PDR

ORIGINAL

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the matter of:

BEFORE THE FACT-FINDING TASK FORCE

RE: Davis-Besse Event of June 9, 1985

(Closed Session)

Docket No.

Location: Bethesda, Maryland
Date: Thursday, June 27, 1985

Pages: 1 - 133

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BEFORE THE FACT-FINDING TASK FORCE

OF THE NUCLEAR REGULATORY COMMISSION

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CLOSED SESSION

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RE:

Davis-Besse Event
Of June 9, 1985

Proceedings before the Fact-Finding Task Force in re the above-mentioned event, held at 4340 East-West Highway, Room 255, Bethesda, Maryland, commencing at 10:35 a.m., on Thursday, June 27, 1985.

TASK FORCE MEMBERS PRESENT:

E. Rossi, NRC

J.T. Beard, NRC

W. Shafer, NRC

ALSO PRESENT:

W. Lanning

W. McCurdy (MPR)

PRESENT FROM TOLEDO EDISON:

J. Wood	B. Beyer
P. Hildebrandt	C. Rupp
D. Wilczynski	R. Gradomski
T. Isley	S. Jain
L. Stalter	S. Wideman

PROCEEDINGS

MR. ROSSI: We are now starting with the meeting.

What we are going to do is we are going to talk about a number of action plans for troubleshooting the equipment that you have sent to us in the last couple of days, and this is in accordance with our agreement that we would comment on these before you started to work.

Before we go into that, I have got a couple of things that I want to discuss that are sort of general things. One of them is that we want to make sure that we are provided promptly with copies of revisions, the latest revisions of these action plans, and specifically I want to ask somebody to check on what the latest revision is to Action Plan No. 12, which is one on auxiliary feedwater system valve problem analysis.

It is the one on Valves 599 and 608. The latest one that we have is marked Revision 0, and it is dated June 14th of 1985.

John, could you call back during an appropriate break and verify that that is the latest one, and if it isn't the latest one, get a copy of the latest one to us as quickly as possible?

MR. WOOD: Okay. We have brought Revision 2, dated 6/26/85, with us for distribution.

MR. ROSSI: You have. Okay.

MR. BEARD: What about Revision 1, John? Let me review the bidding. Revision Ø is the one you brought to us in the meeting and we commented on.

MR. WOOD: That's correct.

MR. BEARD: And as a result of that discussion and meeting, you revised it and it became Revision 1. What I think I'm hearing is that you have an additional revision and now you are up to Rev. 2, dated yesterday.

MR. WOOD: That's correct.

MR. ROSSI: Okay. Well, in any event, we have the latest one now. Let's make it a part of the transcript right now, the latest one, and note that we want Revision 1 so we will have a complete record of changes. So you ought to get us Revision 1 because we apparently do not have it, but at least we have Revision 2, and that will be marked in the transcript.

[The document referred to, marked Exhibit No. 1, follows:]

Ed. 1 Tp. 1

ACTION PLAN # 12

TITLE: Auxiliary Feedwater System Valve Problem Analysis (AF 599 & AF 608)

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE	APPR. FOR IMPL.
0	6/14/85	Initial Issue	See Rev. 0	for Approval	
1	6/16/85	General format changes. Clarifications as a result of discussion with the NRC.	See Rev. 1	for Approval	
2	6/26/85	Revise Hypothesis #7 and add step 12 to the action plan.	J. Long	B K Bay	

TITLE: Auxiliary Feedwater System Valve Problem Analysis (AF 599 & AF 608)

REPORT BY: James W. Long PLAN NO.: 12

DATE PREPARED: June 16, 1985

This report has been prepared in accordance with the "Guidelines to follow when troubleshooting or performing investigative actions into the root cause surrounding the June 9, 1985, reactor trip", Rev. 2.

INTRODUCTION

The following report is the analysis and evaluation to support the action plan for determining the root cause for the failure of AF 599 and AF 608 (AFW to SG isolation valves) to open during the June 9, 1985 reactor trip.

SUMMARY OF DATA

AF 599 and AF 608 are normally locked open valves and were open prior to the transient. During the transient, both valves went shut automatically because of the improper initiation of SFRCS. After the SFRCS was reset, both valves failed to open automatically. Operators were then sent to open the valves manually. According to the operator, the valves were placed in manual and the handwheel turned in the open direction. The handwheel was hard to turn and was only moved 1/2 turn in the open direction. The handwheel was then turned in the close direction 1/2 turn to try and get a hammerblow in the open direction. This was repeated a second time, and when turned in the close direction the second time a rattling noise came from the operator and the valves were opened electrically. This rattling noise was probably the tripper fingers being kicked out by the motor and is to be expected.

The actual differential pressure (DP) seen by these valves at the time they were attempting to open is unknown but they are designed to open against a 1050 PSID. At 1515 on 6/9/85, both valves were cycled satisfactorily within their required stroke time. At that time S/G pressure was 850 PSIG.

A review of maintenance and surveillance testing history shows that the torque switch settings were changed in March 1984 per FCR 84-0039 as a result of the Limitorque motor operated valves study and both valves were satisfactorily tested per ST5064.01 (CTMT Isolation Valve Post Maintenance Testing). During the 1984 Refueling Outage, the motors and magnetic brakes were replaced on both valves per FCR 83-0067. The brakes were replaced as part of the environmental qualification of safety related electrical equipment program (10CFR50-49 Rule Requirements). In addition, AF 599 was disassembled, 3 bearings replaced, relubricated, and reassembled. During the testing of AF 599 following this maintenance, a loose spacer was found in the spring pack. This was corrected and both valves were tested satisfactorily. The only normal testing for these valves is a stroke time per ST 5071.02 (AFW System 18 month refueling test), which was performed on 12/31/84, with satisfactory results. The brakes were replaced during the outage as noted above.

CHANGE ANALYSIS

The only changes identified from the testing performed on 12/31/84 and the 6/9/85 reactor trip is the plant condition when the valves were cycled. On 12/31/84, the plant was in Mode 5, therefore, the plant was cold and at low pressure so the valves did not see a high DP across them. During the 6/9/85 reactor trip, the plant was in Mode 1, therefore, at normal operating temperature and pressure. Because of their location in the Mechanical Penetration Rooms, they would probably have been close to the ambient temperature of the rooms. However, they would have seen full S/G pressure when shutting. If the upstream check valve leaked, any pressure trapped between the check valve and AF 599 (AF 608) would have bled off. This would have caused a high DP across the valves when attempting to open.

HYPOTHESES

Based on the information collected before, during and after the transient, it appears that both valves torqued out when opening. The following is a list of the hypothesis that could cause a valve to torque out. The Action Plan Item that will prove or disprove each hypothesis is listed.

1. Improperly adjusted torque switch bypass contact (this hypothesis covered by Action Items 3 and 5).

2. Improper torque switch setting (this hypothesis covered by Action Item 2).

3. Wrong or improperly adjusted spring pack (this hypothesis covered by Action Item 7).

4. Failure of motor brake to release when energized or engage when deenergized (this hypothesis covered by Action Items 3 and 4).

5. Improper torque switch setting calculations (this hypothesis covered by Action Items 8-11).

6. Improper torque switch installation (this hypothesis covered by Action Item 6).

2 7. High DP across valve (this hypothesis covered by Action Item 12).

ACTION PLAN

ED 6408

Rev. 2

PLAN NUMBER	PAGE	DATE PREPARED	PREPARED BY
12	1 of 3	6/26/85	M. Bajestani

TITLE

AFW SYSTEM VALVE PROBLEM ANALYSIS (AF 599 and 608)

SPECIFIC OBJECTIVE

To Determine the Root Cause of Motor Operated Valve AF 599 and 608 Failure to Open

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	ALL STEPS OF THIS ACTION PLAN ARE TO BE PERFORMED IN ACCORDANCE WITH THE LATEST REVISION OF "GUIDELINES TO FOLLOW WHEN TROUBLE-SHOOTING OR PERFORMING INVESTIGATIVE ACTIONS INTO THE ROOT CAUSES SURROUNDING THE JUNE 9, 1985 REACTOR TRIP".					
1	Before beginning troubleshooting work, document the as-found condition of the valves (limit to those conditions which can be recorded without changing conditions - i.e., valve position, general condition, environmental conditions).	J. Long				
2	The torque switch settings were changed for MV 599 and 608 under FCR 84-039 (1.5 open and 1.0 closed). These settings should be verified.	J. Long				
3	The stem thrust load should be measured to verify the thrust calculation. MOVATS (Motor Operated Valve Analysis & Test System) should be used to measure valve stem thrust, time of control switch actuation, and dynamic motor current).	J. Long				

ACTION PLAN
ED 6408

Rev. 2

PLAN NUMBER	PAGE
12	2 of 3
DATE PREPARED	PREPARED BY
6/26/85	M. Bajestani

TITLE
AFW SYSTEM VALVE PROBLEM ANALYSIS (AF 599 and 608)

SPECIFIC OBJECTIVE

To Determine the Root Cause of Motor Operated Valve AF 599 and 608 Failure to Open

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
4	MV 599 and 608 are fast speed operators. A magnetic brake is provided to oppose the motor inertia after the power is removed from the motor. The brake and motors were replaced last refueling outage. These brakes should be checked for proper operation.	J. Long				
5	Verify number of turns on the handwheel of the valve from fully closed position, the limit switch contact 33/AC bypass; the torque switch contact 33/TO.	J. Long				
6	With valve in midposition (spring pack relaxed) verify that the torque switch is not preloaded.	J. Long				
2 NOTE	STEP 12 should be performed before STEP 7.					
7	Verify by visual inspection the spring pack model number. If the heavy spring number 60-600-0068-1 is used - no problem. However, if light spring number 60-600-0062-1 is used, the torque switch should prevent valve opening.	J. Long				
*8	Motor horse power calculations should be performed in order to determine if the motor is capable of providing enough torque.	J. Long				

ACTION PLAN

FD 6408 Rev. 2

PLAN NUMBER	PAGE	DATE PREPARED	PREPARED BY
12	3 of 3	6/26/85	M. Bajestani

TITLE

AFW SYSTEM VALVE PROBLEM ANALYSIS (AF 599 and 608)

SPECIFIC OBJECTIVE

To Determine the Root Cause of Motor Operated Valve AF 599 and 608 Failure to Open

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
*9	Actuator size should be checked to determine if it is capable of operating against a 1050 psi differential pressure.	J. Long				
*10	Tortional stem stress and tensile stress should be checked to verify that these stresses do not exceed the ASME design allowable values.	J. Long				
*11	Torque dial settings should be established by opening and closing positions based on the extreme stem operation loads expected during the hot and pressurized condition.	J. Long				
12	Test operate the valves individually with up to a 1050 PSIG pressure differential across the seat.	J. Long				
	* Steps 8-11 are not dependent on Steps 1-7 and can be performed in any order					

2

MR. SHAFER: Revision 2 is dated 6/26, so this is not the Action Plan you used to actually do the job; is that correct?

MR. WOOD: Revision 2 is to reflect the desire to do a test to confirm the failure mechanism.

MR. ROSSI: So Revision 1, then, was used to actually do the troubleshooting, and when the MOVATS man was there to work with you, and then after that, Revision 2 is to run the test.

MR. WOOD: That's correct.

MR. ROSSI: And have you definitely now decided to run the test?

MR. WOOD: We have decided to run the test. We are still reviewing the schedule and the content for the test. I am not prepared at this moment to discuss, really, the details of that. That has been ongoing back in Toledo.

MR. ROSSI: Okay.

Now, while we are talking about these valves, I guess this is a good point to bring up the next subject, and that is, when you have identified the root cause of each of the problems with the equipment, you are supposed to inform us promptly. I assume -- or let me make it a little stronger.

You are going to prepare a written document discussing what the root cause is and justifying that that is the root cause on each of these.

MR. WOOD: That's correct.

MR. ROSSI: That's your plan?

MR. WOOD: That is our plan.

MR. ROSSI: And that can be the mechanism while we are here in Washington and you are there, for us to be notified that you found it. It may be appropriate that you send us the document and then we can look at it and have one series of meetings the next time we come to Davis-Besse to talk about the root causes.

MR. WOOD: That's fine.

MR. ROSSI: Okay, fine. So if you can get those root cause documents to us along with the appropriate justification as quickly as possible, that would be good.

MR. WOOD: It is also our intention to discuss with Region 3, as we are into the actual troubleshooting when we find significant items, to discuss that with the region.

MR. ROSSI: Okay, fine.

MR. LANNING: The record should show that Action Plan No. 12 is Exhibit No. 1. Its title is Auxiliary Feedwater System Valve Problem Analysis.

MR. ROSSI: Okay. I guess we are ready to go on to the auxiliary feed pumps overspeed trip action plan, and the first thing we need to note is we were sent in the mail an initial draft of this, which is dated June 24, 1985, and that should be marked and put in the transcript so we will have

that, and that will be Exhibit 2.

Then today we were provided with a document that has a cover sheet on it dated June 25th, and that will be marked as Exhibit 3. What we are going to do is our marginal notes and comments are marked on the one you sent us in the mail, obviously, but we will attach both of these to the transcript, and you ought to point out to us anything that is significantly different in the June 25th version from the one that was sent to us in the mail so that we don't have surprises later on when we read it.

[The documents referred to, marked Exhibits No. 2 and 3, follow:]

Rec'd 6/26/85
Ef. 2

TITLE: AUXILIARY FEED PUMPS OVERSPEED TRIPS

REPORT BY: Dan Wilczynski, Chuck Rupp

Plan No.: 1A and 1B

DATE PREPARED: 6/24/85

This report has been prepared in accordance with the "Guidelines to Follow When Troubleshooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985, Reactor Trip," Rev. 4. These guidelines were developed in response to Confirmatory Action Letter 85-05.

I. INTRODUCTION

On Sunday, June 9, 1985, normal feedwater flow to the steam generators was interrupted. The reactor was automatically shutdown and reactor heat was removed via steaming through the main steam safeties and the atmospheric vent valves. The water level in the steam generators was decreasing and at 1:41:03 a Steam and Feedwater Rupture Control System (SFRCS) full trip was initiated on Channel 1 due to a low water level in Steam Generator #1 (SG #1). This SFRCS actuation attempted to initiate auxiliary feedwater flow by opening the steam supply valve, MS 106, from SG #1 to auxiliary feedwater pump turbine (AFPT) #1. Five seconds after the initial SFRCS (1:41:08) the reactor operator inadvertently initiated an SFRCS low pressure trip on both channels and both steam generators. This low pressure trip of SFRCS is intended to respond to a steam line break or other equipment failure resulting in depressurizing a steam generator. The manual low pressure SFRCS trip initiated the following, as designed:

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

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

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

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

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

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

This report documents the review of data from previous unit trips, the 6/9/85 trip, AFPT testing, and other utility overspeed trips to determine possible causes of the overspeed trips which occurred at Davis-Besse on 6/9/85. Based on this review, this report presents hypothesized causes of the observed overspeed.

Based on review of currently available information, we conclude that the most likely hypothesis of those considered is introduction of water slugs into the AFPTs causing overspeed. Based on discussions with Terry Turbine, water slugs flash as they pass through the turbine inlet nozzles resulting in acceleration of the turbine rotor. (It appears that introduction of excessive amounts "cold" water (greatly subcooled) may slow down the turbine.)

Although introduction of "hot" water slugs is judged to be the major cause of the observed overspeed, other factors may have contributed and will be further investigated. These other factors include:

1) AFPT governor problems
2) "Double start" due to switchover of steam supply for AFPT #1.
3) Pump discharge flow was through the minimum recirculation path only.

II. SUMMARY OF DATA

In order to determine possible causes of the overspeed trips on 6/9/85, the following data were collected and analyzed. A summary of the analysis for the 6/9/85 plant trip and several previous trips is provided.

For each plant trip and surveillance test, the specific sequence of events was reviewed with particular attention to the following parameters.

- AFPT speed vs. time
- AFP flow and discharge pressure
- Steam generator pressure and level
- Specific valve line-ups

Figure 1 and Attachment 1 provide a summary of pertinent steam and feedwater system features associated with the AFPTs (for reference).

A. June 9, 1985 Plant Trip Summary

During the June 9, 1985 trip transient, the following sequence of events regarding auxiliary feedwater flow initiation occurred:

- Steam flow was initially provided to AFPT #1 via the normal path through MS 106 and turbine speed began increasing. This was initiated by a steam generator low level trip in the SFRCS at 1:41:03. Steam flow to AFPT #2 was not immediately initiated since a low level condition did not exist in SG #2 at this time.

- As a result of an operator initiated low steam header pressure SFRCS trip (1:41:08), the steam supply to AFPT #1 was switched to SG #2 through MS 106A. The SFRCS also initiated steam flow through the MS 107A flow path from SG #1 to AFPT #2.

- The low pressure SFRCS trip resulted in switching the discharge path from the auxiliary feedwater pumps (AF 3870 closed, and AF 3869 and 3871 opened) and AF 599 and AF 608 were closed. The net result of these actions was to isolate the feedwater discharge path of both auxiliary feedwater pumps leaving only the minimum recirculation path available.

A review of the speed vs. time characteristics for AFPT #1 shows the typical characteristics of several oscillations prior to reaching rated speed but the final oscillation was uncontrolled and increased turbine speed to the overspeed trip setpoint. The speed characteristics are shown on Figures 2 and 3 of Attachment 2.

A review of the speed characteristics for AFPT #2 shows an uncharacteristic leveling off at approximately 2500 RPM for about eight (8) seconds from which point turbine speed quickly increases to above 4100 RPM, decreases slightly and then continues to increase to the overspeed trip setpoint. The pause at 2500 RPM could be due to excessive water induction into the turbine.

It should be noted that no previous testing had been performed to date to simulate a "quick start" using only the cross connects (MS 106A and MS 107A) for steam supply to the AFPTs.

B. Past Plant Trips and Surveillance/Testing Data

Based on our evaluation of previous plant trips and surveillance testing, we have the following observations:

1) The AFPT speed vs. time characteristic is relatively uniform for each trip (See Attachment 2).

2) The specific steam supply and feedwater flowpath configuration encountered during the 6/9/85 trip transient has not previously been duplicated.

The similarities and differences for each of the previous trips and tests compared to the 6/9/85 event are described below with particular attention to the hypothesis judged most likely to have caused the overspeed condition.

1. March 2, 1984 Plant Trip

A review of the trip data indicates that a SFRCS low pressure trip was initiated during the event due to a stuck open Main Steam Safety Valve. This SFRCS initiation closed

the steam supply valve (MS 107) from SG #2 to AFPT #2 and opened the cross connect valve MS 107A to supply steam to AFPT #2 from SG #1. This switch of steam supply occurred 21 seconds (12:37:55) after both AFPTs had been started via MS 106 and MS 107. A review of the speed vs. time characteristics (see Figures 4 and 5 of Attachment 2), show that AFPT #2 experienced a decrease of approximately 1000 RPM at sixteen (16) seconds after the SFRCS low pressure trip. This speed decrease may be attributed to excessive water being picked up from the MS 107A line and being carried to the turbine.

The following differences between the 3/2/84 event and the 6/9/85 event assist in explaining why the AFPTs reached the overspeed trip setpoint on 6/9/85 but not on 3/2/84.

- On 3/2/84, since MS 107 was open and heating the line, opening MS 107A introduced only 250' of cold piping, thereby reducing the amount of water introduced to the turbine.

- On 3/2/84, additional water may have been introduced by opening MS 107A because the steam lines were not drained periodically at this time.

- On 3/2/84, since AFPT #2 was pumping approximately 1000 GPM, if a slug of water occurred from opening of MS 107A, there would have been more resistance to a speed increase as compared to the 6/9/85 event when only a min-recirc flow path was available.

- On 3/2/84, both AFPTs had the Woodward PG-PL governors installed.

2. <u>January 15, 1985 Plant Trip</u>

This event initiated a SFRCS trip on low SG level which, due to valve control changes made during the 1984 refueling outage, opened all four steam supply valves to the AFPTs. Also, AFPT #2 had the new PGG governor installed during the 1984 refueling outage. The speed characteristics are shown on Figures 6 and 7 of Attachment 2.

The following differences between the 1/15/85 event and the 6/9/85 event assist in explaining why both turbines tripped on overspeed on 6/9/85 but not on 1/15/85.

- On 1/15/85, due to the pipe configuration, initial steam flow to both turbines would have been via the normal flow paths, MS 106 and MS 107. Therefore, initial heating of the respective lengths (360' and 125') may have occurred prior to steam flow through the cross connects resulting in less total mass of

water introduced to the AFPTs than postulated for the 6/9/85 event.

- On 1/15/85, both pumps had a flow path other than minimum recirculation available, therefore, speed increases would be accompanied by corresponding flow increases, thus maintaining loading on the pump. This flow path was not available on 6/9/85.

3. March 21, 1985 Plant Trip

This event initiated a SFRCS trip on low SG level that resulted in all four steam supply valves opening at the same time.

The speed characteristics are shown on Figures 8 and 9 of Attachment 2. A review of the speed characteristics for AFPT #1 show the typical characteristics consistently seen on AFPT #1 (i.e., several oscillations prior to reaching rated speed).

The following differences between the 3/21/85 event and the 6/9/85 event assist in explaining why both turbines tripped on overspeed on 6/9/85 but not on 3/21/85.

- On 3/21/85, due to pipe configuration, initial steam flow to both turbines would have been via the normal flow path, MS 106 and MS 107. Therefore, initial heating of the respective lengths (360' and 125') would have been done prior to steam flow through the cross connects resulting in less total mass of water introduced to the AFPTs than is postulated to have formed during the 6/9/85 event.

- On 3/21/85, both pumps had a flow path available other than the minimum recirculation, therefore, any speed increase would be accompanied by a corresponding flow increase, thus maintaining loading on the pump. This flow path was not available on 6/9/85.

A review of the speed vs. time characteristics show that AFPT #2 indicates a constant rate of acceleration until approximately 35 seconds after initial roll at which time there was an 800 RPM decrease in 2 seconds followed by an 1800 RPM increase in 3 seconds. This oscillation may be due to slugs of water.

4. April 12, 1985 Testing

After the change-out of the speed setting bushing from a 30 second rated bushing to a 15 second rated bushing on AFPT #2 governor, two quick start tests were performed to verify operability. This changeout was performed to ensure flow was provided by AFPT #2 within 40 seconds as required by

Technical Specifications. These tests were run on the normal steam supply path via MS 107 and with the pump discharge valves closed (i.e., min-recirc path open). Less than 24 hours prior to these two (2) tests some additional testing was done on this same turbine using the same valve line-ups. This prior testing was performed for trouble-shooting. Due to the prior testing, the steam lines may not have been cooled to ambient conditions prior to the two (2) operability tests being run. The speed characteristics are shown in Figures 10 and 11 of Attachment 2.

A review of the speed vs. time characteristics shows that the first run exhibited speed increases which appear to be a series of step changes rather than a constant acceleration to rated speed. The second run (performed immediately after the first) shows a constant rate of acceleration to rated speed. This is attributed to the fact that the steam lines were already heated, therefore, there would have been less condensation.

5. June 2, 1985 Plant Trip

This event initiated a SFRCS actuation on low SG level. Both AFPTs were supplied steam from their respective steam generators via MS 106 and MS 107.

The speed characteristics are shown on Figures 12 and 13 of Attachment 2. A review of the speed characteristics for AFPT #1 shows the typical characteristics consistently seen on AFPT #1 (i.e., several oscillations prior to reaching rated speed).

A review of the speed vs. time characteristics for AFPT #2 shows a fairly steady increase to rated speed but the speed continues past the high speed setpoint (3710 RPM) to approximately 4000 RPM for about three (3) seconds. The turbine then decreased speed and controlled at the high speed setpoint. During the initial increase to rated speed, the speed increases are seen as step changes rather than a straight line. These step changes, and the increase to approximately 4000 RPM, may be attributable to water slugs.

The following differences between the 6/2/85 event and the 6/9/85 event assist in explaining why both AFPTs reached the overspeed trip setpoint on 6/9/85 but not on 6/2/85.

- Both AFPTs were running on the normal steam supply paths via MS 106 and MS 107, therefore, there could be less condensation reaching the turbines.

- Both pumps had a discharge path available other than the minimum recirculation path, therefore, any speed increase would be accompanied by a corresponding flow increase, thus maintaining loading on the pump. This flow path was not available on 6/9/85.

6. June 9, 1985 Testing (Post Trip)

After the plant trip, a quick start test was performed on each of the AFPTs. These tests were run on the normal supply paths via MS 106 and MS 107. Both pumps discharge valves were closed such that only minimum recirculation flow was provided. These tests were run approximately ten (10) hours after the AFPTs had been shut down, therefore, the lines were still warm and condensation would not be expected. The speed characteristics are shown on Figures 14 and 15 of Attachment 2.

A review of each speed vs. time characteristic shows a constant acceleration to rated speed. AFPT #1 does not exhibit oscillations seen at other times. The "smoothness" of these graphs may be attributable to the fact that minimal condensation would be expected since the lines were already heated.

C. Modifications

1. During the 1984 refueling outage, the #2 AFPT governor was changed out from a Woodward PG-PL governor to a Woodward PGG governor. The new governor was supplied with 7 lb/in buffer springs and a 30 second speed setting bushing Prior to startup from the 1984 refueling outage, the 7 lb/in buffer springs were changed to 26 lb/in buffer springs by a Woodward Governor representative. The speed setting bushing was changed from a 30 second bushing to a 15 second busing on 4/12/85 to ensure that AFPT #2 could reach rated speed and deliver flow to the steam generators in less than 40 seconds as required by Technical Specifications.

2. During the 1984 refueling outage, the control logic for the steam supply valves to the AFPTs was changed to allow all four valves (MS 106, 106A, 107 and 107A) to open simultaneously. After the 3/21/85 plant trip, the change was revised so that MS 106A and MS 107A would open only on a SFRCS low pressure trip. This revision was made based on the hanger damage found after the 3/21/85 trip. This was considered a prudent action, the hanger damage was potentially attributable to water slugs.

D. Maintenance History

The maintenance work done excluding oil replacement since the 1984 refueling outage for AFPT 1-1 is as follows:

1. Replacing of governor control motor (6-2-85), MWO# 1-85-1876-03.

   NOTE: Investigations are currently underway to determine cause of motor failure.

2. Adjustment of governor slip clutch (6-2-85), MWO# 1-85-1878-00.

3. Replace low speed stop roll pin (6-2-85), MWO# 1-85-1378-01.

The maintenance work done excluding oil replacement since the 1984 refueling outage for AFPT 1-2 is as follows:

1. Changeout of speed setting bushing (4-12-85), MWO# 2-83-0136-11 (See Modification Item C.3 above).

A review of these maintenance records does not reveal any evidence that could support the overspeed trips of 6/9/85.

E. Investigation of Overspeed Trip Problems at Other Utilities

Various resources have been used to determine if other utilities have had similar failures of the AFPTs on overspeed.

NPRDS had only one overspeed trip reported. This occurrence was the result of the failure of a Woodward Governor ramp generator. A ramp generator as discussed above is not incorporated in the design of either the PG-PL or PGG governor.

"Nuclear Power Experience" reported a total of 10 overspeed trips which are summarized below:

1. Four (4) AFPT overspeeds were reported due to condensation in the line.

2. One (1) overspeed was reported due to a "double start" (i.e., interruption and re-introduction of steam supply when the turbine is already rolling).

3. One (1) loss of suction overspeed was reported (i.e., pump loses suction pressure which effectively reduces pump loading).

4. There were four (4) overspeed trips due to governor problems as listed below:

- Low oil level in governor
- Mechanical misadjustments
- Failed speed sensor (applicable to EG governor only)
- Apparent governor valve sticking

The final source of information was the Nuclear Network System. One (1) response was received which indicated the possibility of turbine overspeed due to water in the steam lines.

III. CHANGE ANALYSIS

The differences associated with the 6/9/85 trip compared to previous trips and actuations are listed below (conditions listed below existed only on 6/9/85 trip).

1. Both auxiliary feedwater containment isolation valves (AF 599 and 608) were closed when overspeed occurred. Pump flow was limited to the min-recirc flow.

2. Both AFPTs were running solely on the cross connect steam supply valves (MS 106A and 107A) at the time of the overspeed trips.

3. AFP #1 was started on steam from MS 106 but then was switched to steam from MS 106A.

These differences are discussed in more detail in Section II, Summary of Data.

IV. HYPOTHESIZED CAUSES OF OVERSPEED

From the above data and from discussions with the turbine vendor, Terry Turbine (Ken Wheeler); MPR Associates Inc. (Phil Hildebrandt, Bob Fink, and Tim Clarke); the following list of possible causes of overspeed was developed.

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

This hypothesis is judged to be a viable description of the cause of the observed AFPT overspeed trips. Terry Turbine indicates that the introduction of water slugs which flash through the nozzles may result in an overspeed condition.

The piping between the steam isolation valves (MS 106, 106A, 107, 107A) and the AFPTs is at a temperature near ambient conditions. When the isolation valves are opened, steam at about 500° to 550°F is introduced.

Steam will be condensed in these lines during initial steam introduction and line heating. Preliminary calculations indicate that several hundred pounds of water may be formed in these lines. This condensate is expected to form water slugs, parti-

cularly in the long, approximately horizontal crossover lines downstream of MS 106A or MS 107A.

It is noted that damage to pipe hanger supports on these lines has been experienced previously, apparently due to transient operational loads. Steam flow loads would not be expected to result in hanger damage. Water slug formation or water hammer may produce these loads. (Investigation of the pipe hanger support problem was in process prior to the 6/9/85 event.)

The design for the AFPTs is a single stage turbine configured similar to a bucket type "water wheel". This design is considered susceptible to increased speed excursions when water slugs are introduced. Analyses are currently being performed to confirm this hypothesis.

B. <u>AFPT 1-1 rolling on steam from MS 106 prior to receiving steam flow from crossover ("Double Start")</u>

This mechanism may be a contributor to the overspeed trip on AFPT 1-1, however, it is not considered likely. Discussions with Terry Turbine, as well as another utility, indicate that if the turbine is rolling, and steam flow is stopped and restarted, the turbine may overspeed. This is because by the speed setting bushing (the internal piece that controls the acceleration to rated speed) being ineffective due to the prior rotation of the turbine which has increased the governor oil pressure to its operating pressure. Since the governor oil pressure is established and controlling, loss or reduction in steam flow results in the governor valve opening in an attempt to increase steam flow. When full steam pressure and flow is reestablished, the governor valve is open further than necessary and cannot close quickly enough, resulting in an overspeed condition.

This sequence may have occurred for AFPT 1-1 as a result of initial roll of the turbine on steam from MS 106 followed by closure of MS 106 coincident with opening of MS 106A. However, examination of the trip event sequence suggests that steam flow would not have been interrupted during switchover from MS 106 to MS 106A as the steam source.

Although considered unlikely, this hypothesis will be tested.

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

This hypothesis, although viable, is judged unlikely to have caused an overspeed trip because discharge piping is assured to be full at all times thereby causing the pumps to operate at min-recirc conditions until the discharge valves are open.

It is noted that pump operation or min-recirc only may be a contributing factor to the overspeed because of the decreased pump load.

D. Governor problems (low oil level, improper settings, etc.), including governor valve and linkage

AFPT #1 has the previously used Woodward PG-PL governor which has experienced speed control oscillation problems, AFPT #2 has the new Woodward type PGG governor design which was installed during the 1984 refueling outage which has not indicated any oscillation problems.

Neither governor apparently could respond to prevent the cause of the turbine overspeed. However, it is not considered that failure or malfunction of the governors was the cause based on the following:

1. The speed graphs for the trip indicate that the governors were controlling speed as designed during the initial turbine acceleration.

2. Post trip testing shows proper operation of both governors.

3. The governor on AFP #1 is a PG-PL model with external Bodine motor for remote speed setting, while the AFPT #2 has a new PGG model with an internal motor for remote speed setting. It is considered unlikely that both of these governors would fail at the same time in a manner capable of causing an overspeed trip on the turbines.

4. The governor valve was free to move during the trip as evidenced by the initial decrease in speed after both AFPTs began to roll.

However, since we have limited experience with the PGG governor (installed during 1984 refueling outage), we plan to further evaluate whether problems with this governor could have contributed to the overspeed. Prior to installation, an engineering evaluation was performed on the PGG governor, which concluded that this governor should be functionally similar to the PG-PL governor.

E. Loss of pump suction source, resulting in no pump load

This is not considered a viable hypothesis, since the control room alarm printer shows no evidence of low pump suction pressure prior to the overspeed. Also, the 1 psig pressure switch on the pump suctions did not close the steam supply valves. Further, there was no decrease in discharge pressure as would be expected if the suction pressure were lost.

DVW:CER:lrh

ATTACHMENT 1

Steam Supply Piping Layout to AEPTs

Figure 1 presents a schematic representation of the steam supply piping to the Auxiliary Feed Pump Turbines.

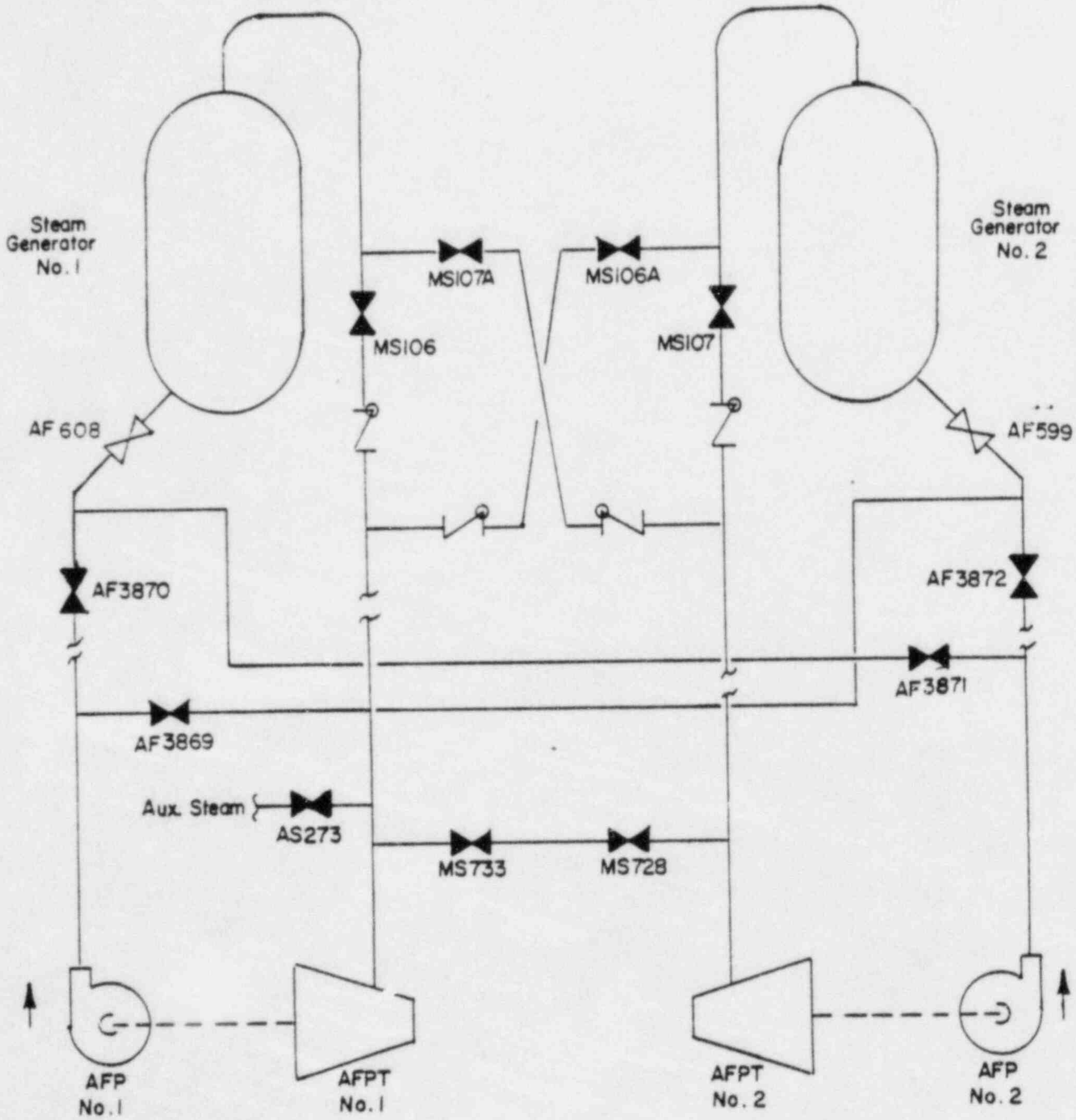
The piping configuration downstream of the 4 steam supply isolation valves are described in more detail below.

1. MS 106 (SG #1 feed to AFPT #1) - The pipe length of this run is approximately 360 feet. Immediately downstream of MS 106 is a downhill run. The length of the pipe run has several vertical drops interrupted by horizontal runs. Total vertical drop is from elevation 623' to elevation 565'. Any condensation is expected to become entrapped in the steam flow or be carried as small slugs.

2. MS 106A (SG #2 feed to AFPT #1) - The pipe length of this run is approximately 650 feet. Immediately downstream of MS 106A is a 290 foot length of essentially horizontal pipe. After the steam/water has traversed the initial length of pipe, it ties into the length of pipe described in item 1 above, which is immediately downstream of MS 106. The 280 foot length of horizontal pipe could allow large water slugs to form prior to entering the downhill run.

3. MS 107 (SG #2 feed to AFPT #2) - The pipe length of this run is approximately 125 feet. Immediately downstream of MS 107 is a downhill run. The total length of the pipe run has an almost continual downhill flow (i.e., very few long lengths of horizontal pipe) dropping from elevation 623 to elevation 565. Any condensation is expected to become entrapped in the steam flow or be carried as small slugs.

4. MS 107A (SG #1 feed to AFPT #2) - The pipe length of this run is approximately 375 feet. Immediately downstream of MS 107A is a 250 foot length of essentially horizontal pipe except for a 7 foot rise near the end of the run. After the rise is a short horizontal run and then the steam supply line has a 14 foot drop and is tied to the steam supply pipe described in item 3 above, immediately downstream of MS 107. The rise, after a long horizontal run, will enable water slugs to form at the bottom of the rise and be carried downstream after filling the pipe.



SCHEMATIC REPRESENTATION OF
AUXILIARY FEED PUMP TURBINE STEAM PIPING SYSTEM

Figure 1

AUX FEED PUMP 1-1 SPEED DATA
JUNE 9, 1985 - TRIP

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	01:41:06	37.9
2	01:41:07	435.9
3	01:41:08	807.1
4	01:41:09	948.7
5	01:41:10	1415.1
6	01:41:11	1793.7
7	01:41:12	2240.5
8	01:41:13	2472.5
9	01:41:14	1703.3
10	01:41:15	NO DATA
11	01:41:16	1793.7
12	01:41:17	2675.2
13	01:41:18	3290.6
14	01:41:19	2211.2
15	01:41:20	3471.3
16	01:41:21	2404.2
17	01:41:22	3801.0
18	01:41:23	4352.9
19	01:41:24	4616.6
20	01:41:25	3315.0
21	01:41:26	1915.8
22	01:41:27	1322.3
23	01:41:28	1024.4

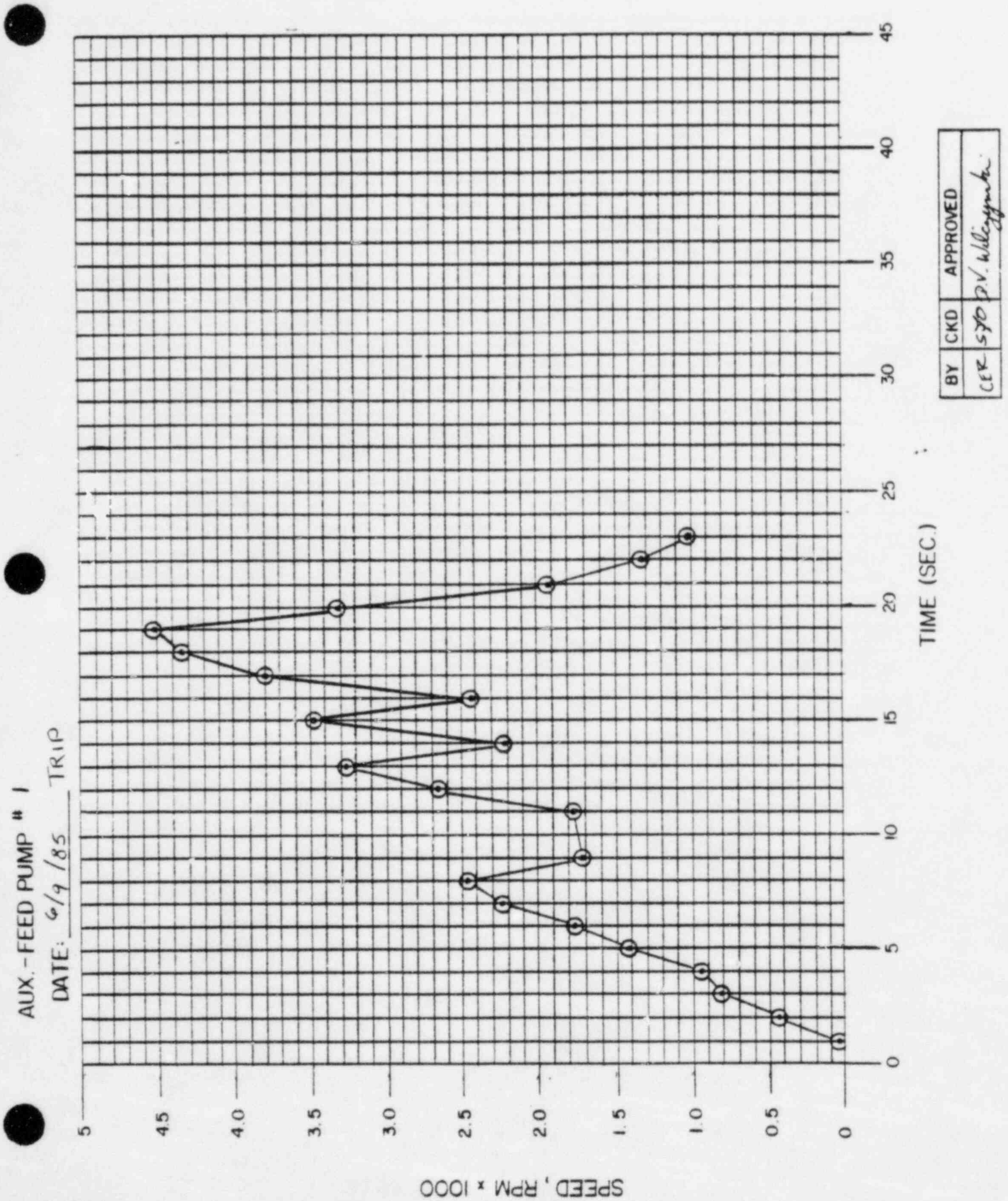

AUX.-FEED PUMP # 1
DATE: 6/9/85 TRIP
TIME (SEC.)
SPEED, RPM x 1000
0
5
10
15
20
25
30
35
40
45
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
BY
CKD
APPROVED

Figure 2

ATTACHMENT 2

AUX FEED PUMP 1-2 SPEED DATA
JUNE 9, 1985 - TRIP

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	01:41:11	35.4
2	01:41:12	565.3
3	01:41:13	570.2
4	01:41:14	1500.6
5	01:41:15	NO DATA
6	01:41:16	2399.3
7	01:41:17	1766.8
8	01:41:18	1923.1
9	01:41:19	2152.6
10	01:41:20	2355.3
11	01:41:21	2389.5
12	01:41:22	2391.9
13	01:41:23	2438.3
14	01:41:24	2460.3
15	01:41:25	2396.8
16	01:41:26	2379.7
17	01:41:27	2428.6
18	01:41:28	2433.5
19	01:41:29	2987.8
20	01:41:30	4118.4
21	01:41:31	4362.6
22	01:41:32	4172.2
23	01:41:33	4162.4
24	01:41:34	4418.8
25	01:41:35	4540.9
26	01:41:36	4655.7
27	01:41:37	4748.5
28	01:41:38	3820.5
29	01:41:39	2120.9
30	01:41:40	1476.2
31	01:41:41	1175.8

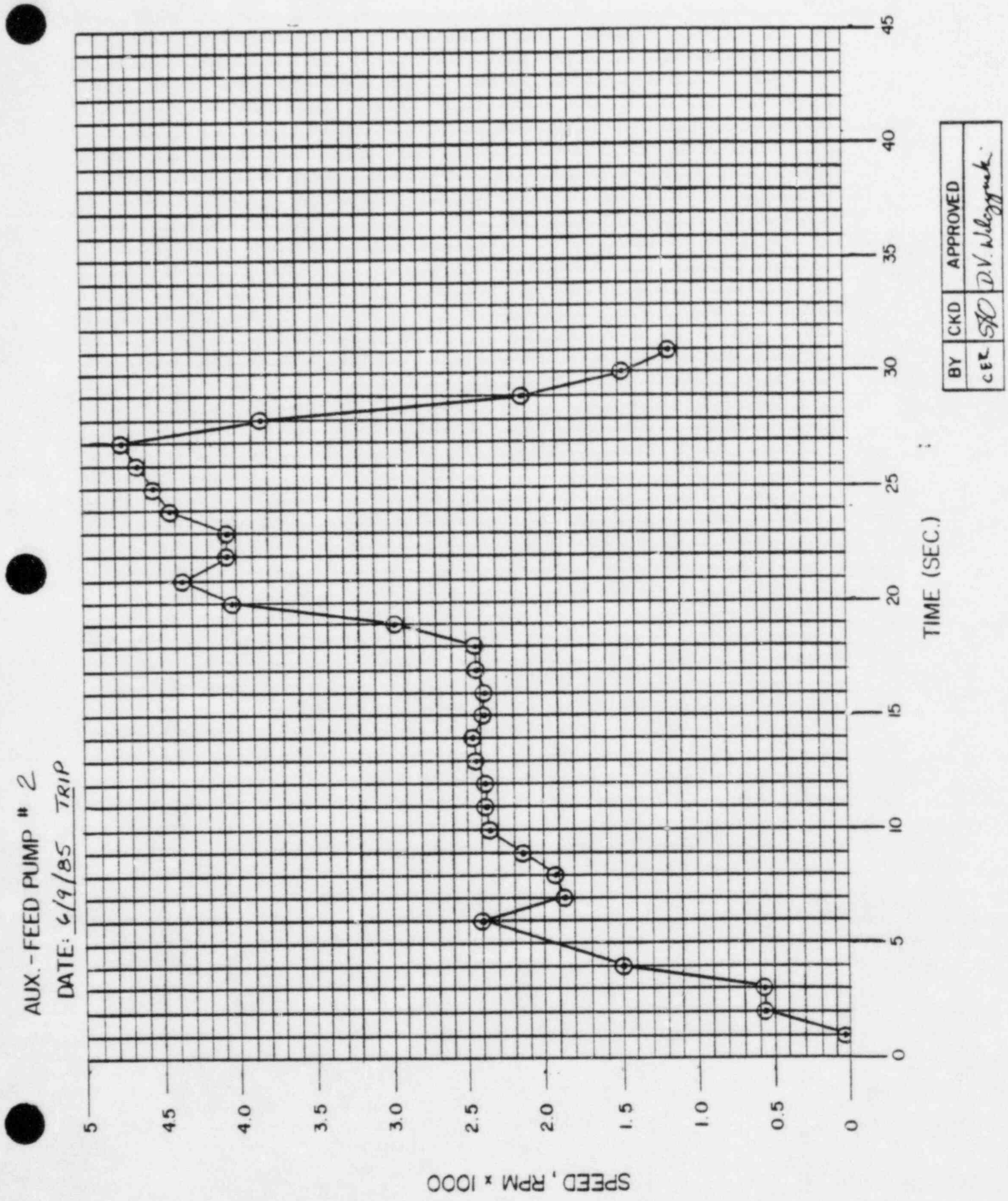

AUX.-FEED PUMP # 2
DATE: 6/9/85 TRIP
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
BY
CKD
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Figure 3

AUX FEED PUMP 1-1 SPEED DATA
MARCH 2, 1984

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	12:37:39	18.3
2	12:37:40	40.3
3	12:37:41	330.9
4	12:37:42	1605.6
5	12:37:43	1310.1
6	12:37:44	NO DATA
7	12:37:45	NO DATA
8	12:37:46	787.5
9	12:37:47	768.0
10	12:37:48	1070.8
11	12:37:49	NO DATA
12	12:37:50	1549.4
13	12:37:51	1483.5
14	12:37:52	1459.1
15	12:37:53	1415.1
16	12:37:54	1400.5
17	12:37:55	1383.4
18	12:37:56	1381.0
19	12:37:57	1371.2
20	12:37:58	1373.6
21	12:37:59	1363.9
22	12:38:00	1359.0
23	12:38:01	NO DATA
24	12:38:02	NO DATA
25	12:38:03	2057.4
26	12:38:04	2318.7
27	12:38:05	2372.4
28	12:38:06	NO DATA
29	12:38:07	2636.1
30	12:38:08	2782.7
31	12:38:09	2929.2
32	12:38:10	NO DATA
33	12:38:11	3229.5
34	12:38:12	NO DATA
35	12:38:13	NO DATA
36	12:38:14	NO DATA
37	12:38:15	3612.9
38	12:38:16	3483.5
39	12:38:17	NO DATA
40	12:38:18	NO DATA
41	12:38:19	NO DATA
42	12:38:20	3564.1
43	12:38:21	3615.4
44	12:38:22	3649.6
45	12:38:23	3664.2

