1720 psig. Operators manually started the HPI pump #1 in the piggyback mode (LPI pump 1 supplying the suction to the HPI pump 1) to maintain pressurizer pressure and level. A slight amount of water (about 50 gallons) was injected.

01:58:08 RCS Loop #1 reaches a minimum pressure of 1716 psig. Loop #1: T-hot = 546.6°F; Tave = 546.2°F.

01:58:28 OTSG #1 Atmospheric vent closed.

01:58:33 AFW Train #1 flow reduced to control OTSG level.

*01:58:40 AFP #1 suction automatically transferred from the condensate storage tank (CST) to the service water system. The operator realigned to CST. 26

01:58:57 AFPT #1 overspeed trip reset.

02:01 When AFPT #2 was returned to service, the control room operator controlled the pump in manual rather than returning it to Automatic.

02:01:13 AFW Train #2 flow reduced.

02:02:27 OTSG #1 returns to above 960 psig.

02:02:30 OTSG #2 returns to above 960 psig.

02:04 Plant conditions essentially stable.

Additional Complications

1. Control Room HVAC system spuriously tripped to its emergency mode.

2. The operator attempted to override/reset the automatic close signal to the OTSG #2 startup feed control valve SP-7A. The reset light for this valve did not come on, indicating that control of the valve had not be regained. The control room operators therefore believed that flow from the startup feedpump went only through SP-7B to OTSG #1 and not through SP-7A to OTSG #2. 18

3. Upon energization, the remaining source range nuclear instrumentation channel failed off-scale low. All control rods were verified to be fully inserted, and emergency boration was initiated. 15

4. The main turbine did not go into its turning gear.

5. When vacuum was restored and the MSIVs opened, a water slug damaged one of the main turbine bypass valves. 9

Notes

1. The above sequence of events is based upon combining information obtained from plant computer printouts and operator interviews.

2. Adequate subcooled margin was available throughout the transient. The Reactor Coolant Pumps remained in operation. The Quench Tank contained the discharge from the PORV.

3. There is a question regarding the operation of the atmospheric vent valves. 16

III. SCOPE OF ANALYSIS

As a result of the NRC Fact Finding Team and the TED effort, twenty-seven Action Plans were generated. These items have been included in a formal program to determine the root cause of the problems and arrive at appropriate corrective actions. As noted previously, BETA's intent has been to limit its review to those problems associated with the loss of feedwater event. To do this, BETA has separated the problems into three categories:

1. Problems which directly related to or resulted from the June 9 loss of feedwater event.

2. Problems which coincidentally occurred with, but were unrelated to, the loss of feed water event. An example of this was the spurious signals in the source range nuclear instruments.

3. Problems of a generic nature which probably contributed to the event but were broader in scope. An example of this is the level of plant maintenance which has existed at Davis-Besse for some time prior to the June 9 event.

In its assessment, BETA has concentrated its effort on the problems in the first category related to equipment maloperation. In addition, BETA has reviewed and commented, where appropriate, on those problems identified in the third category. BETA has not reviewed those problems in the second category. The twenty-seven Action Plans

fall into either the first or second categories. In Table 2 which follows, all twenty-seven Action Plans have been listed and those which BETA has reviewed and commented on in this report are identified. The broader generic issues (category 3) are best identified in the Enclosure to NRC's letter to TED Co. dated August 14, 1985 (Ref. 6). Those generic issues are shown in Table 3.

This report is based on BETA's understanding, as of the date of this report, of Toledo Edison's program to return the Davis-Besse plant to operation. It should be emphasized that the BETA review, comments and conclusions are based on information obtained from various interviews, evaluations, studies and plans that are in preliminary form and may be subject to change as additional information is developed. As the above actions are completed it is possible that new information will be obtained that could alter the BETA conclusions and recommendations.

TABLE 2

LISTING OF TED ACTION PLANS

TED Action Plan No.	BETA Review	
1A & 1B	Yes	Auxiliary Feed Pump Turbines #1 and #2 Overspeed Trips
1C	Yes	AFPT Manual/Auto Essential Control Problem
1D	Yes	AFPT Trip Throttle Valve Problem
2	No	Steam Generator Integrity/Cycle impact due to initiation of Startup Feed Pump water flow.
3	No	Actions of Operators/Adequacy of Procedures.
4	No	Classification of the Event under the Emergency Plan
5	Yes	SFRCS Trip/MSIV closure
6	Yes	SFRCS Alarms
7	Yes	MSIV/SFRCS Response
8	Yes	Main Feed Pump Turbine 1-1 Control System Problems
9	Yes	Turbine Bypass Valve Actuator Failure.
10	Yes	Review of the Operation of the PORV.
11	No	Discuss Event with the Ottawa County Commissioners.
12	Yes	AFW System Valve Problem Analysis (AF599 and AF608)
13	No	Service Water Effect on OTSG
14	Yes	Operator Error on Initiating AFW
15	No	Source Range Nuclear Instruments
16	Yes	Report on Main Steam Header Pressure.

17	No	Problems with SPDS
18	Yes	Startup Feed Valve SP-7A Problems Analysis.
19	No	Adequacy of Information Provided to NRC on June 9, 1985.
20	No	Complete Items 1-5 on Confirmatory Action Letter
21	No	Perform Testing and Demonstrate that the MFP's will operate as required.
22	No	Perform testing and demonstrate that the AFP's will operate as required.
23	No	Report Test Results to NRC Resident Inspector.
24	No	Obtain concurrence from Regional Administrator prior to exceeding 5% power.
25	No	Main Steam Walkdown
26	No	Inadvertent AFWP #1 Suction Supply Transfer
27	Yes	AFPT Main Steam Inlet Isolation Problem Analysis

TABLE 3

1. Adequacy of management practices including control of maintenance programs, use of operational experience, degree of engineering involvement, testing, root cause determination of equipment misoperation, licensed and nonlicensed operator training, and past trip reviews.

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

3. Adequacy of the implementation of the Performance Enhancement Program (PEP) and any other ongoing corrective action programs.

4. Adequacy of the resources committed to the Davis-Besse facility for investigation of the event, resolution of the findings and conclusions prior to restart, and implementation of longer term measures to improve overall performance.

IV. DISCUSSION

A. TOLEDO EDISON ACTION PLANS

1. AUXILIARY FEED PUMP TURBINE (AFPT) OVERSPEED TRIPS ACTION PLANS 1A AND 1B

Problem

During the June 9 event both AFPT's, tripped on overspeed when started.

On the loss of main feed supply the water level in steam generator SG-1 fell to the low level trip point. The low water level actuated a Steam and Feedwater Rupture Control System (SFRCS) full trip. The SFRCS trip initiated action to start the Auxiliary Feedwater Pump Turbine (AFPT #1). This action consists of opening the steam supply valve (MS 106) to AFPT #1.

While MS 106 was traveling to its open position, the reactor operator, in error, manually initiated SFRCS low pressure trip signals for both steam generators. These signals are automatically actuated by SFRCS in the event of a steam line rupture. They act to close containment isolation valves (AF 608 and AF 599) which isolate the

feedwater paths from AFP 1 and AFP 2 to the steam generators.

These signals also send open signals to open the steam cross connect valves MS 106A and MS 107A in an attempt to operate both AFPT's on steam from opposite steam generators.

The steam through MS 106A and MS 107A started both AFPT's with their pump discharge containment isolation valves closed. Both AFPT's tripped on overspeed approximately 25 seconds after initial roll.

Investigation

The cause of the trips is judged to be water slugs in the steam piping to the turbine due to residual water or rapid condensation of steam while heating the long, cold steam supply paths to the AFPT's. The steam path through MS 106A to AFPT 1 is 650 feet. The steam path through MS 107A to AFPT 2 is 375 feet.

The Auxiliary Feed System had not previously been cold started via the steam cross connected paths; A further complication was the starting of the pumps with discharge valves closed. This resulted in reduced load on the AFWT's making them more apt to overspeed. Investigation of other

utility experience has confirmed that condensation in the steam line can result in turbine overspeed on startup. The turbine vendor also confirmed that overspeed can be caused by water slugs.

Tests conducted on June 9 after the event confirmed that a governor problem did not cause this problem. In addition, analysis by TED has shown that the existing piping configuration will generate significant quantities of water.

Corrective Action

Keep the steam lines to the AFPT's hot whenever the plant is in operation.

BETA Comments

BETA agrees with the conclusion of Toledo Edison that water slugs in steam lines caused the overspeeding of the AFPT's.