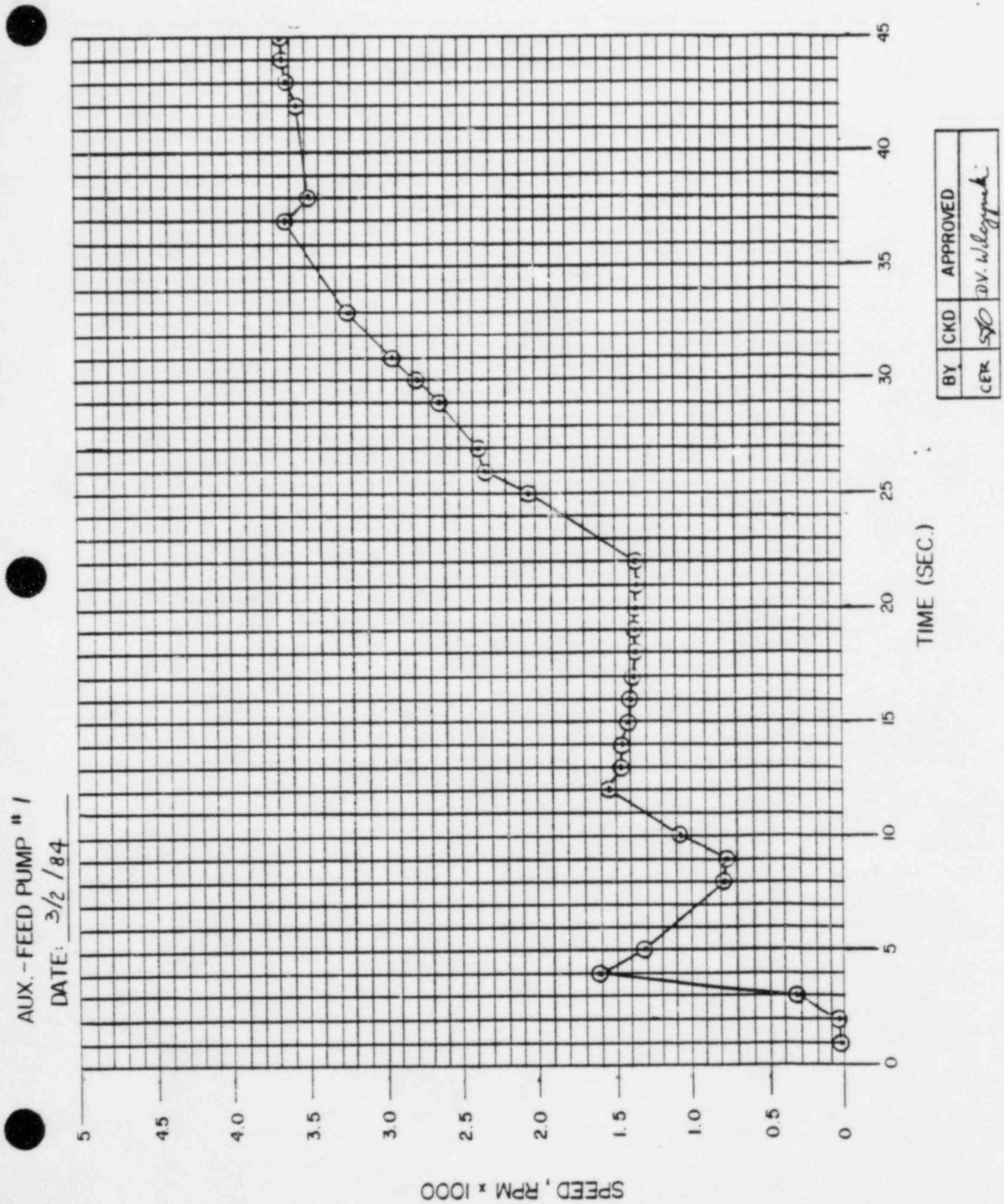

AUX.-FEED PUMP # 1
DATE: 3/2/84
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
BY
CKD
APPROVED
CETR

Figure 4

AUX FEED PUMP 1-2 SPEED DATA
MARCH 2, 1984

DATA POINT	TIME	AFP 1-2 SPEEI (S018)
1	12:37:39	23.2
2	12:37:40	25.6
3	12:37:41	155.1
4	12:37:42	431.0
5	12:37:43	1935.3
6	12:37:44	NO DATA
7	12:37:45	NO DATA
8	12:37:46	1363.9
9	12:37:47	1666.7
10	12:37:48	1947.5
11	12:37:49	NO DATA
12	12:37:50	2267.4
13	12:37:51	2443.2
14	12:37:52	2489.6
15	12:37:53	2584.9
16	12:37:54	2731.4
17	12:37:55	2853.5
18	12:37:56	2948.7
19	12:37:57	3041.5
20	12:37:58	3078.1
21	12:37:59	3207.6
22	12:38:00	3256.4
23	12:38:01	NO DATA
24	12:38:02	NO DATA
25	12:38:03	3334.6
26	12:38:04	3385.8
27	12:38:05	3407.8
28	12:38:06	NO DATA
29	12:38:07	3451.8
30	12:38:08	3424.9
31	12:38:09	3488.4
32	12:38:10	NO DATA
33	12:38:11	2304.0
34	12:38:12	NO DATA
35	12:38:13	NO DATA
36	12:38:14	NO DATA
37	12:38:15	3105.0
38	12:38:16	3078.1
39	12:38:17	NO DATA
40	12:38:18	NO DATA
41	12:38:19	NO DATA
42	12:38:20	3327.2
43	12:38:21	3368.7
44	12:38:22	3412.7
45	12:38:23	3495.7

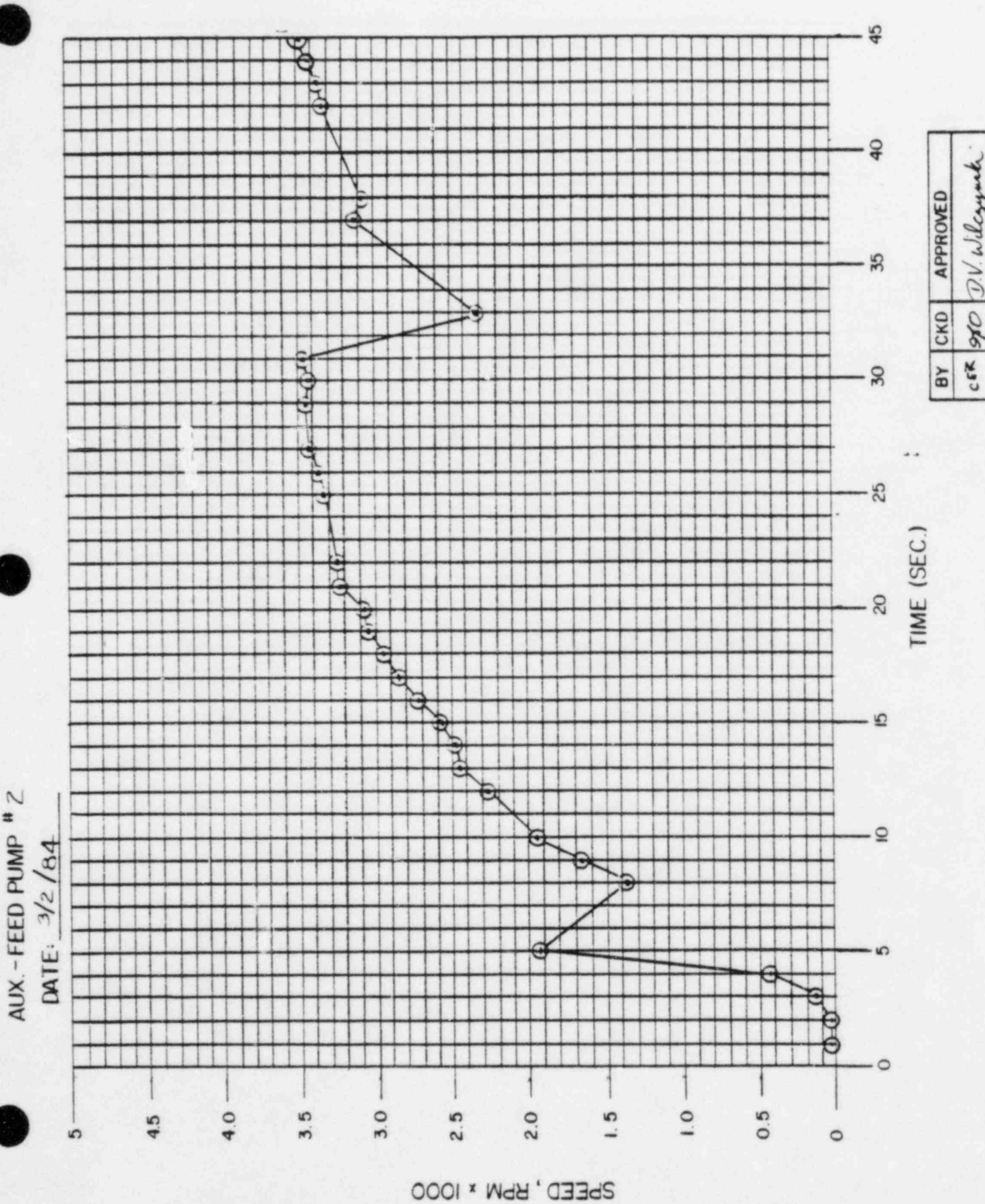

AUX.-FEED PUMP # 2
DATE: 3/2/84
TIME (SEC.)
SPEED, RPM x 1000
0
5
10
15
20
25
30
35
40
45
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
BY
CKD
APPROVED

Figure 5

AUX FEED PUMP 1-1 SPEED DATA
JANUARY 15, 1985

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	12:28:35	20.8
2	12:28:36	494.5
3	12:28:37	777.8
4	12:28:38	1210.0
5	12:28:39	NO DATA
6	12:28:40	NO DATA
7	12:28:41	2243.0
8	12:28:42	1681.3
9	12:28:43	1373.6
10	12:28:44	1783.9
11	12:28:43	NO DATA
12	12:28:46	1915.8
13	12:28:47	3205.1
14	12:28:48	NO DATA
15	12:28:49	NO DATA
16	12:28:50	2785.1
17	12:28:51	2770.5
18	12:28:52	3407.8
19	12:28:53	NO DATA
20	12:28:54	3505.5
21	12:28:55	3527.5
22	12:28:56	3437.1
23	12:28:57	3498.2
24	12:28:58	3446.9
25	12:28:59	3615.4
26	12:29:00	NO DATA
27	12:29:01	3649.6
28	12:29:02	3595.8
29	12:29:03	3603.2
30	12:29:04	3615.4
31	12:29:05	3688.6
32	12:29:06	3813.2
33	12:29:07	3842.5

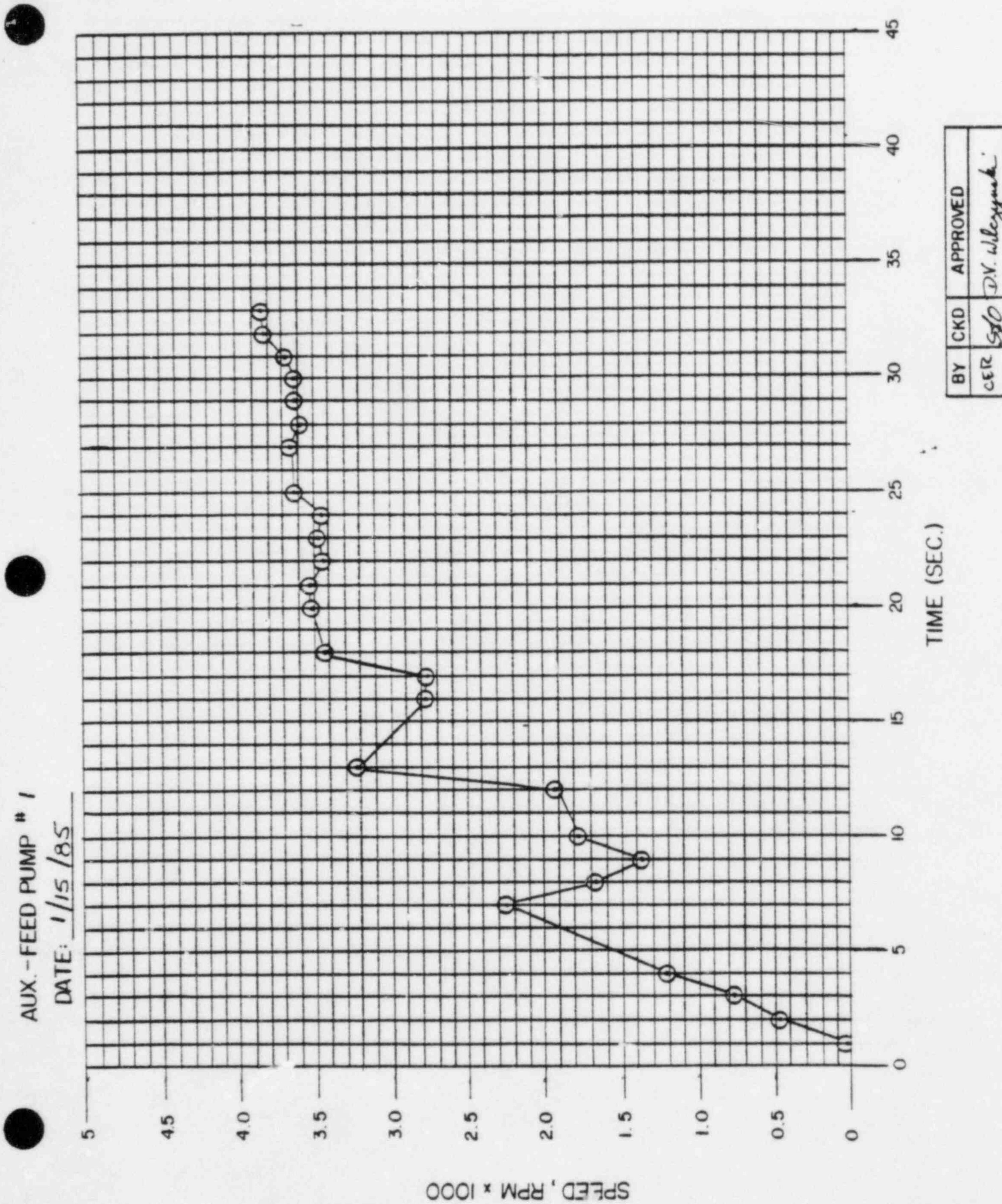

AUX.-FEED PUMP # 1
DATE: 1/15/85
TIME (SEC.)
SPEED, RPM x 1000
BY
CKD
APPROVED
CER
D.Y. Wlezyzmuk

Figure 6

AUX FEED PUMP 1-2 SPEED DATA
JANUARY 15, 1985

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	12:28:54	35.4
2	12:28:55	282.1
3	12:28:56	1197.8
4	12:28:57	2118.4
5	12:28:58	1473.7
6	12:28:59	1390.7
7	12:29:00	NO DATA
8	12:29:01	1593.4
9	12:29:02	1549.4
10	12:29:03	1527.3
11	12:29:04	1515.3
12	12:29:05	1490.8
13	12:29:06	1476.2
14	12:29:07	1466.4
15	12:29:08	1468.9
16	12:29:09	1468.9
17	12:29:10	1471.3
18	12:29:11	1517.7
19	12:29:12	3002.4
20	12:29:13	2992.7
21	12:29:14	307[illegible].7
22	12:29:15	30[illegible]4.4
23	12:29:16	[illegible]82.9
24	12:29:17	2997.6
25	12:29:18	3024.4
26	12:29:19	3026.9
27	12:29:20	3056.2
28	12:29:21	3085.5
29	12:29:22	3097.7
30	12:29:23	3109.9
31	12:29:24	3127.0
32	12:29:25	3139.2
33	12:29:26	3146.5
34	12:29:27	3158.7
35	12:29:28	3161.2
36	12:29:29	3175.8
37	12:29:30	3175.8
38	12:29:31	3180.7

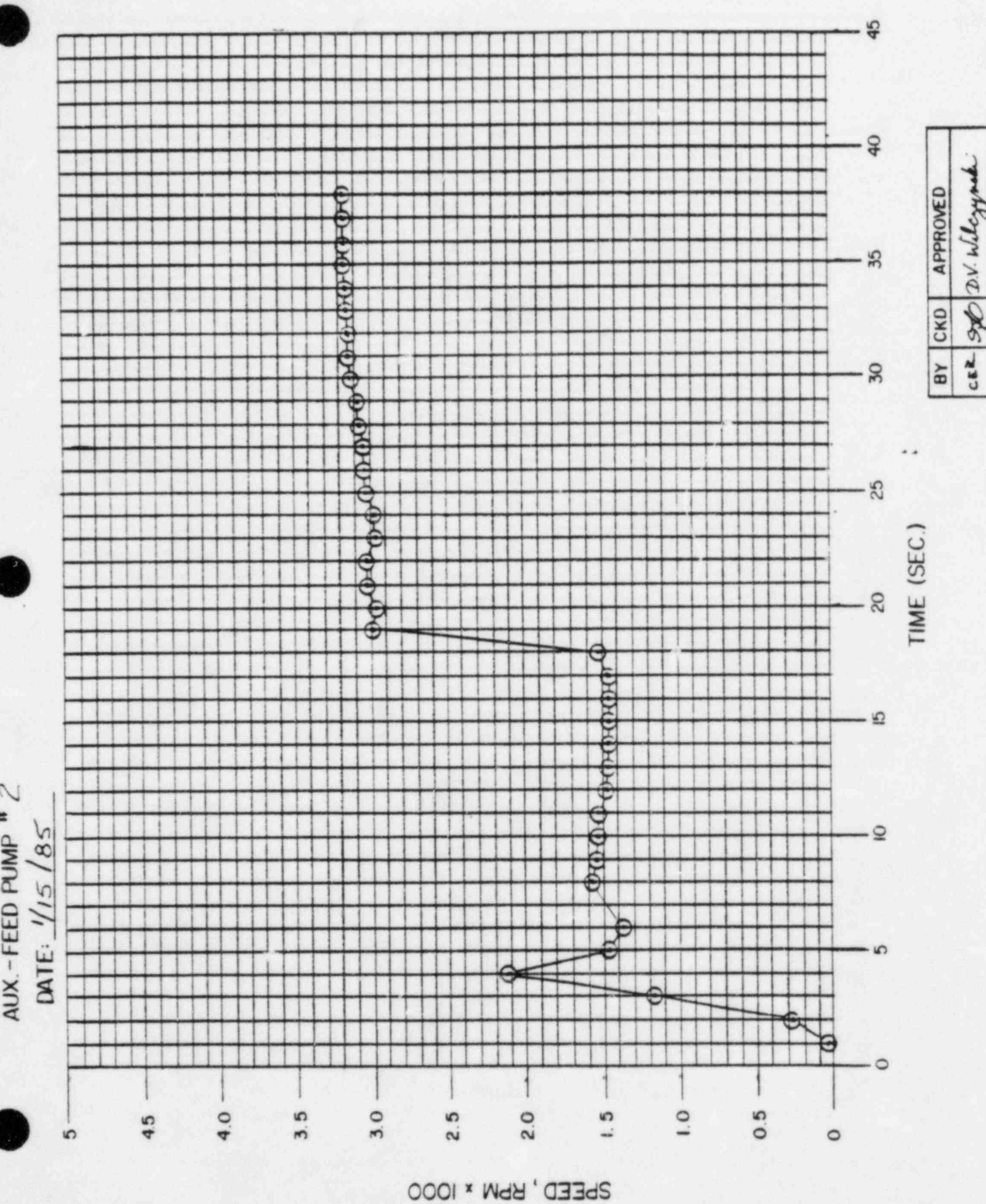

AUX.-FEED PUMP # 2
DATE: 1/15/85
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
BY
CKD
APPROVED
CER

Figure 7

AUX FEED PUMP 1-1 SPEED DATA
MARCH 21, 1985

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	19:54:16	25.6
2	19:54:17	106.2
3	19:54:18	230.8
4	19:54:19	550.7
5	19:54:20	826.6
6	19:54:21	1207.6
7	19:54:22	1708.2
8	19:54:23	2733.8
9	19:54:24	2225.9
10	19:54:25	NO DATA
11	19:54:26	2321.1
12	19:54:27	2819.3
13	19:54:28	1979.2
14	19:54:29	3241.8
15	19:54:30	2328.4
16	19:54:31	3312.6
17	19:54:32	2536.0
18	19:54:33	3134.3
19	19:54:34	3222.2
20	19:54:35	3261.3
21	19:54:36	3319.9
22	19:54:37	3363.9
23	19:54:38	3381.0
24	19:54:39	3444.4
25	19:54:40	3490.8
26	19:54:41	3505.5
27	19:54:42	3520.1
28	19:54:43	3561.7
29	19:54:44	3495.7
30	19:54:45	3534.8
31	19:54:46	3527.5
32	19:54:47	3571.4
33	19:54:48	3556.8
34	19:54:49	NO DATA
35	19:54:50	3573.9
36	19:54:51	NO DATA
37	19:54:52	NO DATA
38	19:54:53	3547.0
39	19:54:54	3571.4
40	19:54:55	NO DATA
41	19:54:56	3551.9
42	19:54:57	3547.0
43	19:54:58	3561.7
44	19:54:59	3591.0
45	19:55:00	3571.4

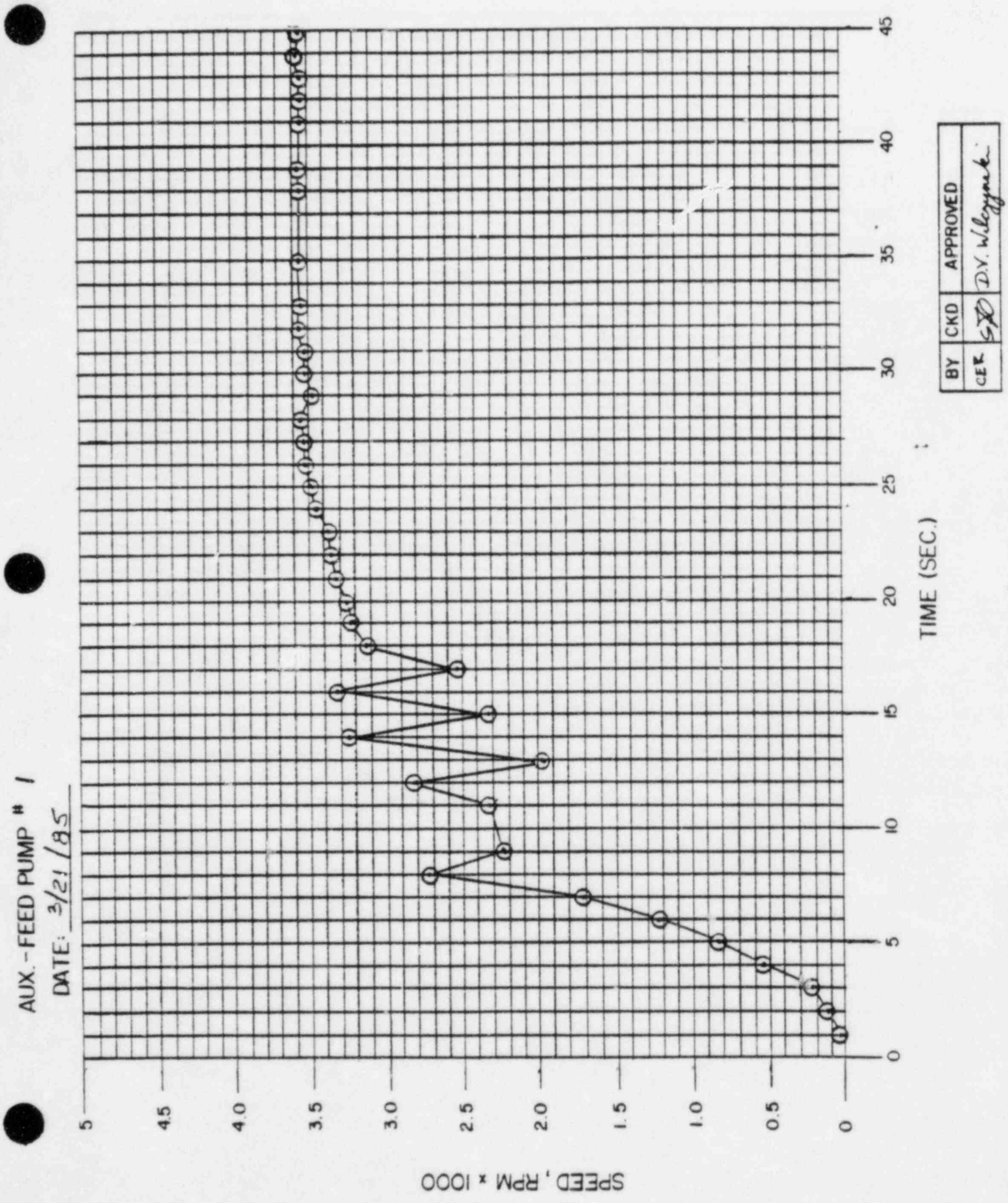

AUX.-FEED PUMP # 1
DATE: 3/21/85
TIME (SEC.)
0 5 10 15 20 25 30 35 40 45
SPEED, RPM x 1000
0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5
BY
CKD
APPROVED

Figure 8

AUX FEED PUMP 1-2 SPEED DATA
MARCH 21, 1985

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	19:54:15	28.1
2	19:54:16	616.6
3	19:54:17	1669.1
4	19:54:18	1520.1
5	19:54:19	1188.0
6	19:54:20	1422.5
7	19:54:21	1537.2
8	19:54:22	1466.4
9	19:54:23	1498.2
10	19:54:24	1520.1
11	19:54:25	NO DATA
12	19:54:26	1561.7
13	19:54:27	1564.1
14	19:54:28	1547.0
15	19:54:29	1566.5
16	19:54:30	1564.1
17	19:54:31	1608.1
18	19:54:32	1686.2
19	19:54:33	1776.6
20	19:54:34	1803.4
21	19:54:35	1874.2
22	19:54:36	1925.2
23	19:54:37	2035.4
24	19:54:38	2147.7
25	19:54:39	2216.1
26	19:54:40	2255.2
27	19:54:41	2272.3
28	19:54:42	2301.6
29	19:54:43	2438.3
30	19:54:44	2614.2
31	19:54:45	2421.2
32	19:54:46	2614.2
33	19:54:47	2604.4
34	19:54:48	2602.0
35	19:54:49	NO DATA
36	19:54:50	2235.7
37	19:54:51	NO DATA
38	19:54:52	NO DATA
39	19:54:53	1825.4
40	19:54:54	1803.4
41	19:54:55	NO DATA
42	19:54:56	3537.2
43	19:54:57	3647.1

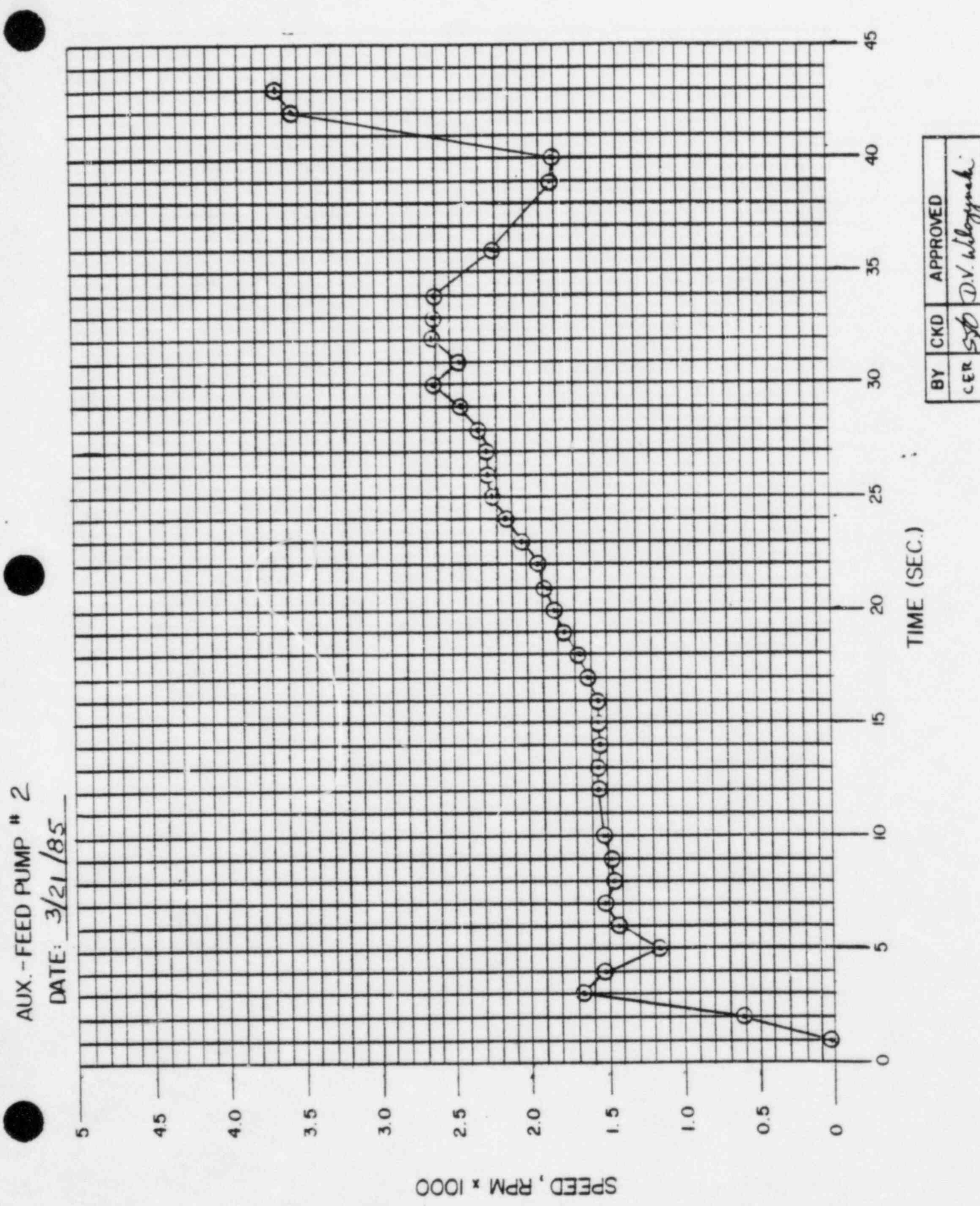

AUX.-FEED PUMP # 2
DATE: 3/21/85
TIME (SEC.)
SPEED, RPM x 1000
0
5
10
15
20
25
30
35
40
45
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
BY
CKD
APPROVED
CER
D.V.

Figure 9

AUX FEED PUMP 1-2 SPEED DATA
APRIL 12, 1985 - FIRST RUN

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	04:09:13	23.2
2	04:09:14	30.5
3	04:09:15	74.5
4	04:09:16	716.7
5	04:09:17	1962.1
6	04:09:18	1744.8
7	04:09:19	1998.8
8	04:09:20	2123.3
9	04:09:21	2172.2
10	04:09:22	2203.9
11	04:09:23	2457.9
12	04:09:24	2648.4
13	04:09:25	2792.4
14	04:09:26	3503.1
15	04:09:27	3678.9
16	04:09:28	3698.4
17	04:09:29	3722.8
18	04:09:30	3698.4
19	04:09:31	3710.6
20	04:09:32	3759.5
21	04:09:33	3801.0

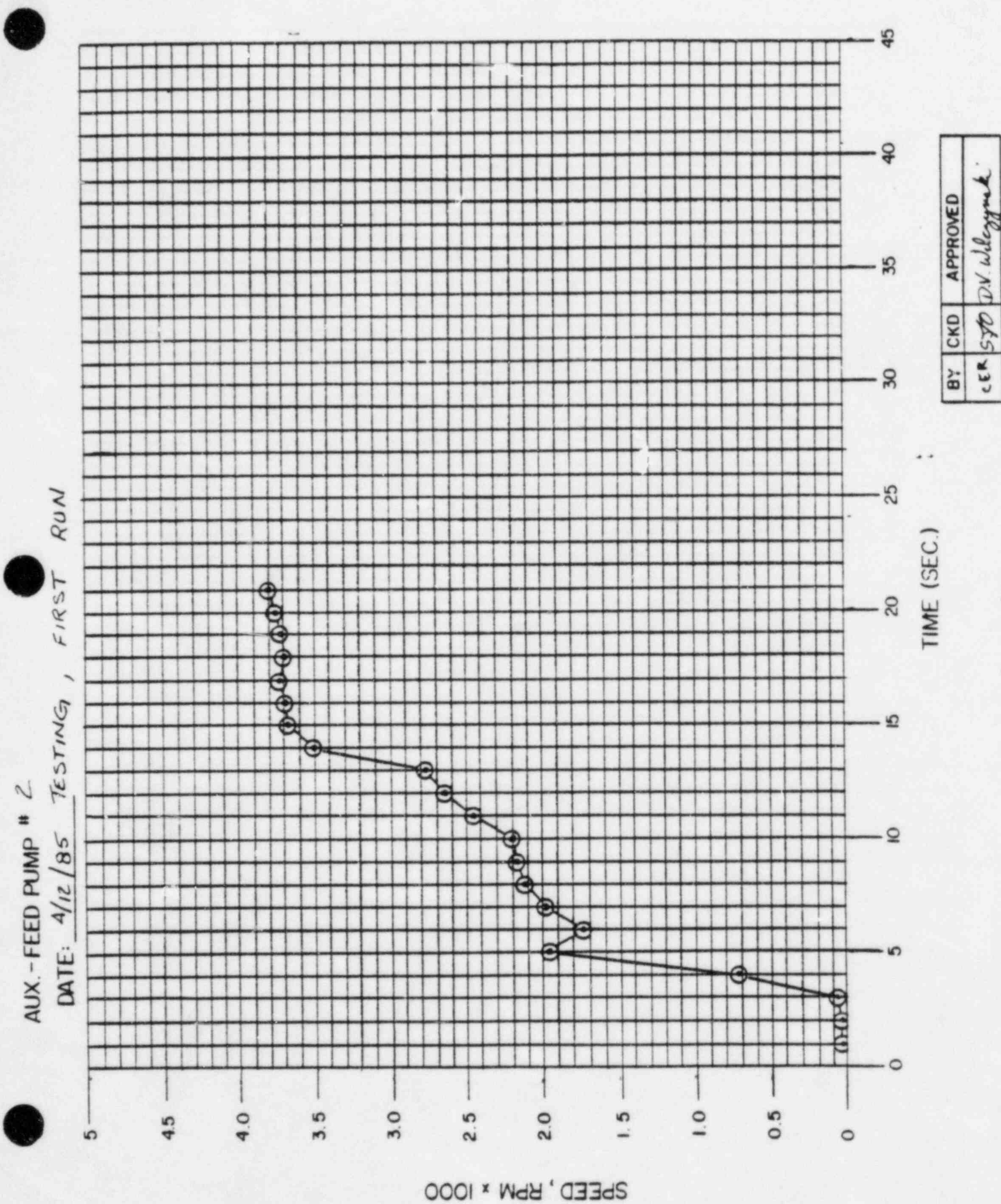
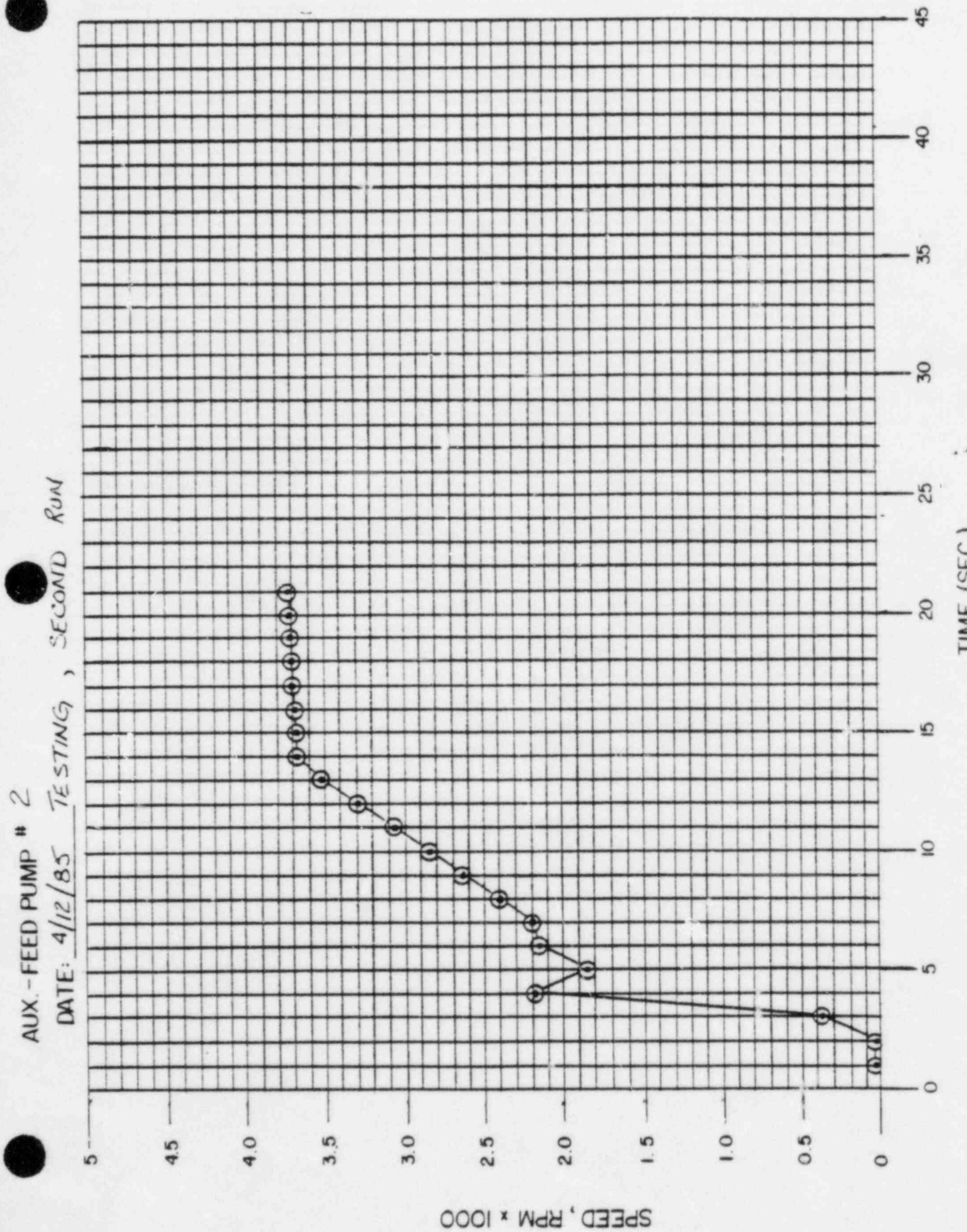

AUX.-FEED PUMP # 2
DATE: 4/12/85 TESTING, FIRST RUN
SPEED, RPM x 1000
TIME (SEC.)
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
0
5
10
15
20
25
30
35
40
45
BY
CKD
APPROVED
CER
SPO
D.V. Wilczynski

Figure 10

AUX FEED PUMP 1-2 SPEED DATA
APRIL 12, 1985 - SECOND RUN

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	04:17:06	23.2
2	04:17:07	25.6
3	04:17:08	387.1
4	04:17:09	2199.0
5	04:17:10	1847.4
6	04:17:11	2145.3
7	04:17:12	2201.5
8	04:17:13	2404.2
9	04:17:14	2633.7
10	04:17:15	2855.9
11	04:17:16	3075.7
12	04:17:17	3302.8
13	04:17:18	3525.0
14	04:17:19	3678.9
15	04:17:20	3676.4
16	04:17:21	3691.1
17	04:17:22	3703.3
18	04:17:23	3710.6
19	04:17:24	3715.5
20	04:17:25	3717.9
21	04:17:26	3722.8



BY	CKD	APPROVED
CER	SJO	D.V. Wilczynski

Figure 11

AUX FEED PUMP 1-1 SPEED DATA
JUNE 2, 1985

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	06:05:36	45.2
2	06:05:37	125.8
3	06:05:38	707.0
4	06:05:39	1053.7
5	06:05:40	1637.4
6	06:05:41	2470.1
7	06:05:42	1837.6
8	06:05:43	1427.3
9	06:05:44	1246.6
10	06:05:45	2692.3
11	06:05:46	2155.1
12	06:05:47	1769.2
13	06:05:48	2846.2
14	06:05:49	2074.5
15	06:05:50	3041.5
16	06:05:51	2936.5
17	06:05:52	3080.6
18	06:05:53	3095.2
19	06:05:54	3185.6
20	06:05:55	3241.8
21	06:05:56	3319.9
22	06:05:57	3327.2
23	06:05:58	3361.4
24	06:05:59	3366.3
25	06:06:00	3395.6
26	06:06:01	3361.4
27	06:06:02	3385.8
28	06:06:03	3381.0
29	06:06:04	3407.8
30	06:06:05	3395.6
31	06:06:06	3400.5
32	06:06:07	3390.7
33	06:06:08	3468.9

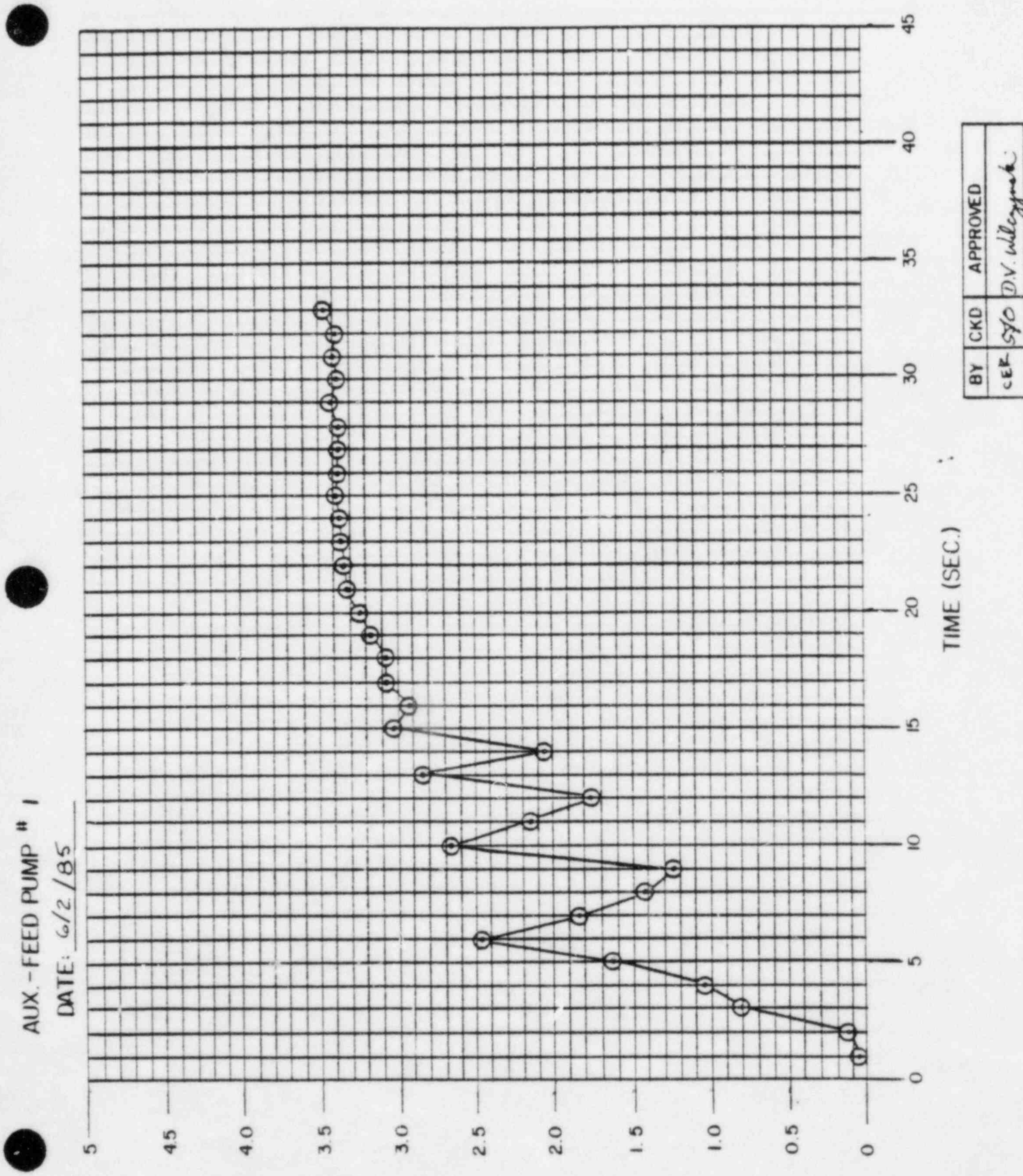

AUX. -FEED PUMP # 1
DATE: 6/2/85
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
BY
CKD
APPROVED

Figure 12

AUX FEED PUMP 1-2 SPEED DATA
JUNE 2, 1985

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	06:05:21	40.3
2	06:05:22	406.6
3	06:05:23	1627.6
4	06:05:24	2418.8
5	06:05:25	1600.7
6	06:05:26	2113.6
7	06:05:27	2076.9
8	06:05:28	2123.3
9	06:05:29	2460.3
10	06:05:30	2575.1
11	06:05:31	2619.0
12	06:05:32	2628.8
13	06:05:33	2641.0
14	06:05:34	2687.4
15	06:05:35	2741.1
16	06:05:36	2926.7
17	06:05:37	3144.1
18	06:05:38	3144.1
19	06:05:39	3149.0
20	06:05:40	3146.5
21	06:05:41	3149.0
22	06:05:42	3158.7
23	06:05:43	3170.9
24	06:05:44	3200.2
25	06:05:45	3283.3
26	06:05:46	3412.7
27	06:05:47	3488.4
28	06:05:48	3525.0
29	06:05:49	3576.3
30	06:05:50	3610.5
31	06:05:51	3654.5
32	06:05:52	3688.6
33	06:05:53	3727.7
34	06:05:54	3781.4
35	06:05:55	3827.8
36	06:05:56	3866.9
37	06:05:57	3920.6
38	06:05:58	4033.0
39	06:05:59	4023.2
40	06:06:00	3952.4
41	06:06:01	3910.9
42	06:06:02	3879.1
43	06:06:03	3852.3
44	06:06:04	3830.3
45	06:06:05	3808.3

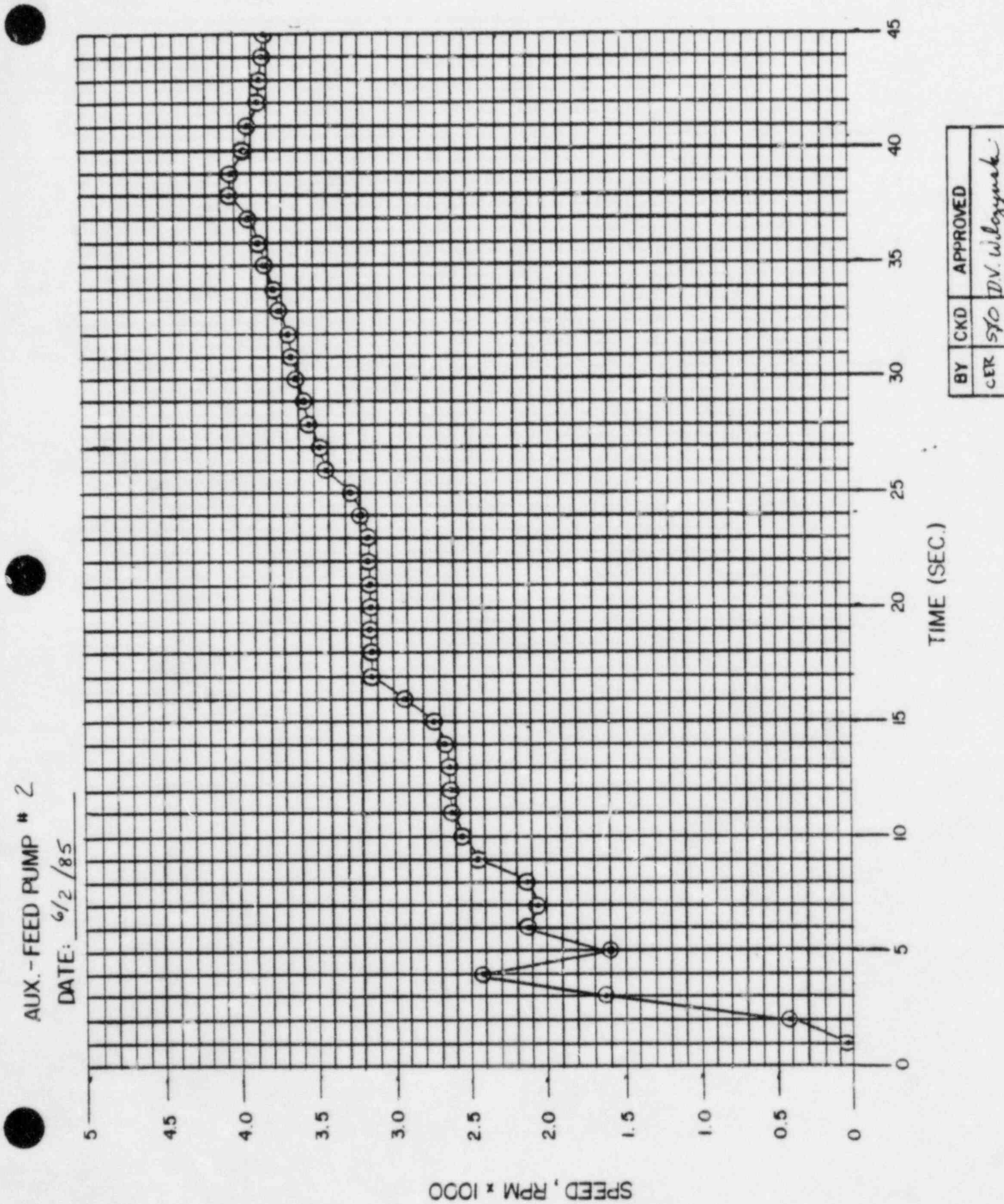

AUX.-FEED PUMP # 2
DATE: 6/2/85
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
BY
CKD
APPROVED