BETA, based upon its review of the June 9 event, concluded that additional auxiliary feed system changes were necessary to enhance decay heat removal. BETA therefore recommended to Toledo Edison management that a Task Force consisting of personnel experienced in nuclear plant design, engineering, operations, and licensing be estab-

lished to recommend improvements in Davis-Besse decay heat removal capability.

Toledo Edison established such a Work Group. Recommendations of this group are contained in the report, "Recommended Improvements to Davis-Besse Decay Heat Removal Capability" dated August 14, 1985 (Reference 7).

That report recommends that remotely operable valves be installed in the steam lines near the auxiliary feed pump turbines and that the steam lines to these new valves be kept hot and pressurized. If the above cannot be accomplished in the short term, the report recommended that both auxiliary feed pump turbines be run periodically to keep the lines hot. The valves and their controls would be installed as soon as feasible.

BETA considers that the above actions should resolve the auxiliary feed pump turbine overspeed trip problem.

2. <u>AUXILIARY FEED PUMP TURBINE MANUAL/AUTO-ESSENTIAL CONTROL PROBLEM</u>

<u>ACTION PLAN 1C</u>

<u>Problem</u>

The Auxiliary Feed Pump Turbines are governor controlled. The speed to which the governors are set is adjusted by a motor operator controlled from the Control Room. This control system has a switch in the Control Room which selects either "Manual" control of speed or "Auto-Essential" control which sets the speed on signals from steam generator water level.

As discussed in Section IV.A.1., both auxiliary feed pump turbines tripped on overspeed. Operators were dispatched to the Auxiliary Feed Pump rooms to reset the trip throttle valves. Control room operators reported an inability to take either manual or auto-essential control in the control room after they understood that the trip throttle valves had been reset.

<u>Investigation/Results</u>

Later review of the computer alarm printouts revealed that the trip throttle valves were not fully reset when the remote (Control Room) control operations were attempted in

the manual and auto-essential modes. These remote controls would not be expected to be effective during this condition since interlocks are provided on the trip throttle valves to assure that the valves are fully reset.

Test ST 5071.02, AFWS Refueling Test, was conducted shortly after the trip throttle valves were reset. This test indicated proper control from the Control Room. Action Plan 1C has been revised to check the remote manual and auto-essential controls when the plant is returned to operation.

BETA Comments

BETA considers that the planned actions should resolve this problem. Problems with resetting the turbine trip throttles are discussed in Section IV.A.3.

3. AUXILIARY FEED PUMP TURBINE TRIP THROTTLE VALVE PROBLEM ACTION PLAN 1D

Problem

After the AFPT's tripped on overspeed, operators dispatched to the Auxiliary Feed Pump rooms had problems in relatching the Auxiliary Feed Pump Turbine overspeed trip throttle valve linkages. In addition, difficulty was experienced in

opening the trip throttle valves after the linkages were reset.

Investigation

Investigation of the reset problem revealed that the operator did not properly perform the reset actions. Procedures did not adequately define the actions required. Previous training had not adequately prepared the operators to perform the reset actions.

The difficulty with opening the trip throttle valves after they were reset, was attributed to the high differential pressure across the valve being experienced at that time and to the fact that the operators thought they had to hold the linkage in the latched position while opening the valve.

While opening the valve required considerable force, it was judged to be well within the capability of the operators.

Corrective Action

Action has been taken to train the operators on the proper actions to reset the trip throttle valves. Operating procedures are being revised to describe in detail the

actions required and operating instructions will be posted at the turbines.

BETA Comments

BETA agrees with the evaluation of this problem and considers additional action such as providing remote reset of the trip throttle valves from the control room to be unnecessary.

4. STEAM AND FEEDWATER RUPTURE CONTROL SYSTEM (SFRCS) TRIP ACTION PLAN 5

Problem

On June 9, 1985, a low steam generator (SG) level trip (full) of the Steam and Feedwater Rupture Control System (SFRCS) occurred immediately following a main turbine trip and closure of the turbine stop valves. This trip of the SFRCS appears to have been spurious.

Investigation

The primary TED hypothesis as to the cause of this spurious trip is that the SG level transmitters developed oscillations due to pressure oscillations from the closure of the main turbine stop valves. During the 1984 outage the SG

level transmitters providing startup level indication on the control panel and SG level control were changed from Bailey BY to Rosemount 1153 transmitters. The Rosemount transmitters are more sensitive to pressure disturbances than the Bailey transmitters.

Other hypotheses relate to cross-talk between logic channels, logic malfunctions, changes to SG level channel response characteristics, and swings in steam generator level.

This Action Plan tests the above hypotheses where possible through measurement of instrumentation and control equipment performance under test conditions and by reviewing the results of past preoperation tests at Davis-Besse.

Results/Corrective Action

Test results and analysis to date described in a Preliminary Findings Report dated August 24, 1985, have shown it is unlikely that this spurious trip was a result of cross-talk between logic channels, logic malfunctions, changes to SG level channels response characteristics, or swings in steam generator level. Review of available data and analysis of the response of the new Rosemount level transmitters indicates that the trip probably resulted from the output of the level transmitter due to pressure oscilla-

tions in the steam line following turbine stop valve closure. Additional testing is underway to provide further confirmation of this conclusion.

An approved corrective action recommendation for this problem has not been issued. However, current plans are to install a filter (0 to 0.1 hertz) at the input to the SFRCS trip bistables. This filter is designed to prevent spurious trips while still permitting the system to meet the requirements of the Davis-Besse technical specifications. Additional testing will be performed prior to and during Mode 1 operation to verify the effectiveness of the corrective action taken.

BETA Comments

BETA concurs with TED's conclusions and proposed corrective action.

5. SFRCS FULL TRIP ALARM (Q963) FUNCTION
ACTION PLAN 6

Problem

On June 9, 1985, a Steam Generator (SG) low level full trip of the Steam and Feedwater Rupture Control System (SFRCS) occurred immediately following a main turbine trip and

closure of the turbine stop valves. There was no apparent cause for this trip and only the Main Steam Isolation Valves (MSIV's) moved in response to this SFRCS trip. The occurrence of a spurious full trip of the SFRCS was identified by computer alarm Q963. It was postulated by TED that in reality a trip might not have occurred and the alarm was a result of a malfunction. Prior to this event this alarm had malfunctioned twice in recent months. The problem is to determine if the apparent trip was not real but instead was a failure of alarm Q963.

Investigation

TED conducted a review of the sequence of events computer output and the alarm log.

Results/Corrective Action

The above records indicated an SFRCS full trip and reset (Q963), an ARTS trip (Q777) and an SFRCS trip of the turbine (X044). Based on this data TED concluded that the trip occurred and the Q963 alarm was valid. No corrective action was recommended.

BETA Comments

BETA concurs with TED's conclusion that the June 9, 1985, trip of the SFRCS actually occurred and that there is no basis to assume that alarm Q963 malfunctioned. BETA has the following comment with regard to this Action Plan:

> TED should attempt to determine if the June 2, 1985, and April 24, 1985, SFRCS spurious half trips were a result of "inadequate performance of this alarm function (Q963)" as postulated in the "Preliminary Findings Report Plan No. 5, 6 and 7" dated August 24, 1985 or a result of the increased sensitivity of the new SG level sensors (see the discussion of Action Plan 5). If it is concluded that the alarm had malfunctioned, action should be taken to identify the cause and repair the alarm.

6. PARTIAL ACTUATION OF SFRCS
ACTION PLAN 7

Problem

On June 9, 1985, a spurious steam generator low level trip (full) of the Steam and Feedwater Rupture Control System (SFRCS) occurred immediately following a main turbine trip and closure of the turbine stop valves. Both Main Steam

Isolation Valves (MSIV) closed approximately 5 seconds after the SFRCS full trip. However, other SFRCS equipment did not actuate as it should have after a trip.

Investigation

TED's primary hypothesis as to the cause of partial actuation of the SFRCS is that the duration of the full trip was sufficient to actuate the MSIV air system trip but not long enough to "seal-in" the SFRCS signals to the motor operated valves and the Main Feedwater Startup Control Valves.

Other hypotheses relate to possible malfunctions of the MSIV closure circuitry and the possibility that the turbine trip induced a transient in the MSIV air supply system causing the valve to close independent of the SFRCS trip.

Tests were made to determine the trip duration required to close the MSIV and other SFRCS valves. In addition, an analysis was made comparing the time response of these valves versus the measured duration of the SFRCS trip. Tests of the MSIV's closure circuitry will be performed to determine that it did not malfunction during the June 9 event.

Results/Corrective Action

The analysis described in the SFRCS Trip/MSIV Closure Preliminary Findings Report dated August 24, 1985, shows that the seal-in time response of the MSIV's is within the range of the SFRCS June 9 trip duration. The data for the other valves indicate they should not have moved during the spurious June 9 trip. In some cases, manufacturer-supplied data has been used to define the "seal-in" time for these valves. These times will be confirmed by additional testing. TED concludes that, subject to test confirmation, the partial actuation of the SFRCS was a result of the short duration of the spurious trip and not a result of additional equipment failures.

TED has not identified, at this time, the need for any corrective action.

BETA Comment

BETA concurs that the available information supports the conclusion that the partial actuation of the SFRCS system was the result of the short duration of the spurious trip and no corrective action is required.

7. MAIN FEED PUMP CONTROL SYSTEM

ACTION PLAN 8

Problem

On June 9, 1985, a loss of feed water event was initiated by the loss of main feed pump #1.

Investigation

Review of the recordings from the computer and feed flow charts indicated that the main feed pump turbine speed increased to the overspeed trip point and the turbine tripped.

Circuit checks made after the trip found a frequency to voltage converter which had failed resulting in a low frequency (speed) signal to the governor control system. This failure caused the speed to increase to the overspeed trip level. The failure of the integrated circuit which provides this frequency to voltage signal was confirmed by General Electric Co.

The integrated circuit was sent to the vendor, Teledyne Industries, Inc., for failure analysis. This analysis revealed a failed capacitor in the circuit board.

The complete main feed pump turbine control systems for both turbines were checked and no further problems were found. The controls will be exercised through their complete range when the plant is returned to operation.

Corrective Action

Replace the defective circuit board.

BETA Comments

Review of previous experience with the General Electric MDT 20 turbine control system indicates that over one hundred systems are in operation and a frequency to voltage converter failure has not been experienced previously.

BETA has considered the possibility of providing dual control systems for these feed pump turbines but concludes that such action is not warranted considering the extra circuit complexity and cost involved. The independent control systems for the two main feed pump turbines and the installation of the electric motor driven feed pump should provide sufficient backup for the infrequent failure of this electric governor control system.

8. TURBINE BYPASS VALVE ACTUATOR

ACTION PLAN 9

Problem

Several hours after the June 9 event, during reactor cooldown to cold shutdown condition, a turbine bypass valve (SP13A2) actuator failed. This failure did not significantly affect plant operations or recovery from the reactor trip.

Investigation

Visual inspection found that the SP13A2 turbine bypass valve actuator had failed in two places and that there were no signs of damage to the valve body, attached piping, piping supports, insulation, or other turbine bypass valves. Disassembly of the valve revealed that the pilot plug disc and washer, hex nut, and cotter pin were missing from the bottom of the pilot plug and stem assembly. An inspection of the other turbine bypass valves revealed that the failed valve had a different design from the others. In the failed valve, a cotter pin had been used to lock the hex nut which retains the main disc to the stem assembly. The other five valves were of an earlier design which used a lock washer with deformable tabs to lock the hex nut.

One steam trap on the header associated with the failed valve was found to be filled with debris and incapable of passing flow; the other trap had distorted internals and was stuck open. In any case, the common drain line isolation valve for these two traps was found closed such that the function of the traps was defeated.

Results/Corrective Action

With the stem not connected to the valve plug, the valve actuator withdrew the stem in response to a demand to pass turbine bypass flow, but the disconnected main valve disc remained on its seat. In this condition, any leakage under the main seat would allow upstream pressure to build up below the main disc, lifting it rapidly until it collided with the withdrawn stem assembly. The impact load of the disc rising rapidly was imparted to the actuator, causing the cast aluminum and cast iron components of the actuator to fail.

All turbine bypass valves will be inspected during each of the next two refueling outages to assure proper assembly. The results of these next two inspections will be used to determine the appropriate preventive maintenance procedure for subsequent inspections.

Prior to startup, the failed valve actuator will be repaired and tested and new steam traps and trap bypass valves will be installed on bypass valve header A. Plant operating procedures will be revised to provide improved bypass header warmup procedures to minimize the potential for water hammer.

BETA Comments

BETA concurs in the TED analysis of the sequence of events which resulted in the failure of the valve actuator. Given the short service life of this failed valve (installed in 1982) with the cotter pin locked nut, consideration should be given to modifying the cotter pin locking device to a positive lock washer with deformable tabs to lock the hex nut which assembles the disc and the stem.

9. PILOT OPERATED RELIEF VALVE (PORV) OPERATION ACTION PLAN 10

Problem

During the loss of feedwater event on June 9, the PORV cycled open three times. The first time the valve closed at the proper setpoint, the second time the valves closed 25 psi below the setpoint, and the third time, the PORV did not reseat even though the solenoid operator position

indicator light showed closed, indicating the control circuitry worked properly. Since system pressure was decreasing the Reactor Operator shut the PORV block valve and the pressure decrease stopped at 2075 psi. Subsequently, the block valve was opened and the PORV proved to be shut.

Investigation

A visual inspection of the PORV and its linkages revealed no abnormalities which could have any effect on the operability of the PORV. The PORV was then disassembled and a complete visual and dimensional inspection of the internal parts was performed using a check list prepared by the vendor, Crosby. This inspection revealed minor steam cuts on the pilot seat and disc and minor wear marks on the main disc guide lands. The PORV was then reassembled and bench tested for leakage and failed. Flushing the pilot valve while moving the solenoid lever manually revealed foreign material in the flush discharge. After flushing, the PORV leak test was satisfactory. The PORV actuation circuitry was checked with no results that could have had any adverse effect on the operability of the actuation circuitry. Analysis of possible thermally induced dimensional changes revealed no basis for assuming that differential expansion had caused the valve to stick.

Results/Corrective Action

The inspection and analysis of the preceeding paragraph do not reveal a direct cause for the failure of the PORV to reclose during the June 9 event. The most likely cause is demonstrated by the leak test of the PORV discussed above wherein foreign material in the pilot valve caused the PORV to fail its leak test.

To assist the Reactor Operator in coping with an unseated PORV, changes will be made on the PORV control panel. The PORV flow indication from the acoustic monitor will be displayed at the PORV panel and identified as PORV position. The PORV solenoid valve position indicator will be labeled as the solenoid position indicator vice PORV position indicator.

BETA has been informed that, in the absence of definitive findings related to the valve's failure to close, consideration is being given to replacing all valve parts with new parts so that a completely refurbished valve will be in place prior to restart.

BETA has been informed that consideration is also being given to providing a control feature for automatic closure of the PORV blocking valve on a decreasing pressure signal.

In the longer term a program will be developed to identify, evaluate, and procure an alternative PORV.

BETA Comments

BETA considers that the investigation of the PORV was appropriate and likewise agrees that the most likely cause of the valve's not closing was foreign material on the seat of the pilot valve.

BETA concurs in the additional corrective action being considered to rebuild the PORV with new parts. This rebuild of the PORV should be pursued as a readily available, conservative approach which will enhance future valve operation.

BETA concludes that the plant should not be modified to provide automatic closure of the PORV blocking valve. The additional complexity of the system is not justified given the new PORV flow and pilot valve position indicators that will be installed on the PORV control panel prior to startup.

10. AUXILIARY FEEDWATER SYSTEM VALVES AF 599 and AF 608 ACTION PLAN 12

Problem

During the loss of feedwater event on June 9, a Reactor Operator erroneously manually tripped the Steam and Feedwater Rupture Control System (SFRCS) on low pressure. This created a signal to close the normally open motor operated valves AF 599 and AF 608, and they closed in response to the demand. Subsequently, after the SFRCS had been reset and tripped on low level, an SFRCS signal was generated to open the valves. The valves did not open in response to this demand. When an equipment operator manually opened the valves to the point where system pressure could equalize across the discs, each valve motor operator took over and opened the valves the rest of the way.

Investigation

A visual inspection of the valves and operators revealed no deficiencies that would relate to the failure of the valves to open. A visual inspection of the torque switch settings showed them to be in accordance with specification (FCR 84-039), but further document review showed that the FCR value for the opening torque switch should have been 2.0 vice 1.5 as listed. This error had been uncovered in June 1984, but on

the date of the June 9th event, the torque switch had not been reset.