Figure 13

AUX FEED PUMP 1-1 SPEED DATA
JUNE 9, 1985 - TESTING

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	13:49:43	42.7
2	13:49:44	NO DATA
3	13:49:45	623.9
4	13:49:46	1007.3
5	13:49:47	1942.6
6	13:49:48	1876.7
7	13:49:49	NO DATA
8	13:49:50	1412.7
9	13:49:51	1854.7
10	13:49:52	2238.1
11	13:49:53	2362.6
12	13:49:54	2467.6
13	13:49:55	2638.6
14	13:49:56	2728.9
15	13:49:57	2821.7
16	13:49:58	2970.7
17	13:49:59	3107.4
18	13:50:00	NO DATA
19	13:50:01	3300.4
20	13:50:02	NO DATA
21	13:50:03	NO DATA
22	13:50:04	NO DATA
23	13:50:05	NO DATA
24	13:50:06	3586.1
25	13:50:07	NO DATA
26	13:50:08	NO DATA
27	13:50:09	3595.8
28	13:50:10	3573.9
29	13:50:11	3583.6
30	13:50:12	3598.3
31	13:50:13	3576.3
32	13:50:14	3605.6
33	13:50:15	3622.7
34	13:50:16	3622.7
35	13:50:17	NO DATA
36	13:50:18	NO DATA
37	13:50:19	NO DATA
38	13:50:20	3622.7
39	13:50:21	NO DATA
40	13:50:22	3639.8
41	13:50:23	3639.8
42	13:50:24	3637.4
43	13:50:25	3632.5

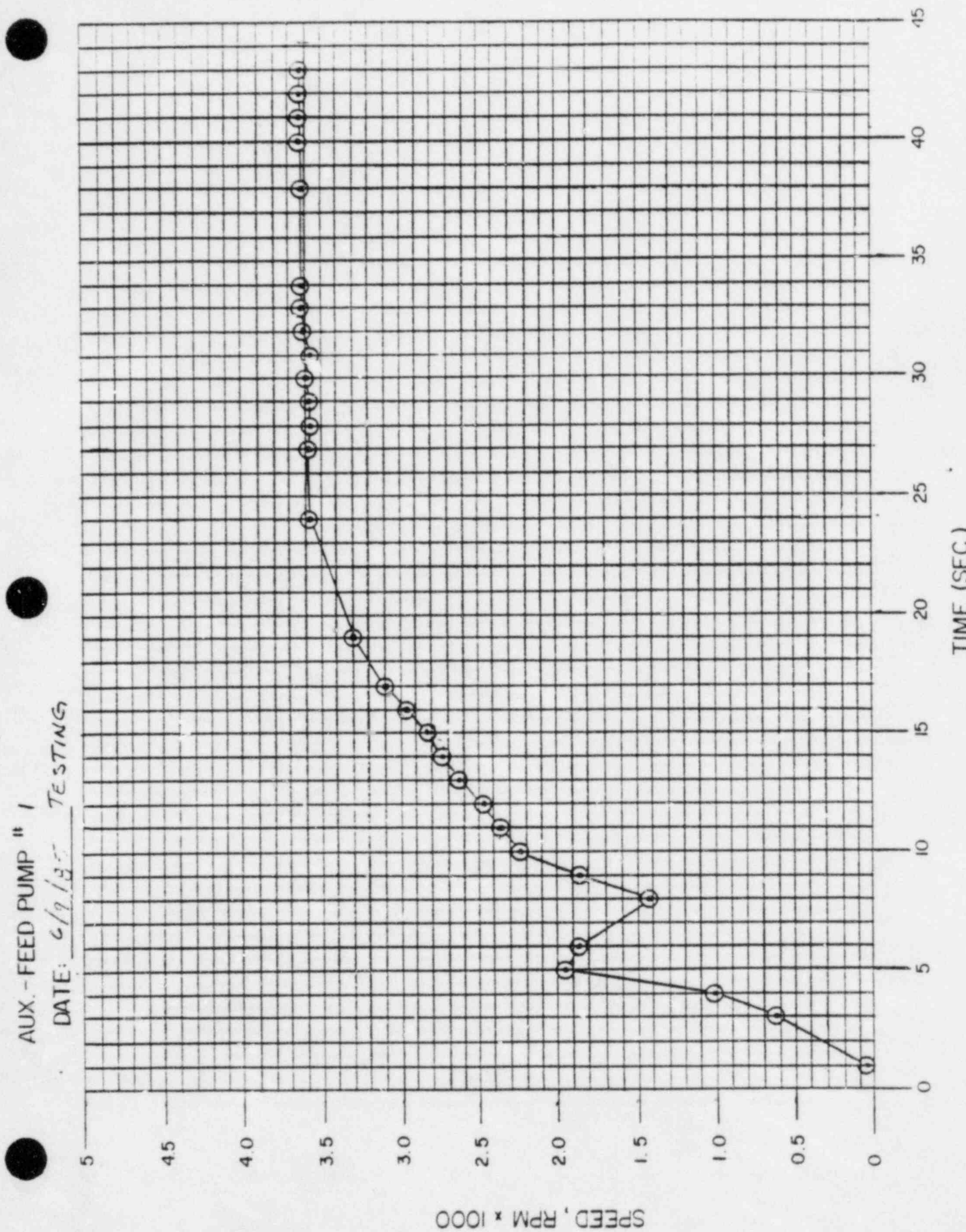


FIGURE 14

BY	CKD	APPROVED
CER	[illegible]	D.V. Wilczynski

AUX FEED PUMP 1-2 SPEED DATA
JUNE 9, 1985 - TESTING

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	12:34:52	35.4
2	12:34:53	382.2
3	12:34:54	NO DATA
4	12:34:55	2089.1
5	12:34:56	1610.5
6	12:34:57	2054.9
7	12:34:58	NO DATA
8	12:34:59	2028.1
9	12:35:00	2250.3
10	12:35:01	NO DATA
11	12:35:02	NO DATA
12	12:35:03	2731.4
13	12:35:04	NO DATA
14	12:35:05	3092.8
15	12:35:06	NO DATA
16	12:35:07	NO DATA
17	12:35:08	3625.2
18	12:35:09	3691.1
19	12:35:10	3715.5
20	12:35:11	NO DATA
21	12:35:12	3732.6
22	12:35:13	3713.1
23	12:35:14	3683.8
24	12:35:15	NO DATA
25	12:35:16	3627.6
26	12:35:17	3571.4
27	12:35:18	NO DATA
28	12:35:19	NO DATA
29	12:35:20	NO DATA
30	12:35:21	NO DATA
31	12:35:22	NO DATA
32	12:35:23	NO DATA
33	12:35:24	3271.1
34	12:35:25	NO DATA
35	12:35:26	3219.8
36	12:35:27	NO DATA
37	12:35:28	3122.1
38	12:35:29	3092.8
39	12:35:30	3036.6
40	12:35:31	NO DATA
41	12:35:32	2951.2
42	12:35:33	2914.5
43	12:35:34	2868.1
44	12:35:35	2794.9
45	12:35:36	2765.6

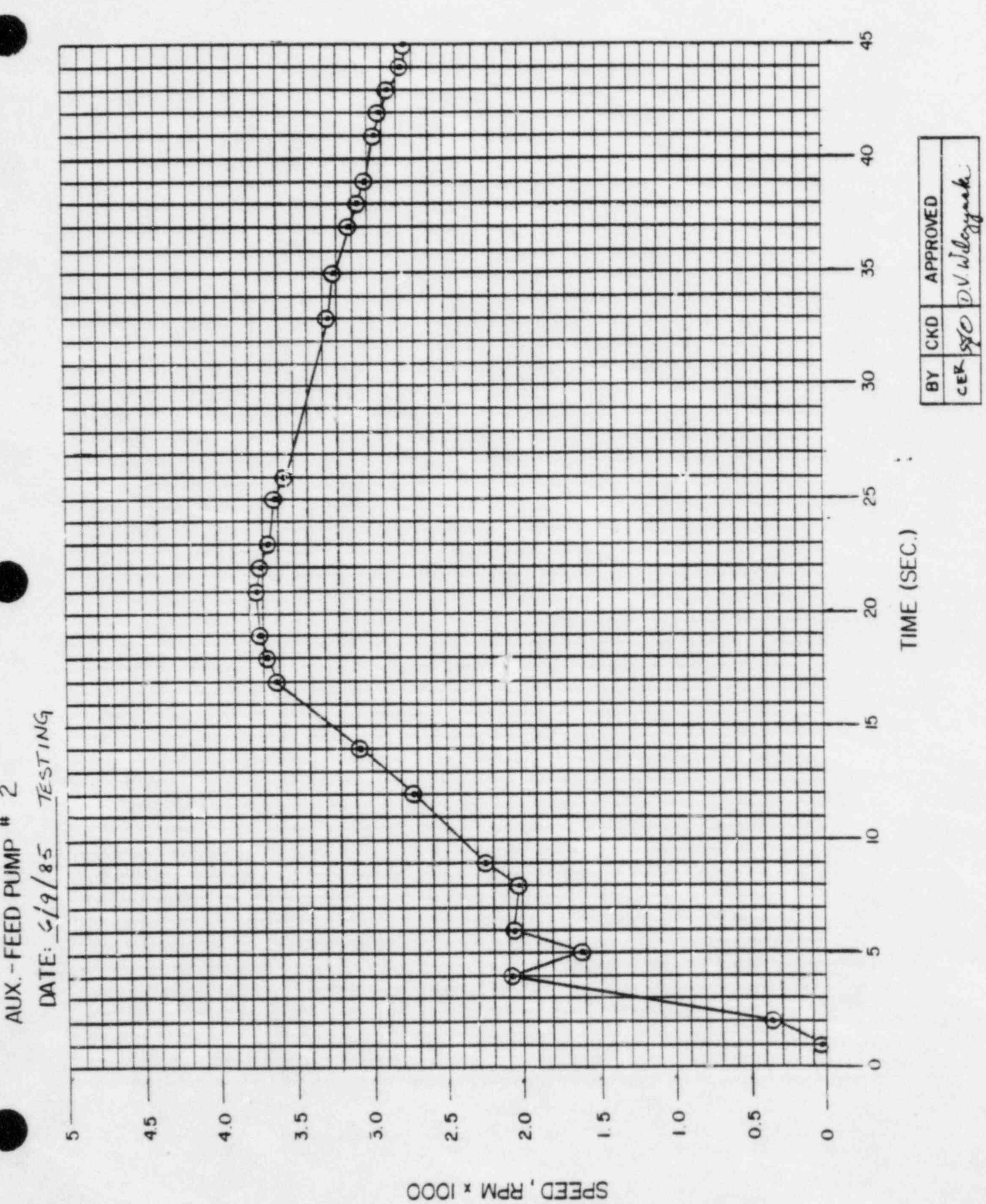

AUX.-FEED PUMP # 2
DATE: 6/9/85 TESTING
TIME (SEC.)
0 5 10 15 20 25 30 35 40 45
SPEED, RPM x 1000
0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5
BY
CKD
APPROVED
CER

Figure 15

ACTION PLAN

ED 4408

PLAN NUMBER	PAGE
1A	1 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	ALL STEPS OF THIS ACTION PLAN ARE TO BE PERFORMED IN ACCORDANCE WITH THE LATEST REVISION OF "GUIDELINES TO FOLLOW WHEN TROUBLESHOOTING OR PERFORMING INVESTIGATIVE ACTIONS INTO ROOT CAUSES SURROUNDING THE JUNE 9, 1985 REACTOR TRIP".					
1.0	Test of Hypothesis D: <u>Governor Malfunction Caused AFPT #1 to Overspeed</u>.	Wilczynski	Wilczynski	No Action Required		
1.1	Prepare Maintenance Work Order (MWO) for removal of governor cover, inspection, and reassembly of governor. All work to be performed by a representative of Woodward Governor Co.	Wilczynski	Thompson			
1.2	Remove governor cover on AFPT #1.	Wilczynski	Thompson			
1.3	Perform a visual inspection to determine any obvious damage.	Wilczynski	Thompson			
1.4	Check oil level and cleanliness.	Wilczynski	Thompson			
1.5	Document the as-found condition.	Wilczynski	Wilczynski			

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1A	2 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
1.6	Using Woodward Engineering Representative, determine if any repairs are required prior to testing the governors. The basis for this determination will be: "If the repairs are required to preclude further damage to the governor, turbine, or pump, then the repairs shall be made. If further operation of the governor will not cause further damage, then the repairs will be made after the test for overspeed is run to determine if the failed item could have caused the overspeed on 6/9/85". Document all decisions.	Wilczynski	Gradomski			
1.7	Prepare MWO and perform repair work as determined in Step 1.6. All work to be done by Woodward Representative.	Wilczynski	Thompson			
1.8	Install a remote manual trip device in case of failure of the overspeed trip.	Wilczynski	Thompson			
1.9	Perform "quick start" test of AFPT #1 using ST 5071.02 Phase 1 to test Hypothesis D.	Wilczynski	Missig			

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1A	3 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
1.10	Repeat step 1.9 to prove repeatability.	Wilczynski	Missig			
1.11	Prepare MWO for repair of governor for all items that were not repaired under step 1.7 as determined by step 1.6.	Wilczynski	Thompson			
1.12	Review data to verify applicability to hypothesis.	Wilczynski	Wilczynski			

ACTION PLAN

PLAN NUMBER	PAGE
1A	4 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
2.0	Test of Hypothesis A: Condensate in the Main Steam Crossover Line Caused AFPT #1 to Overspeed.	Wilczynski	Wilczynski	No Action Required		
2.1	Develop a Test Procedure (TP) to simulate as close as practical the actual conditions of the June 9, 1985 AFPT #1 overspeed trip. A brief outline of the TP is shown below:	Wilczynski	Missig			
	PURPOSE:					
	- To verify hypothesis that condensate in the cross connect steam supply lines (MS 106A) can cause an overspeed trip of AFPT #1.					
	EQUIPMENT NEEDED:					
	- Existing plant instrumentation					
	- Back-up system for tripping turbines manually					
	- Instrumentation to monitor the thermohydraulic conditions in the steam supply piping to the AFPTs.					

ACTION PLAN

ED 6408

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

PLAN NUMBER	PAGE
1A	5 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	PREREQUISITES:					
	- Governor is at its high speed stop.					
	- Steam supply lines to the AFPTs are at ambient conditions.					
	- Pump discharge valves are closed.					
	- Verify min-recirc valves are open.					
	- Steam Generator (SG) pressures are greater than 870 psig.					
	NOTE: SG pressure will be less than 1050 psig and decreasing during testing. This will not exactly duplicate the conditions of [illegible]9/85.					
2.2	Perform Test Procedure	Wilczynski	Missig			
2.3	Review test data to verify applicability to hypothesis.	Wilczynski	Wilczynski			
2.4	Repeat Test Procedure	Wilczynski	Missig			
2.5	Review test data from second test to verify applicability to hypothesis.	Wilczynski	Wilczynski			

ACTION PLAN

ED 4408

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

PLAN NUMBER	PAGE
1A	6 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination. *

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
3.0	Test Hypothesis B: "Double Start" due to cycling of valves MS 106 and MS 106A.	Wilczynski	Wilczynski	No Action Required		
3.1	Develop a Test Procedure (TP) to simulate the cycling of valves MS 106 and MS 106A as occurred on 6/9/85. Prerequisites to be the same as shown in Step 2.1.	Wilczynski	Missig			
3.2	Perform the TP developed above.	Wilczynski	Missig			
3.3	Review test data to verify applicability to hypothesis.	Wilczynski	Wilczynski			
3.4	Perform the TP again.	Wilczynski	Missig			
3.5	Review test data to verify applicability to hypothesis.	Wilczynski	Wilczynski			
4.0	Write final report to document root cause.	Wilczynski	Wilczynski			

ACTION PLAN

TD 6408

TITLE	PLAN NUMBER	PAGE
AUXILIARY FEED-PUMP TURBINE (AFPT) #2 OVERSPEED TRIP (Rev. 1)	1B	1 of 5
	DATE PREPARED	PREPARED BY
	6/24/85	C. E. Rupp Wilczynski D. Missig

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	ALL STEPS OF THIS ACTION PLAN ARE TO BE PERFORMED IN ACCORDANCE WITH THE LATEST REVISION OF "GUIDELINES TO FOLLOW WHEN TROUBLESHOOTING OR PERFORMING INVESTIGATIVE ACTIONS INTO ROOT CAUSES SURROUNDING THE JUNE 9, 1985 REACTOR TRIP".					
1.0	Test of Hypothesis D: <u>Govern malfunction caused AFPT #2 to overspeed</u>.	Wilczynski	Wilczynski	No Action Required		
1.1	Prepare Maintenance Work Order (MWO) for removal of governor cover, inspection, and reassembly of governor. All work to be performed by a representative of Woodward Governor Co.	Wilczynski	Thompson			
1.2	Remove governor cover on AFPT #2.	Wilczynski	Thompson			
1.3	Perform a visual inspection to determine any obvious damage.	Wilczynski	Thompson			
1.4	Check oil level and cleanliness.	Wilczynski	Thompson			
1.5	Document the as-found condition.	Wilczynski	Wilczynski			

ACTION PLAN

ED 6408

PLAN NUMBER	PAGE
1B	2 of 5
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #2 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
1.6	Using Woodward Engineering Representative, determine if any repairs are required prior to testing the governors. The basis for this determination will be: "If the repairs are required to preclude further damage to the governor, turbine, or pump, then the repairs shall be made. If further operation of the governor will not cause further damage, then the repairs will be made after the test for overspeed is run to determine if the failed item could have caused the overspeed on 6/9/85." Document all decisions.	Wilczynski	Gradomski			
1.7	Prepare MWO and perform repair work as determined in Step 1.6. All work to be done by Woodward Representative.	Wilczynski	Thompson			
1.8	Install a remote manual trip device in case of failure of the overspeed trip.	Wilczynski	Thompson			
1.9	Perform "quick start" test of AFPT #2 using ST 5071.02 Phase 1 to test Hypothesis D.	Wilczynski	Missig			

ACTION PLAN

ED 6408

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #2 OVERSPEED TRIP (Rev. 1)

PLAN NUMBER	PAGE
1B	3 of 5
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
1.10	Repeat step 1.9 to prove repeatability.	Wilczynski	Missig			
1.11	Prepare MWO for repair of governor for all items that were not repaired under Step 1.7 as determined by Step 1.6.	Wilczynski	Thompson			
1.12	Review data to verify applicability to hypothesis.	Wilczynski	Wilczynski			
2.0	Test of Hypothesis A: <u>Condensate in the Main Steam crossover line caused AFPT #2 to overspeed.</u>	Wilczynski	Wilczynski	No Action Required		
2.1	Develop a Test Procedure (TP) to simulate as close as practical the actual conditions of the June 9, 1985 AFPT #2 overspeed trip. A brief outline of the TP is shown below: PURPOSE: - To verify hypothesis that condensate in the cross connect steam supply lines (MS 107A) can cause an overspeed trip of AFPT #2.	Wilczynski	Missig			

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1B	4 of 5
DATE PREPARED	**PREPARED BY**
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #2 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	EQUIPMENT NEEDED:	Wilczynski	Missig			
	- Existing plant instrumentation.					
	- Back-up system for tripping turbines manually.					
	- Instrumentation to monitor the thermohydraulic conditions in the steam supply piping to the AFPTs.					
	PREREQUISITES:					
	- Governor is at its high speed stop.					
	- Steam supply lines to the AFPTs are at ambient conditions.					
	- Pump discharge valves are closed.					
	- Verify min-recirc valves are open.					
	- Steam Generator (SG) pressures are greater than 870 psig.					
	NOTE: SG pressure will be less than 1050 psig and decreasing during testing. This will not exactly duplicate the conditions of 6/9/85.					
2.2	Perform Test Procedure.	Wilczynski	Missig			
2.3	Review test data to verify applicability to hypothesis.	Wilczynski	Wilczynski			

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1B	5 of 5
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #2 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
2.4	Repeat Test Procedure.	Wilczynski	Missig			
2.5	Review test data from second test to verify applicability to hypothesis.	Wilczynski	Wilczynski			
3.0	Evaluate the design of the PGG governor versus the PG-PL governor to determine differences that may cause undesired performance characteristics. (This action to be independent of all other action steps.)	Wilczynski	Gradomski			
4.0	Write final report to document root cause.	Wilczynski	Wilczynski			

Lay-in
Cat. 3

ACTION PLAN # 1A,1B

TITLE: Auxiliary Feed Pumps Overspeed Trips

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE	APPR. FOR IMPL.
0	6/20/85	Initial Issue	See Rev. 0 for approvals		
1	6/25/85	General Rewrite	D.V. Wilczynski 6/26/85	[signature]	

TITLE: AUXILIARY FEED PUMPS OVERSPEED TRIPS

REPORT BY: Dan Wilczynski, Chuck Rupp

Plan No.: 1A and 1B

DATE PREPARED: 6/24/85

This report has been prepared in accordance with the "Guidelines to Follow When Troubleshooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985, Reactor Trip," Rev. 4. These guidelines were developed in response to Confirmatory Action Letter 85-05.

I. INTRODUCTION

On Sunday, June 9, 1985, normal feedwater flow to the steam generators was interrupted. The reactor was automatically shutdown and reactor heat was removed via steaming through the main steam safeties and the atmospheric vent valves. The water level in the steam generators was decreasing and at 1:41:03 a Steam and Feedwater Rupture Control System (SFRCS) full trip was initiated on Channel 1 due to a low water level in Steam Generator #1 (SG #1). This SFRCS actuation attempted to initiate auxiliary feedwater flow by opening the steam supply valve, MS 106, from SG #1 to auxiliary feedwater pump turbine (AFPT) #1. Five seconds after the initial SFRCS (1:41:08) the reactor operator inadvertently initiated an SFRCS low pressure trip on both channels and both steam generators. This low pressure trip of SFRCS is intended to respond to a steam line break or other equipment failure resulting in depressurizing a steam generator. The manual low pressure SFRCS trip initiated the following, as designed:

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

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

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

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

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

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

This report documents the review of data from previous unit trips, the 6/9/85 trip, AFPT testing, and other utility overspeed trips to determine possible causes of the overspeed trips which occurred at Davis-Besse on 6/9/85. Based on this review, this report presents hypothesized causes of the observed overspeed.

Based on review of currently available information, we conclude that the most likely hypothesis of those considered is introduction of water slugs into the AFPTs causing overspeed. Based on discussions with Terry Turbine, water slugs flash as they pass through the turbine inlet nozzles resulting in acceleration of the turbine rotor. (It appears that introduction of excessive amounts of water may slow down the turbine.)

Although introduction of water slugs is judged to be the major cause of the observed overspeed, other factors may have contributed and will be further investigated. These other factors include:

1) AFPT governor problems
2) "Double start" due to switchover of steam supply for AFPT #1.
3) Pump discharge flow was through the minimum recirculation path only.

II. SUMMARY OF DATA

In order to determine possible causes of the overspeed trips on 6/9/85, the following data were collected and analyzed. A summary of the analysis for the 6/9/85 plant trip and several previous trips is provided.

For each plant trip and surveillance test, the specific sequence of events was reviewed with particular attention to the following parameters.

- AFPT speed vs. time
- AFP flow and discharge pressure
- Steam generator pressure and level
- Specific valve line-ups

Figure 1 and Attachment 1 provide a summary of pertinent steam and feedwater system features associated with the AFPTs (for reference).

A. June 9, 1985 Plant Trip Summary

During the June 9, 1985 trip transient, the following sequence of events regarding auxiliary feedwater flow initiation occurred:

- Steam flow was initially provided to AFPT #1 via the normal path through MS 106 and turbine speed began increasing. This was initiated by a steam generator low level trip in the SFRCS at 1:41:03. Steam flow to AFPT #2 was not immediately initiated since a low level condition did not exist in SG #2 at this time.

- As a result of an operator initiated low steam header pressure SFRCS trip (1:41:08), the steam supply to AFPT #1 was switched to SG #2 through MS 106A. The SFRCS also initiated steam flow through the MS 107A flow path from SG #1 to AFPT #2.

- The low pressure SFRCS trip resulted in switching the discharge path from the auxiliary feedwater pumps (AF 3870 closed, and AF 3869 and 3871 opened) and AF 599 and AF 608 were closed. The net result of these actions was to isolate the feedwater discharge path of both auxiliary feedwater pumps leaving only the minimum recirculation path available.

The speed characteristics are shown on Figures 2 and 3 of Attachment 2. A review of the speed vs. time characteristics for AFPT #1 shows the typical characteristics of several oscillations prior to reaching rated speed but the final oscillation was uncontrolled and increased turbine speed to the overspeed trip setpoint.

A review of the speed characteristics for AFPT #2 shows an uncharacteristic leveling off at approximately 2500 RPM for about eight (8) seconds from which point turbine speed quickly increases to above 4100 RPM, decreases slightly and then continues to increase to the overspeed trip setpoint. The pause at 2500 RPM could be due to excessive water induction into the turbine.

B. Past Plant Trips and Surveillance/Testing Data

Based on our evaluation of previous plant trips and surveillance testing, we have the following observations:

1) The AFPT speed vs. time characteristic is relatively uniform for each trip (See Attachment 2).

2) The specific steam supply and feedwater flowpath configuration encountered during the 6/9/85 trip transient has not previously been duplicated.

3) No previous testing had been performed to simulate a "quick start" using only the cross connects (MS 106A and MS 107A) for steam supply to the AFPTs.

The similarities and differences for each of the previous trips and tests compared to the 6/9/85 event are described below with particular attention to the hypothesis judged most likely to have caused the overspeed condition.

1. March 2, 1984 Plant Trip

A review of the trip data indicates that a SFRCS low pressure trip was initiated during the event due to a stuck open Main Steam Safety Valve. This SFRCS initiation closed

the steam supply valve (MS 107) from SG #2 to AFPT #2 and opened the cross connect valve MS 107A to supply steam to AFPT #2 from SG #1. This switch of steam supply occurred 21 seconds (12:37:55) after both AFPTs had been started via MS 106 and MS 107. A review of the speed vs. time characteristics (see Figures 4 and 5 of Attachment 2), show that AFPT #2 experienced a decrease of approximately 1000 RPM at sixteen (16) seconds after the SFRCS low pressure trip. This speed decrease may be attributed to excessive water being picked up from the MS 107A line and being carried to the turbine.

The following differences between the 3/2/84 event and the 6/9/85 event assist in explaining why the AFPTs reached the overspeed trip setpoint on 6/9/85 but not on 3/2/84.

- On 3/2/84, since MS 107 was open and heating the line, opening MS 107A introduced only 250' of cold piping, thereby reducing the amount of water introduced to the turbine.

- On 3/2/84, additional water may have been introduced by opening MS 107A because the steam lines were not drained periodically at this time.

- On 3/2/84, since AFPT #2 was pumping approximately 1000 GPM, if a slug of water occurred from opening of MS 107A, there would have been more resistance to a speed increase as compared to the 6/9/85 event when only a min-recirc flow path was available.

- On 3/2/84, both AFPTs had the Woodward PG-PL governors installed.

2. <u>January 15, 1985 Plant Trip</u>

This event initiated a SFRCS trip on low SG level which, due to valve control changes made during the 1984 refueling outage, opened all four steam supply valves to the AFPTs. Also, AFPT #2 had the new PGG governor installed during the 1984 refueling outage. The speed characteristics are shown on Figures 6 and 7 of Attachment 2.

The following differences between the 1/15/85 event and the 6/9/85 event assist in explaining why both turbines tripped on overspeed on 6/9/85 but not on 1/15/85.

- On 1/15/85, due to the pipe configuration, initial steam flow to both turbines would have been via the normal flow paths, MS 106 and MS 107. Therefore, initial heating of the respective lengths (360' and 125') may have occurred prior to steam flow through the cross connects resulting in less total mass of

water introduced to the AFPTs than postulated for the 6/9/85 event.

- On 1/15/85, both pumps had a flow path other than minimum recirculation available, therefore, speed increases would be accompanied by corresponding flow increases, thus maintaining loading on the pump. This flow path was not available on 6/9/85.

3. <u>March 21, 1985 Plant Trip</u>

This event initiated a SFRCS trip on low SG level that resulted in all four steam supply valves opening at the same time.

The speed characteristics are shown on Figures 8 and 9 of Attachment 2. A review of the speed characteristics for AFPT #1 show the typical characteristics consistently seen on AFPT #1 (i.e., several oscillations prior to reaching rated speed).

The following differences between the 3/21/85 event and the 6/9/85 event assist in explaining why both turbines tripped on overspeed on 6/9/85 but not on 3/21/85.

- On 3/21/85, due to pipe configuration, initial steam flow to both turbines would have been via the normal flow path, MS 106 and MS 107. Therefore, initial heating of the respective lengths (360' and 125') would have been done prior to steam flow through the cross connects resulting in less total mass of water introduced to the AFPTs than is postulated to have formed during the 6/9/85 event.

- On 3/21/85, both pumps had a flow path available other than the minimum recirculation, therefore, any speed increase would be accompanied by a corresponding flow increase, thus maintaining loading on the pump. This flow path was not available on 6/9/85.

A review of the speed vs. time characteristics show that AFPT #2 indicates a constant rate of acceleration until approximately 35 seconds after initial roll at which time there was an 800 RPM decrease in 2 seconds followed by an 1800 RPM increase in 3 seconds. This oscillation may be due to slugs of water.

4. <u>April 12, 1985 Testing</u>

After the change-out of the speed setting bushing from a 30 second rated bushing to a 15 second rated bushing on AFPT #2 governor, two quick start tests were performed to verify operability. This changeout was performed to ensure flow was provided by AFPT #2 within 40 seconds as required by

Technical Specifications. These tests were run on the normal steam supply path via MS 107 and with the pump discharge valves closed (i.e., min-recirc path open). Less than 24 hours prior to these two (2) tests some additional testing was done on this same turbine using the same valve line-ups. This prior testing was performed for trouble-shooting. Due to the prior testing, the steam lines may not have been cooled to ambient conditions prior to the two (2) operability tests being run. The speed characteristics are shown in Figures 10 and 11 of Attachment 2.

A review of the speed vs. time characteristics shows that the first run exhibited speed increases which appear to be a series of step changes rather than a constant acceleration to rated speed. The second run (performed immediately after the first) shows a constant rate of acceleration to rated speed. This is attributed to the fact that the steam lines were already heated, therefore, there would have been less condensation.

5. <u>June 2, 1985 Plant Trip</u>

This event initiated a SFRCS actuation on low SG level. Both AFPTs were supplied steam from their respective steam generators via MS 106 and MS 107.

The speed characteristics are shown on Figures 12 and 13 of Attachment 2. A review of the speed characteristics for AFPT #1 shows the typical characteristics consistently seen on AFPT #1 (i.e., several oscillations prior to reaching rated speed).

A review of the speed vs. time characteristics for AFPT #2 shows a fairly steady increase to rated speed but the speed continues past the high speed setpoint (3710 RPM) to approximately 4000 RPM for about three (3) seconds. The turbine then decreased speed and controlled at the high speed setpoint. During the initial increase to rated speed, the speed increases are seen as step changes rather than a straight line. These step changes, and the increase to approximately 4000 RPM, may be attributable to water slugs.

The following differences between the 6/2/85 event and the 6/9/85 event assist in explaining why both AFPTs reached the overspeed trip setpoint on 6/9/85 but not on 6/2/85.

- Both AFPTs were running on the normal steam supply paths via MS 106 and MS 107, therefore, there could be less condensation reaching the turbines.

- Both pumps had a discharge path available other than the minimum recirculation path, therefore, any speed increase would be accompanied by a corresponding flow increase, thus maintaining loading on the pump. This flow path was not available on 6/9/85.

6. June 9, 1985 Testing (Post Trip)

After the plant trip, a quick start test was performed on each of the AFPTs. These tests were run on the normal supply paths via MS 106 and MS 107. Both pumps discharge valves were closed such that only minimum recirculation flow was provided. These tests were run approximately ten (10) hours after the AFPTs had been shut down, therefore, the lines were still warm and the amount of condensation would be less than expected for ambient temperature lines.

The speed characteristics are shown on Figures 14 and 15 of Attachment 2. A review of each speed vs. time characteristic shows a constant acceleration to rated speed. AFPT #1 does not exhibit oscillations seen at other times. The "smoothness" of these graphs may be attributable to the fact that minimal condensation would be expected since the lines were already heated.

C. Modifications

1. During the 1984 refueling outage, the #2 AFPT governor was changed out from a Woodward PG-PL governor to a Woodward PGG governor. The new governor was supplied with 7 lb/in buffer springs and a 30 second speed setting bushing. Prior to startup from the 1984 refueling outage, the 7 lb/in buffer springs were changed to 26 lb/in buffer springs by a Woodward Governor representative. The speed setting bushing was changed from a 30 second bushing to a 15 second bushing on 4/12/85 to ensure that AFPT #2 could reach rated speed and deliver flow to the steam generators in less than 40 seconds as required by Technical Specifications.

2. During the 1984 refueling outage, the control logic for the steam supply valves to the AFPTs was changed to allow all four valves (MS 106, 106A, 107 and 107A) to open simultaneously. After the 3/21/85 plant trip, the change was revised so that MS 106A and MS 107A would open only on a SFRCS low pressure trip. This revision was made based on the hanger damage found prior to the 3/21/85 trip. This was considered a prudent action, the hanger damage was potentially attributable to water slugs.

D. Maintenance History

The maintenance work done excluding oil replacement since the 1984 refueling outage for AFPT 1-1 is as follows:

1. Replacement of governor control motor (6-2-85), MWO# 1-85-1876-03.

   NOTE: Investigations are currently underway to determine cause of motor failure.

2. Adjustment of governor slip clutch (6-2-85), MWO# 1-85-1878-00.

3. Replacement of low speed stop roll pin (6-2-85), MWO# 1-85-1878-01.

The maintenance work done excluding oil replacement since the 1984 refueling outage for AFPT 1-2 is as follows:

1. Changeout of speed setting bushing (4-12-85), MWO# 2-83-0136-11 (See Modification Item C.1. above).

A review of these maintenance records does not reveal any evidence that could support the overspeed trips of 6/9/85.

E. Investigation of Overspeed Trip Problems at Other Utilities

Various resources have been used to determine if other utilities have experienced overspeed trips of the AFPTs.

NPRDS had only one overspeed trip reported. This occurrence was the result of the failure of a Woodward Governor ramp generator. A ramp generator is not incorporated in the design of either the PG-PL or PGG governor.

"Nuclear Power Experience" reported a total of 10 overspeed trips which are summarized below:

1. Four (4) AFPT overspeeds were reported due to condensation in the line.

2. One (1) overspeed was reported due to a "double start" (i.e., interruption and re-introduction of steam supply when the turbine is already rolling).

3. One (1) loss of suction overspeed was reported (i.e., pump loses suction pressure which effectively reduces pump loading).

4. Four (4) overspeed trips due to governor problems as listed below:

- Low oil level in governor
- Mechanical misadjustments
- Failed speed sensor (applicable to electronic EG governor only)
- Apparent governor valve sticking

The final source of information was the Nuclear Network System. One (1) response was received which indicated the possibility of turbine overspeed due to water in the steam lines.

III. CHANGE ANALYSIS

The differences associated with the 6/9/85 trip compared to previous trips and actuations are listed below (conditions listed below existed only on 6/9/85 trip).

1. Both auxiliary feedwater containment isolation valves (AF 599 and 608) were closed when overspeed occurred. Pump flow was limited to the min-recirc flow.

2. Both AFPTs were running solely on the cross connect steam supply valves (MS 106A and 107A) at the time of the overspeed trips.

3. AFP #1 was started on steam from MS 106 but then was switched to steam from MS 106A.

These differences are discussed in more detail in Section II, Summary of Data.

IV. HYPOTHESIZED CAUSES OF OVERSPEED

From the above data and from discussions with the turbine vendor, Terry Turbine (Ken Wheeler); MPR Associates Inc. (Phil Hildebrandt, Bob Fink, and Tim Clarke); the following list of possible causes of overspeed was developed.

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

This hypothesis is judged to be a viable description of the cause of the observed AFPT overspeed trips. Terry Turbine indicates that the introduction of water slugs which flash through the nozzles may result in an overspeed condition.

The piping between the steam isolation valves (MS 106, 106A, 107, 107A) and the AFPTs is at a temperature near ambient conditions. When the isolation valves are opened, steam at about 500° to 550°F is introduced.

Steam will be condensed in these lines during initial steam introduction and line heating. Preliminary calculations indicate that several hundred pounds of water may be formed in these lines. This condensate is expected to form water slugs, parti-

cularly in the long, approximately horizontal crossover lines downstream of MS 106A or MS 107A.

It is noted that damage to pipe hanger supports on these lines has been experienced previously, apparently due to transient operational loads. Steam flow loads would not be expected to result in hanger damage. Water slug formation or water hammer may produce these loads. (Investigation of the pipe hanger support problem was in process prior to the 6/9/85 event.)

The design for the AFPTs is a single stage turbine configured similar to a bucket type "water wheel". This design is considered susceptible to increased speed excursions when water slugs are introduced. Analyses are currently being performed to confirm this hypothesis.

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

This mechanism may be a contributor to the overspeed trip on AFPT #1, however, it is not considered likely. Discussions with Terry Turbine, as well as another utility, indicate that if the turbine is rolling, and steam flow is stopped and restarted, the turbine may overspeed. This is because the speed setting bushing (the internal piece that controls the acceleration to rated speed) is ineffective due to the prior rotation of the turbine which has increased the governor oil pressure to its operating pressure. Since the governor oil pressure is established and controlling, loss or reduction in steam flow results in the governor valve opening in an attempt to increase steam flow. When full steam pressure and flow is reestablished, the governor valve is open further than necessary and cannot close quickly enough, resulting in an overspeed condition.

This sequence may have occurred for AFPT #1 as a result of initial roll of the turbine on steam from MS 106 followed by closure of MS 106 coincident with opening of MS 106A. However, examination of the trip event sequence suggests that steam flow would not have been interrupted during switchover from MS 106 to MS 106A as the steam source.

Although considered unlikely, this hypothesis will be tested.

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

This hypothesis, although viable, is judged unlikely to have caused an overspeed trip because discharge piping is assured to be full at all times thereby causing the pumps to operate at min-recirc conditions until the discharge valves are open.

It is noted that pump operation on min-recirc only may be a contributing factor to the overspeed because of the decreased pump load.

D. Governor problems (low oil level, improper settings, etc.), including governor valve and linkage

AFPT #1 has the previously used Woodward PG-PL governor which has experienced speed control oscillation problems, AFPT #2 has the new Woodward type PGG governor design which was installed during the 1984 refueling outage which has not indicated any oscillation problems.

Neither governor apparently could respond to prevent the cause of the turbine overspeed. However, it is not considered that failure or malfunction of the governors was the cause based on the following:

1. The speed vs. time characteristics for the trip indicate that the governors were controlling speed as designed during the initial turbine acceleration.

2. Post trip testing shows proper operation of both governors.

3. The governor on AFP #1 is a PG-PL model with external Bodine motor for remote speed setting, while the AFPT #2 has a new PGG model with an internal motor for remote speed setting. It is considered unlikely that both of these governors would fail at the same time in a manner capable of causing an overspeed trip on the turbines.

4. The governor valve was free to move during the trip as evidenced by the initial decrease in speed after both AFPTs began to roll.

Prior to installation, an engineering evaluation was performed on the PGG governor, which concluded that this governor should be functionally similar to the PG-PL governor. However, since we have limited experience with the PGG governor (installed during 1984 refueling outage), we plan to further evaluate whether problems with this governor could have contributed to the overspeed.

E. Loss of pump suction source, resulting in no pump load

This is not considered a viable hypothesis, since the control room alarm printer shows no evidence of low pump suction pressure prior to the overspeed. Also, the 1 psig pressure switch on the pump suctions did not close the steam supply valves. Further, there was no decrease in discharge pressure as would be expected if the suction pressure were lost.

DVW:CER:lrh

ATTACHMENT 1

Steam Supply Piping Layout to AFPTs

Figure 1 presents a schematic representation of the steam supply piping to the Auxiliary Feed Pump Turbines.

The piping configuration downstream of the 4 steam supply isolation valves are described in more detail below.

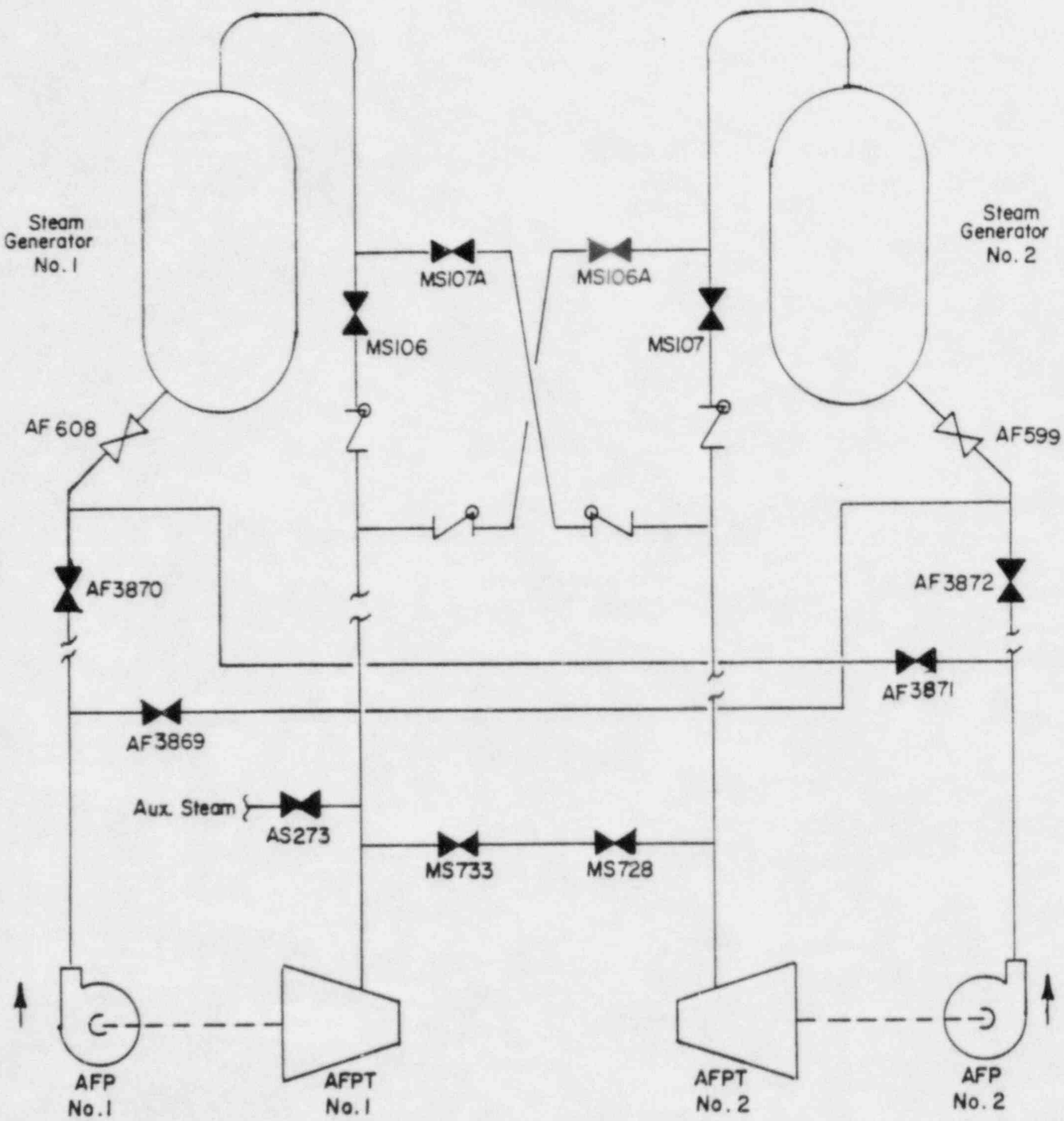
1. MS 106 (SG #1 feed to AFPT #1) - The pipe length of this run is approximately 360 feet. Immediately downstream of MS 106 is a downhill run. The length of the pipe run has several vertical drops interrupted by horizontal runs. Total vertical drop is from elevation 623' to elevation 565'. Any condensation is expected to become entrapped in the steam flow or be carried as small slugs.

2. MS 106A (SG #2 feed to AFPT #1) - The pipe length of this run is approximately 650 feet. Immediately downstream of MS 106A is a 290 foot length of essentially horizontal pipe. After the steam/water has traversed the initial length of pipe, it ties into the length of pipe described in item 1 above, which is immediately downstream of MS 106. The 280 foot length of horizontal pipe could allow large water slugs to form prior to entering the downhill run.

3. MS 107 (SG #2 feed to AFPT #2) - The pipe length of this run is approximately 125 feet. Immediately downstream of MS 107 is a downhill run. The total length of the pipe run has an almost continual downhill flow (i.e., very few long lengths of horizontal pipe) dropping from elevation 623' to elevation 565'. Any condensation is expected to become entrapped in the steam flow or be carried as small slugs.

4. MS 107A (SG #1 feed to AFPT #2) - The pipe length of this run is approximately 375 feet. Immediately downstream of MS 107A is a 250 foot length of essentially horizontal pipe except for a 7 foot rise near the end of the run. After the rise is a short horizontal run and then the steam supply line has a 14 foot drop and is tied to the steam supply pipe described in item 3 above, immediately downstream of MS 107. The rise, after a long horizontal run, will enable water slugs to form at the bottom of the rise and be carried downstream after filling the pipe.

Figure 1



SCHEMATIC REPRESENTATION OF
AUXILIARY FEED PUMP TURBINE STEAM PIPING SYSTEM

ATTACHMENT 2

AUX FEED PUMP 1-1 SPEED DATA
JUNE 9, 1985 - TRIP

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	01:41:06	37.9
2	01:41:07	435.9
3	01:41:08	807.1
4	01:41:09	948.7
5	01:41:10	1415.1
6	01:41:11	1793.7
7	01:41:12	2240.5
8	01:41:13	2472.5
9	01:41:14	1703.3
10	01:41:15	NO DATA
11	01:41:16	1793.7
12	01:41:17	2675.2
13	01:41:18	3290.6
14	01:41:19	2211.2
15	01:41:20	3471.3
16	01:41:21	2404.2
17	01:41:22	3801.0
18	01:41:23	4352.9
19	01:41:24	4616.6
20	01:41:25	3315.0
21	01:41:26	1915.8
22	01:41:27	1322.3
23	01:41:28	1024.4

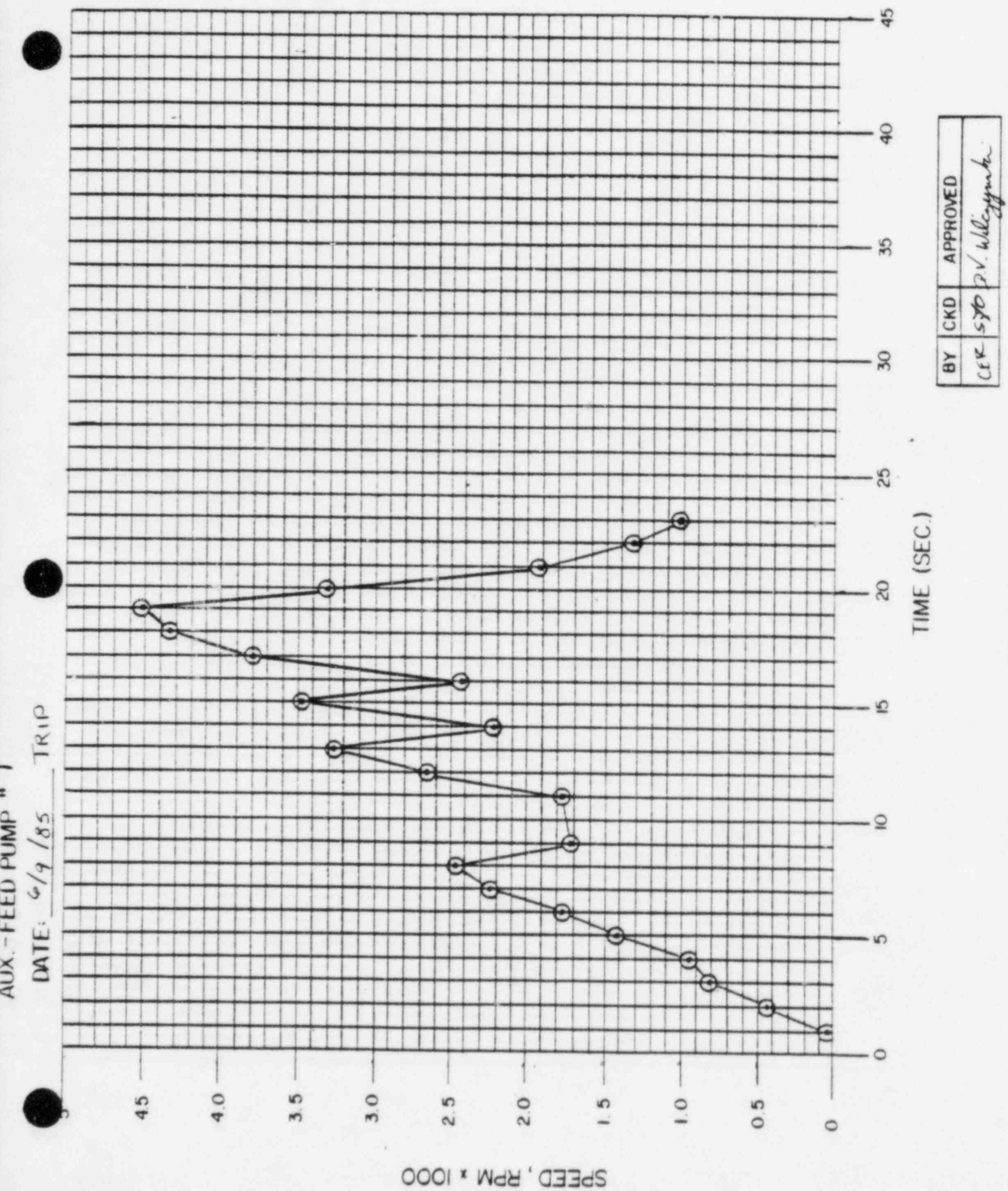

AUX.-FEED PUMP # 1
DATE: 6/9/85 TRIP
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
BY
CKD
APPROVED
CEK
SYO

Figure 2

AUX FEED PUMP 1-2 SPEED DATA
JUNE 9, 1985 - TRIP

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	01:41:11	35.4
2	01:41:12	565.3
3	01:41:13	570.2
4	01:41:14	1500.6
5	01:41:15	NO DATA
6	01:41:16	2399.3
7	01:41:17	1766.8
8	01:41:18	1923.1
9	01:41:19	2152.6
10	01:41:20	2355.3
11	01:41:21	2389.5
12	01:41:22	2391.9
13	01:41:23	2438.3
14	01:41:24	2460.3
15	01:41:25	2396.8
16	01:41:26	2379.7
17	01:41:27	2428.6
18	01:41:28	2433.5
19	01:41:29	2987.8
20	01:41:30	4118.4
21	01:41:31	4362.6
22	01:41:32	4172.2
23	01:41:33	4162.4
24	01:41:34	4418.8
25	01:41:35	4540.9
26	01:41:36	4655.7
27	01:41:37	4748.5
28	01:41:38	3820.5
29	01:41:39	2120.9
30	01:41:40	1476.2
31	01:41:41	1175.8

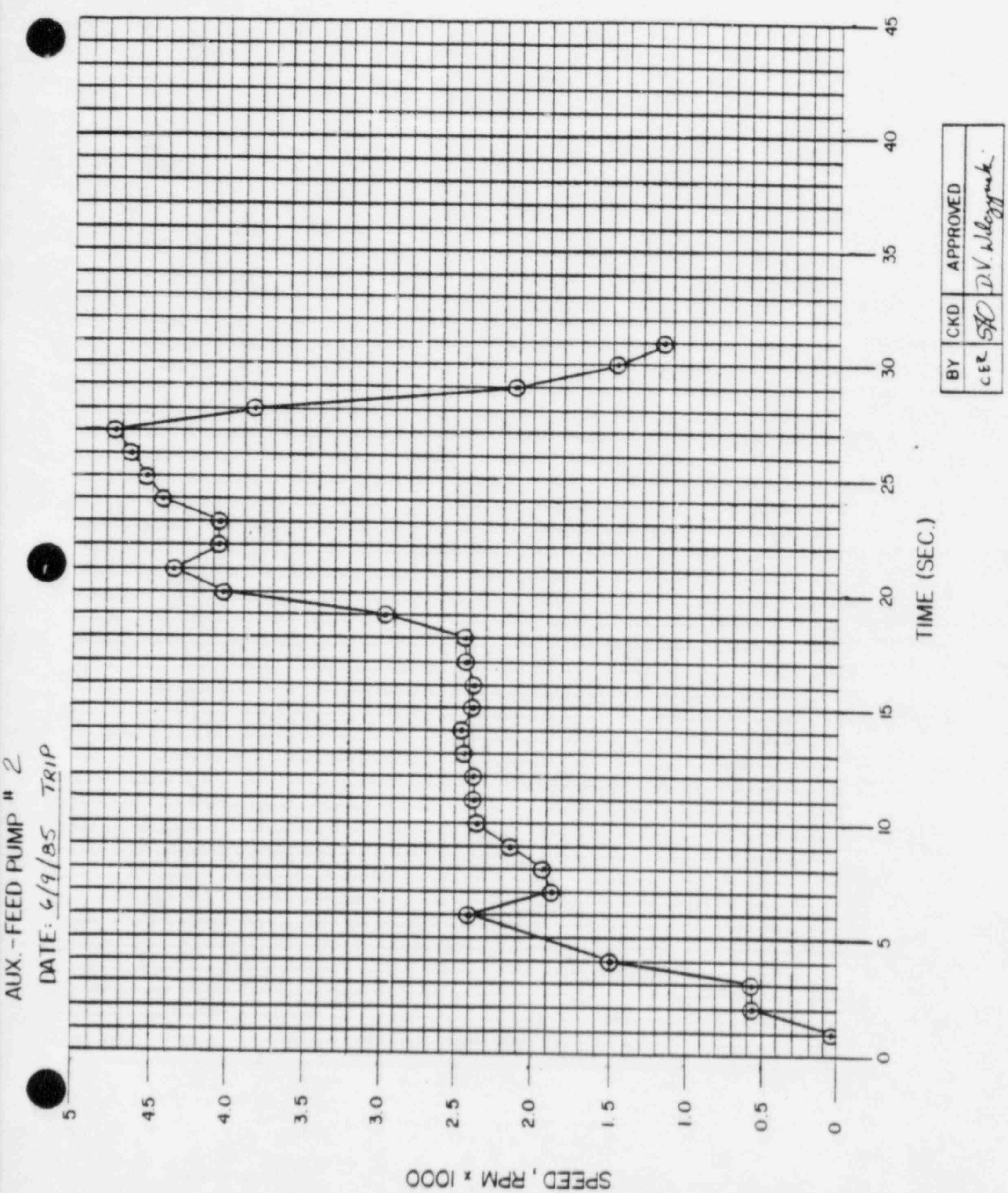

AUX.-FEED PUMP # 2
DATE: 6/9/85 TRIP
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
BY
CKD
APPROVED
CER
SAO
D.V. Wilczynski

Figure 3

AUX FEED PUMP 1-1 SPEED DATA
MARCH 2, 1984

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	12:37:39	18.3
2	12:37:40	40.3
3	12:37:41	330.9
4	12:37:42	1605.6
5	12:37:43	1310.1
6	12:37:44	NO DATA
7	12:37:45	NO DATA
8	12:37:46	787.5
9	12:37:47	768.0
10	12:37:48	1070.8
11	12:37:49	NO DATA
12	12:37:50	1549.4
13	12:37:51	1483.5
14	12:37:52	1459.1
15	12:37:53	1415.1
16	12:37:54	1400.5
17	12:37:55	1383.4
18	12:37:56	1381.0
19	12:37:57	1371.2
20	12:37:58	1373.6
21	12:37:59	1363.9
22	12:38:00	1359.0
23	12:38:01	NO DATA
24	12:38:02	NO DATA
25	12:38:03	2057.4
26	12:38:04	2318.7
27	12:38:05	2372.4
28	12:38:06	NO DATA
29	12:38:07	2636.1
30	12:38:08	2782.7
31	12:38:09	2929.2
32	12:38:10	NO DATA
33	12:38:11	3229.5
34	12:38:12	NO DATA
35	12:38:13	NO DATA
36	12:38:14	NO DATA
37	12:38:15	3612.9
38	12:38:16	3483.5
39	12:38:17	NO DATA
40	12:38:18	NO DATA
41	12:38:19	NO DATA
42	12:38:20	3564.1
43	12:38:21	3615.4
44	12:38:22	3649.6
45	12:38:23	3664.2

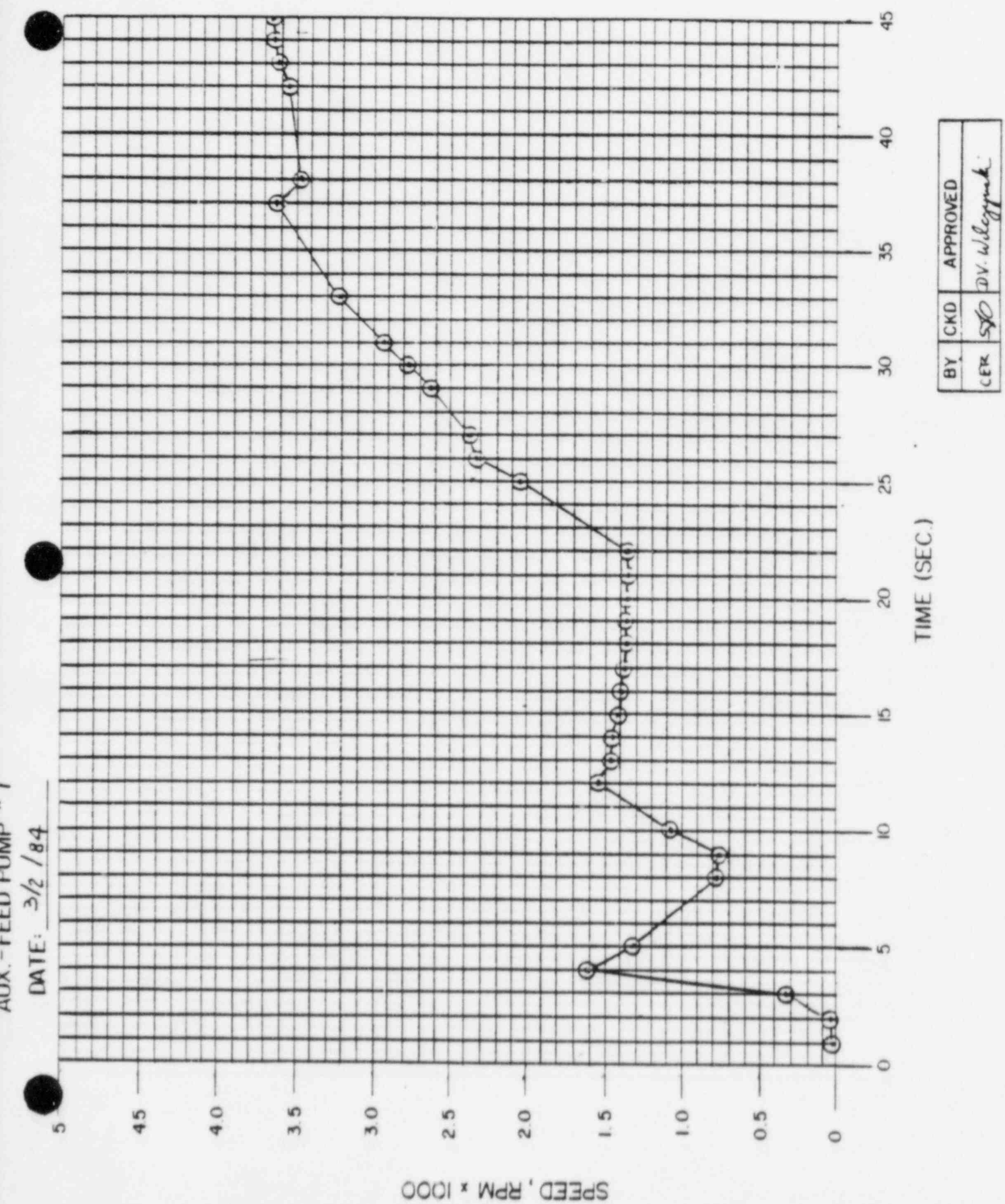

AUX.-FEED PUMP
DATE: 3/2/84
SPEED, RPM x 1000
5
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
BY
CKD
APPROVED
CER

Figure 4

AUX FEED PUMP 1-2 SPEED DATA
MARCH 2, 1984

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	12:37:39	23.2
2	12:37:40	25.6
3	12:37:41	155.1
4	12:37:42	431.0
5	12:37:43	1935.3
6	12:37:44	NO DATA
7	12:37:45	NO DATA
8	12:37:46	1363.9
9	12:37:47	1666.7
10	12:37:48	1947.5
11	12:37:49	NO DATA
12	12:37:50	2267.4
13	12:37:51	2443.2
14	12:37:52	2489.6
15	12:37:53	2584.9
16	12:37:54	2731.4
17	12:37:55	2853.5
18	12:37:56	2948.7
19	12:37:57	3041.5
20	12:37:58	3078.1
21	12:37:59	3207.6
22	12:38:00	3256.4
23	12:38:01	NO DATA
24	12:38:02	NO DATA
25	12:38:03	3334.6
26	12:38:04	3385.8
27	12:38:05	3407.8
28	12:38:06	NO DATA
29	12:38:07	3451.8
30	12:38:08	3424.9
31	12:38:09	3488.4
32	12:38:10	NO DATA
33	12:38:11	2304.0
34	12:38:12	NO DATA
35	12:38:13	NO DATA
36	12:38:14	NO DATA
37	12:38:15	3105.0
38	12:38:16	3078.1
39	12:38:17	NO DATA
40	12:38:18	NO DATA
41	12:38:19	NO DATA
42	12:38:20	3327.2
43	12:38:21	3368.7
44	12:38:22	3412.7
45	12:38:23	3495.7

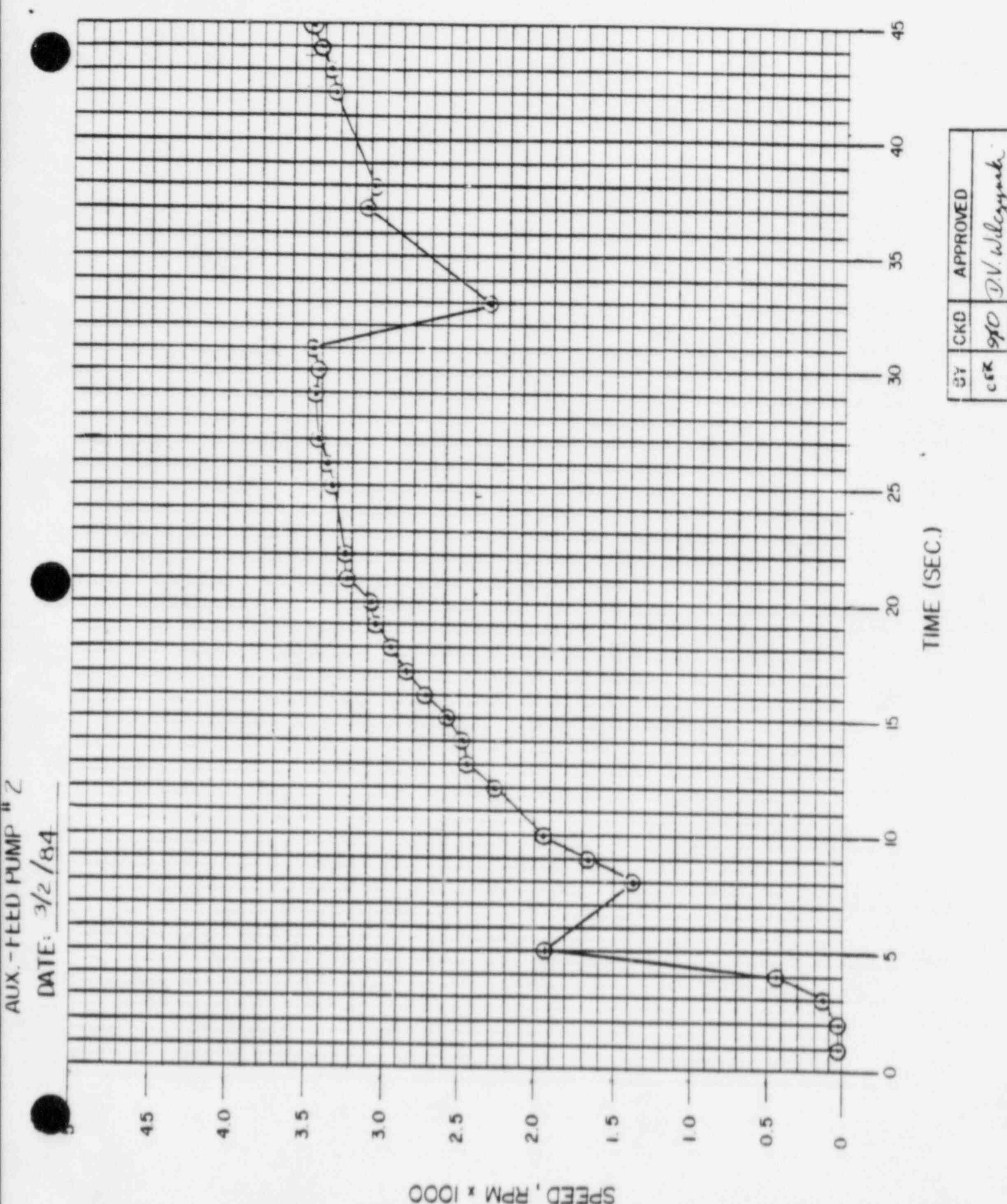

AUX.-FEED PUMP # 2
DATE: 3/2/84
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
BY
CKD
APPROVED

Figure 5

AUX FEED PUMP 1-1 SPEED DATA
JANUARY 15, 1985

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	12:28:35	20.8
2	12:28:36	494.5
3	12:28:37	777.8
4	12:28:38	1210.0
5	12:28:39	NO DATA
6	12:28:40	NO DATA
7	12:28:41	2243.0
8	12:28:42	1681.3
9	12:28:43	1373.6
10	12:28:44	1783.9
11	12:28:45	NO DATA
12	12:28:46	1915.8
13	12:28:47	3205.1
14	12:28:48	NO DATA
15	12:28:49	NO DATA
16	12:28:50	2785.1
17	12:28:51	2770.5
18	12:28:52	3407.8
19	12:28:53	NO DATA
20	12:28:54	3505.5
21	12:28:55	3527.5
22	12:28:56	3437.1
23	12:28:57	3498.2
24	12:28:58	3446.9
25	12:28:59	3615.4
26	12:29:00	NO DATA
27	12:29:01	3649.6
28	12:29:02	3595.8
29	12:29:03	3603.2
30	12:29:04	3615.4
31	12:29:05	3688.6
32	12:29:06	3813.2
33	12:29:07	3842.5

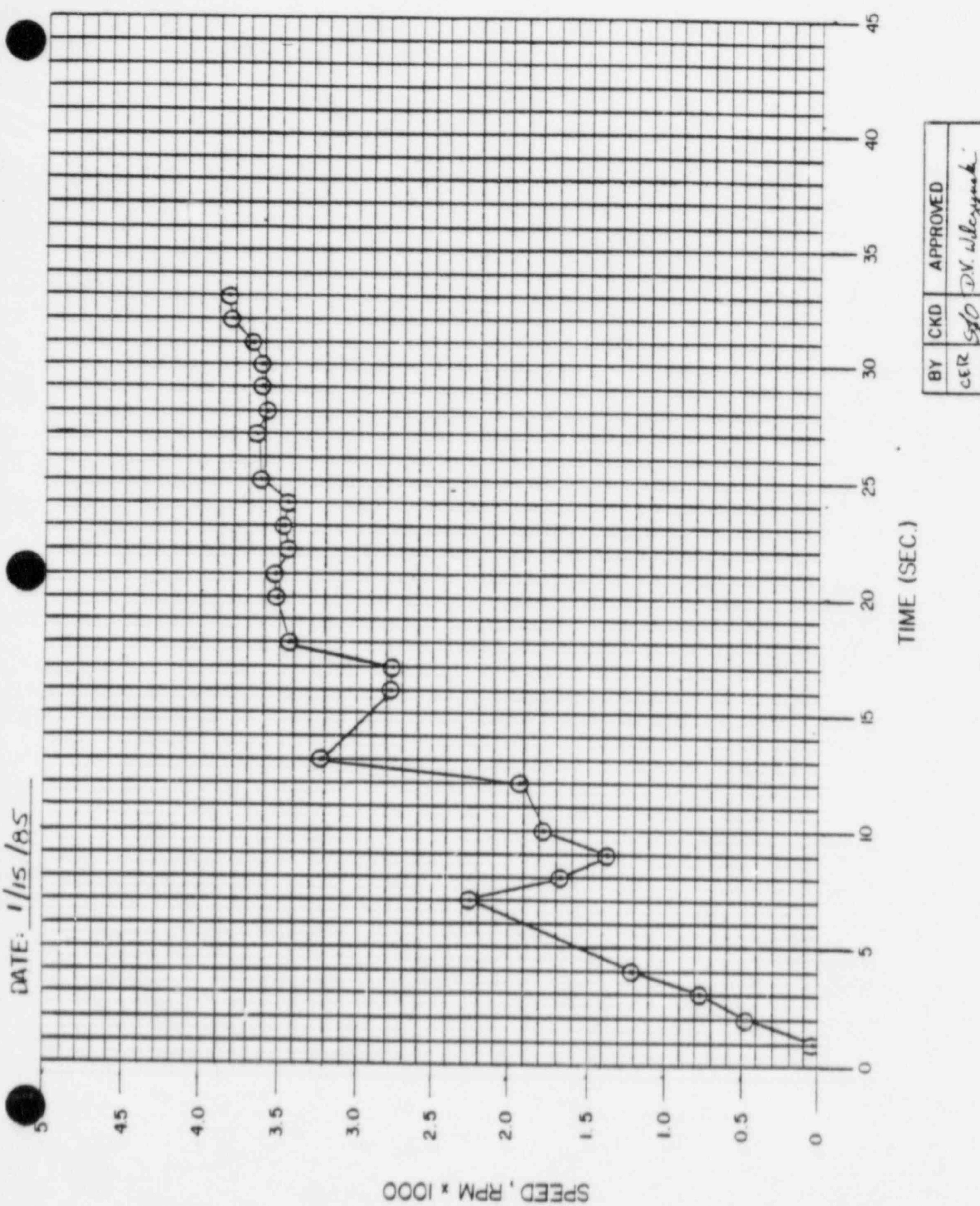
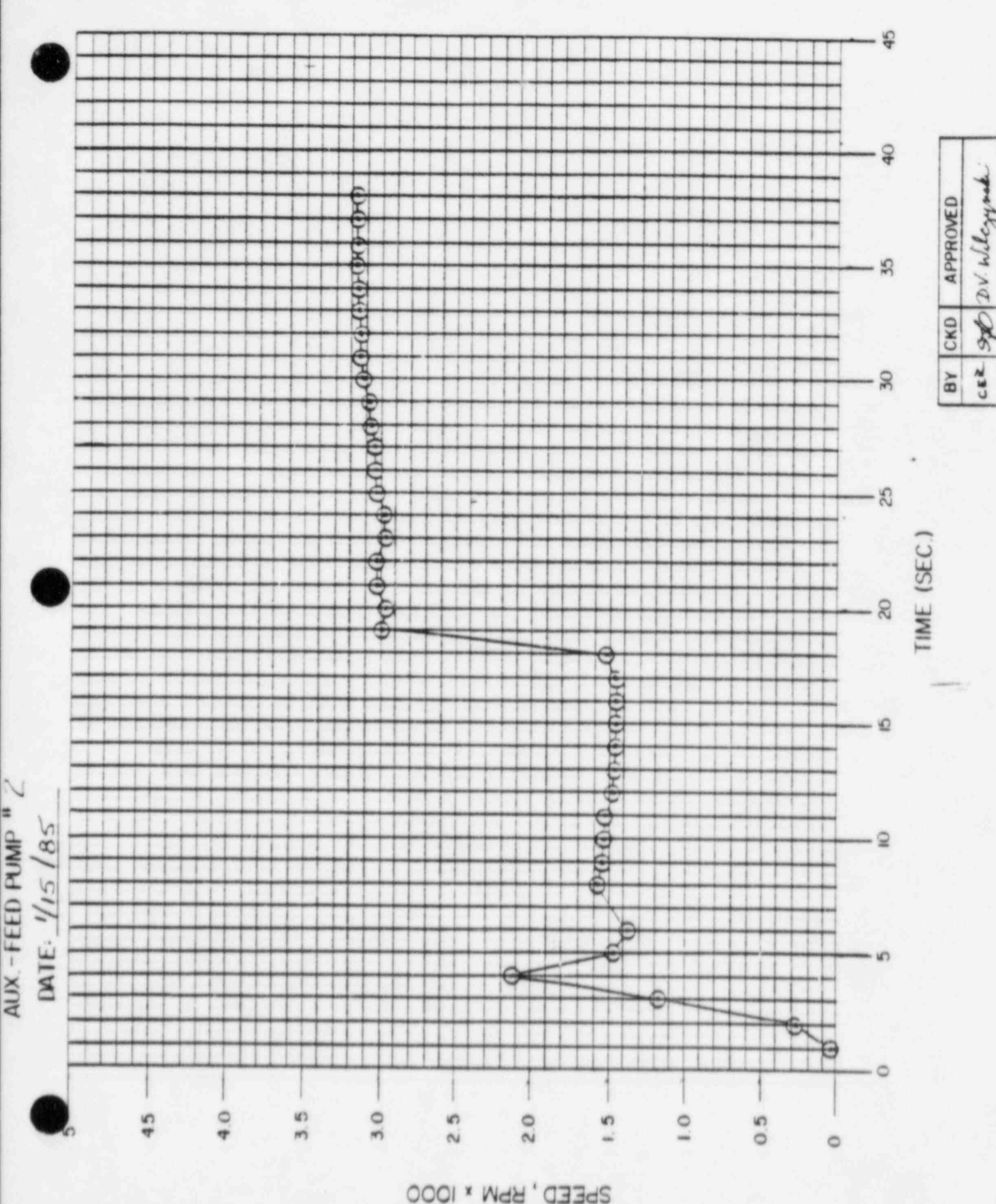

AUX.-FEED PUMP # 1
DATE: 1/15/85
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
BY
CKD
APPROVED
CER

Figure 6

AUX FEED PUMP 1-2 SPEED DATA
JANUARY 15, 1985

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	12:28:54	35.4
2	12:28:55	282.1
3	12:28:56	1197.8
4	12:28:57	2118.4
5	12:28:58	1473.7
6	12:28:59	1390.7
7	12:29:00	NO DATA
8	12:29:01	1593.4
9	12:29:02	1549.4
10	12:29:03	1527.3
11	12:29:04	1515.3
12	12:29:05	1490.8
13	12:29:06	1476.2
14	12:29:07	1466.4
15	12:29:08	1468.9
16	12:29:09	1468.9
17	12:29:10	1471.3
18	12:29:11	1517.7
19	12:29:12	3002.4
20	12:29:13	2992.7
21	12:29:14	3031.7
22	12:29:15	3024.4
23	12:29:16	2982.9
24	12:29:17	2997.6
25	12:29:18	3024.4
26	12:29:19	3026.9
27	12:29:20	3056.2
28	12:29:21	3085.5
29	12:29:22	3097.7
30	12:29:23	3109.9
31	12:29:24	3127.0
32	12:29:25	3139.2
33	12:29:26	3146.5
34	12:29:27	3158.7
35	12:29:28	3161.2
36	12:29:29	3175.8
37	12:29:30	3175.8
38	12:29:31	3180.7



AUX.-FEED PUMP # 2
DATE: 1/15/85
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
BY
CKD
APPROVED
CEZ

Figure 7

AUX FEED PUMP 1-1 SPEED DATA
MARCH 21, 1985

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	19:54:16	25.6
2	19:54:17	106.2
3	19:54:18	230.8
4	19:54:19	550.7
5	19:54:20	826.6
6	19:54:21	1207.6
7	19:54:22	1708.2
8	19:54:23	2733.8
9	19:54:24	2225.9
10	19:54:25	NO DATA
11	19:54:26	2321.1
12	19:54:27	2819.3
13	19:54:28	1979.2
14	19:54:29	3241.8
15	19:54:30	2328.4
16	19:54:31	3312.6
17	19:54:32	2536.0
18	19:54:33	3134.3
19	19:54:34	3222.2
20	19:54:35	3261.3
21	19:54:36	3319.9
22	19:54:37	3363.9
23	19:54:38	3381.0
24	19:54:39	3444.4
25	19:54:40	3490.8
26	19:54:41	3505.5
27	19:54:42	3520.1
28	19:54:43	3561.7
29	19:54:44	3495.7
30	19:54:45	3534.8
31	19:54:46	3527.5
32	19:54:47	3571.4
33	19:54:48	3556.8
34	19:54:49	NO DATA
35	19:54:50	3573.9
36	19:54:51	NO DATA
37	19:54:52	NO DATA
38	19:54:53	3547.0
39	19:54:54	3571.4
40	19:54:55	NO DATA
41	19:54:56	3551.9
42	19:54:57	3547.0
43	19:54:58	3561.7
44	19:54:59	3591.0
45	19:55:00	3571.4

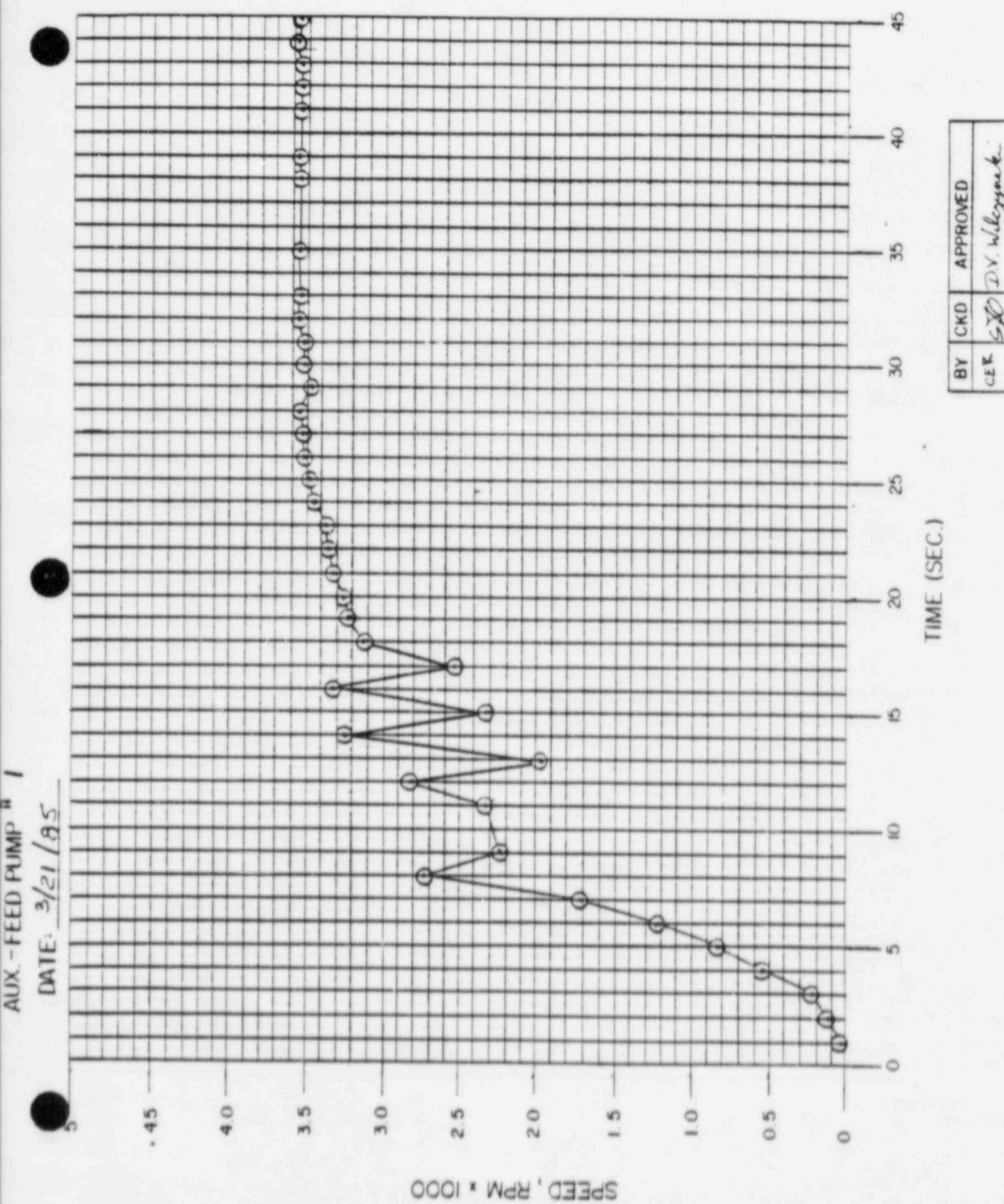

AUX.-FEED PUMP # 1
DATE: 3/21/85
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
.45
5
BY
CKD
APPROVED
CER

Figure 8

AUX FEED PUMP 1-2 SPEED DATA
MARCH 21, 1985

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	19:54:15	28.1
2	19:54:16	616.6
3	19:54:17	1669.1
4	19:54:18	1520.1
5	19:54:19	1188.0
6	19:54:20	1422.5
7	19:54:21	1537.2
8	19:54:22	1466.4
9	19:54:23	1498.2
10	19:54:24	1520.1
11	19:54:25	NO DATA
12	19:54:26	1561.7
13	19:54:27	1564.1
14	19:54:28	1547.0
15	19:54:29	1566.5
16	19:54:30	1564.1
17	19:54:31	1608.1
18	19:54:32	1686.2
19	19:54:33	1776.6
20	19:54:34	1803.4
21	19:54:35	1874.2
22	19:54:36	1925.2
23	19:54:37	2035.4
24	19:54:38	2147.7
25	19:54:39	2216.1
26	19:54:40	2255.2
27	19:54:41	2272.3
28	19:54:42	2301.6
29	19:54:43	2438.3
30	19:54:44	2614.2
31	19:54:45	2421.2
32	19:54:46	2614.2
33	19:54:47	2604.4
34	19:54:48	2602.0
35	19:54:49	NO DATA
36	19:54:50	2235.7
37	19:54:51	NO DATA
38	19:54:52	NO DATA
39	19:54:53	1825.4
40	19:54:54	1803.4
41	19:54:55	NO DATA
42	19:54:56	3537.2
43	19:54:57	3647.1

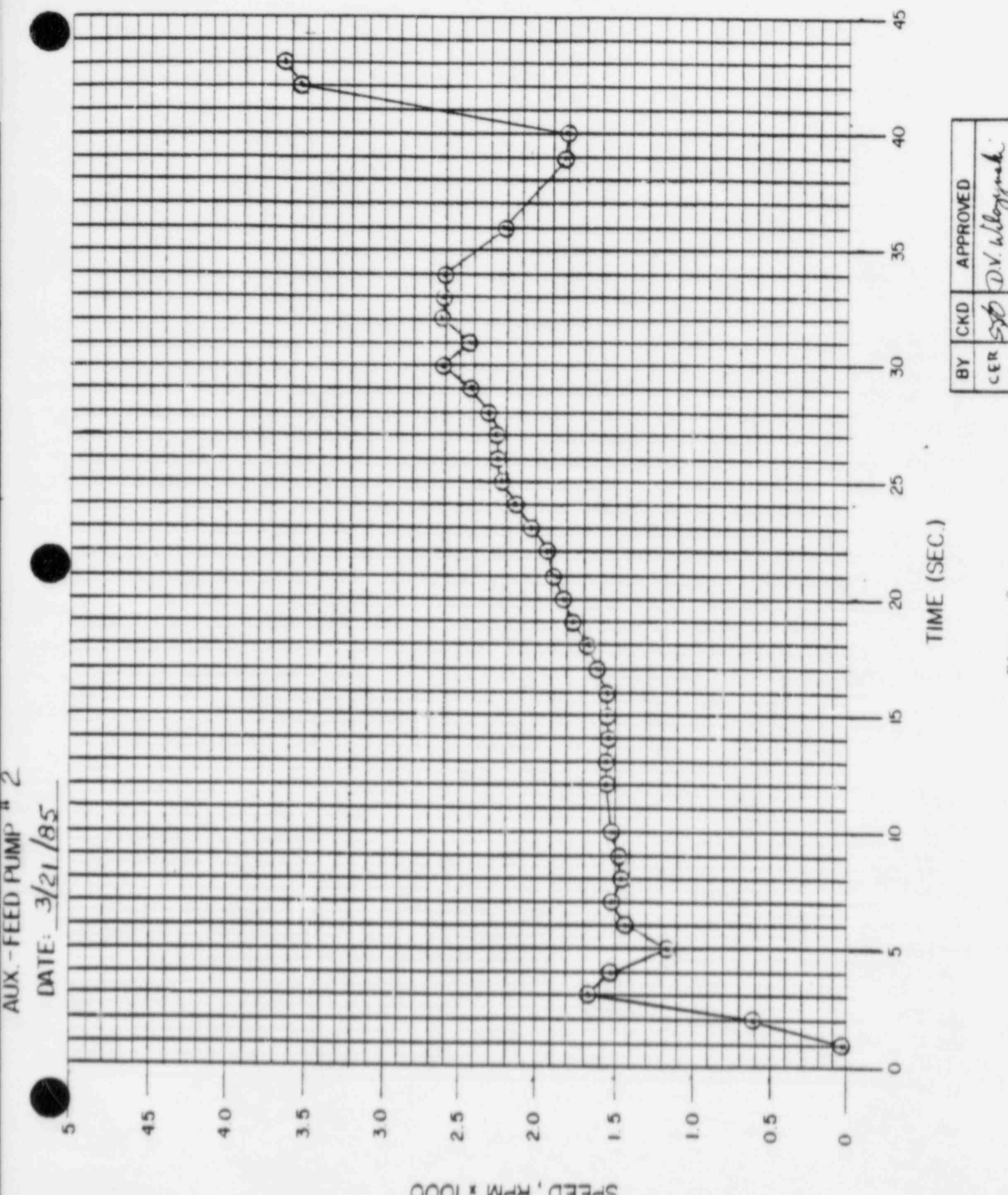

AUX.-FEED PUMP # 2
DATE: 3/21/85
TIME (SEC.)
SPEED, RPM x 1000
0
5
10
15
20
25
30
35
40
45
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
BY
CKD
APPROVED
CER

Figure 9

AUX FEED PUMP 1-2 SPEED DATA
APRIL 12, 1985 - FIRST RUN

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	04:09:13	23.2
2	04:09:14	30.5
3	04:09:15	74.5
4	04:09:16	716.7
5	04:09:17	1962.1
6	04:09:18	1744.8
7	04:09:19	1998.8
8	04:09:20	2123.3
9	04:09:21	2172.2
10	04:09:22	2203.9
11	04:09:23	2457.9
12	04:09:24	2648.4
13	04:09:25	2792.4
14	04:09:26	3503.1
15	04:09:27	3678.9
16	04:09:28	3698.4
17	04:09:29	3722.8
18	04:09:30	3698.4
19	04:09:31	3710.6
20	04:09:32	3759.5
21	04:09:33	3801.0

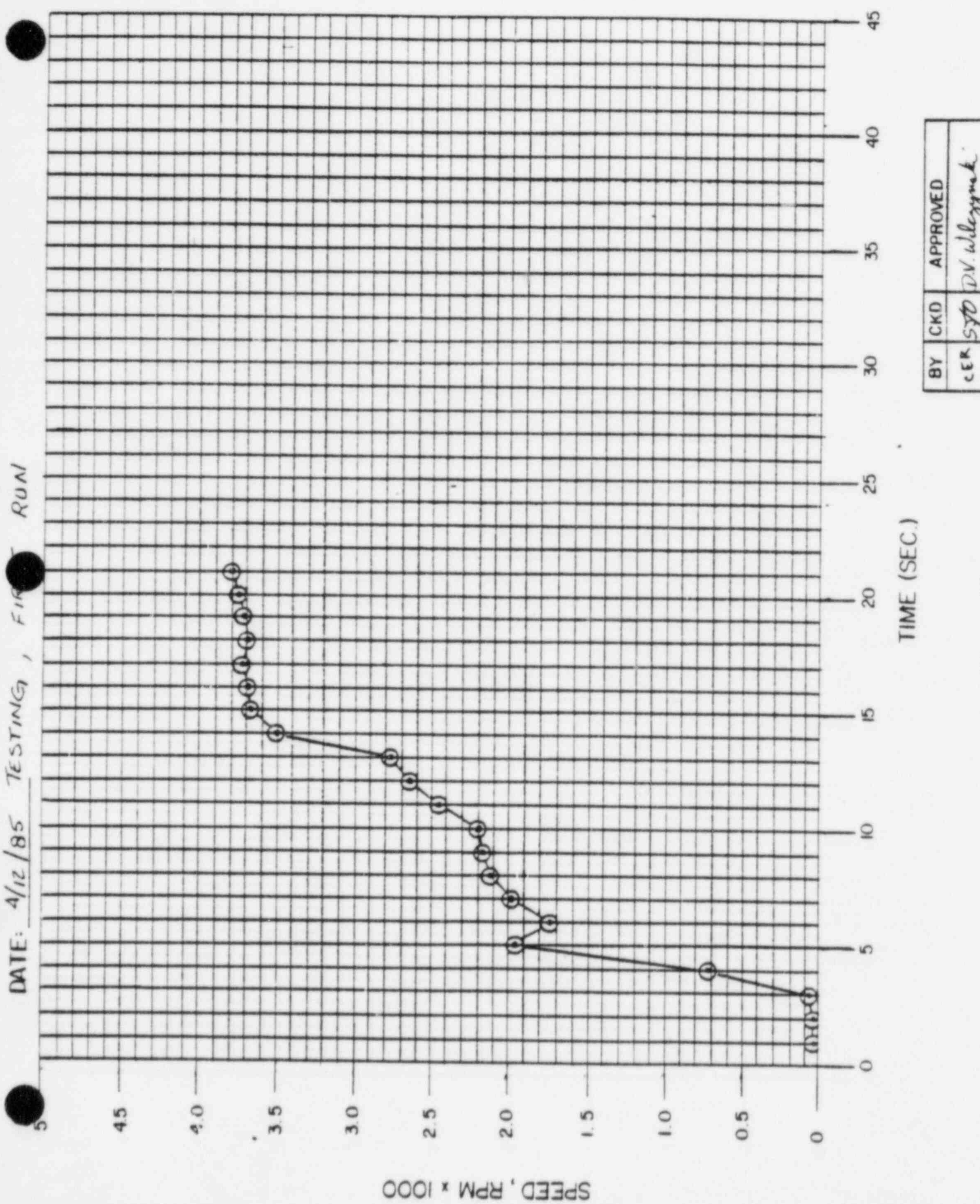
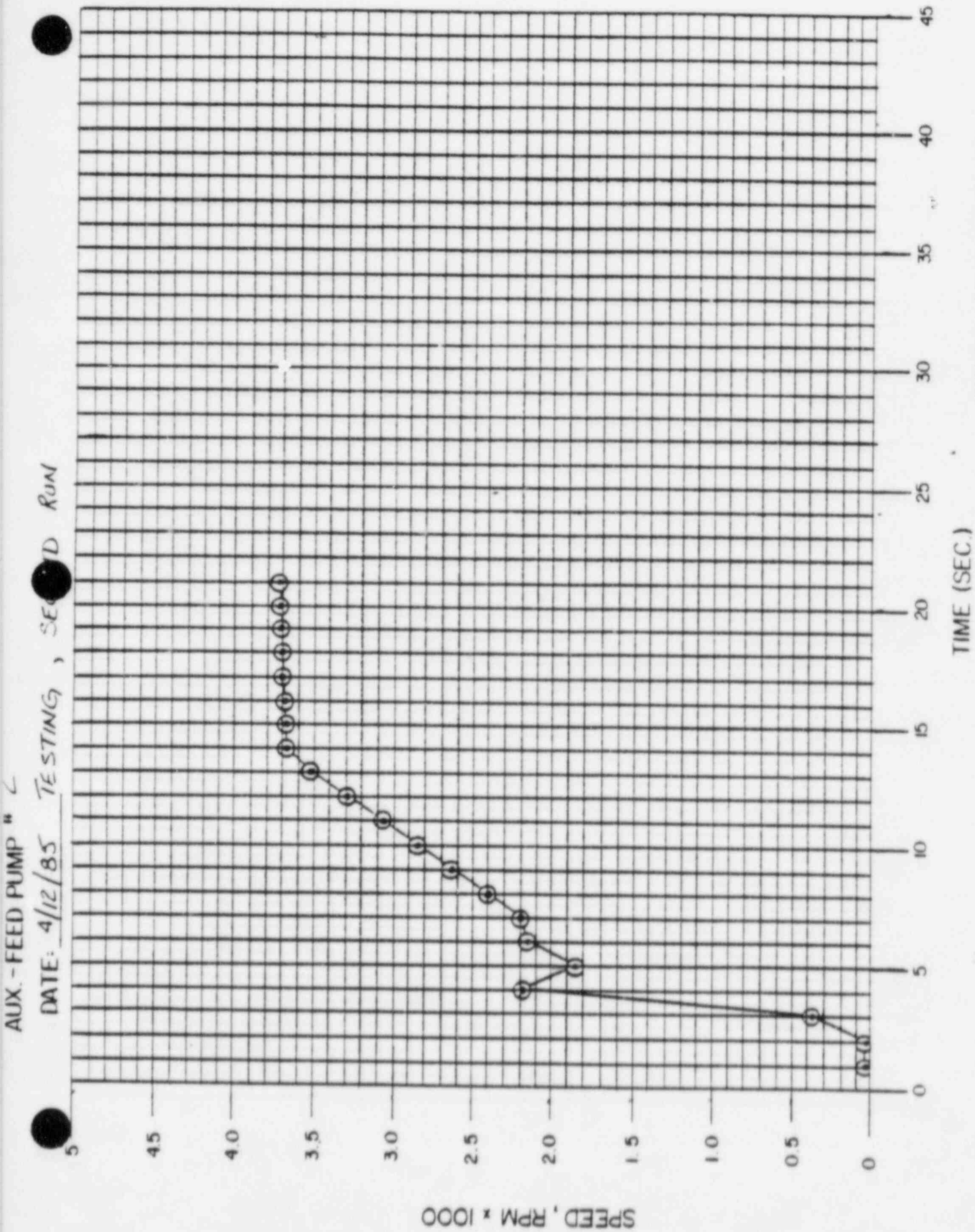

AUX.-FEED PUMP # 2
DATE: 4/12/85 TESTING, FIRST RUN
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
BY
CKD
APPROVED
CER
STO
D.V. Wileczynk

Figure 10

AUX FEED PUMP 1-2 SPEED DATA
APRIL 12, 1985 - SECOND RUN

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	04:17:06	23.2
2	04:17:07	25.6
3	04:17:08	387.1
4	04:17:09	2199.0
5	04:17:10	1847.4
6	04:17:11	2145.3
7	04:17:12	2201.5
8	04:17:13	2404.2
9	04:17:14	2633.7
10	04:17:15	2855.9
11	04:17:16	3075.7
12	04:17:17	3302.8
13	04:17:18	3525.0
14	04:17:19	3678.9
15	04:17:20	3676.4
16	04:17:21	3691.1
17	04:17:22	3703.3
18	04:17:23	3710.6
19	04:17:24	3715.5
20	04:17:25	3717.9
21	04:17:26	3722.8



BY	CKD	APPROVED
CER	SJO	D.V. Wileczynk

Figure 11

AUX FEED PUMP 1-1 SPEED DATA
JUNE 2, 1985

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	06:05:36	45.2
2	06:05:37	125.8
3	06:05:38	707.0
4	06:05:39	1053.7
5	06:05:40	1637.4
6	06:05:41	2470.1
7	06:05:42	1837.6
8	06:05:43	1427.3
9	06:05:44	1246.6
10	06:05:45	2692.3
11	06:05:46	2155.1
12	06:05:47	1769.2
13	06:05:48	2846.2
14	06:05:49	2074.5
15	06:05:50	3041.5
16	06:05:51	2936.5
17	06:05:52	3080.6
18	06:05:53	3095.2
19	06:05:54	3185.6
20	06:05:55	3241.8
21	06:05:56	3319.9
22	06:05:57	3327.2
23	06:05:58	3361.4
24	06:05:59	3366.3
25	06:06:00	3395.6
26	06:06:01	3361.4
27	06:06:02	3385.8
28	06:06:03	3381.0
29	06:06:04	3407.8
30	06:06:05	3395.6
31	06:06:06	3400.5
32	06:06:07	3390.7
33	06:06:08	3468.9