Subsequent operational testing using the Motor Operated Valve Analysis and Test System (MOVATS) showed that both valves operated satisfactorily with no differential pressure (dp) across the valves, however, the MOVATS showed that on both valves the limit bypass switches opened before the valves had unseated. In that test, the reduced torque capability caused by the improperly set limit switches and torque switches did not preclude the valves' opening. In subsequent testing both valves were tested with differential pressure across the valve:

1. With 1050 psid, AF 599 torqued out and failed to open on all three tests.

2. With 1050 psid, AF 608 opened successfully on each of two test operations, but with dp's of 1095 psid and 1100 psid across the valve, it failed to open on either test.

An analysis of plant conditions during the event on June 9th indicates that the dp across AF 599 and AF 608, at the time they were supposed to open, was greater than 1050 psid.

Results/Corrective Action

The direct cause of the failure of these two valves to open in response to a demand from SFRCS was incorrect setting of the limit switch which cut in the torque switch before the valves had unseated. The limited torque of the motor operator was insufficient to open the valves with a high dp across the valve. Further, the torque switch was not set to the correct value since the calculated value for torque switch settings had been based on erroneous valve dimensions.

These two errors had not been detected during previous surveillance tests since those tests had been conducted with no dp across the valve.

The following corrective actions have been taken or planned:

1. Maintenance Procedures have been issued to provide proper instructions for corrective maintenance, for setting limit and torque switches and for testing Limitorque operators using MOVATS.

2. Limit switch bypass settings for AF 599 and AF 608 will be adjusted to 20% of full stroke in the open direction, as measured by disc (not stem) movement, to

ensure the torque switch is not cut in prior to the valves being unseated.

3. Torque switch setpoints in the valve open direction will be set to the maximum value specified.

4. Valve data and measurements used in calculation of the torque switch settings for AF 599 and AF 608 have been verified in the field to assure accuracy.

5. Retest the valves after setting limit and torque switches with a 1050 psid across the valve to verify proper operation after reviewing system design and operating parameters to ensure that a differential pressure of 1050 psid is adequate for testing the operability of AF 598 and AF 608.

Further, the limit switches on all safety-related Limitorque operated gate valves will be reset prior to startup as described for AF 598 and AF 608 above, and the torque switch settings of those valves will be set to the maximum specified torque for each such valve.

In addition to the actions described above which will be completed prior to startup, TED plans the following additional actions:

1. Review surveillance tests and post-maintenance tests to determine if that testing can be performed at operational differential presssures.

2. Limitorque operated valves that are not safety-related will have their limit switches and torque switches set as described above for AF 559 and AF 608 on a system-available basis after restart.

3. Limitorque operated globe valves, ball valves, butterfly valves, etc., will be reviewe to determine actions required based on AF 599 and AF 608 experience.

<u>BETA Comments</u>

BETA concurs with the results of the investigation as being a valid explanation of the reasons for the maloperation of these Limitorque operated valves. The corrective actions will correct the deficiencies discovered. However, given the multitude of Limitorque operator problems shown during this event and in Davis-Besse's maintenance history, continued management attention will be required while carrying out the long-term corrective actions listed above.

11. OPERATOR ERROR ON INITIATING AFW

ACTION PLAN 14

Problem

This Action Plan relates to the operator error that occurred during the June 9 event. This error resulted in isolating both steam generators from the auxiliary feedwater supply.

The Steam and Feedwater Rupture Control System (SFRCS) manual initiation control panel arrangement is subject to operator errors. The actuating switches can be misoperated in such a manner as to completely isolate both steam generators from feedwater sources.

During the June 9 event the operator observed the water levels in both steam generators dropping due to loss of feed flow and safety valves lifting. He recognized that the Steam and Feedwater Rupture Control System (SFRCS) would initiate Auxiliary Feedwater System flow in a short time. Operator training is such that, if possible, an operator will manually trip systems that he sees are going to be tripped automatically. The operator went to the SFRCS manual initiation switch panel and pushed two switches to trip the SFRCS on SG low level. By mistake he pushed the wrong switches, and as a result both steam generators

were isolated from their auxiliary feed systems (he had pushed the top set of switches indicating both steam generators had low pressure, in lieu of the fourth set from the top indicating both steam generators had low level).

The operator initiated SFRCS operation by pushing two of 10 switches located on a back panel in the control room. These switches are used to identify the casualty condition requiring SFRCS operation, permitting the system to properly align the auxiliary feed system. Five different conditions are identified:

1. Steam generator level Hi/Low
2. Steam generator 1-1 low pressure
3. Steam generator 1-2 low pressure
4. Feedwater ΔP
5. Loss of Reactor Coolant Pumps

For each of the above conditions, two switches are provided, one for Channels 1 and 3 and the other for Channels 2 and 4. Either switch will initiate a portion of the SFRCS protection. However, both switches must be pressed to assure complete SFRCS protection.

Investigation

As a result of this operator error, an investigation was undertaken under Action Plan #14, to determine what action could be taken to reduce the likelihood of a similar error in the future. This investigation considered human engineering improvements that could be made to the SFRCS switch array. In addition, a review was made by the Davis-Besse staff of the current philosophy relating to manual vs. automatic safety system actuation.

Results/Corrective Action

This investigation resulted in a recommendation to rearrange the switch array to avoid confusion and install guards (covers) over eight of the switches to minimize the possibility of inadvertent operation.

Independent of the above investigation, a work group has been convened by TED. The purpose of this group is to evaluate Davis-Besse's decay heat removal capability. The Work Group's recommendations, both short term and long term, to simplify the SFRCS have an impact on this Action Plan. These recommendations are:

Short Term

If analysis confirms that it is possible delete autoclosure of valves AF 599 and AF 608. This change will assure that operator errors in initiating SFRCS can not completely isolate the steam generators from their feed systems.

Long Term

Provide revised functions and improved labels for SFRCS manual actuation buttons.

The Davis-Besse staff review of the current philosophy relating to manual vs. automatic safety system actuation concluded, "the licensed operators have a responsibility to manually actuate safety systems. There are also procedures which direct manual actuation during deteriorating plant conditions; i.e., loss of instrument air. The committee does not feel it prudent to attempt to provide specific case-by-case guidance for when it is appropriate to manually actuate the SFRCS, RPS, ARTS, SFAS, etc. The operators must evaluate all conditions present at the moment, then make the decision for manual actuation. The Reactor Operator should not be required specific permission from the Control Room SRO prior to taking manual action if he deems them appropriate. However, if the SRO is in the

Control Room at the time, the RO must communicate his intent to manually actuate a safety system. At that point, the SRO may choose the direct action not be taken."

BETA Comments

BETA concludes, based upon its review, that the action proposed by TED and the recommendations of the Decay Heat Removal Work Group contained in its draft summary report will provide a satisfactory resolution of the issue subject to the following comments:

1. The deletion of autoclosure of valves AF 599 and AF 608 assures that operator error in initiating SFRCS can not result in complete isolation of the steam generators. In the event it is not possible to delete the autoclosure of these valves, other action should be taken to provide this assurance.

2. Both the current SFRCS actuation switch configuration and the configuration recommended by the working group (Long Term) require actuation of two switches to manually actuate the system. The need for a pair of switches is not apparent and the long term change should have as its objective reducing the two switches for each actuation mode to one.

12. REPORT ON MAIN STEAM HEADER PRESSURE

ACTION PLAN 16

Problem

Protection against overpressurization of the main steam system (steam generators) is provided by 18 code safety valves (9 per steam generator) and two atmospheric vent valves (one per steam generator). The atmospheric vent valves are controlled by the integrated control system (ICS) and are used in controlling steam pressure during large transients. Starting very shortly after the event of June 9th (~30 seconds), all main steam safety valves appear to have lifted repeatedly. This action is not abnormal. However, review of the recordings indicates that steam pressure swung as much as 200 psi during periods when the atmospheric vent valves were supposedly controlling header pressure. This is abnormal.

A similar problem was observed on June 2, 1985, following a plant trip. Although this problem is not directly related to the loss of feed water event, it did occur as a result of it and because it existed on both headers, it was considered worthy of investigation.

Investigation

The investigation being conducted by TED is centering on three main areas:

1. Determination of proper functioning of the Main Steam Safety Valves (MSSV).

2. Determination of proper functioning of the Atmospheric Vent Valves (AVV).

3. Determination of the proper functioning of the Integrated Control System (ICS) with respect to control of the AVV's.

Results/Corrective Action

As of the date of this report, TED has not been able to identify the exact cause of this problem. However, it appears that the problem centers on either the control or the functioning of the AVV's, rather than being a problem with the MSSV's. Effort is continuing on reviewing the ICS circuitry. The MSSV's setpoints are to be tested prior to criticality.

BETA Comments

Based on its review of this problem, BETA concludes that the investigative plan being pursued by TED is appropriate and should be continued. It would appear that the specific problem noted during the June 9 event probably resulted from some malfunctioning of the AVV's by way of the ICS since the phenomena was experienced on both steam headers.

In addition, BETA considers the relatively poor performance of the MSSV's and the AVV's over the past several years as shown by maintenance history to be a further reflection on Davis-Besse's lack of sensitivity to pursuing equipment malfunctions. For this reason, BETA recommends that even if an ICS module is found defective and thus establishes the root cause of this problem, TED should continue its engineering/maintenance effort on fixing the MSSV's and AVV's. It is not clear whether the problems being experienced with these valves are a result of is design, maintenance, or both.

13. STARTUP FEED VALVE SP-7A

ACTION PLAN 18

Problem

At the beginning of the incident, Startup Feed Valve SP-7A was open. When SFRCS was initiated the valve closed as designed. When the SFRCS trip was reset the SP-7A, Channel 4 reset switch indicating light did not come on to indicate the reset action.

It was believed that the lack of a light indicated a burned out lamp bulb. A 6 volt bulb was mistakenly inserted whereas a 120 volt bulb should have been used. The 6 volt lamp bulb blew.

Investigation

Review of the Data Acquisition Display System readouts and feed flow charts indicated that the valve operated toward the close position when called for by the SFRCS system. However, this review indicated that the flow measuring instrument for feed flow through SP-7A was out of calibration high, or that the valve was not fully closed, or that it was leaking.

During inspection after the incident, an air leak was discovered in the actuator for valve SP-7A. This could prevent full closure of the valve.

Channel 4 is powered by alternating current. The 6 volt light bulb was taken from Channel 1 which is powered by direct current. Blowing of the 6 volt bulb would be expected. The fact that the bulb blew indicates that Channel 4 had reset, since if the channel had not reset there would have been no power to the bulb.

Corrective Action

The flow instrument was recalibrated and found to be out of calibration by approximately 0.36% high whereas specified tolerance is ±0.25%. This indicated that the Data Acquisition System reading resulted from the flow instrument being out of calibration and that the valve was shut even though the instrument indicated that flow was present.

The valve was cycled with the leaky air operator. This test showed that the valve performed satisfactorily even with the leak. The leak has been repaired.

BETA Comment

BETA concludes that this item has been adequately evaluated. Operators have been trained on the proper bulbs to use in their circuits and label plates showing lamp voltage have been installed.

14. AUXILIARY FEED PUMP TURBINE MAIN STEAM INLET ISOLATION VALVE (MS-106)
ACTION PLAN 27

Problem

The Main Steam Isolation Valve (MS-106) to the turbine driven Auxiliary Feed Pump Turbine (AFPT) 1-1 received an open signal from the Steam and Feedwater Rupture Control System (SFRCS) due to low steam generator level following loss of the Main Feed Pumps. The valve began to open. Then, two seconds later, a Control Room operator erroneously manually tripped the SFRCS on Low Steam Pressure, intending, to have tripped the SFRCS on low level. This action was taken to anticipate the steam generator low level trip generated by SFRCS following loss of main feed flow.

The low level trip generated a signal for MS-106 to open and the valve did begin to open. Subsequently, the manual SFRCS trip on low pressure generated a close signal. Under these circumstances the valve should have gone fully open, then, with the existing signal to close, the valve should close. The normal stroke time for this valve is 25 seconds to open and 25 seconds to close, so the sequence of events described above should have required 50 seconds from closed back to closed again. Yet, only 19 seconds passed from the time the valve began to open, indicated it was mid-positioned, then returned to the fully closed position.

Investigation

A number of visual and electrical inspections were performed on the motor operator for MS-106, including the motor controller, connected wiring, and signal and control cables. Nothing was noted that would account for the anomalous operation of the valve. Testing of the valve was then performed using MOVATS (Motor Operated Valve Analysis and Test System). The MOVATS equipment permits determining the actual valve stem thrust, the time of actuation of all control switches, motor current, and operator torque.

With MOVATS installed, the valve at ambient temperature, and no differential pressure across the valve, MS-106 opened successfully. However, the test data indicated that

the limit switch bypass opened before the valve was unseated. It was further determined that a gap in the spring pack caused the operator to trip on limited torque at a lower torque value than its closing torque switch setting would normally produce. This gap in the spring pack existed because of prior incorrect assembly of the spring pack.

The valve was then tested again with MOVATS in place and with an artificial restraint provided to limit stem movement. This restraint was placed so that the limit switch would trip, but the valve would not be fully unseated. This test revealed that when given an open signal, the limit switch bypass opened placing the torque switch in the circuit and sending a valve midposition signal. When the restraint was encountered, the motor operator was deenergized by the torque limit switch. When deenergized, the spring pack relaxed, the torque limit switch closed, the motor operator then tried to open the valve against the restraint until the operator torqued out again. This sequence of open, torque out, spring pack release, open, torque out, spring pack release, open, torque out was allowed to continue for a few seconds before a close signal was originated. The next torque switch trip in the open direction then allowed the close circuit to energize and reverse the direction of stem travel. However, the gap in the improperly assembled spring pack permitted the close

torque switch to open and deenergize the motor operator, whereupon the spring pack relaxed, the close torque switch closed, and the motor operator again drove in the close direction, only to torque out again. This sequence of drive close, torque out, spring pack relax, drive close continued for nine seconds until a valve closed indication was received.

Results/Corrective Action

The results of this investigation revealed that the bypass limit switch was improperly set, such that the opening torque switch was cut in before the valve was off its seat and the torque capability of the motor operator, as set, was not sufficient to take the valve off its seat. Further, the closing spring pack had been improperly assembled with a gap permitting movement and torque limiting action at very low torque in the close direction.

The following corrective actions have been taken or planned:

1. New maintenance procedures have been issued providing proper instructions for all phases of motor operator maintenance and testing of these motor operators using MOVATS.

2. Prior to restart the limit switch bypass setting of MS 106 will be set to a value of 20% of full stroke in the open direction as measured from the point of valve disc (not stem) movement to ensure the torque switch is not in the opening circuit until the valve is unseated.

3. FCR 85-134 specifies the torque switch maximum settings that will preclude valve damage. Adjust the torque switches of MS 106 to this maximum specified setting prior to startup.

4. On all other Limitorque operated wedge disc gate valves at Davis-Besse, set the limit switch bypass contacts to 20% of the full opening stroke as measured from the point of disc movement, and for all safety-related valves, set the opening torque switch setting to the maximum value specified in FCR 85-134.

5. Maintenance procedures have been prepared and formal training for those who conduct maintenance and testing has commenced.

BETA Comments

BETA concludes that the corrective actions planned and performed on MS 106 will cause the valve to perform properly in the future. The TED Action Plan, when trying to account for why the valve performed properly on previous surveillance tests, yet failed to perform properly during this event, concluded that a previous manual closing of the valve, jamming the wedge shaped disc on the seat or foreign material on the seating surface, caused the valve to require higher than previous torque to open the valve during the event. This conclusion is reasonable, but the maloperation of the valve could also have been caused by the packing follower that was found to be pulled down crooked in the gland. In either case, a few minutes later, when establishing normal main steam supply to the auxiliary feed pump turbines, after the SFRCS had been reset, MS 106 opened on demand with proper timing. Resetting the limit switches and torque switches as described above will, in BETA's opinion, resolve the initial problem and will provide proper future performance.

B. IMPROVEMENTS TO DAVIS-BESSE DECAY HEAT REMOVAL CAPABILITY

The June 9, 1985, event resulted in the total loss of main and auxiliary feedwater. Action Plans were formulated by TED to investigate the problems directly related to the event. BETA's preliminary review of the problems led BETA to the conclusion that a fresh look should be taken at the subject of decay heat removal at Davis-Besse. BETA recommended that review be performed by a task force of persons experienced in nuclear plant design, engineering, and operations. The objective of the review would be to define practical measures to improve the reliability of systems used for decay heat removal at Davis-Besse. Toledo Edison management agreed with this recommendation and established a Work Group.