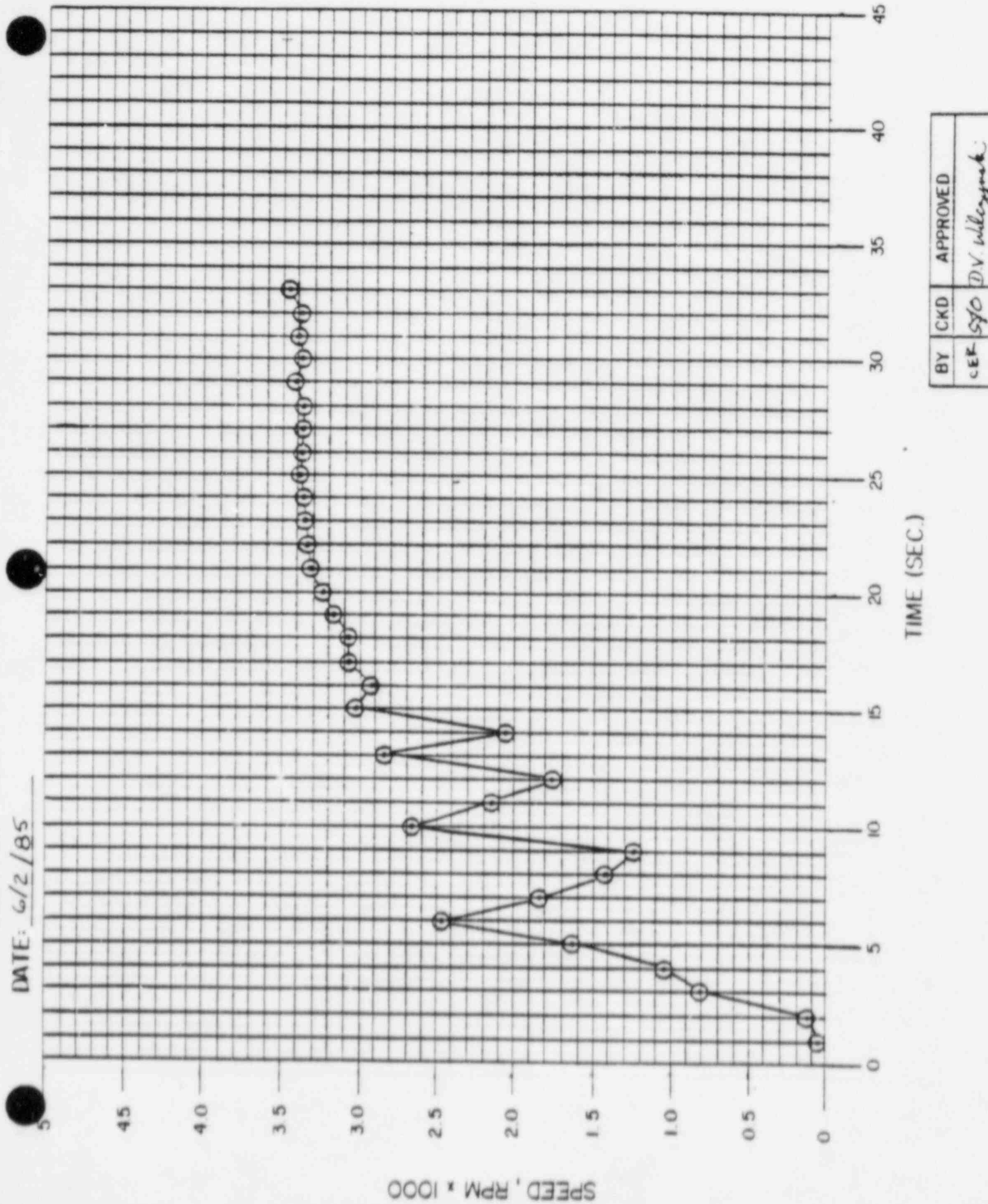

AUX.-FEED PUMP # 1
DATE: 6/2/85
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
45
5
BY
CKD
APPROVED

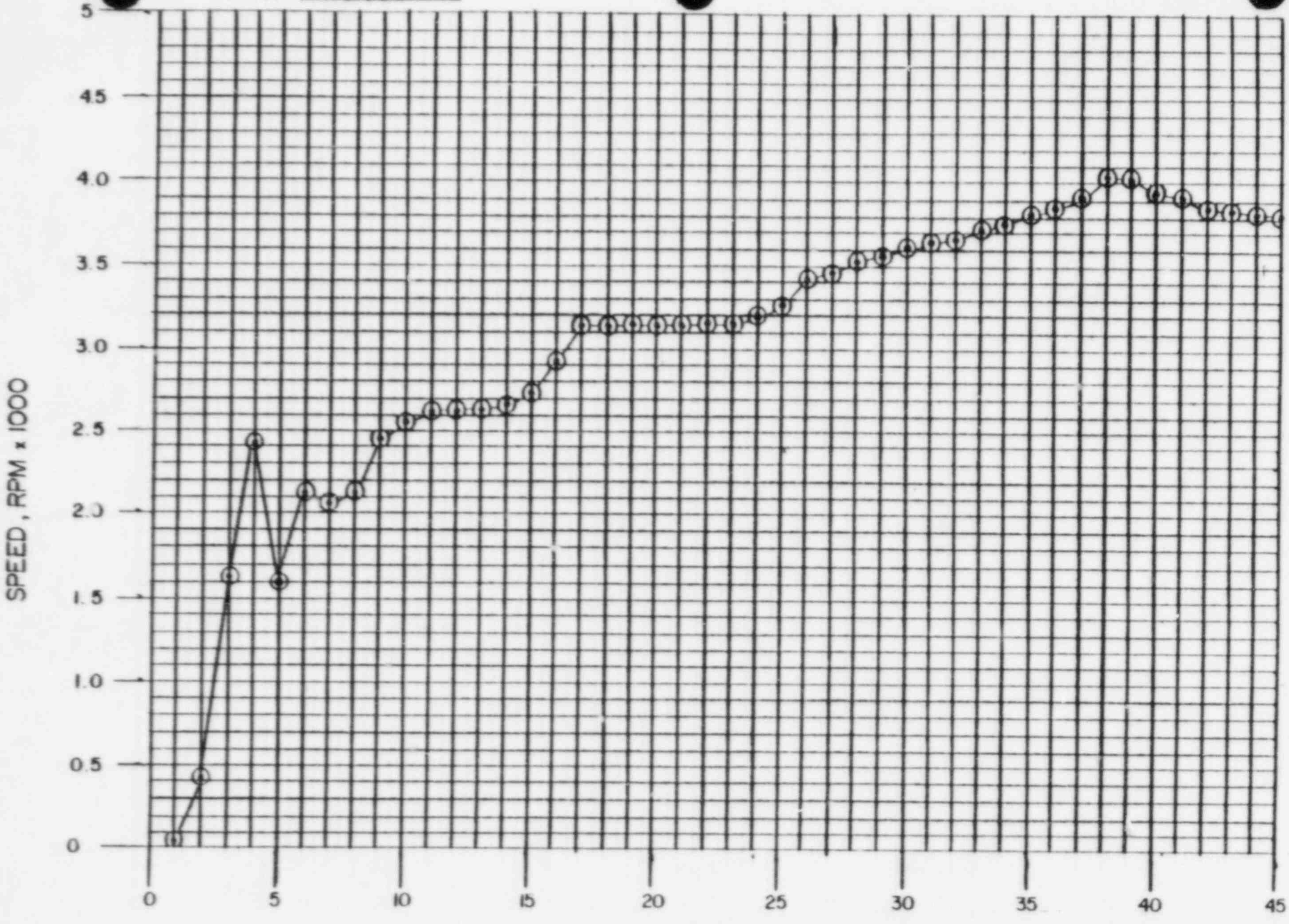
Figure 12

AUXFEED PUMP 1-2 SPEED DATA
JUNE 2, 1985

DATA POINT	TIME	AFP 1-2 SPEED (3018)
1	06:05:21	40.3
2	06:05:22	406.6
3	06:05:23	1627.6
4	06:05:24	2418.8
5	06:05:25	1600.7
6	06:05:26	2113.6
7	06:05:27	2076.9
8	06:05:28	2123.3
9	06:05:29	2460.3
10	06:05:30	2575.1
11	06:05:31	2619.0
12	06:05:32	2629.8
13	06:05:33	2641.0
14	06:05:34	2687.4
15	06:05:35	2741.1
16	06:05:36	2926.7
17	06:05:37	3144.1
18	06:05:38	3144.1
19	06:05:39	3149.0
20	06:05:40	3146.5
21	06:05:41	3149.0
22	06:05:42	3158.7
23	06:05:43	3170.9
24	06:05:44	3200.2
25	06:05:45	3283.3
26	06:05:46	3412.7
27	06:05:47	3488.4
28	06:05:48	3525.0
29	06:05:49	3576.3
30	06:05:50	3610.5
31	06:05:51	3654.5
32	06:05:52	3688.6
33	06:05:53	3727.7
34	06:05:54	3781.4
35	06:05:55	3827.8
36	06:05:56	3866.9
37	06:05:57	3920.6
38	06:05:58	4033.0
39	06:05:59	4023.2
40	06:06:00	3952.4
41	06:06:01	3910.9
42	06:06:02	3879.1
43	06:06:03	3852.3
44	06:06:04	3830.3
45	06:06:05	3808.3

AUX.-FEED PUMP # 2

DATE: 6/2/85



BY	CKD	APPROVED
CER	STO	D.V. Wilczynski

Figure 13

AUX FEED PUMP 1-1 SPEED DATA
JUNE 9, 1985 - TESTING

DATA POINT	TIME	AFP 1-1 SPEED (S008)
1	13:49:43	42.7
2	13:49:44	NO DATA
3	13:49:45	623.9
4	13:49:46	1007.3
5	13:49:47	1942.6
6	13:49:48	1876.7
7	13:49:49	NO DATA
8	13:49:50	1412.7
9	13:49:51	1854.7
10	13:49:52	2238.1
11	13:49:53	2362.6
12	13:49:54	2467.6
13	13:49:55	2638.6
14	13:49:56	2728.9
15	13:49:57	2821.7
16	13:49:58	2970.7
17	13:49:59	3107.4
18	13:50:00	NO DATA
19	13:50:01	3300.4
20	13:50:02	NO DATA
21	13:50:03	NO DATA
22	13:50:04	NO DATA
23	13:50:05	NO DATA
24	13:50:06	3586.1
25	13:50:07	NO DATA
26	13:50:08	NO DATA
27	13:50:09	3595.8
28	13:50:10	3573.9
29	13:50:11	3583.6
30	13:50:12	3598.3
31	13:50:13	3576.3
32	13:50:14	3605.6
33	13:50:15	3622.7
34	13:50:16	3622.7
35	13:50:17	NO DATA
36	13:50:18	NO DATA
37	13:50:19	NO DATA
38	13:50:20	3622.7
39	13:50:21	NO DATA
40	13:50:22	3639.8
41	13:50:23	3639.8
42	13:50:24	3637.4
43	13:50:25	3632.5

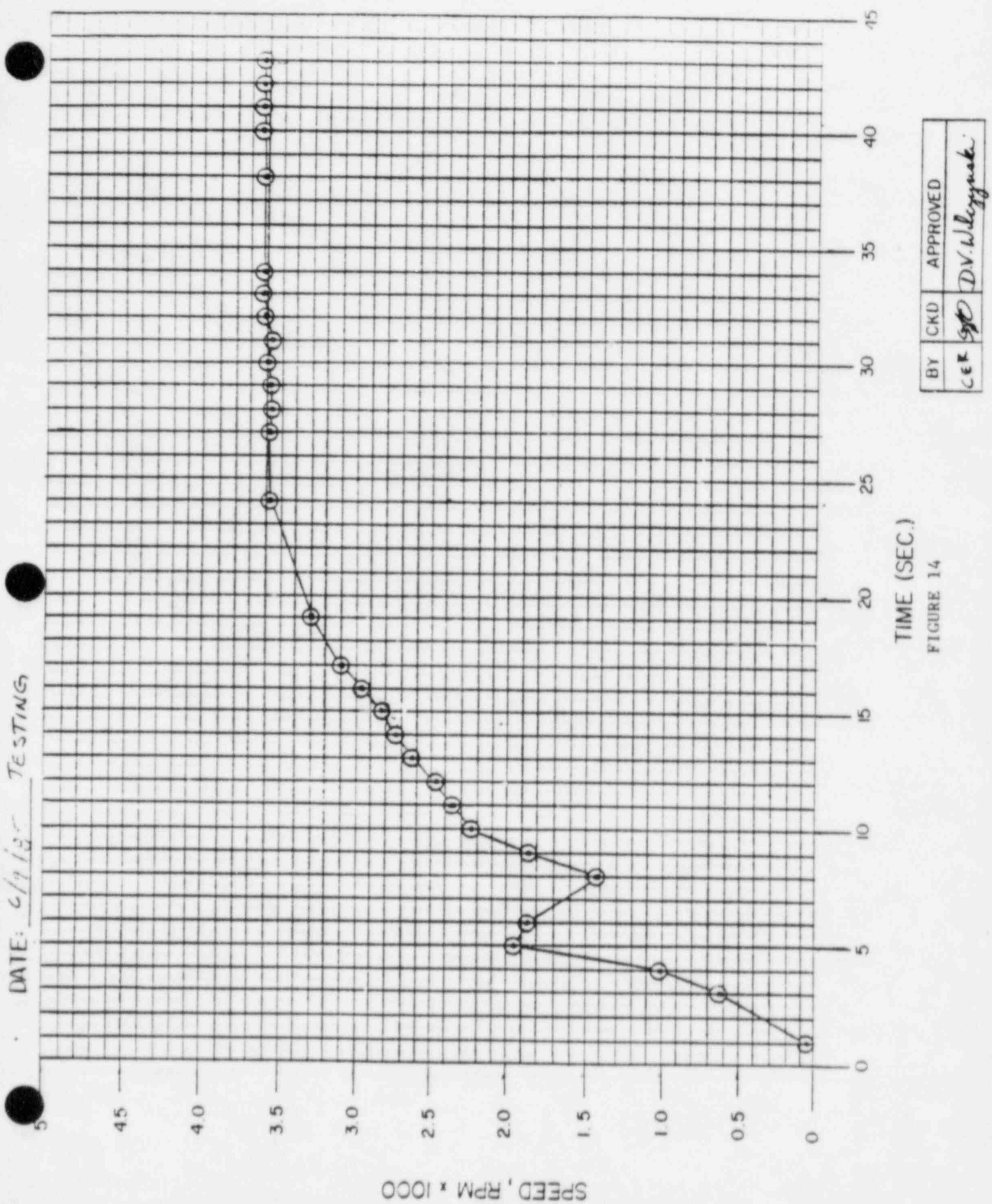

AUX. FEED PUMP # 1
DATE:
TESTING
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
BY
CKD
APPROVED
CER

FIGURE 14

AUX FEED PUMP 1-2 SPEED DATA
JUNE 9, 1985 - TESTING

DATA POINT	TIME	AFP 1-2 SPEED (S018)
1	12:34:52	35.4
2	12:34:53	382.2
3	12:34:54	NO DATA
4	12:34:55	2089.1
5	12:34:56	1610.5
6	12:34:57	2054.9
7	12:34:58	NO DATA
8	12:34:59	2028.1
9	12:35:00	2250.3
10	12:35:01	NO DATA
11	12:35:02	NO DATA
12	12:35:03	2731.4
13	12:35:04	NO DATA
14	12:35:05	3092.8
15	12:35:06	NO DATA
16	12:35:07	NO DATA
17	12:35:08	3625.2
18	12:35:09	3691.1
19	12:35:10	3715.5
20	12:35:11	NO DATA
21	12:35:12	3732.6
22	12:35:13	3713.1
23	12:35:14	3683.8
24	12:35:15	NO DATA
25	12:35:16	3627.6
26	12:35:17	3571.4
27	12:35:18	NO DATA
28	12:35:19	NO DATA
29	12:35:20	NO DATA
30	12:35:21	NO DATA
31	12:35:22	NO DATA
32	12:35:23	NO DATA
33	12:35:24	3271.1
34	12:35:25	NO DATA
35	12:35:26	3219.8
36	12:35:27	NO DATA
37	12:35:28	3122.1
38	12:35:29	3092.8
39	12:35:30	3036.6
40	12:35:31	NO DATA
41	12:35:32	2951.2
42	12:35:33	2914.5
43	12:35:34	2868.1
44	12:35:35	2794.9
45	12:35:36	2765.6

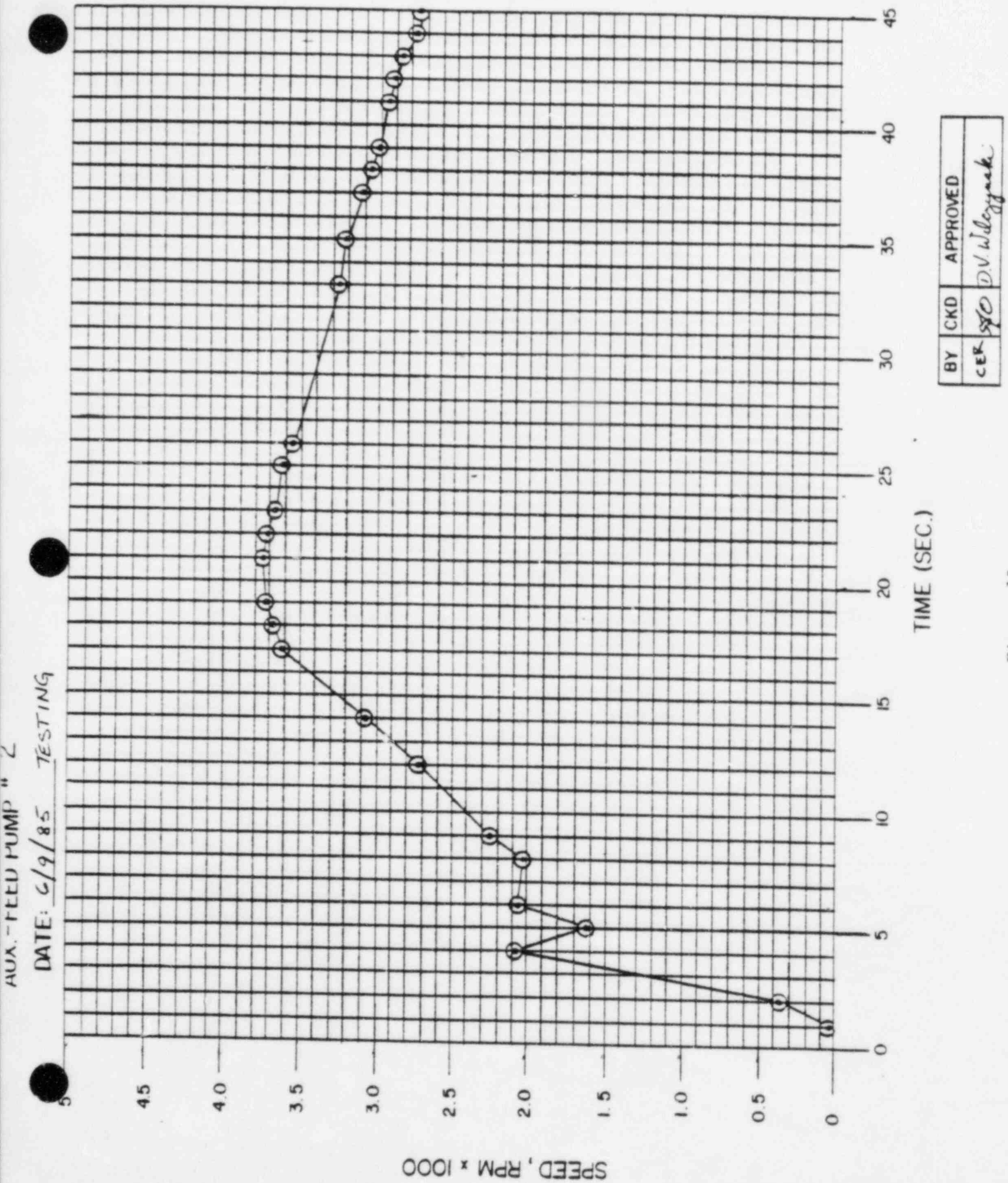

AUX.-FEED PUMP # 2
DATE: 6/9/85 TESTING
TIME (SEC.)
0
5
10
15
20
25
30
35
40
45
SPEED, RPM x 1000
0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5
BY
CKD
APPROVED
CER

Figure 15

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1A	1 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE
AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	ALL STEPS OF THIS ACTION PLAN ARE TO BE PERFORMED IN ACCORDANCE WITH THE LATEST REVISION OF "GUIDELINES TO FOLLOW WHEN TROUBLESHOOTING OR PERFORMING INVESTIGATIVE ACTIONS INTO ROOT CAUSES SURROUNDING THE JUNE 9, 1985 REACTOR TRIP".					
1.0	Test of Hypothesis D: Governor Malfunction Caused AFPT #1 to Overspeed.	Wilczynski	Wilczynski	No Action Required		
1.1	Prepare Maintenance Work Order (MWO) for removal of governor cover, inspection, and reassembly of governor. All work to be performed by a representative of Woodward Governor Co.	Wilczynski	Thompson			
1.2	Remove governor cover on AFPT #1.	Wilczynski	Thompson			
1.3	Perform a visual inspection to determine any obvious damage.	Wilczynski	Thompson			
1.4	Check oil level and cleanliness.	Wilczynski	Thompson			
1.5	Document the as-found condition.	Wilczynski	Wilczynski			

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1A	2 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
1.6	Using Woodward Engineering Representative, determine if any repairs are required prior to testing the governors. The basis for this determination will be: "If the repairs are required to preclude further damage to the governor, turbine, or pump, then the repairs shall be made. If further operation of the governor will not cause further damage, then the repairs will be made after the test for overspeed is run to determine if the failed item could have caused the overspeed on 6/9/85". Document all decisions.	Wilczynski	Gradomski			
1.7	Prepare MWO and perform repair work as determined in Step 1.6. All work to be done by Woodward Representative.	Wilczynski	Thompson			
1.8	Install a remote manual trip device in case of failure of the overspeed trip.	Wilczynski	Thompson			
1.9	Perform "quick start" test of AFPT #1 using ST 5071.02 Phase 1 to test Hypothesis D.	Wilczynski	Missig			

ACTION PLAN

ED 6408

PLAN NUMBER	PAGE
1A	3 of 6
DATE PREPARED	**PREPARED BY**
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
1.10	Repeat step 1.9 to prove repeatability.	Wilczynski	Missig			
1.11	Prepare MWO for repair of governor for all items that were not repaired under step 1.7 as determined by step 1.6.	Wilczynski	Thompson			
1.12	Review data to verify applicability to hypothesis.	Wilczynski	Wilczynski			

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1A	4 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
2.0	Test of Hypothesis A: <u>Condensate in the Main Steam Crossover Line Caused AFPT #1 to Overspeed.</u>	Wilczynski	Wilczynski	No Action Required		
2.1	Develop a Test Procedure (TP) to simulate as close as practical the actual conditions of the June 9, 1985 AFPT #1 overspeed trip. A brief outline of the TP is shown below:	Wilczynski	Missig			
	PURPOSE:					
	- To verify hypothesis that condensate in the cross connect steam supply lines (MS 106A) can cause an overspeed trip of AFPT #1.					
	EQUIPMENT NEEDED:					
	- Existing plant instrumentation					
	- Back-up system for tripping turbines manually					
	- Instrumentation to monitor the thermohydraulic conditions in the steam supply piping to the AFPTs.					

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1A	5 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	PREREQUISITES:					
	- Governor is at its high speed stop.					
	- Steam supply lines to the AFPTs are at ambient conditions.					
	- Pump discharge valves are closed.					
	- Verify min-recirc valves are open.					
	- Steam Generator (SG) pressures are greater than 870 psig.					
	NOTE: SG pressure will be less than 1050 psig and decreasing					
	during testing. This will not exactly duplicate the conditions					
	of 6/9/85.					
2.2	Perform Test Procedure	Wilczynski	Missig			
2.3	Review test data to verify applicability to hypothesis.	Wilczynski	Wilczynski			
2.4	Repeat Test Procedure	Wilczynski	Missig			
2.5	Review test data from second test to verify applicability	Wilczynski	Wilczynski			
	to hypothesis.					

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1A	6 of 6
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #1 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
3.0	Test Hypothesis B: "Double Start" due to cycling of valves MS 106 and MS 106A.	Wilczynski	Wilczynski	No Action Required		
3.1	Develop a Test Procedure (TP) to simulate the cycling of valves MS 106 and MS 106A as occurred on 6/9/85. Prerequisites to be the same as shown in Step 2.1.	Wilczynski	Missig			
3.2	Perform the TP developed above.	Wilczynski	Missig			
3.3	Review test data to verify applicability to hypothesis.	Wilczynski	Wilczynski			
3.4	Perform the TP again.	Wilczynski	Missig			
3.5	Review test data to verify applicability to hypothesis.	Wilczynski	Wilczynski			
4.0	Write final report to document root cause.	Wilczynski	Wilczynski			

ACTION PLAN
ED 6405

PLAN NUMBER	PAGE
1B	1 of 5
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #2 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	ALL STEPS OF THIS ACTION PLAN ARE TO BE PERFORMED IN					
	ACCORDANCE WITH THE LATEST REVISION OF "GUIDELINES TO					
	FOLLOW WHEN TROUBLESHOOTING OR PERFORMING INVESTIGATIVE					
	ACTIONS INTO ROOT CAUSES SURROUNDING THE JUNE 9, 1985					
	REACTOR TRIP".					
1.0	Test of Hypothesis D: <u>Govern malfunction caused</u>	Wilczynski	Wilczynski	No Action Required		
	<u>AFPT #2 to overspeed</u>.					
1.1	Prepare Maintenance Work Order (MWO) for removal of	Wilczynski	Thompson			
	governor cover, inspection, and reassembly of governor.					
	All work to be performed by a representative of Woodward					
	Governor Co.					
1.2	Remove governor cover on AFPT #2.	Wilczynski	Thompson			
1.3	Perform a visual inspection to determine any obvious damage.	Wilczynski	Thompson			
1.4	Check oil level and cleanliness.	Wilczynski	Thompson			
1.5	Document the as-found condition.	Wilczynski	Wilczynski			

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1B	2 of 5

TITLE
AUXILIARY FEED-PUMP TURBINE (AFPT) #2 OVERSPEED TRIP (Rev. 1)

DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
1.6	Using Woodward Engineering Representative, determine if any repairs are required prior to testing the governors. The basis for this determination will be: "If the repairs are required to preclude further damage to the governor, turbine, or pump, then the repairs shall be made. If further operation of the governor will not cause further damage, then the repairs will be made after the test for overspeed is run to determine if the failed item could have caused the overspeed on 6/9/85." Document all decisions.	Wilczynski	Gradomski			
1.7	Prepare MWO and perform repair work as determined in Step 1.6. All work to be done by Woodward Representative.	Wilczynski	Thompson			
1.8	Install a remote manual trip device in case of failure of the overspeed trip.	Wilczynski	Thompson			
1.9	Perform "quick start" test of AFPT #2 using ST 5071.02 Phase 1 to test Hypothesis D.	Wilczynski	Missig			

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1B	3 of 5
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #2 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
1.10	Repeat step 1.9 to prove repeatability.	Wilczynski	Missig			
1.11	Prepare MWO for repair of governor for all items that were not repaired under Step 1.7 as determined by Step 1.6.	Wilczynski	Thompson			
1.12	Review data to verify applicability to hypothesis.	Wilczynski	Wilczynski			
2.0	Test of Hypothesis A: Condensate in the Main Steam crossover line caused AFPT #2 to overspeed.	Wilczynski	Wilczynski	No Action Required		
2.1	Develop a Test Procedure (TP) to simulate as close as practical the actual conditions of the June 9, 1985 AFPT #2 overspeed trip. A brief outline of the TP is shown below: PURPOSE: - To verify hypothesis that condensate in the cross connect steam supply lines (MS 107A) can cause an overspeed trip of AFPT #2.	Wilczynski	Missig			

ACTION PLAN
ED 6608

PLAN NUMBER	PAGE
1B	4 of 5
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #2 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	EQUIPMENT NEEDED:	Wilczynski	Missig			
	- Existing plant instrumentation.					
	- Back-up system for tripping turbines manually.					
	- Instrumentation to monitor the thermohydraulic					
	conditions in the steam supply piping to the AFPTs.					
	PREREQUISITES:					
	- Governor is at its high speed stop.					
	- Steam supply lines to the AFPTs are at ambient conditions.					
	- Pump discharge valves are closed.					
	- Verify min-recirc valves are open.					
	- Steam Generator (SG) pressures are greater than 870 psig.					
	NOTE: SG pressure will be less than 1050 psig and decreasing					
	during testing. This will not exactly duplicate the conditions					
	of 6/9/85.					
2.2	Perform Test Procedure.	Wilczynski	Missig			
2.3	Review test data to verify applicability to hypothesis.	Wilczynski	Wilczynski			

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
1B	5 of 5
DATE PREPARED	PREPARED BY
6/24/85	C. E. Rupp Wilczynski D. Missig

TITLE

AUXILIARY FEED-PUMP TURBINE (AFPT) #2 OVERSPEED TRIP (Rev. 1)

SPECIFIC OBJECTIVE

Verify hypothesis to support root cause determination.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
2.4	Repeat Test Procedure.	Wilczynski	Missig			
2.5	Review test data from second test to verify applicability to hypothesis.	Wilczynski	Wilczynski			
3.0	Evaluate the design of the PGG governor versus the PG-PL governor to determine differences that may cause undesired performance characteristics. (This action to be independent of all other action steps.)	Wilczynski	Gradomski			
4.0	Write final report to document root cause.	Wilczynski	Wilczynski			

MR. ROSSI: I guess I am ready to begin.

What I would suggest we do is just to go through page by page of the document, and anybody on the team that has got a question or a comment on it, just bring it up as we go through.

Some of the things are just questions of verification, and I have got one of those right now. The first page. Valves 3869, 70, 71 an 72, those are normally closed until you get a signal to operate the auxiliary feedwater pump; is that correct? All four of those are closed. All right.

Does anybody have anything else on page 1?

MR. BEARD: Just a point of clarification. Up in the first paragraph there, it says 5 seconds after the initial steam feed rupture control system, 1:41:08, the reactor operator inadvertently initiated the steam feed rupture control system low pressure trip on both channels and both generators.

We are really saying one channel on each of the two generators, are we not?

MR. RUPP: Well, I think the main point is that it did cross-connect the two steam generators to the opposite sides.

MR. BEARD: But he did not initiate actuation Channel 1 and actuation Channel 2 for both steam generators,

did he?

MR. JAIN: I think J. T. is correct. We only tripped Channel 1 on steam generator 1 and tripped Channel 2 on steam generator 2.

MR. BEARD: Okay. I just want to make sure that you aren't telling me something new here, that's all.

MR. WOOD: This is describing the same item that we have talked about before, pushing the two top buttons.

MR. ROSSI: Okay.

Going on to page 2, in the second paragraph you talked about the discussions you have had with Terry Turbine. Can you give us any more details of how much Terry Turbine has done to verify that these water slugs can indeed cause acceleration of the rudder? I mean have they done calculations? Is this engineering judgment, or exactly what have they done?

MR. WILCZYNSKI: Since we talked last, we have talked to Terry Turbine again and we have found out what they have done in this area, and it is purely their engineering judgment and their expertise as the turbine designer.

MR. ROSSI: So they have not done an actual simple calculation to determine whether this phenomena could explain the overspeed? It's just engineering judgment and nothing more?

MR. WILCZYNSKI: That's what they told us, yes.

MR. ROSSI: Have they indicated that other plants have reported this problem or that they have experienced it on other Terry Turbines?

MR. WILCZYNSKI: They knew of no other plants that had had this problem, but we were able to get other data throughout the industry, as shown in the report from NPRDS, nuclear power experience and the nuclear network system.

MR. ROSSI: Okay. We will get to that when we get to the page that has that on it.

Have you considered asking either Terry Turbine or someone else to do a simulation calculation or something of that sort to see if this is a feasible mechanism?

MR. WILCZYNSKI: Yes. MPR Associates is in the process of doing calculations of that type.

MR. ROSSI: Okay. So you are going to do a calculation to try to verify that this is a plausible explanation for the amount of overspeed that occurred; is that right?

MR. HILDEBRANDT: Yes, sir, both in terms of formation of the water in the lines and acceleration of that water through the determine and determine whether indeed it is a viable mechanism for overspeeding the turbine.

MR. ROSSI: And that will be obviously documented and will either be a part of your root cause documentation or we can get it if it's referenced in there then.

MR. WILCZYNSKI: Yes, definitely.

MR. BEARD: On this discussion with Terry Turbine, the last time we met you had stated that you had talked with Terry Turbine initially, told them your experience during the event, and they said, well, that could have been caused by -- and went on to describe this flashing phenomenon, if I can use that term.

Is it still your opinion that Terry Turbine was aware of this phenomenon at the time you called him?

MR. WILCZYNSKI: I can't say that they were aware of it, but as soon as it was brought up in conversation, then he did lead into the thought that yes, indeed, that could cause an overspeed condition.

MR. BEARD: I guess I am trying to just understand who suggested this concept, that's all. The last time we met, I was given the distinct impression that Terry Turbine suggested this as a possibility when you called him, and now I'm not sure I know whether they suggested it to you as an explanation of their equipment behavior or maybe you had suggested it and they confirmed it, or --

MR. WILCZYNSKI: I guess the way it came up into the discussion was we related that we did have an overspeed condition, and discussion led to the fact that water is presumed to be in our steam lines because of the hanger damage that we had experienced earlier, and we had asked if that

could be a contributor to the overspeed condition. And then, of course, their response said yes, indeed, it could.

MR. ROSSI: Now, I gather from your analysis of speed curves and so forth that, depending on the temperature of the water that might go through the turbine, it could either slow it down or speed it up. That's the hypothesis, right? If it's cold water, it slows it down; if it's hot water, it speeds it up.

MR. WILCZYNSKI: That's true. The definition of hot and cold is yet to be determined. There were some very rough calculations done by MPR yesterday or the day before yesterday showing that cold water, as we had thought before, being somewhat below the saturation point, could indeed also speed up the turbine. So we are not sure exactly what the definition of cold water is, and that will be part of the MPR analysis.

But there are times when we have seen water going through the turbine as evidenced by the sentinel relief valve lifting and spraying water throughout the room, and at that time you see turbine RPMs slow down.

MR. ROSSI: I have in my marginal notes here that in the sequence of events, there was Steam and Feed Rupture Control System Channel 2 actuation at 1:35 and 31 seconds into the thing. Could that have done anything in terms of starting the motion of valves? I mean you talk about providing flow

initially to the number one auxiliary feedwater pump through MS 106. Are you sure that a similar kind of thing didn't happen with the other pump?

That's really my question.

MR. WILCZYNSKI: Yes. There was no indication that MS 107 had gone open to supply steam to the number 2 aux feed pump.

MR. ROSSI: And you have an actual indication that MS 106 did open?

MR. WILCZYNSKI: Yes.

MR. ROSSI: Okay. Do you have anything on page 2?

MR. BEARD: Well, I guess page 2 is where you reference Attachment 1 and Figure 1, and maybe this is the time to jump over and cover that information before we get it out of context.

As I remember, as I turn the pages here, Attachment 1 is really two pages, a one-page description and narrative and one page of figures, which, by the way, I think is a pretty clear figure.

On the narrative page of Attachment 1, a couple of things that I find, just to make sure I understand. The lines from 106 and 107 valves are 360 and 125 feet each, whereas the lines from the cross feed steam valves, MS 106A and 106B, are 650 and 375 each, which means that they are significantly longer and, as you have indicated, have long runs of

horizontal pipes.

You had said earlier, I believe, that these pipes are also not insulated, and I believe you had indicated that they may not have the best design in terms of steam traps or drains or something like that. Can you make sure that we are up to date on that? Are they insulated?

MR. RUPP: They are insulated.

MR. BEARD: All pipes insulated.

MR. ROSSI: And the reason they are cold is not because they aren't insulated, just simply because they have no flow through them for long periods of time.

MR. RUPP: That's correct.

MR. BEARD: What about steam traps or water drains or things of that nature?

MR. RUPP: There are steam traps, and the drains off the traps, but we really haven't done a whole lot of analysis to determine how efficient those are in terms of how much water they can take out. Just from preliminary, it doesn't look like they are going to be able to take out anywhere near the amount of condensation that is going to be generated.

MR. BEARD: And I believe that someplace else in this document you mentioned that you had not prior to this event had a program to periodically drain or flush the system or whatever these pipes.

MR. WILCZYNSKI: Sometime in mid-1983, Operations

began a program by which they do periodically drain these lines.

MR. BEARD: So that has been in effect since mid-1983, roughly?

MR. SHAFER: Would you explain how that is done?

MR. RUPP: That's what we got from Operations, mid-1983. Essentially, all they do is uncap the drains and let the water run out.

MR. SHAFER: What is the periodicity on that; do you know?

MR. RUPP: No, we don't.

MR. ROSSI: Well, let me make sure I understand. The mechanism that is being hypothesized is not so much that you have water in the lines at the start but that you get water in the lines as the initial steam flow comes down and condenses; is that correct?

MR. HILDEBRANDT: Yes, sir, that's correct.

MR. ROSSI: So the fact that you have drains in there to keep them drained all the time when there isn't any flow through may not help if the drains don't have the capacity that is sufficient to carry out the condensation that occurs when the steam flow comes down the line.

MR. HILDEBRANDT: That's correct. Any residual water would tend to worsen the effect. We don't know if there is very much residual water, but what you just said is

correct, and we do not expect that the existing traps have sufficient capacity to handle the large amount of condensation initially involved with entering steam into the cold lines.

MR. LANNING: So why do you dismiss the hypothesis that the water came on to start with?

MR. HILDEBRANDT: We don't dismiss that.

MR. LANNING: Why do you think it is not that residual water that's the primary source of water that adversely affects the turbines?

MR. HILDEBRANDT: It could be part of the mechanism. The amount of water that has been drained periodically out of there is a small amount. Do you recall, Chuck, the amount?

MR. RUPP: Yes. For the most part it is just a mililiter or two. There was one occasion where we did have more than that, but most of them, all you are getting is the amount of water out of the actual bucket coming off the pipe and down the drain line.

MR. ROSSI: Are these drains continually in operation or are they something that people have to go and are they either capped --

MR. HILDEBRANDT: The drains associated -- I'm sorry.

MR. BEARD: I believe you said earlier, and correct me if I'm wrong, that the periodic drain consisted of going

around and uncapping these drains, so I presume that between times, they are capped.

MR. HILDEBRANDT: The drains also have traps associated with them. The traps are not designed to be very efficient -- and the word "efficient" has to be quantified and has not yet been -- but they are not very efficient during periods when there is very little pressure in the pipe, and the drains are aligned the condenser, which is the normal lineup for these systems.

But the efficiency of the traps in these conditions has not yet been determined.

MR. ROSSI: But the real point is that even in a drain that has a very small capacity, and as long as it works at all, would probably drain most of the water out that would collect in the piping when it is not being used at all, but then along comes this transient where you condense a lot of steam suddenly, and it just wouldn't have the capacity to handle it.

MR. HILDEBRANDT: It appears to be that way so far. We do not have the final answer, but it appears to be that way so far.

MR. ROSSI: Wayne, you had a question?

MR. SHAFER: Yes. It appears that if in 1983 you decided to periodically start draining those lines, then you had to know at that time that your steam traps were not

capable of handling the problem. Is that a fair statement?

MR. RUPP: I don't think anybody here can answer that. The decision to start draining was done by Operations, and we don't really have all the background.

MR. BEARD: Is there anyone here representing that department, the Operations Department?

MR. BEYER: We really don't have any body from the Operations Department.

MR. BEARD: I had another question. Because they are describing the layout of the pipes, it brings it to mind that someplace in the document you say that in the piping -- I believe it's associated with MS 107A, where there is, I believe, a 250-foot long essentially horizontal pipe, and then a rise -- that this could cause the accumulation of several hundred pounds of water?

Can anybody give me any feel for something a bit more precise than several hundred pounds? I assume you have done some calculation or some estimate to come up with that statement. I'm just wondering can we get a better feel for what we are talking about.

MR. HILDEBRANDT: Chuck will get the actual numbers. The calculation is done on a steady state basis, presuming the steam -- that you have taken all the heat capacity available in the pipe and condensed the water and brought the pipe up to the temperature of steam.

Now, those are very conservative numbers. They do not consider the transient effects.

On that basis, which is very conservative, those are the numbers that Chuck will now read to you.

MR. RUPP: On the 107A side -- well, just the 250-foot long length pipe, it was about 640 pounds mass condensate.

MR. ROSSI: Okay. Can we go on to page 3?

MR. BEARD: Yes. I just thought it would be a good way to get that one into context.

MR. ROSSI: I do note that you now apparently checked your testing for the whole life of the plant, and your conclusion is that the steam supply and feedwater flow path configuration on the 9th had not previously been duplicated in either real operation of the system or a test. When you say that, does that mean both of them cross-connected to the other steam generator, or does it mean that you have not even tested individual lines cross-connected to the other steam generator?

MR. WILCZYNSKI: I'm not sure exactly where you are reading, but it's true that we have not tested either of the cross-connects for a quick start on the turbines.

MR. ROSSI: Okay. And that's over the lifetime of the plant.

MR. WILCZYNSKI: Yes, that's true.

MR. BEARD: And wasn't there a period of time where

you modified the logic such that on any start, all four steam valves would open?

MR. WILCZYNSKI: Yes, that's true.

MR. BEARD: And I believe there were some starts while the system was configured that way.

MR. WILCZYNSKI: Yes.

MR. BEARD: And then you had some more water hammer experience so you revised the logic back to something equivalent to what it had been?

MR. WILCZYNSKI: That's true.

MR. ROSSI: What was the reason for the original modification to open up all four valves at the same time?

MR. JAIN: It was basically based on the reliability or the PRA study that we submitted to the NRC in 1981, which evaluated several options for improving the system reliability versus an optional --

MR. ROSSI: So it was not to solve a water hammer problem; it was really to increase the redundancy of the steam supplied to the pumps. Is that basically the reason?

MR. JAIN: Basically that is correct. And the basic intent there was to provide a redundant path so if an MOV failes to open, you have another path for the turbine to run, and MOVs were found to be one of the most dominant contributors in the study.

MR. ROSSI: Okay. And then after you did that

modification, you did find water hammer problems in the lines as evidenced by hanger damage.

MR. JAIN: Correct.

MR. ROSSI: But you never had any overspeed trips of the pumps or anything like that?

MR. JAIN: Not to my knowledge.

MR. ROSSI: The pumps must have been operated in that configuration --

MR. WILCZYNSKI: They were, and there were no overspeeds.

MR. ROSSI: Okay.

Does anybody have any more questions?

MR. BEARD: I have one. About a third of the way down on page 3, you say that you then reviewed the speed and time characteristics for pump number 1, and you mention that their oscillations -- and I guess at one point the oscillation becomes uncontrolled, but I would like to understand, and maybe this is the right place and maybe not, but I would like to understand that these oscillations -- I would like to understand what you believe the cause is for these oscillations.

In particular, is it water? Is it governor response? Or is it some combination or something different or what?

MR. WILCZYNSKI: Right now we believe that the cause

of these oscillations is indeed due to water.

MR. BEARD: Do you have any experience that says when you don't have water in the lines, the speed curve comes up nice and smooth?

MR. WILCZYNSKI: If you turn back to the speed curves, the June 9th testing that was done after the trip, it's page 26 and 28 -- maybe ten back from the back of the report -- shows aux feed pump number 1, 6/9/85 testing. This was done approximately ten hours after the plant trip. Therefore, the lines were still warm, and you see that the graph is quite smooth all the way up to rate of speed.

MR. BEARD: So you believe that there was no condensate involved in that start?

MR. WILCZYNSKI: Right.

MR. BEARD: Okay, thank you.

MR. ROSSI: Does anybody have anything on page 4? Page 5? Page 6?

MR. BEARD: Page 6. In the second paragraph there it says review of the speed-time characteristics showed -- and here we are talking about an occurrence on April 12, 1985 of testing -- says a review of speed-time characteristics showed speed increases appeared to be a series of step changes rather than a constant acceleration to rated speed.

I'm just wondering if you had any explanation or more information as to why that occurred.

MR. WILCZYNSKI: Once again, we believe that is due to some amount of water going through the turbine. That testing that is talked about there, that first run was done approximately 24 hours after that turbine had been run prior, so --

MR. BEARD: Wait a minute. I'm getting confused because you are saying that in this test, 24 hours after the turbine had been run, you felt like you still had water, and a minute ago in another test, you said you felt 10 hours after it had been run you felt there was no water. I'm confused.

MR. WILCZYNSKI: Well, the 10 hours -- we would assume that the lines would still be warm and therefore there would be less condensation. This test that we are talking about here on page 6 was run in 24 hours.

MR. BEARD: Oh, I'm sorry. I am confused this morning, too. All right.

MR. ROSSI: Anything more on 6?

On page 7 I had a question. Have you actually superimposed the movements of 599 and 608 on the speed curves for the day of the event? I mean have you actually analyzed the times when those valves started to close and when they got all the way closed and superimposed that on the speed curve? The reason I ask that question is that I would assume that when the valve is moved from the open position to the closed position, that the loading on the pump will change and that

that could either be your cause or at least a contributing cause of the event.

I am trying to get a feel for the degree to which you carefully analyzed and looked for that possibility.

MR. WILCZYNSKI: We did indeed look at the closure of valves 599 and 608, and what we noticed was the valves had begun closing prior to the turbines and pumps even coming up to speed, and those valves have a 9-second closure time, which has them being full closed at approximately 1:41:19, at which time turbine No. 2 was only at 570 RPM and turbine No. 1 was at 2400 RPM.

MR. ROSSI: Okay. So you didn't see an increase in speed at the time the valve went through its last little bit of motion that presumably changed the flow significantly. You have looked at that, then.

MR. WILCZYNSKI: That's true.

MR. HILDEBRANDT: There is insufficient discharge pressure on the pumps at this point for both the check valves, which are downstream of that pump before you get to the containment isolation valves 599 and 608. The check valves would have most likely been closed at that point. The pump probably didn't realize -- either of the pumps probably did not realize the valves were open or closed.

MR. ROSSI: Okay. So what you are saying is your analysis has indicated that the load on the pump was basically

for no flow through that whole time.

MR. HILDEBRANDT: Thruogh that period, yes.

MR. BEARD: Can I ask a question on that trace? I guess it's page 2 of 28 in Attachment 2, which is the speed trace for pump No. 1 during the 6/9 event. I was trying to do some of the kind of thing that Ernie was just describing myself, and I had difficulty in relating the time scale to any of the previous information we had with regard to time, and I am wondering if we can establish some way to correlate these things.

It seemed like the peak speed up here before the sharp decay should correspond to the time of the overspeed trip. Is that correct or am I missing something there? I need to establish some time reference so that I can then go back and say, okay, because I now have a time reference to the event, I can know when valves close and open.

MR. RUPP: The page prior to it has the time in seconds and the related speed.

MR. WILCZYNSKI: Data Point 19, which is time 1:41:24

MR. BEARD: Okay. So it's 1:41:24 is the time of the overspeed trip.

MR. RUPP: Okay. The times as shown there -- I'm not sure which is which, but there is a 6-second difference between the two computer times, so the actual overspeed trip

for pump No. 1 came in at 1:41:31.

MR. HILDEBRANDT: Approximately 6 seconds should be added to the data in Attachment 2. I think that editorial comment ought to be put in here just to make it clear.

MR. BEARD: Okay. Well, if I do that, which is what I had done yesterday, you assume that the peak of this curve is 1:41:31, okay? Then I go back through the alarm printer and ask myself what valves are doing what. What I come up with is that 3 seconds prior to the actual overspeed trip, the discharge valve to steam generator No. 1 is no longer open, and I come up also that at the point on the curve that you have labeled as 10 seconds into the start, that is actually 1:41:22, and that is the time at which the steam generator isolation valve -- I assume it is 608 -- is fully closed. It is 10 seconds into the start. And that causes a little valley in the acceleration curve that appears.

MR. HILDEBRANDT: Again, there are two check valves downstream of the pumps. You will see on one side of them steam generator pressure which is somewhere between 930 and 990 pounds. On the upstream side of those check valves or immediately downstream of the pumps, the pumps are somewhere less than that pressure by several hundred pounds. Yes, sir.

MR. BEARD: Right. I was just trying to not draw any significance from it, but I understand at least the point in time on the acceleration curve where the valves were

changing position. So it appears that the full cycle of the isolation valve 608 was during the first ten seconds of the start of this pump.

MR. LANNING: Well, you must be careful with using the alarm printouts for determining valve positions because they are not by themselves an absolute indication of whether the valve is closed or open.

MR. BEARD: Well, let me ask that. I assumed that there were some position switches where you get like an A and B contact on a breaker so get either a not fully open, open, not fully closed, or closed. You know, those kinds of indications. Is that incorrect or inaccurate?

MR. JAIN: It should give you either NC or NO or things like that, which are off the limit switch.

MR. LANNING: That's right. And the ones I was quoting a minute ago were either open, closed, or not open.

MR. JAIN: If it says not open, that means that it's just starting to close.

MR. BEARD: That's right. So the pump's discharge valve was starting to close just as the final acceleration took place that led to the overspeed.

MR. WILCZYNSKI: Which discharge valve are you referring to now? 3870?

MR. BEARD: I think 3870. It's not 608. No. 608 is labeled on the alarm print as the inlet isolation valve, and

the discharge valve is a different beast.

MR. WILCZYNSKI: Right.

MR. ROSSI: Did you superimpose what was happening to 3870 and that bunch of valves also, to make sure that they couldn't have closed and and taken load off the pump right before the overspeed trip?