The Work Group approach to achieving reliability improvements was to:

(a) Define those changes that could reduce the frequency of isolations of main feedwater and/or main steam. Such isolations result in requiring emergency means of decay heat removal.

(b) Reduce the number of automatic system responses required to obtain auxiliary feed flow to steam generators. This included reduction in the number of

motor-operated valve actuations and keeping steam lines hot to the auxiliary feed pump turbines.

(c) Reduce the potential for common-mode failures which could disable all means of decay heat removal via the steam generators. This approach included installation of a motor-driven auxiliary feed pump and keeping discharge paths to the steam generator and suction paths to the pump open.

(d) Evaluate decay heat removal from the primary system by the feed and bleed method.

WORK GROUP RECOMMENDATIONS

The Work Group recommended changes to the Auxiliary Feedwater System and to the Steam and Feedwater Rupture Control System (SFRCS). The Work Group also reaffirmed the Toledo Edison prior decision to install a larger motor-operated startup feedwater pump and recommended that this be accomplished prior to restart. In addition, the Work Group also recommended changes to primary system operating procedures to improve the ability to remove decay heat by the feed and bleed method.

The Work Group concluded that implementation of their recommended changes to the main and auxiliary feedwater systems and their associated control systems is expected to result in

approximately two orders of magnitude improvement in the reliability of removing decay heat from the reactor.

The Work Group conclusions and recommendations are discussed in more detail in Reference 7. These improvements will be achieved in two phases. Short term improvements are to be accomplished prior to plant restart and include some interim actions to provide improvements in reliability until the long term recommendations can be implemented. The recommended changes are summarized in the following paragraphs.

Auxiliary Feedwater System/SFRCS

The Work Group recommended the following short term and long term modifications for the Auxiliary Feedwater System and the SFRCS.

Short Term:

- Several specific logic changes in the SFRCS to: 1) If analysis confirms that it is feasible, eliminate the ability to completely isolate auxiliary feedwater from the steam generators (e.g., deletion of auto closure of AF599 and AF608), 2) reduce the number of plant parameters which can cause automatic closure of the main steam isolation valves, and 3) improve the

reliability of the steam generator low level signal for initiating auxiliary feedwater flow.

- Install remotely operable valves in the main steam lines near the auxiliary feedwater pump turbines with additional condensate traps as needed to preclude water slug formation and consequent possible overspeed and piping or pipe hanger damage.

  If this can not be accomplished in the short term, continuously run both auxiliary feedwater pump turbines.

  NOTE: These recommendations lead to the reclassification of the steam lines to the auxiliary feed pump turbines as high energy lines, since they will be filled with steam at a pressure above 275 psig all the time, instead of less than 2% of the time--the current basis. In a preliminary evaluation, the Architect-Engineer concluded that reclassification of the lines as high energy lines will require: 1) the addition of 5 to 10 pipe whip restraints, or 2) analysis to demonstrate that before a crack exceeding the critical flaw size for the steam lines would develop, the leak through such a crack

would be reliably detected. The Architect-Engineer states that an unknown amount of safety-related equipment might require requalification for service in an elevated temperature environment. A detailed work scope and schedule, including all environmental qualification evaluations, is being prepared that will permit a thorough assessment of this option.

The Work Group also considered that the possibility of obtaining NRC approval to operate on an interim basis until the lines are completely restrained for pipe whip should be investigated.

Both recommendations relate to introduction of water slugs into the turbines due to condensation in the currently initially cold, long steam lines. For both configurations, all four existing steam inlet valves to the turbines would be kept open.

- Open all valves in the discharge path from each auxiliary feedwater pump to its respective steam generator to improve overall system reliability by reducing the number of valves required to change position.

- Reduce the number of failure mechanisms on the suction side of the auxiliary feedwater pumps including removal of suction strainers, revising the setpoint of suction transfer interlock, and eliminating the steam inlet valve closure interlock.

- Modify auxiliary steam system configuration to provide turbine gland steam and motive steam for steam jet air ejectors from both main steam headers. This is to preclude a loss of condenser vacuum on closure of one MSIV.

- Revise the design of the "new" SFRCS panel to incorporate the SFRCS logic changes and auxiliary feedwater system changes recommended herein. The human factors of this panel should be thoroughly reviewed with the operating staff.

- Correct overheating and excessive ripple problems in SFRCS electronic power supplies.

<u>Long Term</u>

- Install regulating valves in the auxiliary feedwater flow path to the steam generators and control flow using feed flow and steam generator water level signals. This would eliminate the basic instability

problems associated with controlling level via a speed control turbine governor.

- Eliminate several additional actuations of the SFRCS by analysis of plant response, e.g., analytically demonstrate that the core will not go recritical due to overcooling by main feed or that if recriticality is predicted, that fuel damage will not occur, thus allowing the elimination of an automatic isolation of main feedwater.

Motor Driven Feedwater Pump:

The Work Group concluded that a motor-driven pump capable of providing feedwater to the steam generators is required. It was recommended that this capability be provided via the "Startup Feedpump" system currently being installed, which provides the functions of both an auxiliary feedwater and main feedwater source. This pump should have the capability to take suction from the deaerating storage tank, the condensate storage tank or service water (this latter capability is not presently included) and provide flow to either the main or auxiliary feedwater nozzles on either steam generator by plant operator manual alignment. The normal alignment of pump discharge would be to main feedwater.

The present design of the new motor driven startup feedpump subsystem provides a filter in the common suction line from the condensate storage tank and the deaerating storage tank. The Work Group considered this location inappropriate. The filter is an unnecessary obstruction to flow from the deaerator and should be moved to the line from the condensate storage tank only or eliminated altogether.

The Work Group concluded that it is impractical to provide, within the structure of the existing Davis-Besse power plant, an electrically driven auxiliary feedwater train that would meet all the existing regulatory requirements for a safety-related system. The difficulty arises because the only practical location for the new system lies in the turbine building--a building which was not designed to NRC standards for seismic disturbances. This is not to say that the system in the chosen location, would not survive a severe earthquake. The Work Group considered it extremely important that the electrically driven feedwater subsystem provide a reliable source of feedwater under all realistic conditions of operation. These conditions include the survival of the system in plausible off-normal situations in which it may be required to function (such as a fluid system line break in its vicinity). Accordingly, the Work Group recommended the following actions:

- Install the motor driven startup pump subsystem as recommended above as soon as possible. A careful review of the system design should be made to ensure that problems that have occurred with other backfitted electric drive pump subsystems will not be encountered.

- Perform an analysis to evaluate the magnitude of seismic event that the turbine building in the vicinity of the new system would be likely to survive.

- Define a set of plausible environmental disturbances, e.g., line breaks, that might affect the system's operation, and survey the system's components to determine their ability to survive these environments. Should this survey identify components that might not survive, such components should be replaced, if practical, with components that are capable of survival. Such changeouts should be done deliberately and should not delay the initial installation and use of the system.

- The reliability of the new system should be demonstrated and documented by surveillance test following startup.

Given the satisfactory completion of the above measures, the Work Group recommended that the electrically driven feedwater pump susbystem be considered and used as a bonafide third train of the auxiliary feedwater system. Effective use of this train might or might not require its automatic actuation. However, the Work Group recommends that, when the qualifications of the system have been demonstrated as defined above, the following additional simplifications to the SFRCS and auxiliary feedwater system be evaluated:

- Elimination of the automatic closure of the MSIVs on low steam pressure (conservation of steam for auxiliary feed pump turbines is not necessary since the motor drive backs up both turbine drives).

- Permanently align the steam driven auxiliary feed pump 1 to feed and draw steam from steam generator 1, with a similar arrangement for pump 2 and steam generator 2. Eliminate the automatic crossover valve alignment and "feed only good generator" logic features for these pumps. The motor driven pump will provide backup to either steam driven pump, should that pump fail coincident with a leak in the other steam generator.

Feed and Bleed Cooling

The Work Group concluded that feed and bleed cooling capability is desirable to provide a backup means of removing decay heat without use of the auxiliary feedwater system.

Feed and bleed capability should be analytically demonstrated using realistic assumptions consistent with the emergency procedures that are implemented at Davis-Besse. Specifically, those assumptions include the following:

1) realistic decay heat with a 100% power operating history;
2) no steam condensation in the reactor vessel;
3) operator action taken within 10 minutes of determining that heat transfer via the steam generator has ceased;
4) equipment needed to provide feed and bleed cooling need not meet single failure criteria

The acceptance criterion for the analysis of the feed and bleed cooling mode should be that the collapsed liquid level in the reactor core remains above the top of the core throughout the duration of the transient.

Several alternatives were reviewed by the Work Group that could lead to analytical demonstrations of acceptable feed and bleed cooling. They were:

1) Evaluate the acceptability of presently installed capability.
2) Increase the size of the PORV to provide blowdown capability sufficient to depressurize the RC system to permit use of existing high pressure injection pumps for decay heat removal.
3) Increase total flow of the existing system, i.e., the discharge path, in addition to increasing the size of the PORV.
4) Provide additional makeup flow capacity, e.g., larger pump, modifications to current makeup pump, larger impeller; using the existing PORV capacity.
5) Replace existing HPI pumps with high head HPI pumps.

The Work Group initiated analyses to assess the existing equipment's feed and bleed capability. Included in this assessment was an evaluation of the criteria used in emergency procedures for initiating the feed and bleed cooling mode.

Preliminary analytical results from Babcock & Wilcox show that existing equipment can be successfully used to feed and bleed the reactor coolant system following a total loss of feedwater. The RELAPS Mod 2 analysis model included the following assumptions:

- Initial power 102% of rated core power
- Decay heat: 1.0 x 1979 ANS 5.1 Standard
- Total loss of feedwater at time zero
- No credit taken for any anticipatory reactor trip (ARTS)
- Operator action to initiate feed and bleed ten minutes after reaching the initiation criteria for feed and bleed cooling.

The analysis assumed that the operator's actions to initiate feed and bleed cooling included the following:

- Start both Makeup System pumps at full flow
- Open the PORV
- Open the hot leg high point vents
- Put HPI in the piggyback mode

The results of the analysis show that the Work Group's recommended acceptance criterion for feed and bleed cooling is satisfied. Minimum collapsed liquid level in the reactor vessel remained above the core at all times.

As a result of this assessment, the Work Group recommended that a new criterion be implemented in the emergency procedures for initiation of feed and bleed cooling. The new criterion should be an RCS hot leg temperature of 610°F. Other parameters, such as steam generator level and pressure, may be used by the operator to determine the condition of primary to secondary heat transfer. However, once a hot leg temperature of 610°F is reached, feed and bleed cooling should be initiated. This parameter is readily determined from the Control Room, involves an accurate instrument string, and is unambiguous in interpretation. It will serve for either forced flow or natural circulation conditions. The analysis assumed operator action ten minutes after reaching the 610°F criterion.

In conclusion, the Work Group recommended adoption and implementation of the new criterion for initiating feed and bleed cooling. In addition, the emergency procedures should be brought into compliance with the analysis assumptions. No equipment alterations or replacements are required. The analysis demonstrated that the existing equipment provides significant margin against uncovering the core using conservative analysis assumptions.

BETA Comments on Work Group Report

BETA considers that the changes recommended by the Decay Heat Removal Work Group will significantly upgrade the reliability of the Davis-Besse plant. The recommendations are strongly endorsed.

It is noted that some of the recommendations are based on preliminary analysis and simplified engineering calculations. It is recommended that this analysis work be carefully documented and independently checked to provide added assurance that the basis for the recommendations is absolutely sound.

The Work Group recommendations, if supported by analysis, will result in a simplification of the SFRCS. However, based on its performance in the past and the significance of its function, BETA considers that additional long term effort should be directed toward additional simplification. These long term studies should compare the SFRCS to corresponding systems at other plants and should evaluate available generic studies which may be applicable to Davis-Besse.

C. NRC GENERIC CONCERNS

As previously discussed, the NRC identified prior to the June 9 event a number of concerns relating to the operation of the Davis-Besse plant. Most significant of these concerns were those identified in the NRC's Systemmatic Assessment of Licensee Performance (SALP) #4 in which five functional areas were placed into Category 3 (the lowest grade). This report was transmitted to TED by an NRC letter dated December 6, 1984 (Reference 8). TED responded to that NRC letter on February 4, 1985 (Reference 9).

The five areas receiving Category 3 ratings were:

1. Maintenance
2. Fire Protection
3. Emergency Preparedness
4. Quality Programs and Administrative Controls
5. Training

Plant Operations was given a Category 2 rating but was listed as declining.

While there is no direct evidence that the poor performance of the Davis-Besse plant, as reflected by the SALP #4 report, specifically caused or contributed to the June 9 event, it is reasonable to assume that many of the identified deficiencies

had a causal effect. For example, it is most probable that the deficiencies in both maintenance and training had a bearing on many of the malfunctions noted during the June 9 event.

The purpose of the BETA review in this area was not to attempt to establish a direct link between the event and these generic weaknesses, but to attempt to make a judgment as to whether the TED actions in response to the SALP Report and other NRC correspondence would provide some degree of additional assurance of safe operation. It was not BETA's intent to confirm the weaknesses noted by the NRC. BETA accepted the NRC position.

Prior to discussing the specific actions planned or in process, it should be noted that Toledo Edison senior management, for whatever reason, had decided to take fairly drastic corrective action after the December 1984 SALP report. Intent to do so is evident in the Williamson (CEO) letter to Keppler (Region III, NRC) dated February 4, 1985 responding to the SALP report. Quotes from that letter clearly demonstrate recognition of the seriousness of the situation. Namely, "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". "I intend that this Company embark upon a program where strong, unrelenting, critical self-appraisal will become a routine way of life to our operations and support staffs and their managers. We should be the first to detect deficiencies in our own performance." "We intend to provide the

leadership and the resources needed to elevate performance of our operation of Davis-Besse to a state of excellence."

The most direct evidence of the sincerity of this purpose was the hiring of a new Senior Vice President, Nuclear and the charging of him to take the necessary steps to achieve the promised excellence. This action was taken prior to the June 9th event. Consequently, many of the generic issues highlighted by the NRC would probably have been corrected had there not been a June 9 event. In the discussion that follows it is important to note that while the generic issues are related indirectly to the event, they are not necessarily tied to it.

The enclosure to the NRC's letter to TED of August 14, 1985, specifically discussed the management and programmatic issues raised by the SALP #4 and other past NRC correspondence as they related to the June 9 event. Those issues were listed earlier in this report in Table 3. The following sections discuss these NRC generic issues.

1. ADEQUACY OF MANAGEMENT PRACTICES

a. Control of Maintenance Programs

One of the first actions taken by the new Senior Vice President Nuclear was to hire a new experienced person to be responsible for all plant maintenance. This

management change resulted in a number of rather drastic changes in how maintenance is to be conducted. These included:

1) the bringing in of new, experienced high-level maintenance personnel
2) increased supervisory personnel
3) improved foreman/craftsmen ratio
4) increased training
5) increased control over spare parts, material, etc.

Based on BETA's review, it appears that there is a serious, concerted effort underway at Davis-Besse to improve every facet of how maintenance is performed. Unfortunately, there are many ills to be corrected, and most of them take more time than is reasonably available prior to restart. This means that all corrective action with respect to maintenance will not be completed prior to restart.

Recognizing that the upgrading of plant maintenance will require time, TED has established a program to direct attention to elements of the plant that need additional maintenance attention prior to startup. In that program, an extensive review is being made of past records and operator experience (interviews) to

identify equipment that has had an unsatisfactory operating history. Maintaining or modifying this equipment should provide the necessary assurance that any "bad actors" are fixed prior to restart.

b. Use of Operational Experience

One of the organizational changes implemented after the June 9 event was to move the Plant Manager to Group Director of Engineering for Davis-Besse. While this one change alone will not assure the increased use of operational experience, it does provide a vital link between the plant and engineering. It is also clear that the management philosophy of the new Senior Vice President Nuclear will add greatly to a better understanding of and appreciation for the feedback of operational experience into plant activities.

c. Degree of Engineering Involvement

In the three months since the event, a number of changes have occurred with respect to how engineering is performed at Davis-Besse. The decision has been made to relocate the Davis-Besse engineering from staff headquarters in Toledo to the site. The moves are already underway. In addition to organizational changes and the shifting of people, there is a tempo-

rary heavy reliance on engineering assistance from outside organizations. Much of this is necessary because of the increased workload associated with resolving the June 9 event issues. BETA senses that once this flurry of activity subsides, senior management will restructure the entire engineering effort at Davis-Besse.