MR. WILCZYNSKI: We also did look at that, and if you notice at 01:31:34 and 35 the crossconnect discharge valves, 3869 and 3871 indicate full open at that point.

MR. BEARD: But that's after the pumps tripped.

MR. WILCZYNSKI: But that shows that they were beginning to open at the same time the 3870 was beginning to close. So now, that flow path would have been available.

MR. BEARD: I understand.

MR. ROSSI: Well, in testing that you do, assuming that you go through and you can't prove that it was the water by itself, and that could happen I guess, then I assume you do have the ability to go back and start actually operating the valves at the same time during the pump startup as what occurred in the event. I mean, you would be able to do that.

MR. WILCZYNSKI: That's true. We would be able to do that.

MR. ROSSI: Okay. I'm not suggesting that you add it to your plan now because if you go through and you find the root cause is the water and you prove it's the water and so

forth, then that becomes kind of an unimportant point. If you go through and you can't cause them to overspeed again, then that could be a different problem.

Okay. Does anybody have anything on page 7 before we go to page 8?

Okay. The first question that I have on page 8 is I wanted to get a better understanding of this nuclear power experience reports that you got.

MR. BEARD: May we go off the record a moment?

[Discussion off the record.]

MR. ROSSI: Back on the record. On the nuclear power experience information here, -- and I would like to caution people that you ought to be careful for the transcript purposes of giving specific plant names or anything of that sort that may be considered proprietary.

But the nuclear power experience reports that are summarized here. Item 1, the four overspeeds that were reported due to condensation in the line -- can you tell us whether that means the same phenomena as what you believe you had? Those four cases?

MR. RUPP: Talking to the plants that we've been able to contact, we seem to be unique in that our valves are a long distance away. The plants did have what they presume to be condensation build up into their line, but it was because of inadequate steam traps, and whenever they actuated -- the

inlet valves are right next to the turbine, and they would have the steam and the water going into the turbine immediately. And they would have overspeeds in a lot shorter time than what we did.

They did contribute to condensation in the lines.

MR. ROSSI: Okay. And it was more than one plant? I mean, it was not all the same plant.

So what you're saying is your summary of experience here, you've contacted -- were they four different plants?

MR. RUPP: Three different plants -- well actually, four different plants, yes. One was a similar utility.

MR. BEARD: Wait a minute. The information contained in the nuclear power experience -- is that proprietary information? I don't think it is.

MR. RUPP: I'm not sure.

MR. ROSSI: Well, I'm not sure we need -- we can get the plants presumably, if we want to know them. We can get that, but you're saying that there are reports from four different plants that they believe they have had overspeeds due to condensation in the lines that may not have been exactly the way things worked out for your plant but something similar.

MR. RUPP: Correct.

MR. ROSSI: That gives additional credibility to your hypothesis.

MR. LANNING: Not exactly. What I heard you say was that this was residual water that remained in the lines, not condensation due to steam flow.

MR. HILDEBRANDT: Wayne, we very carefully said earlier that we're looking at both. We think the primary reason is the one of condensation which would make steam. Both are being considered.

MR. LANNING: But I'm trying to understand the "due to condensation in the line" part of this statement on number 1. It's not condensation during steam flow; it's before steam flow is occurring.

There's a difference. I'm trying to understand the difference because I don't understand the source of the water yet.

MR. RUPP: Well, the condensation is going to come from steam no matter what. The difference in our situation is that we have cold pipe upstream that is condensing the water; theirs is that they have a hot pipe that sits and the water condenses.

MR. LANNING: So in the operating experience the water is in the pipe before the steam admission valves are opened. Is that what you're saying?

MR. RUPP: Correct.

MR. ROSSI: So the similarity is really only the flashing of the water as it goes through the turbine. I mean,

that part is similar. How the water got there may be different, but the thing that adds credibility to your hypothesis is simply the fact that they believe the water going through the turbines, regardless of its source, caused them to overspeed on four different plants.

MR. RUPP: True.

MR. ROSSI: Wnat did they do to fix the problem? Do you know?

MR. WILCZYNSKI: There were various fixes.

MR. ROSSI: But they did, indeed, make fixes based on the assumption that it was that problem.

MR. WILCZYNSKI: Yes.

MR. ROSSI: Does anybody else have anymore questions on page 8?

MR. BEARD: The only one I had was, I guess this being pretty much the end of your review of history, did you say earlier that when you talked to the Terry Turbine folks, the vendor's experiences, that he had none of these problems reported to him previously?

MR. RUPP: Yes, that's true.

MR. BEARD: Okay, thank you.

MR. ROSSI: Page 9 I do have another very closely-related question. You talk about information from the nuclear network system, and you got one response which indicated the possibility of turbine overspeed due to water in

the steam lines. Is that based on somebody's experience, or their engineering judgment or what?

MR. RUPP: It was strictly engineering judgment.

MR. ROSSI: So it's not a fifth occurrence of the phenomena, or a possible fifth occurrence.

MR. RUPP: Right. They did not, in fact, have an overspeed, but that was listed as what possibly could happen from it.

MR. ROSSI: Okay. Anybody else have any comments on page 9?

MR. BEARD: Here's the point at the bottom of page 9 where he said the several hundred pounds of water could have formed. This was a 640 pounds or -- I guess let me ask you a different question. What's the total number that would be in that place for all the different lines and all the different places?

MR. HILDEBRANDT: J.T., let me caution that these numbers are on the basis we talked about earlier.

MR. BEARD: I realize that.

MR. HILDEBRANDT: And they may be misleading, but we can give you those numbers later.

MR. BEARD: I'm just trying to get a ballpark feel. Are we talking 5000, 100.

MR. HILDEBRANDT: I just want to make sure you appreciate how they were done.

MR. BEARD: Yes, I'm trying to do that.

MR. WILCZYNSKI Okay. On aux feedpump No. 1 which is valve MS-1Ø6, the calculations show approximately 8ØØ pounds of water in that line. Side No. 1 crossover, MS-1Ø6A, approximately 15ØØ pounds. Aux feedpump No. 2, through valve MS-1Ø7, 25Ø pounds. And aux feedpump No. 2 through MS-1Ø7A, approximately 9ØØ pounds.

MR. BEARD: I think you ought to briefly scope the assumptions used for those calculations.

MR. ROSSI: Here, just for the meeting.

MR. BEARD: Right now, yes.

MR. HILDEBRANDT: I'll repeat what I said earlier. One, that we assumed a cold pipe and ambient conditions to make steam at I believe between 55Ø degrees; we take the total heat capacity available to you and you heat the pipe up and condense the steam, it's basically heat balance, energy balance. And you determine how much water you could have formed in that condition with no consideration of time; it's a steady state -- how much total water could I probably condense in that cold pipe.

The actual transient event will, in all likelihood, look different than that.

MR. ROSSI: So what you did is you took the enthalpy change, water going to steam times the unknown pounds of water, and you said that equaled the heat capacity of the

metal of the piping times the total pounds of the piping, and you solved for the pounds of water. Is that a good description?

MR. HILDEBRANDT: Yes, sir, that's correct.

MR. SHAFER: Let me ask a question because I recall earlier you said that when you did the periodic drain on those crossover pipes that you got about a liter of water out of them. Isn't that so?

MR. RUPP: Yes.

MR. SHAFER: So the residual water then is a very small part of this amount of water that could be in there. Is that what you're saying?

MR. RUPP: To the best of our knowledge, yes.

MR. LANNING: I'm having a hard time understanding that, if that's the case. In other words, after you have had steam in those lines and you isolate those lines initially that's going to cool and condense, why is it there's only a liter of water after those lines cool down, compared to hundreds of pounds of water when there's steam flow in those lines initially?

That's got to be part of your hypothesis when you get to that point.

MR. HILDEBRANDT: Yes, sir.

MR. ROSSI: Have you done any even preliminary calculations yet on the turbine overspeed as to how many

pounds of water it may take to cause the turbine to overspeed?

MR. HILDEBRANDT: Those are being done right now.

MR. ROSSI: So you don't have the same kind of preliminary, back of the envelope calculations on that?

MR. HILDEBRANDT: No, sir.

MR. ROSSI: Okay. Anything on pages 10 and 11?

MR. BEARD: Yes. I had one on page 10. In Section B in your hypothesis regarding the double start, at the end of that paragraph there is a sentence there that says the governor valve is opened further than necessary and cannot close quickly enough, resulting in an overspeed condition.

Have you discussed with the vendor, the Terry Turbine folks, the impact of water in the governor on its speed capabilities to respond?

MR. WILCZYNSKI: There was discussion with Terry Turbine about the water condition in the governor valve and the design of the valve was strictly for the steam flow, and they did say that with water in there, the valve would have trouble closing.

MR. BEARD: So if there was water at that point, it would tend to be reluctant to come off the high speed stop during the initial acceleration phase, and I suppose that would suggest, then, that it would tend to allow the motor to accelerate further than it would if the governor were working as fast as it normally would.

MR. WILCZYNSKI: That's true. If the governor were trying to close the valve with water in it, their feeling is that it would not be able to as easily as it could if just the steam were there.

MR. GRADOMSKI: The governor speed-setting motor at that point in time has nothing to do with it.

MR. ROSSI: Have you now looked at the Terry Turbine information supplied with their pump and governor specs and that kind of thing as to whether the kind of limitations on steam quality and so forth that they are telling you verbally were there in their written material provided with the pump?

MR. WILCZYNSKI: A cursory glance at the instruction manual did not indicate that they had given us any warning or told us what the quality of steam should be.

MR. ROSSI: Have you found anything that indicates a quality requirement for the steam going to the Terry Turbine?

MR. WILCZYNSKI: No, not as of yet.

MR. ROSSI: Are you ready for page 11?

Now, the governor valve and the Terry Turbine, everything associated with the auxiliary feedwater pump overspeed is in this document, so you are looking at the governor and the turbine, and then you are going to test it for your overspeed hypothesis. That's all here?

MR. WILCZYNSKI: That's true.

MR. ROSSI: And the governor vendor will be there

for looking at the governor, and Terry Turbine people will be there for looking at either the governor or the turbine, I would assume.

MR. WILCZYNSKI: They will be there for the testing of the turbine.

MR. ROSSI: And when you try to reproduce this phenomenon, the Terry Turbine people will be involved in that.

MR. WILCZYNSKI: Yes, sir.

MR. LANNING: And you will be looking at the governor's performance not only as it relates to your overspeed but also control of the turbine later in the event.

MR. WILCZYNSKI: There will be an investigation of the new PGG governor that will take place simultaneously with the rest of the action plan to research its design capabilities.

MR. ROSSI: Late in the event on June 9th, were you finally able to get normal control room control back on both of these pumps?

MR. JAIN: It is my understanding that later in the event, they were controlling aux feed from turbine locally using the trip throttle valve. The indication that I have is that the/ had not attempted to take control from the control room to infer that the operation from the control room was inoperable.

MR. BEARD: Well, maybe you have more recent

information than we do, but let me recall to your attention that Friday a week ago tomorrow, we had a meeting with you folks in which we discussed our sequence of events to make certain that we were in factual agreement and that we had the latest information from you folks, and at your request, we added a statement on here at the time of entry 01:53:22 discussing the aux feed pump No. 2 that the pump could not be controlled from the control room.

If you are talking hours later, that may be true, but during the course of the event, up through, say, four minute after 2 a.m., our present understanding is that at least No. 2 could not be controlled from the control room, and I believe the man who developed your sequence of events for you -- I want to say Stan -- also indicated that on pump No. 1, that one was questionable because he didn't attempt it. It either could be or could not be, but since he didn't try it, we don't know.

Now, are we in conflict here? Do you have some more recent information that causes us to change our sequence of events again?

MR. JAIN: Well, let me tell you my reasoning for disputing that. I haven't been able to substantiate that we indeed had a problem with the No. 2 control from control room. Unfortunately, the operators who were handling this, they were not available for the last few days. There is

nothing that told me from the computer output or anything that they were attempting to control it from the control room.

MR. BEARD: I believe that there is some information on computer output, and I'm talking from memory now, but there are several places, at least two or three, where it says manual essential switch, and the flag is trouble, and then it would say normal. I assume that is where they would try it, and then apparently take it back out. Because a switch was in an abnormal position for that condition of the plant, the flag came up trouble.

From that, we deduced that he had tried it in manual; for one reason or another, he took it back out.

MR. JAIN: Your deduction is correct, but the timing, I think, is from 1:46 to 1:50, one o'clock, 46 minutes, to one o'clock, 50 minutes. At that time he did indeed have a problem with taking control from the control room, but we correlated that to not being able to open the trip throttle valve.

This here is 1:53, and I cannot correlate that with anything at all.

MR. BEARD: Well, I guess what we need to do is go back to John over here and say: John, if you are the senior person and therefore the spokesman for the company, we would like to get one story from the company, and we trust that you as the senior person will coordinate all your people and tell

us if the sequences need to be revised.

MR. WOOD: We will need to caucus and get that story uncrossed.

MR. ROSSI: Well, in any event, the governor and the turbine are currently under quarantine, and anything that is done on those as part of troubleshooting for whatever reason is -- there will be the records and so forth kept of it. I mean it is entirely possible that when you start looking at the governor, you may find some additional problem that wasn't even recognized that probably occurred during the event, or some problem that may have been unrelated to the overspeed condition that would have caused it not to be operable later in the event after they reset the trip throttle valve.

Do you have anything more until we get to the back? Do you have anything on curves that you want to ask specifically, J.T. or Wayne?

MR. BEARD: I have no questions on the curves.

MR. LANNING: I want to understand why there is going to be an analysis done in lieu of or in addition to actual tests to try to quantify water in the steam line problems.

MR. WILCZYNSKI: I'm not sure I understand what it is you are looking for. Yes, it is true we are going to do an analysis. At the same time --

MR. LANNING: Are there also plans to do a test of

the auxiliary feedwater system using all the valves in the steam emission lines?

MR. WILCZYNSKI: As detailed in the action plan. First there will be a test using the normal valve lineup through MS 106 and 107, and then there will be a test using the cross-connect valve lineup through MS 106A and 107A.

MR. ROSSI: Were the temperatures allowed to reach appropriate values that are consistent with what they were during the event, I assume, after the first test?

MR. WILCZYNSKI: That's true. Right.

MR. BEARD: Are you referring in the detailed action plan 1A to item 2.1? This would be page 4 of 6, I guess. Is that what you are referencing?

MR. WILCZYNSKI: Right. Item 2.1 is the test using the cross-connect valve MS 106A.

MR. BEARD: And you said there is another place where you are going to do it on 106?

MR. WILCZYNSKI: Yes. The first test, if you turn back to page 1, is the test using Valve MS 106. Actually, the test is Step 1.9.

MR. BEARD: Oh, I see. So you are saying something that is really not written on the page here, aren't you?

MR. WILCZYNSKI: That's true. Our normal ST 5070 102 is using the normal valve lineup, and that is not clearly stated here.

MR. BEARD: So this would be using MS 106 only?

MR. WILCZYNSKI: Yes, sir.

MR. HILDEBRANDT: Did that answer the question?

MR. BEARD: No, I was just trying to lead up to it, but --

MR. ROSSI: Well, Wayne's question, as I understand it, was simply are you going to do a test as well as do analyses? And the answer I heard was that you are going to do both. You are going to do the analysis and you are going to do the test, and I would assume you are going to get the analysis done before the test. And if you find out from your analysis that none of this hypothesis makes any sense, then you are going to be back looking at the hypothesis again, I would think.

MR. HILDEBRANDT: Yes, sir. There are two major reasons for doing an analysis. One is the one you just stated, and two is there is no direct way to measure water slugs in the pipe even if we managed to recreate an overspeed. You are measuring indirectly the other instrumentation in the line. We are trying to make a comparison between what can be measured, which you can show analytically, and what you observe in terms of an overspeed. You have no direct way to measure the actual phenomenon.

MR. BEARD: What about uncapping the drains?

MR. HILDEBRANDT: I can see water. I still don't

know that the water says that is the problem. I have to make some sense analytically and empirically, and by empirically, both in terms of finding perhaps an overspeed plus other indications of pressure, temperature and other measurements be made on the line.

MR. BEARD: Well, is it a correct assumption that your plan would include some way of getting whatever data is available on the amount of water that is accumulating? Maybe it is crude, as you were saying a minute ago, but is that part of the plan, is what I am asking, and I think that is what Wayne was asking.

I didn't read that into it, but maybe it's an implication that the thing of using MS 106 only is in there somemplace, but --

MR. HILDEBRANDT: I'm not sure I can deduce that information, but we can go think about that because the water does not stay in the water state. It will evaporate as it exhausts or, you know, it doesn't stay in the turbine or anyplace else. I mean as I exhaust to the atmosphere, it again evaporates. As I expand it to the turbine, it evaporates. I'm not sure that I can get any quantitative information from that, but we can look at that further. We hadn't tried to use that particular indication.

MR. ROSSI: Well, you know, needless to say, when you come back with your identification of the root cause,

that's going to get much more fine-tooth-comb reviewed by us than the action plans because that is going to be the crux of the whole thing, you know.

We have got to make sure we know what caused these problems, and I just caution you again to keep very careful records of everything you do; and where it is practical to do tests to prove your hypotheses that are conclusive, that is obviously the best way to do it if you can do that safely because I think that is far more believable than analytical work.

And that is one of the reasons why we are asking you to look at the test on the valves because it appears that what you have got here is several pieces of equipment that you may not find any broken parts in but you have sort of strange phenomena that occurred because of very special conditions on June 9th, and it was in three or four different pieces of equipment, so your root causes are going to be looked at pretty deeply.

Do you have more on the plan? I don't have anything more.

MR. BEARD: I think just a couple of real tiny questions. In Step 1.1 where you are taking apart the governor, is it part of your plan to have photographs of this area?

MR. WILCZYNSKI: That will be done. It's not

written there, but yes, that will be done.

MR. BEARD: On Step 1.6 on the next page, this is part of your program where you say you are looking to see if the governor is the culprit, and you have a statement in here that says if repairs are required to preclude further damage to the governor, turbine or pump, then repairs shall be made.

I have two questions in this area. One, wouldn't this constitute a hold point for your lead individual to be advised and to come in and decide what to do further? And secondly, if you got to that point, wouldn't that be prima facie evidence that you have a governor problem?

MR. WILCZYNSKI: Yes, that's true. If we do find a problem with the governor, that will be a hold point.

MR. BEARD: And I suppose at that point you would also want to advise the NRC in the form of either your senior resident inspector or Region 3 because of the general guidelines under which all these troubleshooting action plans are developed.

MR. WILCZYNSKI: That's true.

MR. ROSSI: Let's see. The testing of the water phenomena can only be done with the plant hot; is that correct?

MR. WILCZYNSKI: Yes. We might get to Mode 3 --

MR. ROSSI: When are you planning, schedule-wise, to do this?

MR. WILCZYNSKI: I'm not sure that we have any restraints on Mode 3.

MR. WOOD: Well, it somewhat depends on how we go about some of the other action plans, and if we need to sequence such that we have some of the other things identified and under control before we take the plant into a hot condition. We have not put that whole sequence together of what it would take to get to Mode 3.

MR. ROSSI: Do you have even any rough idea of the kind of schedule you are thinking of?

MR. WOOD: No, we don't.

MR. ROSSI: Do you have any comments on the Mode 3 or anything more?

MR. SHAFER: No. It's fairly obvious that some of the other action plans will have to be completed before they go to Mode 3. I can't postulate when that is going to happen.

MR. BEYER: I would even think that we may find some of our corrective action plans will have to be completed to assure operability before we have done Mode 3, and some of those may be extensive where we have generic implications. It's difficult now to even guess at when Mode 3 would be.

MR. BEARD: Well, I guess one of the considerations is that at the time where you have accumulated some significant results on items of major interest as a result of your troubleshooting and are prepared to give us the story on

the root cause and defend whatever that position turns out to be, we are thinking along the line of maybe comeing to the site to hear that presentation and also, if possible, to see the equipment; so we are beginning to think along the line of what time frame that might be, but I get the general impression it's not going to be this week or next.

MR. WOOD: I think that's probably a safe assumption, and I will also say we are not precluding going to Mode 3 and coming back down again. It's not our intent, necessarily, to proceed from Mode 3 right on up through the sequence. You know, we are considering heating the plant up and then bringing it back down.

MR. ROSSI: Do you have any more on the action plan?

MR. LANNING: Depending on what we find out about the governor valve and control of the aux feedwater pump turbine late in the event will determine whether that specific area will be also included in this action plan.

If you find that you could not automatically control the aux feedwater pumps, that will be factored into this action plan.

MR. WOOD: It probably would not be factored into this action plan, but there may be a couple of action plans that would have to be integrated in order to sequence the thing properly, if I am understanding your question.

MR. LANNING: Let's assume for a moment that because

the governor valve was malfunctioning, you could not assume automatic control of the pump.

Now where would you diagnose the reasons why the governor valve malfunctioned?

MR. WOOD: You have an action plan for the trip throttle valve that I believe you have seen, and we have another action plan dealing with the problems or non-problems with auto central control from the control room.

MR. BEARD: We have not seen this?

MR. WOOD: That's right.

MR. BEARD: One of the problems that we are running into, John, is that the way -- we are not familiar with that piece of paper. How you have broken it up has never been presented to us. So we are now taking time to ask questions, like this one we are on now.

MR. WOOD: The way that was broken up is addressed in our action items list that was provided very early. There is listed a 1(a), 1(b), 1(c).

What we have been discussing is Action Plan 1(a) and 1(b). You have discussed Action Plan 1(d), which is the trip throttle valve. 1(c) is the auto central control.

MR. LANNING: I don't ever recall seeing a list of action plan numbers with the equipment at this point.

MR. BEARD: I think it's fair to say that if we ever saw it, we don't remember it. And it's very possible we never

saw it.

MR. ROSSI: That is your latest one that we have just put in the record now?

MR. LANNING: Would you state what that is?

MR. WIDEMAN: This is the action item list from the 6/9 reactor trip that was developed by Toledo Edison, and the current revision of this list is Rev. 2 dated June 18, 1985.

MR. BEARD: Does someone have a copy that we can use to put in the record?

MR. ROSSI: Well, we will simply have a copy made of it and give it back.

How many total action plans are we now talking about for quarantined equipment?

MR. WOOD: I can tally that up and get back to you very shortly on that.

MR. ROSSI: Well, if you don't know off the top of your head, we can count them, I guess.

MR. WIDEMAN: Understand that this says 26 on it, but not all of this is items that deal with equipment on the freeze list. There are other items that Toledo Edison is looking at that you will not be getting action plans for.

MR. WOOD: A typical example is the steam generator integrity. We evaluated the steam generators because of a concern for delta-Ts, and that would be an entry on our action items list.

MR. ROSSI: And that is to satisfy Region III, rather than this fact finding team.

MR. WOOD: That is correct.

MR. ROSSI: If we don't have any more specific comments on this, why don't we take a break and caucus? Or the other thing we can do is take a break, caucus, and eat lunch.

Which do you want to do?

MR. BEARD: I vote for eating lunch.

[Chorus of "seconds."]

MR. ROSSI: Okay. We will break for an hour.

MR. WOOD: Can we just discuss what the course of events is for this afternoon?

MR. ROSSI: Yes. We will talk about whether we have got any comments or anything more we want to make on these auxiliary feedpump overspeed trip documents, and then we're going to talk -- I guess people want to talk about the PORV next. So we'll talk about the PORV next. Then the steam feedwater rupture control system, and then the startup feedpump valve. That's all we had copies of.

MR. BEARD: Let me say before we break, if this is a convenient time, as we said earlier, there was a meeting last Friday when we were out there at your place to make sure that we had the latest and greatest information on the sequence of events. As a result of that, some other information.

We have issued -- the team has issued a Revision 2 to our preliminary sequence of events, and we would like at this time to let you know there is a stack here for your access.

MR. HILDEBRANDT: Ernie, if you wish, as we come back -- we went past one point of Wayne's with regard to residual water sitting in a line, and when we come back from lunch, there is a possible explanation, and we could perhaps go through that and see if he understands that point, if you wish.

MR. ROSSI: Okay, fine. We can do that. We can start with that.

So why don't we break now?

[Whereupon, at 12:00 o'clock, noon, the meeting was recessed, to reconvene at 1:00 o'clock, p.m., this same day.]

AFTERNOON SESSION

(1:10 p.m.)

MR. ROSSI: All right, let's go back on the record.

We caucused on the auxiliary feedpumps overspeed trips, and I guess we have no more comments on it at this time. And we will be waiting for your identification and justification that you found for the root cause, and we will obviously go through that very carefully. So just make sure it's all well-documented and supported by tests and analyses as needed.

MR. LANNING: The record should show that prior to the recess for lunch, that we were discussing an action item list, and that should be Exhibit No. 4.

[The document referred to, marked Exhibit No. 4, follows:]

Ef. 9

ACTI[illegible]TEM LIST
FROM 6[illegible]85 Rx TRIP

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
1.	AFW Pump Turbine Governor Control				
a.	#1 AFWPT - 1. Establsh cause(s) of inadvertent trip (CAL Item 3a) 2. Determine and implement corrective action to prevent recurrence (CAL Item 3b)	Wilczynski	Hartigan Missig MPR		
b.	#2 AFWPT - 1. Establish cause(s) of inadvertent trip (CAL Item 3a) 2. Determine and implement corrective action to prevent recurrence (CAL Item 3b)	Wilczynski	Hartigan Missig MPR		
c.	Auto/Essential Control Problems	Jain	Yarger		
d.	Trip Throttle Valve Problem	Gradomski	Terry Turbine		
2.	SG Integrity/Cycle Impact Due To SUFP Initiation of Water • Evaluation of thermal shock considerations on both S/G's (CAL Item 5) • Maximum S/G shell differential temperature (CAL Item 5)	Chen	B&W	N/A	Preliminary info. from B&W indicates no problems. Draft report due from B&W on 6/19/85.

Rev. 0 - 6/11/85
Rev. 1 - 6/14/85
Rev. 2 - 6/18/85

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
3.	Actions of Operators Adequacy of Procedures	O'Connor	Derivan		
4.	Classification of the Event Under the Emergency Plan (EAL Pg. 3 of 37) • Basis for event classification (CAL Item 5)	Scott-Wasilk	O'Connor		Complete 6/13/85 (A85-204H)
5.	SFRCS Half Trip On One Level Input	Yarger	Stalter		Problem appears to be analytical, new bistables and response to secondary pressure upset after turbine trip.
6.	SFRCS Alarms	Miller	Lingen-felter		
7.	MSIV/SFRCS Response • Establish cause(s) of unexpected valve closure (CAL Item 2a) • Determine and implement corrective action (CAL Item 2b) • Conduct testing to ensure operating as required (CAL Item 2c)	Miller	Jain Yarger		MSIV's may have properly responded to low level SFRCS trip which cleared quickly. Related to Item 5.

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
8.	MFP Control System • Establish cause of inadvertent trip of #1 MFP (CAL Item 4a) • Determine and implement corrective action to prevent recurrence for both MFP's (CAL Item 4b)	Blay	J.Johnson Missig Topor Isley G.E.		Action plan ready for NRC FFT on 6/18/85.
9.a.	Damaged turbine bypass valve	Raynes	Hiss Lammon		
b.	Water hammer indication during transient				
10.	PORV Condition - Cycled 3 Times (3rd cycle looked inconsistent) # of Stress Cycles	Isley	Straube Marley		
11.	Discuss Event With Ottawa County Commissioners (Significance)	Scott-Wasilk		N/A	Completed - 6/11/85 at 1:00 p.m. (A85-203H)
12.	S/G Isolation Valves Capability To Open Against Large D/P (AFW 599 & 608)	Long	Bajestani	6/14-Action plan approved for trouble-shooting.	Troubleshooting expected to begin 6/18/85.

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
13.	Service Water Effect on S/G	Briden			No detectable impact to S/G's was found - to be documented.
14.	Operator Error for Initiating AFW				
a.	HED on switches (FCR	Calcamuggio	Czuba Batch		
b.	Plastic covers	E.Johnson			
15.	Source Range NI's (RPS)				Action plan to be ready for NRC FFT on 6/18/85.
a.	NI-1	Borysiak			
b.	NI-2	Isley			
16.	MSSV's - Blowdown to 900 #'s	Huston	Mahoney		
17.	Problems With SPDS	Smith			Item removed from equipment freeze list.
18.	SP7A Problems (S/U Feedwater)	Uebbing	Bonner		Valve appeared to have opened during the transient. May however, be a panel light problem.
19.	Adequacy of Information as Originally Provided to NRC on June 9, 1985 (CAL Item 5)	MacDonald	Wideman		

Rev. 0 - 6/11/85
Rev. 1 - 6/14/85
Rev. 2 - 6/18/85

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
20.	Complete Items 1-5 of CAL. Obtain concurrence of Regional Administrator Prior to Restart, Mode 2 (CAL Item 6)	Wood	Wideman		
21.	Perform Testing and Demonstrate that the AFP's Will Operate as Required (CAL Item 7a)	Topor	Blay G.E.		
22.	Perform Testing and Demonstrate that the MFP's Will Operate as Required (CAL Item 7b)	Gradomski	Hartigan Missig		
23.	Appropriate Test Results, Conclusions and Corrective Actions Shall be Reported to the NRC Resident Inspector (CAL Item 7c)	Wood	Wideman		
24.	Obtain Concurrence from Regional Administrator Prior to Exceeding 5% Reactor Power	Wood	Wideman		
25.	Main Steam Walkdown (Outside Containment) • Document any walkdown performed • prior to June 12 approx. 5:00 p.m.	Hiss	Raynes Dieterich		Completed - info. given to NRC.

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
25. Cont.	• QC - Conduct a damage inspection walkdown of the main steam system.	Rhodes			QC walkdown completed 6/14/85 per QPIC-037. Bechtel to review and disposition results started 6/18/85.
26.	Review service water transfer of suction to AFW pumps. • Determine if actions were appropriate • Determine corrective actions if appropriate.	Czuba	Yarger		
27.	MS 106 - investigate seal in open circuit.	Bonner			

Rev. 0 - 6/11/85
Rev. 1 - 6/14/85
Rev. 2 - 6/18/85

ACTION ITEM LIST
FROM 6[illegible]85 Rx TRIP

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
1.	AFW Pump Turbine Governor Control				
a.	#1 AFWPT - 1. Establsh cause(s) of inadvertent trip (CAL Item 3a) 2. Determine and implement corrective action to prevent recurrence (CAL Item 3b)	Wilczynski	Hartigan Missig		
b.	#2 AFWPT - 1. Establish cause(s) of inadvertent trip (CAL Item 3a) 2. Determine and implement corrective action to prevent recurrence (CAL Item 3b)	Wilczynski	Hartigan Missig		
c.	Auto/Essential Control Problems	Jain	Yarger		
d.	Trip Throttle Valve Problem	Gradomski			
2.	SG Integrity/Cycle Impact Due To SUFP Initiation of Water • Evaluation of thermal shock considerations on both S/G's (CAL Item 5) • Maximum S/G shell differential temperature (CAL Item 5)	Chen	B&W		

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
3.	Actions of Operators	O'Connor	Derivan		
4.	Classification of the Event Under the Emergency Plan (EAL Pg. 3 of 37) • Basis for event classification (CAL Item 5)	Scott-Wasilk	O'Connor		
5.	SFRCS Half Trip On One Level Input	Yarger	Stalter		
6.	SFRCS Alarms	Miller	Lingen-felter		
7.	MSIV/SFRCS Response • Establish cause(s) of unexpected valve closure (CAL Item 2a) • Determine and implement corrective action (CAL Item 2b) • Conduct testing to ensure operating as required (CAL Item 2c)	Miller	Jain Yarger		

ACTI[illegible]TEM LIST
FROM 6/[illegible]/85 Rx TRIP

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
8.	MFP Control System • Establish cause of inadvertent trip of #1 MFP (CAL Item 4a) • Determine and implement corrective action to prevent recurrence for both MFP's (CAL Item 4b)	Blay	J.Johnson Missig Topor Isley G.E.		
9.a.	Damaged turbine bypass valve	Raynes	Hiss Lammon		
b.	Water hammer indication during transient				
10.	PORV Condition - Cycled 3 Times (3rd cycle looked inconsistent) # of Stress Cycles	Isley	Straube Marley		
11.	Discuss Event With Ottawa County Commissioners (Significance)	Scott-Wasilk			Completed - 6/11/85 at 1:00 p.m. (A85-203H)
12.	S/G Isolation Valves Capability To Open Against Large D/P (AFW 599 & 608)	Long	Bajestani		
13.	Service Water Effect on S/G	Briden			

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
14.	Operator Error for Initiating AFW				
a.	HED on switches (FCR	Calcamuggio	Czuba Batch		
b.	Plastic covers	E.Johnson			
15.	Source Range NI's (RPS)				
a.	NI-1	Borysiak			
b.	NI-2	Isley			
16.	MSSV's - Blowdown to 900 #'s	Huston	Mahoney		
17.	Problems With SPDS	Smith			
18.	SP7A Problems (S/U Feedwater)	Yarger	Bonner		
19.	Adequacy of Information as Originally Provided to NRC on June 9, 1985 (CAL Item 5)	MacDonald	Wideman		
20.	Complete Items 1-5 of CAL. Obtain concurrence of Regional Administrator Prior to Restart, Mode 2 (CAL Item 6)	Wood	Wideman		

ACTI[illegible]TEM LIST
FROM 6[illegible]85 Rx TRIP

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
21.	Perform Testing and Demonstrate that the AFP's Will Operate as Required (CAL Item 7a)	Topor	Blay G.E.		
22.	Perform Testing and Demonstrate that the MFP's Will Operate as Required (CAL Item 7b)	Gradomski	Hartigan Missig		
23.	Appropriate Test Results, Conclusions and Corrective Actions Shall be Reported to the NRC Resident Inspector (CAL Item 7c)	Wood	Wideman		
24.	Obtain Concurrence from Regional Administrator Prior to Exceeding 5% Reactor Power	Wood	Wideman		
25.	Main Steam Walkdown (Outside Containment)				
	• Document any walkdown performed • prior to June 12 approx. 5:00 p.m.	Hiss	Raynes Dieterich		
	• QC - Conduct a damage inspection walkdown of the main steam system.	Rhodes			

#	ISSUE/CONCERN	TED LEAD	SUPPORT	NRC EVAL/CONCUR	COMMENTS
26.	Review service water transfer of suction to AFW pumps. • Determine if actions were appropriate. • Determine corrective actions if appropriate.	Marley			

MR. ROSSI: Does anybody want to talk about the auxiliary feedwater pump overspeed anymore before we go on to the power-operated relief valve -- pilot-operated relief valve?

[No response.]

MR. ROSSI: Okay.

MR. SHAFER: You have an outstanding question with regard to the sequence of events.

MR. BEARD: Help me remember.

MR. SHAFER: They were going to caucus.

MR. WIDEMAN: Right. The item was, what is Toledo Edison's position on the control of the aux feedpump turbine from the control room. And I think our position is that we would like to get back to you later on that. I don't think at this point that we have had time to talk with the operators to verify that, and we would either -- if we are going to be here tomorrow, at that time, we could possibly address that.

MR. ROSSI: Is that whole issue covered in this Action Plan 1(c) on auto essential control problem?

MR. GRADOMSKI: As a matter of fact, it is covered in 1(c), talking about the auto essential non-control.

MR. BEARD: But I think the issue was that the gentleman who prepared that action plan has a little different perception of what took place than the operators told us. So I think -- and correct me, if I am stating your plan wrong --

it's based on one premise, and we are trying to resolve the two different points -- or what appears to be two different points. And that's what we asked John to research for us and have the company come to one position.

So I think while it is discussed in that action plan, yours is based on one side of the discussion, and we have been told a different side.

MR. JAIN: Yes. We need to verify that.

MR. WOOD: It creates a problem with the sequence of events.

MR. BEARD: You say it does or does not?

MR. WOOD: I say it does. As we have discussed it in this meeting today, there is a concern whether the sequence of events needs to be changed as a matter of this information, and that's what we intend to get back to you on.

MR. BEARD: All right.

MR. ROSSI: All right. Why don't we go on to the PORV action plan, and we can do it the same way that we did the other one. We'll just start and go through it.

MR. WOOD: Could we pause for a minute and reshuffle our players?

MR. ROSSI: Yes, we can do that. If we're going to do that, we probably ought to stop the stenographer for awhile until she gets the names of everyone. So why don't we do that, and then we'll start again.

[Discussion off the record.]

MR. ROSSI: Okay. We're back on the record. So everybody speak one at a time and clearly.

MR. BEARD: Could I ask that the new players identify themselves and sort of give us a brief statement as to what your position is with the company?

MR. ISLEY: My name is Tom Isley, Maintenance Specialist, Instrumentation Control Department, Station Maintenance.

MR. McCURDY: My name is Bill McCurdy, Engineer working for MPR Associates, and we are acting as a consultant to the Toledo Edison Company.

MR. ROSSI: Okay. Does anybody have any questions or comments on the first page?

MR. LANNING: We are now talking about Action Plan No. 10?

MR. ROSSI: Action Plan No. 10, Review of the Operation of the PORV.

MR. LANNING: That will be Exhibit No. 5.

MR. BEARD: It's a document dated June 22, 1985.

[The document referred to, marked Exhibit No. 5, follows:]

Ex. 5

ACTION PLAN # 10

TITLE: REVIEW OF THE OPERATION OF THE PORV

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE
0	6/22/85	Initial Issue	T. Isley	E K Baye

Rev. 0 Approved for Implementation ________

TITLE: REVIEW OF THE OPERATION OF THE PORV

REPORT BY: Tom Isley PLAN NO: 10

DATE PREPARED: 6/22/85

This report has been prepared in accordance with the "Guidelines to Follow When Troubleshooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip", Rev. 4.

I. INTRODUCTORY STATEMENT:

This report describes the way the PORV responded during the transient on 6/9/85 and identifies analysis and actions needed to identify root cause(s).

II. SUMMARY OF DATA:

During the transient on 6/9/85, the PORV cycled three (3) times. The first time the PORV opened for 3 seconds and then closed at the proper setpoint. The second time the PORV opened at the proper setpoint for 3 seconds and then closed approximately 25 psi below the required setpoint. The third time the valve opened at the proper setpoint but did not reseat at the proper pressure. The operator manually closed the PORV block valve. RCS pressure stopped decreasing at approximately 2075 PSIG. The block valve was reopened 2 min. 13 sec. later and the PORV appeared to hold RC pressure. When the PORV failed to close, the operator noticed that the close light was lit indicating the control circuit worked properly, deenergizing the PORV solenoid.

It should be noted the PORV block valve stoke time is approximately nine seconds. The accoustical monitor indicated that flow stopped in approximately seven seconds after the block valve started to move to the close position. The exact time at which flow stopped is uncertain because the accoustical monitors are not designed to indicate accurately at low flow rates. Therefore, it cannot be positively identified if the PORV reset (at approximately 300 psi below the required setpoint) or the block valve closed which stopped the flow through the PORV.

Reviewing the previous operations of the PORV shows a total of 91 hot cycles and 17 cold prior to 6/9/85. Adding the 3 hot cycles gives a total of 94 hot and 17 cold, as compared to an allowable number of 440 hot and 25 cold cycles. It has also been determined that the temperature of the loop seal was 469°F which is greater than the required 400°F (minimum), therefore, no piping analysis is needed.

III. MAINTENANCE AND SURVEILLANCE/TEST HISTORY:

12-14-76 The PORV was disassembled, inspected, and the seating surfaced lapped (MWO 2161). The valve had lifted 8 times since it was installed.

08-01-77 The PORV failed to open. Replaced power fuses (MWO 77-1592).

09-06-77 The PORV was disassembled, inspected, and seating surfaces lapped (MWO 77-1903). The valve had lifted 14 times since last maintenance.

09-24-77 The PORV failed open during a loss of feedwater accident. The valve was disassembled and the pilot valve was found stuck open. The pilot valve stem was replaced and the nozzle guide was cleaned. When the valve was reassembled and tested, the valve again failed open on the sixth cycle. The valve was again disassembled and inspected. The pilot valve stem was machined to correct the pilot stem-nozzle guide clearance, and the stroke of the pilot valve was adjusted. The valve was cycled 12 times at reduced pressure and once at 2200 psig with no problems. (Reportable Occurrence NP-32-77-16, MWO 77-2120 and MWO 77-2256.)

01-18-79 Because the PORV was leaking, it was disassembled and inspected. The disc, seat, and pilot valve were found to have minor cutting. They were lapped and the valve was reassembled (MWO 79-1307). The valve had lifted 67 times since last maintenance.

04-19-79 The PORV actuating linkage was checked for proper operation and proper supply voltage to the solenoid coil was verified. No problems found (MWO 79-1978).

05-17-79 The setpoints for the PORV were changed to open at 2400 psig and close at 2350 psig (FCR 79-169).

10-29-79 Because the PORV was leaking, it was disassembled and inspected. The valve disc and pilot disc were lapped and the valve was reassembled (MWO 79-3433). The valve had lifted 2 times since last maintenance.

03-24-82 Because the PORV was leaking, the valve was disassembled and repaired (MWO 81-3662). No lifts since last maintenance.

09-01-82 The PORV was stroked per PT 5164.02. No problems found.

09-06-83 The setpoints for the PORV were changed to open at 2425 psig and close at 2375 psig (FCR 79-348).

09-14-83 The bistable setpoints were checked by ST 5040.02 and found to be acceptable.

12-28-84 The bistable setpoints were checked by ST 5040.02 and found to be acceptable.

Maintenance and Test Summary

The majority of the maintenance was to correct for minor leakage. The valve failed open one time, was repaired, and had operated properly prior to June 9, 1985. The routine testing has not found any problems with the PORV.

Change Analysis

Since the PORV was last operated on September 1, 1982, the only change was to the bistable setpoints. Since the bistable functioned properly and the setpoints have been verified twice since they were changed, this did not have any effect on the operation of the PORV. There have been no other changes since the last successful operation.

Failure Hypotheses Summary

A discussion with B&W about the way the PORV operated, produced several possible causes.

1. During the first two lifts of the PORV, the loop seal could have emptied which would have allowed the valve to pass only steam during the third lift. The hot steam could have caused the disc to expand more rapidly than the valve body causing the disc to stick. After the valve temperatures had equalized, the disc would free up and then reseat. Subsequent Toledo Edison calculations have shown that the loop seal would have been emptied during the first lift of the PORV.

2. The linkage for the pilot valve could have broken allowing closed indication but the pilot valve would still be open, keeping the PORV open.

3. One of the solenoid coil guides could have broken causing the valve to stay open. This has happened on a similar valve by a different manufacturer.

4. Possible corrosion or boric acid buildup on the solenoid coil linkage causing the linkage to stick.

5. A piece of foreign material inside the valve caused the disc or pilot valve to stick open.

6. The possibility exists that pressurizer level was high enough to put water through the valve. This has been rejected as a possible cause for the failure because the valves tested by EPRI all worked properly when tested with water.

The Crosby Valve and Gage Co. was contacted and they were unable to provide any additional information about possible failure modes for

the PORV. They reminded us that their valve worked very well in all of the testing done by EPRI.

We have reviewed the EPRI test data to determine if the testing done would provide any information. The testing done by EPRI used a similar Crosby valve with a 1 3/8" bore while ours has a 1½" bore. They had some problems initially with the pilot valve bellows cracking or being improperly machined but the valve functioned properly after those problems were corrected. Previous maintenance has detected no prob'ems with the bellows in the valve at Davis-Besse. The EPRI test demonstrated that the tested valve closed in 0.1 to 0.2 seconds.

The EPRI test set up did have a loop seal. In one test, the conditions were very close to the conditions experienced on June 9, 1985 immediately prior to the first lift of the valve. In the EPRI test the valve closed properly, however, they only did one cycle while we experienced multiple cycles.

Our review of the NPRDS data since TMI 2 found a PORV failed open at another utility one time. The valve that failed is a different design and that failure is not believed to be related to the failure we experienced.

IV. HYPOTHESES:

1. The PORV stuck open due to differential expansion of the disc and body.

2. The valve mechanically malfunctioned causing it to not close during the transient.

3. The solenoid coil linkage could be broken or have corrosion buildup causing faulty operation.

4. A piece of foreign material caused the disc or pilot valve to stick.

TRI:lrh
Attachment

ACTION PLAN
ED 6408

Rev. 0

PLAN NUMBER	PAGE
10	1 of 1
DATE PREPARED	PREPARED BY
6/21/85	T. R. Isley

TITLE

REVIEW OF THE OPERATION OF THE PORV

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	ALL STEPS OF THIS PLAN ARE TO BE PERFORMED IN ACCORDANCE WITH THE LATEST REVISION OF "GUIDELINES TO FOLLOW WHEN TROUBLESHOOTING OR PERFORMING INVESTIGATIVE ACTIONS INTO THE ROOT CAUSES SURROUNDING THE JUNE 9, 1985 REACTOR TRIP".					
1	Perform a visual inspection of the PORV and associated linkage. Check for broken or missing parts, boric acid buildup, or other abnormalities.	Isley				
2	Under the direction of the Crosby representative, disassemble the PORV. Check the internals for damage, proper clearances, abnormal wear, or foreign material. Also check the bellows for proper fit or cracking.	Isley				
3	Analyze the results of the inspection and data surrounding the transient to determine if differential expansion caused the valve to stick open. This analysis is expected to take several weeks and will require the results of the valve inspection before proceeding.	Isley				

MR. BEARD: I had a question on the first paragraph under "Summary of Data," and I had asked Bill Rowles to see what could be done about bringing some supplemental information about the controls of the PORV to this meeting, and it deals with the subject here. And the sentence in your report says, "When the PORV failed to close, the operator noted that the close light was lit, indicating the control circuit worked properly deenergizing the PORV solenoid."

Was Bill successful in getting this information to you folks, or do we have it here today?

MR. ISLEY: I have a copy of the control circuits diagrams.

MR. BEARD: A copy that we may keep?

MR. ISLEY: If you'd like.

MR. BEARD: That's what we had asked for. I just want to make sure.

MR. ROSSI: Well, maybe you could start out by giving a little, brief explanation of how the thing works. Is that the appropriate thing to do?

MR. BEARD: Well, yes. My question is that I'm not sure that I understand that the light coming on or going off tells whether that's the input to the solenoid or the output from the solenoid, and that's the reason I asked for the information.

MR. ISLEY: Certainly.

The bistable that controls the solenoid valve itself is not monitored. It energizes the solenoid valve to open the valve and deenergizes to close the valve. On the solenoid itself, we have mounted a limit switch. When that solenoid is energized, it provides an "open" indication on the operator's console. When that solenoid is deenergized, it provides a "closed" indication on the operator's console.

Due to the construction of the valve, it does not mean the valve is open and closed. It merely means that the solenoid is energized or deenergized.

We have installed additional monitoring in the form of acoustic monitors on the discharge piping to provide a more correct indication that the valve is either opened or closed. That indication is not available to the operator directly on the console where the control switch is, but is available on indicating lights on our post-accident indicating panels, which would essentially be to the operator's left as he is looking at the control switch.

MR. BEARD: This is that vertical panel where your T-sat meters are, and it's something like six feet to his left?

MR. ISLEY: That's correct.

MR. ROSSI: The operation of the light that the operator noticed, can that be verified from any of the sequence of events printouts or any of that kind of thing,

that that actually occurred, or are you totally dependent on what he remembers?

MR. ISLEY: Totally dependent on what he remembers.

MR. ROSSI: Okay. And he feels -- well, you just have to make your judgment on what he remembers, I guess. But your whole action plan is based on the solenoid and control circuit working properly, and if there is a problem, it's in the PORV?

MR. ISLEY: That's correct.

MR. ROSSI: And you aren't looking at any other hypotheses on control circuits?

MR. ISLEY: That is correct.

MR. ROSSI: Is there anything more on the first page?

MR. LANNING: I'd like to ask a question about the second paragraph on that page where you talk to whether or not you could positively identify if the PORV reset.

If you look at the quenchtank data for level and pressure, that data showed that there appears to be flow to the quenchtank until the block valve was closed. So doesn't that imply that the PORV was still at least partially open?

MR. ISLEY: Yes. And based on the response of the acoustic monitor, it also indicates that there was flow to the PORV until very close to the same time that the block valve indicated "closed."

MR. BEARD: Do you have a separate printout on when the block valve was closed, other than the acoustic monitoring?

MR. ISLEY: Yes, sir, I believe I do.

That should have been on the computer alarm printout.

MR. LANNING: Okay. So to summarize, then, is it accurate that the PORV was at least partially opened until the block valve was closed?

MR. ISLEY: I think what we are saying there is, we're not positive of that. We have some indication that says we believe it was open. The indication is that it was.

MR. ROSSI: That's the acoustic monitor, primarily, that showed that it was open until about the time that the block valve was closed?

MR. ISLEY: That's correct. And supplemented with the quenchtank data that Wayne had quoted.

MR. BEARD: Tom, I think the question that has arisen is that with the stroke time of roughly nine seconds, and seven seconds later you get the acoustic monitor indicator of flow below its setpoint on low flow, it's possible that the PORV could have closed simultaneous with reaching that time.

But I think what I hear you saying is that -- well, let me ask it.

If the stroke time is nine seconds for the block

valve, and if the setpoint for no flow in terms of trips for alarm purposes for the acoustic monitor is 20 or 22 percent of full flow, then it would be very reasonable that the block valve closing would give you the acoustic monitor 22 percent value at seven seconds, is it not?

MR. ISLEY: That's correct.