BETA considers it too early to make a judgment on how engineering work at Davis-Besse will ultimately be performed. The early indications of the increased emphasis on performance and quality would lead one to believe they will be improved.

d. Testing

A review is being conducted by TED of past surveillance test procedures and test records to determine the completeness and adequacy of past testing. Identified concerns will be documented and modified test requirements developed. This could also result in new or modified surveillance tests. This program should provide the basis for determining if previous testing at Davis-Besse was effective.

e. Root Cause Determination of Equipment Misoperation

BETA considers that the management philosophy displayed by the new Senior Vice President, Nuclear will ensure that maloperation of equipment will be investigated to determine root causes and that the root causes will be addressed.

f. Licensed and Non-Licensed Operator Training

As pointed out previously, training received a Category 3 rating by the NRC. One of the bases for this appears to have been a lack of understanding of who is responsible for what in the area of training. While it is the responsibility of the Training Manager and his staff to provide the necessary training, the line organizations such as Maintenance and Operations are fully responsible to see that their people are fully and properly trained. This apparently was not happening at Davis-Besse prior to the recent changes in senior management. It is evident that the role of training and its importance in the operation of the plant will be elevated over the next several months. For example, the Training Manager now reports directly to the Senior Vice President, Nuclear. In addition, unfilled training instructor positions are being filled and new positions have been added.

With respect to the June 9 event, it appears that training of the operators or the lack thereof was not a contributing factor. In fact, by all accounts the operators performed exceedingly well with few exceptions. A larger issue can and has been made of the lack of sufficient training in the area of maintenance. As previously discussed, maintenance training is receiving added attention.

g. Post Trip Reviews

BETA considers that with the changes already made within the Davis-Besse organization, the strengthening of the management philosophy, the hiring of new senior staff, and the increased emphasis on maintenance the issue of inadequate post trip reviews will be resolved.

2. ADEQUACY OF THE MAINTENANCE PROGRAM

The preliminary results of the Action Plan investigation underway support the contention that deficiencies in the Davis-Besse maintenance program contributed to the severity of the June 9 event. TED corrective actions initiated both before and after the event are directed toward significantly upgrading the maintenance program at Davis-Besse. These

improvements in the maintenance program include the following:

- The company has hired a new Assistant Plant Manager, Maintenance to direct the Davis-Besse maintenance program. In addition, new managers have been hired to fill the maintenance support positions of Planning Superintendent, Materials Manager, and the maintenance positions of Instrumentation and Controls Superintendent and Mechanical Maintenance General Foreman. These new managers have many years experience in the area of maintenance support and maintenance operations.

- A review is underway to identify safety related systems and components which on the basis of their past performance, may have design or maintenance deficiencies. Maintenance effort will be directed towards these systems/components to correct deficiencies prior to start-up.

- The Maintenance Department has been restructured to provide increased supervisory attention to field maintenance activities.

- A program to upgrade Maintenance Department Administrative and technical procedures has been identified and will start September 1985. Completion is scheduled for December, 1986.

- Increased emphasis is being placed on;

  - Upgrading spare parts inventories and material control
  - Adequacy of communications between the Engineering and Maintenance Departments
  - The quality of Maintenance activities
  - Determining the root cause of problems

- Increased emphasis is being placed on the hiring of Maintenance Department personnel.

- Supplemental training activities have commenced including sending staff to off-site training facilities.

- A central planning organization independent of the maintenance organization, has been established to develop and implement an integrated plant schedule. Emphasis will be placed on preventive maintenance and reducing the backlog of maintenance work.

- Specific equipment deficiencies identified by the June 9 event and by TED's investigation of that event will be corrected prior to start-up.

Based upon the above actions, BETA considers that TED management is satisfactorily addressing the need to upgrade the level and quality of maintenance at the Davis-Besse Plant. Resolution of deficiencies identified by the Action Plans, the equipment performance review and preoperational testing should provide the confidence of equipment reliability required to permit restart. However, TED will have to actively support its long-range program to upgrade plant maintenance in order to correct past maintenance shortcomings.

3. <u>Adequacy of Performance Enhancement Program (PEP) and Any Other Ongoing Corrective Action Programs</u>

In BETA's opinion, one of the factors contributing to Davis-Besse's declining performance has been the lack of realistic support for and enforcement of the large number of committed specific corrective action programs. While tracking programs, lengthy reports and other elaborate administrative controls were in evidence, it is not apparent that there was much substance behind the effort. It is also noted that there was a lack of funding, and hence manpower, provided to complete these commitments.

The new Senior Vice President, Nuclear recognized this problem and also recognized that all previously made commitments could not be accomplished in the near term or before restart. As a result, all corrective action programs in existence, plus those being generated out of the June 9 event were reviewed. This review included programs such as:

a. Performance Enhancement Program (157 items)

b. SALP Commitments (87 items outstanding)

c. Action Plan Items (590 items)

d. NUREG 1154 Items (some 200 items)

From this review a single list of item is being generated. This list, when it is complete, will include scheduling, funding, and all other necessary features to ensure that the items are completed. If properly handled and enforced, this tool should provide the means to resolve previous concerns. It is an area that obviously requires management attention.

4. <u>Adequacy of the Resources Committed to the Davis-Besse Facility for Investigation of the Event, Resolution of the Findings and Conclusions Prior to Restart, and Implementation of Longer Term Measures to Improve Overall Performance</u>

During the past two months a detailed study has been performed by TED with respect to the Davis-Besse organization. This study addressed not only structure, but also its size and pay structure. As a result of this study the organization's plan has been presented to the TED senior management. This plan involves increasing the size of the Davis-Besse staff from about 660 to about 900 people and realigning the pay structure to ensure that Davis-Besse is comparable to other similar nuclear plants. If this plan is approved it should provide the basis for putting Davis-Besse on a level equal to or better than other plants.

In this interim, BETA has observed a fairly large influx of outside technical resources brought in to assist in the June 9 event evaluation and resolution. This has included engineering talent from Babcock & Wilcox (the NSSS), Bechtel (the A/E), Stone & Webster, MPR Associates, CYGNA, and other vendors. In BETA's opinion there has been no lack of talent during the period of this review.

V. CONCLUSIONS

Based upon its review of the June 9 event and TED's actions relating to this event, BETA concludes that TED's investigations to date have been appropriate and that the corrective actions resulting from these investigations and other corrective actions that had been previously identified by TED will be sufficient to permit restart of the unit.

It should be emphasized that the conclusion that restart is satisfactory is based not only on the actions being taken as a direct result of the review of the June 9 event but also that the conclusion is strongly influenced by other changes underway at the Davis-Besse Plant. These changes, discussed elsewhere in this report, include:

- Management changes
- Organization changes
- Upgraded maintenance
- Improvements in plant design
- Procedure improvement
- Increased staffing
- Relocation of personnel
- Improved training

Although many of these changes involve long term actions, they will be underway prior to restart. Those elements important to the restart have been identified by TED and will be completed prior to restart. They include:

- Resolution of Action Plan items
- Improvements in plant design relating to increased decay heat removal reliability
- Identification and upgrade of potentially deficient safety systems and components
- Maintenance training
- Procedure changes to provide improved backup decay heat removal capability

BETA's conclusions assume that these and the other items that have been identified for completion will be completed or resolved prior to restart.

VI. LIST OF REFERENCES

1. Toledo Edison's License Event Report (LER) Number 85-013 dated July 9, 1985.

2. Toledo Edison letter to H. R. Denton (NRC) and J. G. Keppler (NRC) dated July 18, 1985.

3. NRC Report "Loss of Main and Auxiliary Feedwater Event at the Davis-Besse Plant on June 9, 1985," NUREG 1154, dated July 1985.

4. NRC letter, Acting Chairman Roberts to Congressman Markey, dated July 17, 1985.

5. NRC letter, Chairman Palladino to Congressman Markey, dated July 24, 1985.

6. NRC letter, H. R. Denton to Toledo Edison (J. Williams) dated August 14, 1985.

7. "Summary Report: Recommended Improvements to Davis-Besse Decay Heat Removal Capability" dated August 14, 1985.

8. NRC letter J. G. Keppler to Toledo Edison dated December 6, 1984 - SALP 4 Report.

9. Toledo Edison letter J. P. Williamson to NRC dated February 4, 1985 - Reply to SALP 4 Report.

10. Restart Action Tracking Report - Issued Daily - Reviewed for this report through August 26, 1985.

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