MR. BEARD: So except for the possibility, which is getting to look, in my view, more and more remote, that the PORV happened to close at exactly the same time, all the indications seem to suggest that it was the block valve that terminated the flow through the PORV and not the PORV itself.

I mean, the majority is clearly in that direction.

MR. ISLEY: That's right.

MR. ROSSI: Well, we know that the PORV stayed open too long. There's no question about that. I mean, you can tell that from the acoustic monitor signal and the reactor coolant system pressure.

MR. ISLEY: That's right. I don't think we tried to say that it has not.

MR. ROSSI: So nobody has a question that it was open too long, maybe by 20 to 30 seconds, and there's no question that when he reopened the block valve, that at that time it was closed?

MR. ISLEY: That's right.

MR. ROSSI: So it closed sometime between when the

block valve got closed at or equal to the time that the block valve got closed or up until the time he opened it again. But in any event, it now functioned to some extent.

MR. ISLEY: That's right.

MR. ROSSI: Page 2.

MR. BEARD: I had a couple things I really wanted to just ask about and see if this is really true.

There's an entry here that says date 9/6/77, that the valves lifted fourteen times since the last maintenance, which I read to be one month previous to that. And that says it's open every two days on the average? Is that really true?

MR. ISLEY: According to the data that I had, that was during startup testing. The PORV settime was below our actual trip setpoint. Any kind of transient that we did -- load rejection testing, plant trip testing, even for very low power -- would cause the valve to open.

MR. BEARD: And then there is a further entry that says January of '79, the valve has lifted 67 times since the last maintenance, and the maintenance looks like about fifteen months prior, and that means four times a month, is that right?

MR. ISLEY: Yes, sir.

MR. BEARD: Once a week on the average roughly?

MR. ISLEY: That's what the numbers work out to. It was quite frequent.

MR. BEYER: Would it be fair to say that on some transients the valves may have operated more than once in a given transient, as opposed to necessarily on some given frequency?

MR. ISLEY: That's right.

MR. BEYER: I think I recall during the discussion on the 9/24/77 event, I believe it operated nine times, if I remember right.

MR. ISLEY: Yes. Now this 67 times includes the thirteen times we did the test cycling for the 9/24/77 maintenance.

MR. ROSSI: Well, it lifted a number of times during some of these transients and receded all those times. Were there changes made to the valve dimensions and that kind of thing prior to the June 9th event?

MR. ISLEY: The only changes to the valve concerning dimensions were related to the 9/24/77 maintenance where the valve failed open. There were some dimensional changes made on the pilot valve stem, and there were some adjustments made to the solenoid actuation of that stem, and those should be outlined in the 9/24/77 maintenance.

MR. ROSSI: Now, after that time, were there any events where the valve may have lifted several times like it did in the June 9th event?

MR. ISLEY: There were a couple of times when the

PORV lifted more than one time and the valve operated as expected.

MR. ROSSI: I'm just trying to get a feel for how likely your hypothesis is because if it had done the same kind of thing on several other occasions and worked properly, your hypothesis really is that you got differential expansions in the body and the disk and that's what caused it to stick. And presumably, if it had operated several times during other events, that same thing could have happened.

MR. ISLEY: That's right, and it had operated multiple times and worked properly.

MR. ROSSI: On other events?

MR. ISLEY: On other events.

MR. ROSSI: And you don't know of any changes that were made to dimensions of the valve between those times and the June 9th event?

MR. ISLEY: There is nothing in our records to indicate that.

MR. BEARD: Tom, on the entry on, I guess it is, the fourth month 1979, it says the PORV actuating linkage was checked and the power supply voltage to the solenoid was checked. Can you tell me why a maintenance work order was issued and on that date what was the symptom or why these checks were made?

MR. ISLEY: I could not find any reason, no definite

reason to do this. It appeared to be either manufacturer's recommendation or something to that effect because the checks that were done on 4/19/79 were later turned in to items that are checked on the surveillance tests that we had done later.

MR. BEARD: So these are checked periodically?

MR. ISLEY: Yes.

MR. ROSSI: Any more on page 2? Okay, page 3.

The first one I have is just a verification question. I gather from what you say under the change analysis that the PORV had not been operated either for tests or during any transient prior to June 9 of '85 since it was operated on September 1 of 1982. Is that what this is saying?

MR. ISLEY: That's correct.

MR. ROSSI: So you don't have any periodic testing or anything like that of the valve?

MR. ISLEY: The last time it was stroked was for a periodic test, and that was 9/1/82.

MR. ROSSI: And how often do you do a periodic test of it if it was September of '82?

MR. ISLEY: That was the only time it was stroked for that periodic test. I could find no definite scheduling for that test.

MR. ROSSI: Okay. So it's not really a periodic test; it's a preventive maintenance test that's not scheduled at uniform intervals. That's really what you are saying, I

guess.

MR. ISLEY: That's what I found.

MR. ROSSI: Okay. Is there some reason why this kind of a component wouldn't get a more frequent test, like maybe every refueling?

MR. ISLEY: No, I can't say.

MR. BEARD: You have a statement in here someplace that in the testing that EPRI did, which is brought up by item 6 on page 3, that in those tests there was a single opening or lift of the valve, as contrasted to three lifts as this event experienced, and I guess you had some prior experience with multiple lifts also.

MR. ISLEY: That's correct.

MR. ROSSI: Have you discussed with EPRI your hypothesis for the problem that you had on June 9th?

MR. ISLEY: Not with EPRI, no, sir. We talked to B&W, who originally brought up that hypothesis. We have discussed that with Crosby Valve, and we have also discussed it with MPR. Crosby Valve said, yes, that might be true, and that's about all they would say.

MR. ROSSI: And B&W said?

MR. ISLEY: B&W was the one who originally proposed that and said that that possibly is what happened in causing the valve to stay open.

MR. ROSSI: Has anyone done any scoping calculations

on the dimensions and differential expansions to see how likely this hypothesis is?

MR. ISLEY: Not as yet. I believe that is item 3 on our Action Plan as one of the things that we are going to be doing.

MR. BEARD: All right. Does that take us to page 4?

MR. ROSSI: Yes, we are on page 4.

MR. BEARD: I have a general comment that I would like to throw out. It's not related uniquely to this particular troubleshooting plan, but I notice that you are consulting with NPRDS data, and I would just like to remind you, if you didn't know, that the number of utilities participating and the degree of participation in NPRDS at the time we developed the new LER rule, which I guess went into effect at the beginning of '84, initially was very, very low.

So if you are looking at NPRDS data, you should realize that it's very, very limited before mid-1984, so you are not going back very far if you cover the whole nine yards in NPRDS. So you may want to consider for other efforts -- I'm not suggesting you revise this at all -- but for other efforts, going through some vehicle to look at LER data because the statement here that says "our review of NPRDS data since TMI-2" is very misleading because there is no NPRDS data to amount to anything between the years of the accident and mid-1984, you know.

MR. ROSSI: Is your leading hypothesis the one of the differential expansion?

MR. ISLEY: Yes.

MR. ROSSI: That is your leading hypothesis?

MR. ISLEY: Yes.

MR. ROSSI: And if that turns out to be the problem, we are dependent only on analyses to try and tie it down as the problem?

MR. ISLEY: Well, no. There are two additional hypotheses there, No. 2 and No. 3. Well, and No. 4 also. Those four hypotheses, or three additional hypotheses, will require that we check them out before we actually get into our No. 1 hypothesis.

In order to disassemble the valve, there is a chance that we might destroy the evidence that would lead us to prove Hypothesis 2, 3 or 4, so even though we have picked our lead hypothesis as the differential expansion, we realize that we need to check out those other hypotheses first.

MR. BEARD: Would operation of the PORV have the similar effect of maybe destroying the evidence on the other hypotheses?

MR. ISLEY: I think it would on Hypothesis 4 if there was something inside the valve. We might move that out of there.

MR. BEARD: I had a question as to even though it's

not certainly an hypothesis at this point, but would it be worthwhile to check out your control channel, the pressure channel that drives this thing in terms of rechecking setpoints, and, in fact, that the output signals are all proper, because it appears that it hasn't been checked since September of '82? Or I guess you said it was checked a couple times after that, but it hasn't been checked recently.

MR. ISLEY: The last time that we checked the setpoints of the bistable was 9/14/83. That's when we actually checked the bistable setpoints. Oh, I'm sorry. 12/18/84. December of '84, December of '84 we had checked bistable setpoints.

MR. ROSSI: Well, the bistable presumably worked correctly two times during the event.

MR. ISLEY: That's right.

MR. ROSSI: Anything more?

MR. BEARD: No, other than that very general comment, and that is that I personally am concerned that this particular troubleshooting Action Plan on PORV is likely to lead us to the situation where you can't reproduce the failure, so to speak, and we are depending on analysis to be determining the root cause. And if you are, I'm not so sure how favorably that is going to be perceived.

It clearly is going to be the subject of extremely tight scrutiny, and Toledo Edison is going to be expected to

defend their positions. I am just leery that we are coming upon a number of these where it is analysis only that is showing the root cause, and I am uncomfortable with that.

I don't know what to do about it. I am uneasy.

MR. ROSSI: Is there any additional testing that EPRI could help with on this if you get to the point where you are dependent on analyses only?

MR. MC CURDY: I think you could attempt again to review what tests were done at EPRI. Tests were done with a Crosby relief valve, which is very similar in design to the valve used at Davis-Besse, and this valve was tested on a range of conditions, including steam, water, both saturated and subcooled and this transition situation, going from subcooled water to steam.

I think the response of the valve that we found in those tests, particularly tests with a similar valve, the Dresser valve, indicated that it was very valve-specific response. And there may be a difference in tolerances from one valve to another that could, in fact, produce different results; or, you know, subsequent tests under identical conditions with a valve with tolerances slightly different could show a stuck-open valve; and subsequent tests could show the valve worked properly.

So I guess what I am concluding is that tests could be done but, again, chances for those tests being conclusive,

I think there would be a slim chance.

MR. BEARD: What about pretesting a new PORV and then replacing the one that is installed?

MR. MC CURDY: I think, again, any valve like this, its behavior depends on close tolerances and, you know, close clearance between the parts -- for example, the disk and the guide for the disk -- and to behave properly, that clearance has to be very small. As a result, it is susceptible to this mode of failure with differential expansion between the parts.

Now, I note that at Davis-Besse, the water temperature upstream of the valve was, I think, in excess of 450 degrees, so as a result, the differential expansion for this valve would be only several hundred degrees versus from perhaps 150 to 650 degrees for a valve on our cold water seal.

So I think as far as the installation, it would be less susceptible to the problem, you know, than if installed on a cold water seal.

Now, another valve -- I guess there would be an alternative valve, or this particular valve, depending on the results of the inspection, could determine if the clearances were not adequate, and the clearances could be readjusted to, you know, provide additional room for differential expansion between the parts.

MR. BEARD: Well, I guess what I am thinking of is more along the line that if we end up or if you folks end up,

Toledo Edison ends up that it is only through analysis that you can identify the root cause, and if people are uncomfortable with that, I am trying to ask would it be possible to take a new PORV, run it through a test program to show that that one's adjustments have been tested up on side and down the other and known to be good, and then take that one that has been tested and put it on Davis-Besse so that we then end up in a situation where even if the people are uncomfortable, we now have a known good PORV on that plant?

One of the messages that I got from what you said earlier is the valves may vary not only amongst manufacturers but amongst the units manufactured by one manufacturer, from Crosby to Crosby to Crosby.

MR. MC CURDY: That's right. That is correct. And I think what you propose could be done. I think the problem is that, you know, to really assure with a high degree of confidence that in fact your valve would not exhibit that behavior in later transients.

MR. BEARD: Well, let me make clear that I am just thinking out loud with you, and I'm not suggesting that this be in the troubleshooting plan. If anything, you may want to consider that when it comes to corrective action time.

MR. ROSSI: Yes. The scope of this team really is to find the root cause, and if we can't definitely identify the root cause, that's going to be a problem and we are going

to be back looking for other ways to try to identify the root cause. The corrective action per se will be handled as part of the normal office's work.

MR. SHAFER: Can I ask, with regard to EPRI, did they do multiple cycles on any of the valves?

MR. MC CURDY: By multiple cycles, you mean --- let's say in any 30-second period, lifting the valve a number of times?

MR. SHAFER: Yes.

MR. MC CURDY: No, that wasn't done. The tests were done, you know, by perhaps a 20 to 30-second test where the valve was opened, flowed, water, steam, whatever, and then closed, and the pressurizer feeding the valve was then brought up to initial pressure and the transient was repeated.

Now, the time between those two actuations perhaps was half an hour to an hour, minimum.

MR. ROSSI: Well, this is clearly a case where you want to make sure you do everything and keep track of all the parts, keep a record of everything that is done so that when you get to the end, you will at least know what you have looked at and what isn't the problem, even if you at that time haven't identified the problem. This could be one where, you know, we may want to have somebody independently look at the parts and try to verify your hypothesis.

MR. LANNING: I would like to sugget that you go and

relock at the operating experience again to make sure that you have a good grasp on the failure of this valve that has been experienced by other utilities. I think there is a lot more than one PORV failing open in NPRDS.

MR. ISLEY: The problem with that is we are the only one with a Crosby valve. I realize there may be other failures. In the review that I did, there was only one failure, and from what I can tell -- I could not determine who the manufacturer was, but from the description of the event and the corrective actions taken, it seemed to be a significantly different type of construction.

MR. LANNING: Okay. I understand that now. You did your research only for the Crosby valve.

MR. ISLEY: Well, that's not true. We did search for other -- we just looked for generic PORV failures, but we were limited in our scope. As J.T. pointed out, we used NPRDS and we only looked since the Three Mile Island incident occurred, and as J.T. pointed out, NPRDS before mid-1984 -- or mid-1982, was it -- was very limited in its participation.

MR. LANNING: Well, back to my original comment, then, if you didn't limit your search to only Crosby valves, there are a lot more PORV failures in NPRDS than one since TMI.

MR. ISLEY: Well, are we talking about just the valve failing or the valve failing open?

MR. LANNING: Failing open.

MR. ISLEY: Okay. I only found one in our review. We can go back and recheck that, but I only found one.

MR. ROSSI: Do you have any comments, Wayne?

MR. SHAFER: No.

MR. ROSSI: All right, if nobody has anymore comments on it, I guess, or advice to give you how to find the problem.

Why don't we take a five-minute break and then we'll go on to the next one.

[Recess.]

MR. ROSSI: We have one more question on the PORV, and that question is: have you thought about taking the valve out and testing it? And what is involved with taking it out and testing it?

MR. BEYER: How about if you re-ask the question for Tom?

MR. ROSSI: Have you thought about taking this valve out and testing it somewhere? I mean, assuming that you don't find one of these other kind of problems when you look at the valve.

MR. ISLEY: We have discussed the possibility of reactivating the EPRI test facility. We have not gone any farther than that.

MR. ROSSI: So you're hoping you'll find the problem

short of that?

MR. ISLEY: Yes. If, in fact, we don't find something, that's one of the things we will consider, is possibly retesting that valve either at another facility or even at our own facility.

MR. BEYER: If the flange valve is removal without cutting and welding.

MR. ROSSI: Okay. I guess we are done with the PORV. No one has any other comments on the PORV, so shall we go on now to the action plan 5, 6 and 7 on low steam generator level trip of the SFRCS.

So if you want to go through this one the same way we did the others, we can start on page 1. The first question I had is a very basic one. You seem to have already concluded that the closure of the MSIV's was due to a signal from the SFRCS system. I mean, your entire plan is based on that as an ingoing assumption.

MR. STALTER: That's correct. Our review has been done and we feel that that did happen, and that's the assumption we're going with.

MR. BEARD: Is there another action plan that deals with the MSIV and other sources of control signals? Or is this everything that deals with the MSIVs?

MR. STALTER: This is everything that deals with the MSIVs.

MR. ROSSI: It seems to me that there ought to be something that would at least check that the MSIV other circuitries are all operating properly, and control circuits, because -- I mean, you've assumed that conclusion right at the very start, and that is, you go through the action plan for the SFRCS. It appears that that whole plan is basically a relay race story. I mean, that's what it really is, right? You've got noise spikes that affected some things but didn't affect others.

MR. JAIN: There are reasons for concluding that the SFRCS trip may have been the cause of the MSIV closure. Based on past experience you see the MSIV closing almost exactly five seconds after the SFRCS trip. Exactly the same thing was seen on this one. We saw actual indication of a full SFRCS trip occurring, which would have resulted in closure of the MSIV.

So the indications that were available in the review process directly led us to believe that it was an unwanted, if you will, SFRCS trip that resulted in closure of the MSIV.

MR. ROSSI: Your hypothesis is you got the spurious SFRCS trip and then it reset before it sealed in?

MR. JAIN: Correct.

MR. ROSSI: But it was actuated long enough to close the MSIV.

MR. JAIN: Exactly.

MR. BEARD: Can I follow that up a little bit? I was under the impression last week when we were out at your plant that you had prior experience with, I will call them, spurious actuations of the rupture control system that had led to MSIV closure, you felt. But when I read this write-up here in this particular troubleshooting plan, I get the impression that you had a full actuation of at least one of the actuation channels on the 9th of June, but your prior experience on June 2nd and April 24th of this year were only half trips. And that there were no previous spurious low-level trips prior to the 1984 refueling outage.

Now if I understand correctly the design -- and I'm not sure that I do, but if I understand it correctly, a half trip should not cause the MSIVs to close.

MR. JAIN: Exactly.

MR. BEARD: So that this prior experience that you're talking about of seeing the MSIV closed, I am confused about it.

MR. JAIN: I don't recall personally a closure of the MSIV on a spurious SFRCS trip.

MR. BEARD: Before June 9th?

MR. JAIN: Correct.

MR. BEARD: Okay. I guess I had the wrong impression. I thought you told us a minute ago that you had prior experience at this plant with those occurring.

MR. JAIN: I may have to look further, but I don't recall any such occasion.

MR. STALTER: What you were saying, as far as I recall, is that the full SFRCS trip when it occurs, five seconds later the MSIV closes. Now that full SFRCS trip has occurred in the past, and we have received MSIV closure as a result of that. Did that help you any? That's what Suchel was saying.

MR. BEARD: Well, I guess you had a refueling outage in 1984.

MR. JAIN: Right.

MR. BEARD: Do you remember what months really or when he came back from the 1984 outage?

MR. JAIN: From September to January.

MR. BEARD: He came back in September?

MR. BEYER: Wait a minute. The 1984 refueling outage was completed in January of 1985.

MR. BEARD: Okay. So you returned to power in January of 1985 and you were running about, say, five months before this event, roughly.

MR. JAIN: Correct.

MR. BEARD: So what you're saying is during that five months you had two occasions where you had half trips, and then this particular event where there appears to have been a full trip.

MR. JAIN: Exactly.

MR. ROSSI: Well apparently, you got a full trip alarm on June 2nd, also, right?

MR. SHAFER: That's what I recall.

MR. ROSSI: Yes, that's what your plan says here on page 1, item no. 3, bottom of the page it says you got a full trip alarm on June 2nd and no devices were actuated.

MR. JAIN: Okay. We chased that back, the SFRCS full trip alarm, the Q963. The problem was chased back to a faulty contact in the alarm circuitry. I think it did say that somewhere.

MR. STALTER: It's in the maintenance section, next page, page 2, no. 6.

MR. ROSSI: Okay. So you found a definite problem with the circuitry, then.

MR. BEARD: Is that what you meant by the words in here that say the connection was reterminated?

MR. STALTER: In the process of troubleshooting they lifted a connection and when they reterminated that connection, the problem cleared.

MR. BEARD: Well, I guess I would have read that -- in fact, I did read that -- as the thing disappeared on its own; not that you actually found a smoking gun.

MR. STALTER: I don't know what you mean by that exactly. When they were troubleshooting they lifted the wire

and in the process when they reterminated that, they no longer had that problem. It cleared itself. The assumption there was made that in the process of that troubleshooting action that they cleared the problem.

MR. BEYER: Suggesting that maybe we had a bad connection there.

MR. SHAFER: But then the 9th occurrence again would suggest that it didn't clear the problem again. Is that what happened?

MR. STALTER: We don't feel that we have that same problem.

MR. JAIN: On June 9th there was other evidence which led us to believe that there were actual full SFRCS trips. Howsoever spurious, but they were full trips.

MR. BEARD: At the bottom of the first page, I would like to correct what may be a misunderstanding or whatever. When we were out at your plant last Friday, I thought I remembered being told that you had been made aware of this phenomena I will call a pressure wave that may occur when a turbine trip occurs prior to this event. That was my impression last Friday.

And this write-up indicates very clearly that subsequent to the event you had a discussion with B&W and suggested that it was at that time that you became aware of this pressure wave phenomenon. Could we at least get clear on

when you --

MR. JAIN: Yes, I think it was after the transient when we were trying to determine what exactly could have gone wrong, and we were in the process of talking to B&W and B&W then forwarded us the data.

According to my knowledge, it was after the trip.

MR. BEARD: You say they did forward you some data?

MR. STALTER: Yes, they provided us with some data. Maybe it would help -- I think as a result of analyzing the events in the past we have seen pressure transients occur following turbine trips.

MR. ROSSI: On your plant?

MR. STALTER: On our plant. And they have seen level oscillations in the steam generator levels occur and never really was that attributed to be a plant operational problem. It's something that just happened after the trip and it was not looked at as being a problem.

Now, one of the things that occurs is that the data that is taken, the one-second time interval data on Davis-Besse and the transient data that B&W made us aware of was data that was taken on a two-tenths of a second time interval. And it clearly showed that there were different things going on in the steam generator than what the one-second time data showed.

MR. ROSSI: These were taken at TMI-1?

MR. STALTER: That's correct.

MR. BEARD: Can you give us some feel for the magnitude of these variations? Maybe in terms of percent on the operating range or something?

MR. STALTER: I don't want to quote really the data without having it in front of me and that was the one curve I didn't bring with me. But it clearly showed about an 80-inch reduction in the startup range level indication.

MR. ROSSI: Only the indication?

MR. STALTER: Well, it's the transmitter output that they recorded.

MR. BEARD: This is on the startup range. Did it appear on the operate range?

MR. STALTER: It did appear on the operate range. I don't remember the numbers off of that curve.

MR. ROSSI: Do both of these speed the SFRCS, or just the startup range feeds the SFRCS?

MR. STALTER: Just the startup range for Davis-Besse, that's correct.

MR. BEARD: I guess I have a real problem in the sense that it's like some of these other troubleshooting plans that after the event, you call back to the vendor and the vendor says oh, yes, let me tell you about something. And so, we're talking about a phenomenon that's really new to me. Maybe I'm the only one that didn't know about it.

How much trouble would it be to get some sort of documentation on this testing that occurred at TMI as to exactly when it happened? Or is there a copy of a test report or something of this nature to substantiate this situation?

MR. STALTER: I don't know how much of a problem that would be. I would have to check with B&W and see what it would take to release it or where it is.

MR. ROSSI: So far all they gave you were traces and no report or anything?

MR. STALTER: That's correct, they just gave us a copy of the traces and said, here's what we found.

MR. ROSSI: Do you have any idea over what timeframe they made those recordings? I mean, were they during the TMI-1 startup testing?

MR. STALTER: My impression was that it was the TMI-1 startup testing, but I don't know that for a fact.

MR. SHAFER: Well, could you test this on your system and see, with that kind of signal coming in for that length of time, whether you'd get an MSIV closure? Do you know how many cycles, I guess, per second those oscillations are?

MR. STALTER: Part of the action plan was to do response time testing of the various components to try to build that scenario.

MR. SHAFER: I realize that, but there was no

discussion, I don't think, with regards to trying to validate this information that you got from B&W.

MR. JAIN: You mean during the TMI testing? Is that what you're suggesting?

MR. SHAFER: Well, if you could input a signal to your startup range, because that's where the oscillations took place, you said. I think you said 1.2 to 1.3 cycles per second. Would that cause an MSIV closure?

MR. STALTER: It would depend on the magnitude of the signal, and the magnitude of the signal that was in the TMI data may not be the same magnitude signal we would see at Davis-Besse. We feel that it's very close but we don't know exactly how close it is.

MR. BEARD: Have you taken the data from the June 9th event and plotted it or analyzed it in any way to see if this oscillation was present on June 9th?

MR. STALTER: There's indication from that data that there was oscillation present, and again, it's difficult to say that it's exact oscillation because the frequency of the data that we have is one-second time intervals, and the frequency of the signal is about that same thing. So you could get low peaks a bunch of readings and then something high, and I think that's what we saw there.

MR. JAIN: It is in the DADS data after the SFRCS trip the level went down to, say, about 96 and then 74, 78,

82, 84, 82, 74. So it was going through --

MR. BEARD: Which computer point are you looking at?

MR. JAIN: That would be L883.

MR. BEARD: And this is the startup channel?

MR. JAIN: Startup, yes. And L893. The first one being for the No. 1 generator, the second one for the No. 2.

MR. ROSSI: And the setpoint for the SFRCS is 26 --

MR. JAIN: 26 by 5 inches.

MR. ROSSI: Okay. Those oscillations were far from the 26.5 --

MR. JAIN: One clarification here. These outputs here in the DADS data is from different transmitters than those that feed the SFRCS.

MR. ROSSI: Oh, that explains one thing, then.

MR. BEARD: The DADS data is not the same transmitters that feeds SFRCS.

MR. JAIN: They are, however, connected to the same taps.

MR. ROSSI: Well, your whole plan here is all based on nothing but analyses this time. I mean, what you're going, as I understand it, is go through and figure out what the time response is for all the instruments, and make a hypothesis about the mysterious oscillations and try to demonstrate that you could close the MSIV's without actuating other

equipment that didn't get actuated. Is that a correct overview? No testing at all.

MR. JAIN: No, no, this is all testing.

MR. STALTER: There is testing in here.

MR. ROSSI: But I mean no testing to try to actually reproduce the MSIV closure signal.

MR. BEARD: I think it's all response time testing, not trying to replicate the disease as proposed.

MR. ROSSI: It's not testing to reproduce the failure. Or reproduce the MSIV closure signal without actuation of the other equipment.

MR. SHAFER: I would add on page 1 of 4 of the action plan, item 1B indicates corrective action that you're going to take.

MR. BEARD: Are you talking about Item 1(b), as in Baker?

MR. SHAFER: Yes.

MR. BEARD: I didn't read it that way, but maybe we could get a clarification on it. I read it to say that there would be some -- I will call it study performed, to determine what the appropriate or acceptable response time should be.

MR. BEYER: That's exactly right. We, the group that reviewed these plans, raised the same question about the word "establish" when we reviewed it.

MR. BEARD: It was not physically an adjustment of

any equipment?

MR. BEYER: That's correct. That is to determine a value.

MR. BEARD: On paper.

MR. BEYER: On paper.

MR. BEARD: Well, let me ask, how confident are you in this situation that you understand occurred at TMI-1?

MR. STALTER: You mean the data?

MR. BEARD: Yes.

MR. STALTER: I feel confident that it is good data input that we are looking at.

MR. BEARD: And that it applies to Davis-Besse?

MR. STALTER: That that kind of an oscillation does occur, and that we could use that as an indicator of what does happen at Davis-Besse.

MR. BEARD: Have you looked at the data on your transmitters here to see if it has an oscillation that even approaches the right frequency versus a ten-second frequency -- I mean, ten-second periodicity -- versus one second?

MR. STALTER: It is a little bit difficult. There is a ten-second frequency that is in there, and then a one-second that rides on top of that.

MR. BEARD: Have you analyzed the DADS data is what I'm getting to?

MR. STALTER: The DADS data we've looked at in

relation to that, and it's really hard to say you can exactly fit a point in there, but you can see that that type of thing is going on.

MR. BEARD: Have you analyzed it in any way other than eyeball scanning it, like we just did a minute ago here? Have you plotted the data?

MR. STALTER: We've plotted it, yes.

MR. BEARD: Does it show any indications that would confirm the presence of some harmonic or signal in there at a rate like one cycle per second?

MR. STALTER: No, it doesn't. It would be difficult to do that, because the one-second scan is what we used to take the data.

MR. BEARD: I understand there's a difference.

MR. STALTER: So you don't get in-between points.

MR. BEARD: Yes. But that theorem has to do with how faithfully you can reproduce it. And what I`m suggesting is, if there really is one there -- let's say, just hypothetically, you have got a one cycle per second or one and a half cycle per second sine wave going through there, and you sample it once a second, you're not going to be able to reproduce what that interference is, but you should be able to detect that there is some interference in there.

And what I'm trying to understand is, have you done the analysis to show that there is some interference in there,

or has it just been this eyeball look-see run-down like we just had a minute ago?

MR. STALTER: There hasn't been any in-depth analysis done of that DADS data. We did plot it. We did see that there were oscillations in it.

MR. BEARD: Of the one or two-second variety or the ten-second variety?

MR. STALTER: It was a longer frequency than one or two seconds, because we felt that that system didn't pick up --

MR. BEARD: Would it be a correct statement or a fair statement to say that your analysis of the data does not indicate any one or two-cycle-per-second interference, separating out the ten cycle business? But there is no analysis of the event that shows the presence of a one or one and a half cycle, interfering signal?

MR. STALTER: That's correct.

MR. ROSSI: Tell me, is it possible with the plant shut down to go in with test signals at some point in this circuitry and try to reproduce what happened during the event in terms of actuating some of the equipment and some of the alarms and not others? I mean, do you follow what I'm saying?

At some point, you know that you've got certain things actuated and certain alarms came one, and you know about how long they were on, I gather. And it seems like you

might be able to go in with test signals and try to simulate spikes that would do that same kind of thing and actuate the equipment that was actuated and not actuate the other, as some kind of support for the analyses that you are about to begin.

Is that possible to do with the plant shut down?

MR. STALTER: I think we would have to look at that. I believe it could be done.

MR. ROSSI: I think -- you know, my opinion is that on this one, if you come back with just an analysis and a time response measurement on components and a hypothesized pressure transient from some time in the history of TMI-1, that that's going to be very difficult to convince at least me that you found the root cause. And I am probably easier to convince that J.T.

MR. BEARD: Let me tell you another thing that really bothers me.

The pressure wave transient that you report in this troubleshooting plan was news to me. I mean, the phenomenon is credible, but the magnitude of it and this, that, and the other, that it would interfere with trip setpoints was news to me.

I talked to the TMI folks themselves, and they have no memory of any such event. They have no memory of any such testing. They have no memory of any such traces. And as far as they are concerned, it never happened at their plant, or

they are not able to retrieve any such information.

Now this was done on a short timeframe, but that's where I'm coming from.

They even pointed out that during the startup test program at TMI-1, they had a reactor turbine trip from 74 percent power. They startup test program obligated them to do it at 90 percent or higher, and they had to go back to the Commission to justify that that was an adequate test, from 74 to 90.

And one of the guys that I talked to on the telephone yesterday, who said he was there during the startup phase of TMI-1, said as far as he knew, the turbine never tripped from 90 or 100 percent.

So we've got a lot of doubts about whether this phenomenon is occurring in significant enough magnitudes that this hypothesis has credibility.

MR. HILDEBRANDT: Who was the conversation with, J.T., so I can follow up on it?

MR. BEARD: I'll give it to you after the meeting.

And this is the reason why I asked earlier -- I'm not putting you guys on the spot, but I'm just saying, you know, part of our job is checking out stories, so to speak.

It's very important in my mind that you guys firmly establish the credibility of this information you have received from your NSS vendor.

MR. STALTER: I agree with you. We, in the development of this action plan, we did not provide that firm establishment. But we knew full well that we would have to do that.

MR. ROSSI: Okay. Your action plan really doesn't address possible logic problems with the SFRCS, possible control system problems with the MSIVs. You know, you may have some of those problems, too. You made a lot of modifications to this system, apparently, during the last refueling outage, and I don't know how thoroughly you tested all those afterwards. But it would seem to me that there could be other problems with the SFRCS that might be even more likely than this spike thing, and certainly ought to be looked for.

MR. BEARD: Let me ask a different question.

The other day, I talked to Bill Rowles and told him that after glancing over this action plan, we felt it necessary to look over the technical manuals for these two level transmitters. Apparently, the scenario is based largely on the fact that you had Bailey level transmitters previously, and then for equipment qualification reasons, you changed to a Rosemont transmitter, which are reportedly faster, and therefore now this phenomenon is more noticeable.

MR. STALTER: Let me clarify that problem. As a result of environmental -- for environmental qualification

reasons, we had to change out the amplifier boards and calibration boards in the Rosemont 1152 transmitters that are associated with the SFRCS. Those transmitters were not changed out during the outage, only the boards internal to those. There were no Bailey BYs on the SFRCS system.

MR. BEARD: Is that a correction of a technicality on page 2 here? Item 2 under "Change Analysis" says, "As the SFRC level sensing transmitters were changed from BY to Rosemont transmitters."

I guess what I hear you saying now --

MR. JAIN: J.T., it is different transmitters.

MR. STALTER: Oh, okay. The level transmitters providing startup level indication on the control panel connected to the sensing lines as the SFRCS level transmitters were changed to BYs -- from BYs to Rosemont.

Now those are different transmitters on the same sensing lines.

MR. BEARD: But these are not the inputs to the rupture control system?

MR. STALTER: They are not the inputs to the SFRCS. Those are Rosemont 1152s.

MR. ROSSI: So the inputs to the SFRCS were not changed?

MR. STALTER: That's correct.

MR. ROSSI: They are the same.

MR. BEYER: The transmitters were not changed, you said, right? The amplifier boards were changed?

MR. STALTER: Okay. That's correct.

MR. ROSSI: Have you done scoping looks at the time responses to see if they did, indeed, change since you made the modifications in the last refueling outage?

MR. STALTER: We did response time testing, and they passed all the acceptance criteria. Now of course the acceptance criteria for response time testing is all maximum criteria. There was no minimum criteria.

MR. BEARD: Was it a go/no-go type test or a measurement test?

MR. STALTER: It was a measurement test.

MR. ROSSI: So you must have a record on --

MR. STALTER: We do have that record.

MR. ROSSI: Have you looked at that yet to see if it responded faster?

MR. STALTER: We have looked at -- the transmitters themselves?

MR. ROSSI: No. The things that you changed.

MR. BEARD: Well, the transmitter with the new board.

MR. STALTER: Yes, we have looked at it. The transmitters were essentially the same. They were in the same ballpark. There weren't a whole lot of changes as a result of

changing out the calibration boards and the amplifiers.

The bistables were lengthened somewhat, a little longer response time when we placed the bistables in the SFRCS.

MR. ROSSI: Are those bistables used for closing the MSIVs?

MR. STALTER: Yes.

MR. ROSSI: So they have a longer time response.

MR. STALTER: Very slightly. They went from 3.5 milliseconds to about 20 milliseconds.

MR. BEARD: And can you give me a feel for what typical response time for your level transmitter is? I mean, are we talking 150 milliseconds, 500 milliseconds? Just ballpark.

MR. STALTER: I can get that data for you.

MR. BEARD: Is it here in the room?

MR. STALTER: I think I have it in my briefcase.

MR. BEARD: Maybe after we take a break, we can get, rather than interrupt. But I would like to know just roughly what kind of numbers we're talking about.

I guess at this point, maybe I misread this thing. I had an entire flavor that there was a phenomenon, and that because of the new transmitters, which I read to be faster, now the phenomenon was interfering with the performance of the steam feed rupture control system, and that's why there was a

spurious trip.

MR. STALTER: Some of the latest information we have now -- and they are working on it even today -- is that the response time was increased, and we don't know by how much, because of the Bailey BY replacement in the sensing lines.

Now Bailey BYs act a little different from the Rosemont transmitters in that they are more of a positive displacement type. You actual have to displace fluid in them and move an LBVT to change the signal.

There were three of those on that same sensing line that the Rosemont is on, that actuates the SFRCS. And we replaced those three other transmitters with Rosemont 1153s, which are essentially zero displacement.

So you, in effect, had a buffer in there, if you will --

MR. ROSSI: With the Baileys.

MR. STALTER: -- with the Baileys that affected the response time of what was going to the SFRCS.

MR. HILDEBRANDT: J.T., that's the important of that No. 2 under "Change Analysis," if I can try to just tie those two together.

MR. BEARD: That's what I'm trying to understand.

MR. HILDEBRANDT: I understand. I just want to make sure that we have it together.

MR. ROSSI: The Bailey acted as a filter for

pressure transients in the sensing line, that would then be detected by the Rosemonts, then to feed the SFRCS; that's what you're saying.

MR. STALTER: Yes.

MR. ROSSI: And by replacing the Baileys with Rosemonts, you did away with that filtering, and you may have allowed pressure transients to get passed through the sensing line more easily.

MR. STALTER: Quicker.

MR. ROSSI: Well, or without damping.

MR. STALTER: Without damping; that's the important thing; that's correct.

The effects of that data, I don't have today. They're just looking at it today. There is some data available that shows the differences, and I'm not sure how good that data is or what it says.

MR. BEARD: Is that pressure tap the same as the ones used for the steam generator output pressure sensor?

MR. STALTER: Which pressure tap?

MR. BEARD: The pressure tap that we're discussing here, that has on it -- previously had the Baileys, which acted like a filter, but also has the level transmitters that go into the steam feed rupture control system is one instrument panel, and my question is, does that instrument tap also have on it the pressure instrument that provides the

output signal that's computer point, P as in Paul 936, which would be labeled "steam generator out, steam pressure."

MR. STALTER: I don't think so. I'd have to verify that for you.

MR. ISLEY: I think that that pressure transmitter is actually on the steamline, rather than on the steam generator.

MR. BEARD: Okay. So it would be a different tap.

MR. JAIN: I was confused by your pressure tap and the level sensing tap. These are level sensing taps you are talking about?

MR. BEARD: Do your level transmitters not work on differential pressure?

MR. STALTER: Differential pressure, yes.

MR. BEARD: So they are pressure taps. Sorry, terminology here.

One last question. I had asked Bill Rowles if he would provide the technical manuals on those two transmitters, the Baileys and the Rosemonts, and give us some information as to how those transmitters were plumbed -- in other words, the sensing lines from the taps to the transmitter.

Did you folks bring any of that information?

MR. STALTER: Yes, we have that here. We will leave it for you. We just got the drawings delivered from Bechtel.

MR. BEARD: Which ones are in there?

MR. JAIN: These are the ones for the SFRCS, and then we have a separate set here which is for the others that go to the control panel and otherwise

MR. BEARD: For the instrument transmitters?

MR. JAIN: Yes, level transmitters.

MR. BEARD: As long as they are here, that's fine.

MR. ROSSI: Could you tell us, what was the reason for adding the high-level trip signals to the SFRCS? That was done, I think, the last refueling outage, right?

MR. JAIN: The reason was to provide overflood protection for the steam generators, so you don't spill over water into the main steamlines and carry over into the turbine.

MR. ROSSI: Is that a required item from TMI, or what was that required from?

MR. BEARD: I'm not certain that the NRC ever required it.

MR. WIDEMAN: Oh, yes.

MR. LANNING: It came out of an AEOD study.

MR. BEARD: Some very intelligent person obviously found a fault, and now it's corrected.

MR. WIDEMAN: And there was an open item from the Region regarding that particular issue.

MR. ROSSI: Okay. But was it something that you did as a result of information that you received, or was there

really a commitment that they had for regulatory reasons to add it?

MR. JAIN: I don't recall that we ever had any regulatory commitment to install the high-level trip. I think it was reported from Mr. Michelson in the AEOD report that came out. And I think they also had an overflood event at Arkansas. As a result of that, to provide the safety protection, we put in the high-level trip.

MR. ROSSI: Okay. Have you looked at the design of that to see if there is anything in it that would have caused the MSIVs to close? It also closes the MSIVs; is that correct?

MR. JAIN: The relation there is that the bistables that we put in as a result of the high-level trip, now it's a single module that contains the low as well as the high-level bistable, whereas previously there was only a separate low-level bistable.

MR. BEARD: So it's a dual bistable unit, high and low trips?

MR. JAIN: Correct.

It looks like the difference here is more in response time, and we haven't seen that much difference. In fact, it increased somewhat.

MR. ROSSI: Well, after you go through the high level, low level bistables, is the actual logic in the rest of

the SFRCS going to the MSIVs identical? So all you did is every place you had a low level signal before closing the MSIVs, you now put in this dual bistable that does the same thing when you have got either high or low level with the same logic.

MR. JAIN: Exactly.

MR. ROSSI: And then the blocking of the high level trip -- that's item No. 4 on page 3. What was the reason for that?

MR. JAIN: We flood our steam generators when they shut down, wet layer, and when you flood it to a level which is above the high level trip setpoint --

MR. ROSSI: So that was just a part of the overall modification to add the high level trip.

MR. JAIN: Correct.

MR. ROSSI: And those FCRs were developed at the same time. It's not that you put in item No. 3 and then -- is it the same number? Oh, okay. You are right.

MR. BEARD: I would like to understand a little bit more on item No. 5 and item No. 6 wherein you made a modification such that your aux feedwater steam side crossover valves would open MS 106A and 107A, and then you removed that or defeated that modification.

Could you explain a little bit more about the comparison between the efforts to unmodify as compared to the

efforts to modify?

MR. JAIN: Efforts in terms of man hours?

MR. BEARD: No. I am thinking along the line of -- I understand that when it was modified, the hardware was changed to a certain configuration.

MR. JAIN: Correct.

MR. BEARD: When it was unmodified, it was returned to something that may be functionally equivalent but the hardware is different. It's not the way it was before the modification.

MR. JAIN: That's true.

MR. BEARD: Could you explain a little as to what that was?

MR. JAIN: Was basically the changes in the logic bullets in the SFRCS. There were some functional differences also. Where previously, before the '84 refueling outage, you would send a closed signal to 106A and 107A on a low level signal or reverse differential pressure or a loss of reactor coolant pumps, with the new, unmodified configuration, after we did the 81-178, Revision 8, we don't have a closed signal going to 106A and 107A on the low level. There was differential and loss of reactor coolant pumps.

MR. BEARD: So the functional difference is the closed signal to 106A and 107A is no longer there.

MR. JAIN: Under those three conditions.

MR. ROSSI: They are not just normally closed, so they don't open under low level.

MR. JAIN: Right.

MR. BEARD: Is that the only hardware difference between the modification and the unmodification?

MR. JAIN: That's the only thing I can recall, yes.

MR. BEARD: Is it possible that there is something in that change that may have introduced the problem or contributed to the problem?

MR. JAIN: It would be hard to think so because the change that was done from Rev. 0 to Rev 8 was only on the logic board with some changes within the logic board.

MR. LANNING: Who does these modifications to the SFRCS system?

MR. JAIN: They are mainly done by Consolidated Controls Corporation who is the vendor for the system.

MR. LANNING: What role does Bechtel play in the SFRCS system?

MR. JAIN: Normally, the CCC people. They would prepare a fuel change package which would be generally sent to Bechtel for the engineering review and then Bechtel would be issuing a package to the FCR. That would be the normal process. So they would be performing an engineering review of CCC's work.

MR. BEARD: Was that the process used for these two

modifications?

MR. JAIN: For 81-178, Rev.0, that was the process that was used.

MR. BEARD: What about the unmodification part, the Rev. A?

MR. JAIN: Rev. A was done inhouse within Toledo Edison.

MR. BEARD: Was Bechtel informed or did they concur or give comments on it?

MR. JAIN: They were informed about the logic changes and they concurred, and they were later a sent a copy of all the changes.

MR. BEARD: We are up to the part of the hypothesis -- and you know I hate to repeat this, but it just seems like the evidence is not there. I mean, your analysis of the response of the instruments doesn't indicate one or one and a half cycle oscillations. The magnitude of the oscillations doesn't appear to bring you down to the setpoint, as I understand it. The response time of the transmitters and the logics does not seem to have been made significantly faster to explain the phenomena of having been there all the time. But the damping of the Bailey's may account for part of that.

What are you going to do when you go through and run this and find you cannot prove anything? I mean, it seems to me you've got all your eggs in one basket and we've had this

come up on other troubleshooting plans, and I just don't know where to go from here.

MR. NOBLE: How hard have you thought about testing? I mean, assuming that this hypothesis is true -- and I think there is a question about even that because you may have logic problems in the SFRCS and you may have a problem with the controls of the MSIVs. I mean, those are possibilities, and they may be low probability possibilities but certainly this is an area here that doesn't appear to me to be very high probability.

I mean, how hard have you looked at testing with simulated signals or simulated pressure signals to the sensors, or something like that, to see if you can reproduce the things that were actuated and the things that were not actuated during the June 9th event with the plant shut down?

MR. STALTER: We have not looked into what it would take to do such a test, and I don't know what it would take at this point. You have a number of false signals to put in, you have to look at all the equipment that we actuated as a result of that.

MR. NOBLE: But you're going to have to do time response testing and all that also, so you're going to be in there doing a lot of testing, and it would appear to me that while you were in there doing the testing, you may want to do a little bit more testing and see if you could actually

reproduce the sequence that occurred in this system.

MR. BEARD: This gets into the area where I had comments jotted down on the specific action plan steps.

It seemed like you might want to consider using test signals of magnitudes and duration comparable to this pressure wave phenomena we've discussed, and attempt to duplicate the response of both the rupture control system and its actuated equipment, and then vary the duration of the signal to determine the minimum duration required to cause either a half or full trip and cause the fastest and the slowest seal-in circuit to operate.

In other words, you're starting from an effort that attempts to replicate your primary hypotheses, and then testing everything from there down.

It seems that also, there are other pieces of actuated equipment that I didn't find in your specific action plan that I think you might want to measure the response times of, or at least the seal-in circuits of. And it seems to me also that we heard some discussion that the time of the actuation of the system may not have been the three or four seconds indicated on the alarm printout, because apparently there are some delays in either the actuation or the turn back off phase of the annunciators, which could be on the order of a couple seconds. Some information along that line presented to us.

And it seems to me if that's the case, you need to investigate your annunciator response in the sense of: can we believe the data we do have that is hard.

MR. STALTER: There is a deliberate three-second time delay in the SFRCS turnoff, and that was put in to catch SFRCS alarms so that you didn't one that came in and came out and didn't get the annunciator for it. So we put a three-second time delay in that annunciator, so everytime it actuates, that alarm will not go off until two or three seconds later or thereabouts.

MR. JAIN: I will leave you a drawing here. The drawing shows it to be two seconds and I think the action plan addresses measurements of that delay that could have been two to three seconds. And if you'll look at the sequence of events, the SOE finds that we call them which are of a millisecond type. The SFRCS full trip alarm was there for three seconds and 135 milliseconds. If you subtract off the off-delay of two to three seconds, that leads you to believe that the full trip may have only stayed there maybe a second or a little more than a second. Or even less than that if the time delay delay was set more than two seconds.

MR. BEARD: Well, here are we in a story that's analogous to the one about the PORV? That the intentional delay confuses the matter in terms of we really don't know how long it was actuated? It could be that the thing was actuated

for a little over three seconds, or it could be that it was actuated for as little as less than one second.

MR. JAIN: Well, there is a way to measure that, though. You could go and measure the time delay response time --

MR. BEARD: You mean the annunciator?

MR. JAIN: No, the time delay delay.

MR. BEARD: Are you talking about a time delay in the annunciator?

MR. JAIN: Yes, for the computer printout --

MR. BEARD: Well, the kind of thing I was thinking about was measure delays in the annunciator system, and I didn't see that in your plan. Is that in there?

MR. JAIN: I thought it was in there.

MR. BEARD: Okay, I find it now. I didn't recognize that as a measurement of the annunciator. I guess what I was saying is that it would seem to me you would want to measure the steam feed rupture control system for actuation times that would envelope, you know, either of these possibilities and a few points inbetween, and then see what happens in the system, what happens in the actuated equipment, and see if you can correlate that back to what happened during the event.

MR. ROSSI: Yes. I think the bottom line of what we are both saying is that we think you're going to have a hard time concluding that the root cause is this problem without

testing to back it up where you try to reproduce what occurred with the equipment, if that can be done with the plant shut down. Because, you know, it's going to be just very fuzzy to deal with if it's analyses only.

Now, I think you need the analyses also and you probably want to do that before you try to do any testing, but it looks to us that you ought to be looking at what you can test to prove this hypothesis and to see if you can reproduce what occurred.

MR. BEARD: If this pressure wave phenomena exists and has oscillations on it like one or one and a quarter seconds, would you not be able to see it on other instrumentation such as this output steam pressure transmitter that I was discussing earlier?

I mean, if you go back to fundamentals and say there is some standing wave or reflected wave in that steam line upstream of the turbine stop valves, wouldn't there be other instruments that could confirm or deny its existence in some way or another? Or at least help me get a handle on this beast?

MR. STALTER: We could do that. The instrumentation that we now use doesn't have a response time to pick that up.

MR. BEARD: Have you looked at any of the DADS data to see if we could analyze that in some way that would at least give you a better feel for it?

MR. STALTER: Yes, we could that. That's not a problem.

MR. BEARD: Well, I have plotted the DADS data for one of the steam generator level channels and for one of the steam output pressure channels. And I'll tell you right now my own look-see at it -- and I haven't done a great deal of analysis because that's your job, not mine. But the data does not have the kind of scatter that you would expect with some interfering one-cycle per second signal. It's very, very smooth.

And it really raises questions about the credibility of your central hypotheses.

MR. ROSSI: Well, let me see if I can summarize it. I guess there's the concern that you have assumed the conclusion that the MSIV closure was spurious actuation of the SFRCS. I mean, that's an assumption right upfront. You don't have any other hypotheses like the MSIV closure circuits, logic problems within the SFRCS; you don't have anything else.

And then there's the problem that even if you got the right hypothesis you're headed down the road of analysis only and time response comparisons and that kind of thing, and with no testing. And that's going to be hard when you get to the end, to convince people that you have really found the root cause.

And then in addition, there is the problem of even

demonstrating that you have got any kind of oscillations from this pressure transient at all. And you know, there is very little indication that you had it, and very few ways that you can prove it.

MR. BEARD: Would it be a good time to take a five-minute break.

MR. ROSSI: Yes. Bernie, did you have something?

MR. BEYER: I do have a question. I think I can fully appreciate what your comments, or the thrust of your comments is. I guess one question I would have relative to this action plan, if I was to put it in simple terms, this action plan would be viewed as incomplete in your eyes, as opposed to necessarily being wrong or, in and of itself, such that if we went through these things we would preclude the possibility of finding the real root cause.

MR. ROSSI: I don't see, myself, anything in here that would, if you went through this, that's going to destroy the evidence. I mean, as long as you do it with care and you keep track of everything and do it with QA and all that kind of thing I don't see anything in here. Do you, J.T.?

I mean, it's possible you could because you may be lifting leads to make response time --

MR. BEARD: It depends on the technique.

MR. ROSSI: And the care that it's done with and the QA that is used to make sure that careful records are kept,

and everything is maintained in the same state that it's in now.

MR. BEARD: Yes, the kind of thing I think you'd want to be concerned about, Bernie, is this. If to go in and put a visicorder or similar piece of equipment into the system to make a response time measurement you have to lift a lead, you may very well find that you put yourself back in the situation of the previous event where you found what you call a bad connection because you lifted a lead and put it back and the trouble went away.

So I think the position I would like to take, and I think the Team probably will also, is that if you choose to go forward with this test, you should look carefully at the techniques that are involved in making these measurements with a particular eye for could this disturb something.

MR. ROSSI: And you may want to look at the SFRCS, do tests of the logic in its current condition before you start doing this, or tests of the MSIV controls before you start doing this.

MR. BEYER: That's what I wanted to get a feel for.

I think from your comments today, we definitely will consider what sort of testing we can do to get a better handle on this. I just wanted to get an understanding as to whether what we had here might be destroying evidence or possibly clouding the issue or making it impossible to find another

root cause someplace. And I think I understand that.

MR. ROSSI: Now, your basic vendor for this is Consolidated Controls and Bechtel is the sort of functional designer?

MR. STALTER: For the logic. For the SFRCS system, Consolidated Controls manufactured that.

MR. ROSSI: Bechtel determines what signals are used and how they are combined and what the logic is and all that kind of thing? Is that Bechtel?

MR. STALTER: Bechtel and Toledo Edison determined the logic.

MR. BEARD: You realize that in your experience in the past at Davis Besse there have been questions raised on other events that occurred at your plant on equipment that was designed by Consolidated Controls wherein because of common commons, the power supply returns within actuation channels shared the same common and disturbances came along and affected two channels simultaneously; that that's a possibility because it has happened on other pieces of equipment at your plant.

One of the things that I am surprised by is that some consideration of that is not in this plan when you've had prior experience in that area on other Consolidated Controls equipment.

MR. ROSSI: That's a good point. That is all what,

two out of four logic basically -- ?

MR. BEARD: No, it's entirely different. And I think basically what it amounts to is you've got four logic actuation channels divided into two trains, so to speak, but within one train, one actuation channel, it's a two out of two setup. And two out of two, if they both fire, the logics fire, then you get a full actuation of one actuation channel.

MR. JAIN: I understand your problem about the SFAS and the common grounding.

MR. ROSSI: Well, the point I was trying to get to is that regardless of what the logic is, is it possible to have an electrical transient in one channel that, through improper grounding or improper interactions between channels and logic trains, is enough to close both MSIVs? Is that possible?

MR. STALTER: In and of itself without anything else wrong?

MR. ROSSI: Yes. Just a transient that interconnects with the other channels and logic trains.

MR. BEARD: And correct me if I'm wrong, but my understanding of the system right now -- and I haven't had as much time to refresh myself on the design of this beast as I would like to -- but my understanding at this point in time is that if actuation Channel A, to pick an example, has a spurious signal coming out of it, full actuation, that that is

of itself sufficient to close MSIVs because if you go down through and look at the table of the actuated equipment, Actuation Channel A has sent "close" signals to both MSIVs.

So if you take that as a starting point and then back up and say, now let's go up into the two logics within one actuation channel, which have their power supply commons tied together, it is very credible that an electrical glitch could cause a full actuation in both MSIVs to close, and electrical glitches at the time of a trip of a main generator to a power station have been known to happen.

MR. ROSSI: Which is another thing that you ought to perhaps look at, things that might have occurred that you have records of with power supplies in the plant at about the time the MSIVs closed.

MR. BEARD: So I guess the bottom line that I see personally is that the main hypothesis has a lot of questions about its credibility, and there are other hypotheses floating around that have some credibility.

MR. ROSSI: Why don't we take a five or ten-minute break.

[Recess.]

MR. ROSSI: Back on the record.

I think the first thing we need to do is to get as part of the transcript a copy of the Action Plan that we were talking about, so Wayne, why don't you take care of that.

MR. LANNING: Okay. This will be Exhibit No. 6, which is Action Plan 5, 6 and 7, entitled Low Steam Generator Level Trip of SFRCS, and it is dated June 22, 1985.

[The document referred to, marked Exhibit No. 6, follows:]

Exhibit #6

ACTION PLAN # 5, 6 & 7

TITLE: LOW STEAM GENERATOR LEVEL TRIP OF SFRCS

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE
0	6/22/85	Initial Issue	L. Stalter F. Miller K. Yarger	[signature]

TITLE: Low Steam Generator Level Trip of SFRCS

REPORT BY: L. Stalter, F. Miller, K. Yarger PLAN NO.: 5,6 & 7

DATE PREPARED: June 22, 1985

INTRODUCTION:

This report has been prepared in accordance with the "Guidelines to Follow When Troubleshooting for Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip", Rev. 4.

On June 9, 1985 a low Steam Generator (SG) level full trip of the Steam and Feedwater Rupture Control System (SFRCS) occurred when the main turbine tripped. This information was observed from the alarm log of the event. Additional SG low level half trips have recently occurred on June 2, 1985 and on April 24, 1985. At the time of these trips, the time-averaged SG levels were at least 70 inches above the low level trip setpoint. No previous spurious low SG level trips have occurred at Davis-Besse (DB) prior to the 1984 Refueling Outage.

SUMMARY OF DATA

A detailed review of all of the available data from the June 9, 1985 event indicated that a full SFRCS trip occurred at 1:35:31 at the same time the main turbine stop valves closed. This full SFRCS trip occurred for a very short duration and it resulted in only the two Main Steam Isolation Valves (MSIVs) closing. At 1:35:31 the computer recorded a Channel 2 SG level trip. This alarm could have been caused by a full or a half trip of the SG level strings. No positive data is available to indicate which SG caused this alarm. Alarms were also recorded on the computer at 1:35:31 that indicated that SFRCS had sent trip signals to the main turbine and to the Anticipatory Reactor Trip System (ARTS) to trip the reactor. However, both the reactor and main turbine had been previously tripped after Reactor Protection System (RPS) actuation.

Review of past experience indicates the following:

1. Prior to the 1984 refueling outage, many turbine trips occurred that did not cause spurious SFRCS trips.

2. On April 24, 1985, a half trip of Channel 2 low SG level occurred when the main turbine tripped. No full trip was recorded during this event.

3. On June 2, 1985, a half trip of Channel 2 low SG level also occurred when the main turbine tripped. An SFRCS full trip alarm also was recorded on the computer at this time. No devices were actuated by this event and the SFRCS did not attempt to trip the main turbine.

Subsequent to the June 9, 1985 trip transient, it was determined from discussion with B&W that earlier testing at TMI-1 shows that SG startup range level transmitter output oscillates widely for about 10 seconds

after a main turbine trip from 100%. This information was taken using high speed recorders, and shows oscillations of 1.2 - 1.3 cycles/second. No similar data exist for DB, but the SGs are essentially identical and the same phenomenon could be expected to occur.

MAINTENANCE AND SURVEILLANCE/TESTING HISTORY

The following is a listing of maintenance and surveillance test activities performed since the 1984 refueling outage:

1. Surveillance Test ST 5031.14 was performed on all channels for each input parameter once each month. No abnormalities were found, no drifting of components was noted since the 1984 refueling outage.

2. The apparent spurious trip of the SGLIC Channel 2 was checked out by MWO 1-85-1444-00 dated 4/24/85. This MWO called for running the monthly surveillance test while checking for anomolies. No anomolies were found.

3. A relay driver board was replaced in the SFRCS logic Channel 1 for relay K201A (MWO 1-85-1552-00 dated 5/4/85).

4. A power supply was replaced in SFRCS logic Channel 2 (MWO 1-85-1843-00 dated 5/27/85).

5. The status light socket for K602A relay in the SFRCS logic channel was replaced (MWO 1-85-1860-00 dated 5/29/85).

6. Troubleshooting was performed on SFRCS alarm logic Q963 (MWO 1-85-1877-00 dated 6/2/85). This MWO called for testing the alarm logic to determine why a full SFRCS alarm occurred on a half trip. In the process of checking, a connection was reterminated and the problem cleared. Testing on both SFRCS channel 2 and channel 4 was completed per section 6.4 of ST 5031.14. No drifting of setpoints or other anomalies were found.

A review of the maintenance and surveillance/testing activities indicates that they did not affect the functional operation of the SFRCS.

CHANGE ANALYSIS:

The following changes were completed during or after the 1984 refueling outage.

1. All SFRCS/steam generator level transmitter amplifier and calibration boards were replaced to continue to meet the environmental qualification requirements (MWO 1-84-1269-00).

   All transmitters were calibrated and response time tested by surveillance tests (ST-5031.16). All acceptance criteria were met.

2. The level transmitters providing startup level indication on the control panel connected to the same sensing line as the SFRCS level sensing transmitter were changed from BY to Rosemount transmitters.

3. The Steam Generator Level Indication and Control (SGLIC) circuits were modified by FCR 80-110 which installed new analog - bistable units to add the steam generator high level trip capability. This required that the original bistables used for low level trip also be replaced to gain cabinet space. These units are now a composite unit in that the analog and bistable functions are contained in one unit as compared to separate analog and bistable units previously used for the low level trip function.

   All modules were calibrated and response time tested by surveillance tests (ST-5031.15) and all acceptance criteria was met.

4. The SFRCS actuation channels 1 and 2 were modified to provide for blocking of the steam generator high level trip by FCR 80-110. This change was tested by surveillance test (ST-5031.14 Section 6.1) and Section 6.14. This verified that the installation was correct and that the level set points for both the high trip and the low trip were set properly.

5. The SFRCS actuation Channels No. 1 & 2 were modified by FCR 81-178 to provide for the additional opening of steam supply valves (MS106A & MS107A) to the auxiliary feedwater pump turbines on steam generator high or low level, high steam generator feedwater differential pressure and loss of all four reactor coolant pumps.

6. The addition of the valve actuation logic by FCR 81-178 was defeated by FCR 81-178 Rev. A as it may have caused pipe hanger damage to occur in the steam lines to the auxiliary feedwater pump turbines. FCR 81-178A was tested by TP 580.00 and all acceptance criteria were met.

7. The SFRCS actuation channels No. 1 & 2 were modified to allow operation of the steam generator blowdown valves HV 603 and HV 611 for modes 4, 5, and 6 operation. This change was completed and tested (TP 520.81 and ST 5030.18) during the 1984 refueling outage.

The only changes listed above that could affect the response time of the steam generator level instrument strings were changes 1, 2 and 3. None of the others had any effect on the response time of the SFRCS.

HYPOTHESES

The cause of the half trips of SFRCS appears to be the SG startup range level transmitter output oscillations due to pressure oscillations from the main turbine trip. The modifications that were performed in the SG level instrument string used by SFRCS during the last refueling outage may have made the string's response time faster so that steam generator pressure oscillations are now detectable. This may account for the spurious SG level trips that have occurred since the 1984 refueling outage.

It is postulated that on June 9, 1985 1/2 SG low level trips occurred within each half of an SFRCS actuation channel with the following results:

1. They overlapped long enough to allow the following alarms to occur:

    a. Q963 SFRCS FULL TRIP; this alarm requires that both halves of an SFRCS be tripped simultaneously.

    b. Q777 ARTS TRIP (Anticipatory Reactor Trip System); this alarm indicates that the ARTS was tripped. Since no other ARTS input alarms occurred, the only way that this alarm could have actuated would be due to an SFRCS trip of ARTS.

    c. X044 T-G MN STM (Turbine-Generator Main Steam) and FW TURB TRIP (Feedwater Turbine Trip); this trip indicates that the SFRCS sent a trip signal to the main turbine. However, the main turbine had already been tripped by the reactor trip.

2. Each half trip occurred long enough to allow the electrically operated solenoid valves and the air pilot valves in the MSIV air system to trip. These half trips overlapped long enough to allow the "seal-in" circuits to drop out, and thus, the MSIVs stayed closed after the half trips automatically reset.

3. These half trips did not overlap long enough to pick up and seal-in the starters on any SFRCS actuated motor operated valves (MOV). This would explain why we did not start the auxiliary feedwater pumps during this spurious full trip of SFRCS. In the past, when we were experiencing spurious high reverse delta pressure main feedwater trips, on some occasions only the MSIVs closed and MOVs did not operate.

4. Each half trip occurred long enough to allow the electrically operated solenoid valves in the Main Feedwater Startup Control Valve (SP7A, SP7B) air system to trip. However, these half trips did not overlap long enough to allow the "seal-in" circuits to drop out, and therefore, the Main Feedwater Startup Control Valves remained open.

Special tests are needed to determine the trip and trip reset response times for the components in the MSIV and the Main Feedwater Startup Control Valve control circuits.

Other less likely hypotheses might be possible. The action plan has been designed to preserve the equipment status should the above hypothesis prove false.

ap 5 & 7-1

ACTION PLAN
ED 6408

Rev. 0	PLAN NUMBER: 5 & 7
PAGE: 1 of 4	
DATE PREPARED: 6/20/85	PREPARED BY: L.C. Stalter

TITLE: Low Steam Generator Level Trip of SFRCS

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	All steps of this Action Plan are to be performed in accordance with the latest revision of "Guidelines to Follow When Trouble-shooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip".					
	The following steps may be performed in any sequence. Substeps of any step should be performed in the order listed.					
1	Review available data on the effects on the steam generator startup level from a turbine trip. Use available information from previous transient at Davis-Besse, and data from TMI-1 supplied by B&W for this review.	L. Stalter				
	A. Use the data from 1 to verify the hypothesis.	F. Miller				
	B. Use data from 1 and work with Bechtel and CCC (SFRCS vendors) to establish an appropriate response time for the	L. Stalter				

ACTION PLAN
ED 6408

Rev. 0

PLAN NUMBER	PAGE
5 & 7	2 of 4
DATE PREPARED	PREPARED BY
6/20/85	L.C. Stalter

TITLE
Low Steam Generator Level Trip of SFRCS

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	Steam Generator Level Indicator and Control (SGLIC) bistables to prevent inadvertant actuation of SFRCS following a turbine trip, and still meet the required overall response time for SFRCS actuation on steam generator level.					
2	Determine why the Main Steam Isolation Valve (MSIV) closed and other SFRCS actuated equipment did not change status.	F. Miller				
	A. Perform tests to determine the specific component trip response times and seal in response times of MSIV and Main Feedwater Startup Control Valves.	K. Yarger				
	B. Analyze the data from step 2A to verify that only the MSIV would close upon a full SFRCS trip of short time duration, and other equipment would not actuate.	F. Miller				

ACTION PLAN
ED 4408

Rev. 0

PLAN NUMBER	PAGE
5 & 7	3 of 4
DATE PREPARED	**PREPARED BY**
6/20/85	L.C. Stalter

TITLE
Low Steam Generator Level Trip of SFRCS

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
3	Test the time delay relay (TED shown on drawing E-42B, sheet 54) in the SFRCS "full trip" reset logic to verify the total time the SFRCS full trip was in effect.	K. Yarger				
	A. Determine the length of time the full SFRCS trip was in the tripped condition by combining this time with the sequence of events data.	F. Miller				
	B. Analyze this data for verification of the hypothesis.	F. Miller				
4	A. Visually inspect each steam generator starting level transmitter for loose connections, cleanliness.	K. Yarger				
	B. Verify the response time of each Steam Generator startup level transmitter.	K. Yarger				

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
5 & 7	4 of 4
DATE PREPARED	PREPARED BY
6/20/85	L.C. Stalter

Rev. 0

TITLE
Low Steam Generator Level Trip of SFRCS

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	C. Verify the calibration of each steam generator startup level transmitter.	K. Yarger				
	D. Analyze this data and check for anomolies.	L. Stalter				

ACTION PLAN
ED 6408

Rev. 0

PLAN NUMBER	PAGE
5, 6 & 7	1 of 4
DATE PREPARED	**PREPARED BY**
6/20/85	L.C. Stalter

TITLE
Low Steam Generator Level Trip of SFRCS

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	All steps of this Action Plan are to be performed in accordance with the latest revision of "Guidelines to Follow When Trouble-shooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip".					
	The following steps may be performed in any sequence. Substeps of any step should be performed in the order listed.					
1	Review available data on the effects on the steam generator startup level from a turbine trip. Use available information frc previous transient at Davis-Besse, and data from TMI-1 supplied by B&W for this review.	L. Stalter				
	A. Use the data from 1 to verify the hypothesis.	F. Miller				
	B. Use data from 1 and work with Bechtel and CCC (SFRCS vendors) to establish an appropriate response time for the	L. Stalter				

ACTION PLAN
ED 6408

Rev. 0

PLAN NUMBER	PAGE
5, 6 & 7	2 of 4
DATE PREPARED	PREPARED BY
6/20/85	L.C. Stalter

TITLE
Low Steam Generator Level Trip of SFRCS

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	Steam Generator Level Indicator and Control (SGLIC) bistables to prevent inadvertant actuation of SFRCS following a turbine trip, and still meet the required overall response time for SFRCS actuation on steam generator level.					
2	Determine why the Main Steam Isolation Valve (MSIV) closed and other SFRCS actuated equipment did not change status.	F. Miller				
	A. Perform tests to determine the specific component trip response times and seal in response times of MSIV and Main Feedwater Startup Control Valves.	K. Yarger				
	B. Analyze the data from step 2A to verify that only the MSIV would close upon a full SFRCS trip of short time duration, and other equipment would not actuate.	F. Miller				

ACTION PLAN

ED 6408

TITLE	Rev.	PLAN NUMBER	PAGE	DATE PREPARED	PREPARED BY
Low Steam Generator Level Trip of SFRCS	Rev. 0	5, 6 & 7	3 of 4	6/20/85	L.C. Stalter

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
3	Test the time delay relay (TED shown on drawing E-42B, sheet 54) in the SFRCS "full trip" reset logic to verify the total time the SFRCS full trip was in effect.	K. Yarger				
	A. Determine the length of time the full SFRCS trip was in the tripped condition by combining this time with the sequence of events data.	F. Miller				
	B. Analyze this data for verification of the hypothesis.	F. Miller				
4	A. Visually inspect each steam generator starting level transmitter for loose connections, cleanliness.	K. Yarger				
	B. Verify the response time of each Steam Generator startup level transmitter.	K. Yarger				

ACTION PLAN

ED 6408

Rev. 0

PLAN NUMBER	PAGE
5, 6 & 7	4 of 4
DATE PREPARED	PREPARED BY
6/20/85	L.C. Stalter

TITLE

Low Steam Generator Level Trip of SFRCS

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	C. Verify the calibration of each steam generator startup level transmitter.	K. Yarger				
	D. Analyze this data and check for anomolies.	L. Stalter				

MR. ROSSI: Okay. We have discussed this one, and we have given you the concerns that we have and they are all related to whether this Action Plan and the things you are doing here are going to lead you to a root cause that you are going to be able to justify as being the root cause of the closure of the MSIVs.

We have told you our thoughts on the approach that you are taking and our thoughts on what are the things that you ought to consider. We assume you are going to revise this before you begin work; and in any event, before you begin work, would would like to see any revised plan that you develop. And if you decide not to change the one that you have now, that information ought to be given to Region III.

In any case, what we would like to do is, under the assumption that you are going to revise the plan, we would like to see it again before you start work and have the opportunity after we see it to decide whether we think it is worthwhile to have another meeting to comment on it.

So before you start work on this, you ought to clear it with Region III that we have either decided not to have another meeting on it or we have decided to have another meeting on it.

MR. BEARD: Or we may decide to provide comments by telephone.

MR. ROSSI: Or some other way, letter or something,

yes.

MR. SHAFER: I would like to ask that we receive these Action Plans at least three working days prior to your decision to implement them, and that would be the same for the Team, I believe.

MR. ROSSI: Yes. In any case, you shouldn't start the work until you have agreed with Region III that we either do or don't have comments on it.

I guess that's all we need to say about this one today, isn't it?

MR. BEARD: Maybe I could ask a question in terms of schedule. I'm sure that you probably don't have a firm schedule, but in view of the comments that we have given today, do you have any sort of feel at all for whether or not you intend to revise the plan? If so, what sort of general timeframe? But what is more important is when you might be starting work.

I mean are we talking three days from now, are we talking three months from now, or what are we talking about?

MR. WOOD: To answer your first question, yes, I think we intend to revise the plan, and I see us adding to the plan, not necessarily taking something away here and substituting it in. I see it as an addition. I think by going through the plan, we can see that there is still a lot of analytical-type work that can go on, so it won't bring us

to a screeching halt on trying to get to the bottom of this Action Plan.

I don't have a good feel because we will have to talk to some people back in Toledo yet to find out when we think we can formulate a new Action Plan that we would want to bring before the Team. It certainly won't be three days. It may be a week or in that timeframe. We have to remember next week, however, that the 4th of July complicates things somewhat.

So I think we need to go back and talk with our people and just see what kind of a schedule we are talking about; but I think it is in the week timeframe, not month timeframe.

MR. ROSSI: Okay. And from our end, we just want to make sure that you don't start the work until we have had an opportunity to tell Region III whether we think we need another meeting or whether we think another meeting would not be of any use. And at the root cause meeting, when you come to us and tell us here is the root cause, we will look at your justification at that point in time, and I think you understand the kind of things that we are going to be concerned about.

Okay, why don't we go on, then, to the startup feed valve, Action Plan No. 18.

MR. LANNING: This is Action Plan No. 18, entitled

"Startup Feed Valve SP-7A Problem Analysis," and it is dated June 22, 1985 and should be marked Exhibit No. 7.

[The document referred to, marked Exhibit No. 7, follows:]

Ex 7

ACTION PLAN # 18

TITLE: Startup Feed Valve SP-7A Problem Analysis

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE
0	6/22/85	Initial	T.M. Gibbs	[illegible]

Rev. 0 Approved for Implementation ________

TITLE: STARTUP FEED VALVES SP-7A PROBLEM ANALYSIS

REPORT BY: Ron Uebbing/Tom Gulvas PLAN NO. 18

DATE PREPARED: June 22, 1985 PAGE 1 of 2

This report has been prepared in accordance with the "Guidelines to Follow when Troubleshooting or Performing Investigative Actions into the Root Cause Surrounding the June 9, 1985 Reactor Trip", Rev. 4.

INTRODUCTION:

The following report is the analysis and evaluation for determining if there were problems associated with the operation of the Main Feedwater #2 Starup-Control Valve (SP-7A) or its controls during the June 9 transient.

SUMMARY OF DATA:

SP-7A is normally open when above 20% power. During the transient, SP-7A when closed automatically due to the initiation of SFRCS. After the SP-7A SFRCS trip was reset by the operator, SP-7A did reset properly. The SP-7A Channel 4 reset switch indicating light did not indicate this reset. The operator requested that the I&C technician replace the indicating bulb in this switch. A bulb was removed from the Channel 1 indicator and placed in the Channel 4 indicator by the technician to save time in verifying SP-7A reset status; this bulb blew immediately.

The alarm printout indicates that SP-7A and SP-7B startup feedwater valves reset at the same instance, this verifies the reset circuitry.

Additional verification of proper reset action of SP-7A is present in the DADS printout which reveals that main feedwater startup flow was established through loop 2 (SP-7A) and loop 1 (SP-7B) at the same point in time. SP-7A and SP-7B position printouts verify this. This printout also shows the removal of main feedwater flow as auxiliary feedwater flow was reestablished.

The SP-7A flow printout is higher than SP-7B and does not fall below 74 thousand pounds per hour when SP-7A and SP-7B are closed. This indicates the need to check the calibration of the flow measuring instruments associated with the operation of SP-7A.

As a followup, when time was available (about 0800, June 9, 1985), the SP-7A Channel 4 replacement indicator light bulb was checked and found to be the wrong voltage rating, 6 volt instead of the required 120 volt, the proper bulbs were installed in both channels and worked properly.

SP-7A SFRCS trip and reset logic is tested monthly under ST 5031.14, Sections 6.2, 6.3 and 6.4, and has recently shown no problems to be associated with the reset indication.

CHANGE ANALYSIS:

Not required.

HYPOTHESIS:

1. Startup feed valve SP-7A did function properly. The operator had no indication of proper reset function due to the reset indicating lamp failure. The lamp failure was due to random or normal end of bulb life, or to a voltage spike in the reset circuit.

2. SP-7A did not respond correctly. The action plan will address this hypothesis by the collection of data to show if there could have been flow through SP-7A.

ACTION PLAN
ED 4408

Rev. 0	PLAN NUMBER 18	PAGE 1 of 2	
TITLE Startup Feed Valve SP-7A Problem Analysis	DATE PREPARED 6/22/85	PREPARED BY Ron Uebbing/ Tom Gulvas	

SPECIFIC OBJECTIVE

Verify the determination that there was not a failure of the main feedwater #2 startup control valve or its reset control circuits.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	All steps of this action plan are to be performed in accordance with the latest revision of "Guidelines to Follow when Troubleshooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip".	T. Gulvas				
1*	Collect information regarding possible sources of flow through SP-7A at the time of the transient.					
2	Ensure SP-7A is reset					
3	Have operators open SP-7A at hand/auto station.					
4	Trip SFRCS Ch. 2 & 4 on low steam generator level using "test" switches.					
5	Verify SP-7A closes					
6	With test switches held in block SFRCS 2/4 trip					
7	Reset SP-7A and verify SP-7A opens, monitor channel 4 reset lamp voltage, and verify reset lamp lights.					
8	Release test switches					
9	Repeat steps 1 through 7					
10	Return control of SP-7A to operations control					

ACTION PLAN
ID 4408

Rev. 0

PLAN NUMBER	PAGE
18	2 of 2
DATE PREPARED	**PREPARED BY**
6/22/85	Ron Uebbing/ Tom Gulvas

TITLE
Startup Feed Valve SP-7A Problem Analysis

SPECIFIC OBJECTIVE

Verify the determination that there was not a failure of the main feedwater #2 startup control valve or its reset control circuits.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
11	Verify proper calibration of Main Feedwater 2 Startup flow indication instruments.					
11A	If the Main Feedwater 2 Startup flow indication instruments are within specifications, check SP-7A for faulty position indication.					
11A1	If SP-7A position indication is correct, check SP-7A for closed leakage.					
	*This step is not a prerequisite for the following steps and does not need to be performed before proceeding with Step 2.					

MR. WOOD: I would like to clarify that we didn't bring the lead people for Action Plans other than the three that we have discussed today, but we are in a position to take comments back to those people and evaluate them as we see the need here.

MR. ROSSI: Yes. We may not have very many comments. I think we have some questions that we just wanted to get clarification on.

I guess on page 1 you have indicated that the alarm printout, you have looked at it and it definitely shows that Valves SP-7A and SP-7B were reset and opened.

MR. BEARD: Maybe we could just ask what is the basis for the statement. Maybe you could just elaborate and that will resolve any questions we have. Or do you have the right people --

MR. WOOD: I'm not sure we have the right people here to answer that. What paragraph, specifically?

MR. BEARD: The second paragraph under Summary of Data. It says the alarm printout indicates that the valves reset at the same instance. Now, we did find some data points in the alarm printout specifically at time marks 01:51:40 and 01:51:42 that indicated that control valves were slightly open, and No. 1 was opened at 15 percent 51:40, No. 2 was open 10 percent at 51:42, but I don't think you had a particular printout that showed when the signals to those valves had been

actually reset.

Maybe we are talking the same thing; I don't know.

MR. ROSSI: But I think you are saying that our data indicates that we believe the valves opened also.

MR. BEARD: Yes. Maybe not at the same instance.

MR. ROSSI: Well, a couple of seconds apart, though. Okay. So I don't think we have a comment there that requires any further closure on. I think we are satisfied if you verified that. It looks like the information we have is consistent with it.

MR. BEARD: I had a question on -- I guess it's in the third and fourth paragraphs there, with regard to the information that flow was established from the startup feed pump through these two valves that we are talking about, SP-7A and SP-7B. I went back and looked at the DADS data, the numerical printout, and I was able to discern a distinct and obvious change in the flow on the main feedwater combined or composite flow at the appropriate time, which indicated that some flow had increased through Valve 7B.

But in looking at 7A, I didn't see any distinct and obvious change in the numbers. It's not obvious that you can make the same statement that flow came through. You know, it might be that it's just buried in the data, so to speak.

MR. ROSSI: But you do have indication that the valve opened.

MR. BEARD: Right.

MR. WOOD: That's correct.

MR. BEARD: So I guess it just raises some questions about these two paragraphs. You know, it may not be all that important, but in terms of verifying hard data, I had some difficulty in getting to the point that apparently the author of this was at, and I just throw it out on the table so that you can maybe take it back and reconsider it or do whatever you want to do with it.

MR. ROSSI: Well, we are going to have a meeting on what you find as the root cause, and I guess this entire Action Plan is directed at demonstrating that Valve SP-7A operated properly during the event, and the only problem is with the light bulbs. So we will have another crack at asking these same questions at the time we meet on the root cause, and I don't believe we need closure on any of the comments that have been made so far prior to our reviewing your justification on the root cause.

MR. BEARD: Maybe I could ask for just some better understanding on this thing about the wrong size light bulb. It appears -- I'm not sure I understand it. Are you saying that when the guy went to replace the burned out bulb, he grabbed, apparently, a bulb from Channel 4 which turned out to be a 6-volt lamp; but was it a right volt bulb for its application but a wrong one in the place he was trying to put

it, or was it wrong even in the application he took it from?

MR. BEYER: My understanding from our discussions with Tom Gulvas was that that was right for the application from which he took it but wrong for the application --

MR. BEARD: Fine. That's fine. Thank you.

MR. ROSSI: Do you have anything, Wayne?

MR. SHAFER: In your Action Plan, page 2 of 2, in light of what J.T. was discussing earlier regarding 11A and 11A1, I have a feeling that the risk is here that you might be masking another problem if you don't check this out. It doesn't seem like -- you are saying if you check the main feedwater startup flow indication instruments, then you don't have to do 11A and 11A1.

I don't think the information is available yet to verify that, and this may be a very important thing to look at.

MR. WOOD: Wayne, could you go through it again? I'm not sure I understand what you are saying.

MR. SHAFER: 11A and 11A1. You know, it's based on whether or not 11 -- if you go to 11 and you find no problems, then obviously, from what I read here, you are not going to do 11A or 11A1; is that correct?

MR. BEYER: The words in 11A would suggest that, but we do not have anything here that identified that as a lead-in.

MR. BEARD: That is why I was bringing it up earlier, trying to convey to you a message to tread with caution on that flow indication. Now, if you looked at it and you relooked at it and you are convinced there is a good, solid, clear, distinctive flow indication there in the data, that's fine; but I couldn't see it.

MR. SHAFER: And this might create a problem that would come back to haunt you later.

MR. BEYER: What 11 says is if we find a flow indication problem, a faulty position indication problem, then we would not necessarily look for internal seat leakage. Either 11A or 11A1 -- I shouldn't say that. 11A definitely will be done. 11A might not be done. It's not a matter of one or the other. 11A definitely will be done.

MR. BEARD: Is it the intent of 11, as far as you know, really to verify that where you see flow in the data, that the calibration is reasonable and therefore you can believe there was flow, and therefore it's probably just an indicator problem?

MR. BEYER: The concern here was that we might have leakage through the valve and therefore the position indication would not be an accurate indication of flow.

MR. BEARD: Okay.

Now, if I remember correctly from the data, the numerical values of the amount of flow that were shown through

that valve, a composite of main feedwater flow to that generator, were significantly higher when that valve was supposed to be closed than it was for the other valve when it was supposed to have been opened numerically.

So your question about leakage and these kinds of things may be of more importance than you had previously considered. And it was because the numerical value was so high and the lack of a perceivable, clear and obvious, distinct change in its value that I couldn't detect whether there was flow there or not.

Now, that is off the top of my head from memory, but there was a distinct difference in those values of flow when the valve is supposed to be closed.

MR. BEYER: I don't remember our group having discussion about the relative flows. I can't really respond to your comment.

MR. SHAFER: Had you come up with a date as to when you would like to implement this Action Plan 18?

MR. BEYER: I don't have a date, no. Generally, Wayne, we were told that within about three days from the time we would give the word to the field, the plant to go ahead and start, they could have the service reps in or proceed on the Action Plan. So that is a general guideline.

MR. ROSSI: Okay.

Now, the remaining action plans. We have now looked

at what we consider to be the Action Plans on the key pieces of equipment that affected this event. We have also given you comments numerous times about how important it is to keep the records and how important it is to find the root causes and cautioned you on doing as much test and verification wherever you can to try to reproduce failure so that when you come to us with the root causes, you can adequately justify that you really had them.

What we would propose to do with the remaining Action Plans is that we be sent copies as soon as they are developed, and that prior to your beginning work on any of these Action Plans, that we will contact Region III and ensure that if we do want to have a meeting on them or if we do want to have comments on it, we will get that information to you through Region III.

But before you start on any of these, you ought to clear it with Region III so that they have made sure that we have had an opportunity to decide whether we do or don't want to have a meeting or whether we want to try to make comments in some other way.

I think that the comments we have made on the ones that we have commented on should give you guidance on the kind of concerns that we have all the way through this troubleshooting. We are very concerned, again, about coming to us with the root causes where you haven't been able to

reproduce the failure and it is all analyses that we are depending on in order to decide whether we do or don't know the root cause.

MR. SHAFER: Do you feel uncomfortable being locked into that three working days if you receive it and are given three working days to review it?

MR. ROSSI: Oh, I think if we are given three working days, we can decide whether we need to comment on it or have a meeting. The thing that is going to be the rare case now where another meeting is going to be worthwhile on these other action plans -- you know the kind of concerns that we have, and you know that at the end of the road, you are going to have to justify that you have found the problems and you know what the problem was, and that is really the key. And we will have the opportunity at the end to look at your justifications on the root causes.

MR. LANNING: We have received from you today Action Plan 1C, entitled "Auxiliary Feedwater Pump Turbine Manual/Auto-Essential Control Problem," which will be Exhibit No. 8.

[The document referred to, marked Exhibit No. 8, follows:]

4.8

ACTION PLAN # 1C

TITLE: AFPT MANUAL/AUTO-ESSENTIAL CONTROL PROBLEM

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE	APPR. FOR IMPL.
0	6/24/85	Initial Issue	S.C. Jain	[signature]	

TITLE: AFPT MANUAL/AUTO-ESSENTIAL CONTROL PROBLEM

PREPARED BY: Sushil C. Jain PLAN NO. 1C

DATE PREPARED: June 24, 1985 PAGE 1 of 4

I. INTRODUCTION

This report provides an evaluation of the June 9, 1985, trip in relation to the apparent inability to take manual and auto-essential control of the auxiliary feed pump turbines (AFPT) from the Control Room. This inability was experienced following the full SFRCS trip actuation of both Auxiliary Feedwater System (AFWS) trains and subsequent trip of both AFPT's on overspeed. This report has been prepared in accordance with the "Guidelines to Follow When Trouble-shooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985, Reactor Trip, Revision 4."

SUMMARY OF DATA

A. Known information and operational data for conditions prior to, during, and after the transient.

PRIOR TO THE TRANSIENT:

Both AFWS trains were in their normal standby condition with the associated AFPT controllers (in the Control Room) in the "auto essential" position and the trip throttle valve aligned open. This is established by the absence of alarms from computer points Z012 and Z013 (AFP1 and 2 Auto-Essen Level Control Transfer Switch Alarm) prior to the transient. Also the trip throttle valve must be open for AFPT's to start. Surveillance testing and maintenance history prior to the transient is included in Section B.

DURING THE TRANSIENT:

The following chronology is listed to facilitate cross-referencing with the alarm printout and to identify the development of events relating to SFRCS actuation, AFP/AFPT initiation, and subsequent operation and control of AFWS.

TIME	COMPUTER POINT ID	DESCRIPTION
1:41:04	Q963	A full trip of SFRCS occurred on steam generator low level.
1:41:08	P680/P681	SFRCS main steam line low pressure trip on Channels 1 and 2 (manual trip).

TIME	COMPUTER POINT ID	DESCRIPTION
*1:41:31	S007/Z001	AFPT-1 tripped on overspeed and its stop valve started to close.
1:41:44	S017/Z002	AFPT-2 tripped on overspeed and its stop valve started to close.
1:42:00	P680/P681	SFRCS main steam line low pressure trip on Channels 1 and 2 manually reset.
1:45:50	S017	AFPT-2 overspeed trip reset.
1:46:12	Z013	AFPT-2 control switch in Control Room placed in manual, indicating manual control of AFPT-2 from Control Room.
*1:46:50	Z012	AFPT-1 control switch in Control Room placed in manual, indicating (attempted) manual control of AFPT-1.
*1:47:02	Z012	AFPT-1 control switch placed in auto.
*1:47:26	Z012	Manual control of AFPT-1 re-attempted.
*1:50:47	Z012	AFPT-1 control switch placed in auto.
*1:50:51	Z012	Manual control of AFPT-1 (re-attempted).
1:52:53	Z002	AFPT-2 stop valve fully open.
1:53:51	Z002	AFPT-2 stop valve not fully open.
1:56:08	Z001	AFPT-1 stop valve fully open.
1:56:56	S008	AFPT-1 speed high.
1:57:22	L885	SG-1 start up range level normal.
1:57:37	L895	SG-2 start up range level normal.
1:58:39	Z001	AFPT-1 stop valve started to close.
1:58:55	S008	AFPT-1 speed normal.
1:58:57	S007	AFPT-1 overspeed trip reset.

From a review of the above, it is evident that soon after the SFRCS actuation, both AFPT's tripped on overspeed (also see Action Plans 1A and 1B). The turbine overspeed trip device is connected to the overspeed trip linkage and ultimately to the

trip throttle valve as indicated in Figure 1. The trip throttle valve serves to provide the only steam path to the AFPT's. Note that with an overspeed trip, the trip throttle valve will be closed.

AFTER THE TRANSIENT:

At approximately 2 p.m. on June 9, 1985, ST 5071.02 AFWS Refueling Test was conducted which demonstrated successful control of AFPT's in manual mode from the Control Room.

B. MAINTENANCE AND SURVEILLANCE/TESTING HISTORY

A review of maintenance history for the AFPT level control mechanism revealed no pertinent maintenance being performed on either the Control Room switches or the speed control mechanisms.

The surveillance test of significance to this action plan is ST 5071.04 AFWS monthly functional test. This test ensures Control Room capability and operation of level control mechanism in both the manual as well as auto essential control modes. The test is conducted monthly on a staggered test basis on each AFPT. This test was last conducted on June 7, 1985, for AFPT-1 and on May 21, 1985, for AFPT-2 with all acceptance criteria being met.

Control of AFPTs in manual mode from the Control Room is also demonstrated on a monthly basis by ST 5071.01, AFWS monthly test. This test was last conducted on May 23, 1985, for AFP 1-1 and on June 6, 1985, for AFP 1-2. Although no specific acceptance criteria are associated in this procedure regarding manual control, demonstration of this capability is integral with successful completion of the surveillance test.

III. CHANGE ANALYSIS

A review of the modification and maintenance history from 1983 to date does not reveal any Facility Change Request and/or Maintenance Work Order (preventive or corrective) directly related to Control Room operation of the AFPT's in manual or auto essential mode.

IV. HYPOTHESIS

Following a detailed review of the digital data obtained from the data acquisition and display system and the alarm log, as correlated with operator interviews, it became clear that the perceived inability to take control from the Control Room was directly attributable to the inability to re-latch the trip throttle valve linkage and the difficulty and delay in opening the trip throttle valve following the AFPT trip on overspeed. Following evidence and evaluation is offered to support this hypothesis:

A. The equipment operators that were dispatched to investigate and restore the AFPT's after overspeed trip, identified their difficulty in re-latching the trip linkage to the trip throttle valve in the normal fashion. The operators reported that even though they followed the procedural steps for engaging the trip hook with the latch-up lever, they were unable to open the trip throttle valve for "several" minutes.

B. The problem of interest to this action plan appears to have occurred for approximately 4 minutes (from 1:46:50 - 1:50:51) for AFPT-1 as shown by events highlighted with an asterisk on page 2. This corresponds very well with the overspeed trip, operator dispatch to AFP rooms, attempted opening (with delay) of the trip throttle valve, and inability to completely open this valve.

C. Since the trip throttle valve provides the only path of steam to the AFPT, AFPT motion and speed control cannot be completely established until this valve is latched and fully open. The placement of Control Room switch in manual and speed control switch in raise or lower will only have controlled the governor valve.

D. The Control Room operator believing that the equipment operator in AFP-1 room had fully opened and latched the trip throttle valve realized that turbine was still not up to full speed. In order to improvise, several transfers to manual and auto-essential control were attempted with no appreciable benefits gained in AFPT performance because the trip throttle valve was indeed not fully open.

E. Lack of unavailability of enough steam for AFPT-1 for the above timeframe is substantiated by the digital data on AFPT-1 speed.

It is emphasized that later in the transient, because of initial difficulty in re-latching and fully opening the trip throttle valve as mentioned above, both AFPT's were controlled locally by controlling the trip throttle valve. Auto essential control was never attempted. This is substantiated by absence of associated computer points Z012 and Z013 in the alarm log for the time period of interest.

V. <u>ACTION PLAN</u>

From the above evaluation, it is evident that the root cause of the subject inability to assume control of AFPT-1 from Control Room is the difficulty and delay in opening the trip throttle valve. Since the latter is an integral part of Action Plan 1D, an independent action plan is not necessary and, therefore, is not developed. Further, since the resolution of trip throttle valve issue is being controlled and tracked by that action plan, it is recommended that the AFPT-1 control inability issue be hereby closed.

dt a/6

ACTION PLAN

ED #408

TITLE	PLAN NUMBER	PAGE
AFPT MANUAL/AUTO ESSENTIAL CONTROL PROBLEM (Rev. 0)	1C	1 of 1
	DATE PREPARED	PREPARED BY
	June 25, 1985	Sushil Jain

SPECIFIC OBJECTIVE

To Verify Operability of Manual and Auto-Essential Control of Both AFPT's from the Control Room

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
1.	As part of Action Plan 1A/B, perform visual inspection of the governor control system for each AFPT to identify any mechanical or electrical problem that may have caused loss of remote control.	K.A. Yarger/ S.C. Jain				
2.	Prior to testing to be conducted per Action Plan 1A/B, perform ST 5071.04 to verify AFPT operation in both the manual and auto-essential modes from the Control Room including the following:	K.A. Yarger				
	Manual Mode: Verify control in both increase and decrease directions					
	Auto-Essential Mode: Verify control at low and high setpoints					
3.	Exercise and monitor above controls (as specified in 2) while performing testing per Action Plan 1A/B in Mode 3.	K.A. Yarger				

MR. BEARD: Do you have other Plans that you would like to give us that are complete now?

MR. WOOD: Yes. According to you records, there are three additional Plans that complete the list of Action Plans, the first being Action Plan No. 16, entitled "Report on Main Steam Header Pressure."

MR. LANNING: Let's make that Exhibit No. 9.

[The document referred to, marked Exhibit No. 9, follows:]

#9

ACTION PLAN # 16

TITLE: REPORT ON MAIN STEAM HEADER PRESSURE

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE	APPR. FOR IMPL.
0	6/25/85	Initial Issue	L. Huston	[signature]	

TITLE: June 9, 1985 Trip, Report on Main Steam Header Pressure

REPORT BY: L. L. Huston PLAN NO.: 16

DATE PREPARED: June 25, 1985

INTRODUCTION:

This report has been prepared in accordance with the "Guidelines to Follow When Troubleshooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip", Rev. 4.

This report addresses main steam system and steam generator pressure control during and subsequent to the June 9, 1985 reactor trip transient. Erratic pressure control was experienced in both main steam headers. Possible operational and equipment problems associated with the main steam safety valves (MSSVs), atmospheric vent valves (AVVs), and associated AVV controls are discussed below.

The following organizations were contacted during preparation of this report and the associated action plan.

- o Dresser Industries - MSSV vendor (included service personnel experienced with Davis-Besse MSSVs)
- o Control Components Inc. - AVV vendor (including service personnel experienced with Davis-Besse AVVs)
- o Joyner Engineers and Trainers - Design experience with Integrated Control System (ICS)
- o Babcock & Wilcox Company - Nuclear Steam System Supplier (Mechanical Equipment Division and Field Services)

SUMMARY OF DATA:

Background

Davis-Besse has experienced several occurrences of individual MSSV blowdowns which exceed Dresser design ratings for these valves (i.e., After lifting to relieve an overpressure condition, a MSSV may reseat at a pressure lower than the intended setpoint. The valves are adjusted for approximately three percent blowdown.) Ring settings were modified as a result of blowdown testing at Wylie Labs in 1979. This has improved valve performance. Excessive blowdown of a MSSV can result in larger than desirable cooldown rates of the Reactor Coolant System (RCS) via the steam generators and possible loss of pressure control in the RCS.

As a result of this experience with excessive MSSV blowdown, the Davis-Besse operators use the turbine bypass valves (TBVs) and AVVs to control steam header pressure below MSSV setpoint to preclude MSSV actuation. In the case of the June 9, 1985 reactor trip discussed further below, the AVVs were used for pressure control since the Main Steam Isolation Valves (MSIVs) were closed (the TBVs are downstream of the MSIVs).

Experience during previous trips has generally not shown large pressure swings such as were experienced during the June 9, 1985 trip transient.

Significant conditions prior to the trip for purposes of this analysis include:

On June 2, 1985 following a plant trip, Operations personnel reported an unusually loud and rapid cycling noise which was considered to be due to MSSV actuations. As a result, visual inspections of all MSSVs were performed by Toledo Edison personnel.

All 18 valves appeared to have opened during the plant trip as indicated by missing canvas exhaust hoods (used to prevent cold air from entering MSSV stacks and indicate valve operation). Based on visual examination, the valves appeared in normal physical condition. However, MSSVs A1, A3, B1, B2, B3, B4, and B8 were found to be leaking slightly. This leakage was judged not to impair proper MSSV operation. The #1 AVV was also found to be leaking.

June 9, 1985 Trip

On June 9, 1985, the reactor plant was operating in Mode 1 with a steam pressure of about 860 psig, with ICS in automatic and Main Feedwater Pump No. 2 in manual. The AVVs were closed as normal for this operating condition.

After the reactor trip at 1:35:29, all MSSVs are judged to have lifted, based on observation that all canvas exhaust hoods were missing. Subsequent to the trip, repeated lifts of one or more MSSVs on each header were experienced intermittently for several minutes resulting in pressure swings of approximately 50 psi. In addition, there were several periods when steam header pressure swung over 100 to 250 psi for several minutes. This is not expected for header pressure control when using the AVVs.

MAINTENANCE AND SURVEILLANCE/TESTING HISTORY:

1. There have been several occurrences of MSSV blowdown in excess of rated 3%. Prior to the 1984 refueling outage, reseat pressure experienced during recent plant trips ranged from approximately 980 to 900 psig.

2. In March 1984, the A4 MSSV stuck open after a reactor trip resulting in boiling dry steam generator 1-2. The root cause of this occurrence was failure of a cotter pin permitting the release nut to travel unrestricted down the spindle threads. Maintenance Procedure 1401.28 has been revised to require installation of new stainless steel cotter pins when maintenance is performed on a MSSV.

3. Previous maintenance experience on MSSVs has shown:

    a) Excessive wear of guides and holders
    b) Bending of spindles
    c) Damage to the disc seats requiring replacement
    d) Greater maintenance requirements for the low set pressure MSSVs.

4. All MSSVs on the No. 2 ("A") header were rebuilt during the 1984 refueling outage. Valve B2 was rebuilt in March 1985. Valves B1 and B7 were rebuilt in 1983, and the other valves on the B header were last rebuilt in 1982.

5. Four of the eighteen installed MSSVs have a smaller capacity ("Q" orifice). These valves have required considerably less maintenance than the large ("R") orifice MSSVs.

6. Both AVVs were rebuilt during the 1984/85 refueling outage.

7. Recent maintenance and testing histories of the MSSVs, AVVS, and Integrated Control System were reviewed. Nothing of significance was noted.

CHANGE ANALYSIS:

There have been no known changes to the MSSVs or AVVs since the refueling outage with the exception of rebuilding MSSV B2 on March 25, 1985. The only activity regarding these components was normal maintenance and testing as delineated above.

HYPOTHESES:

The large pressure swings experienced on both steam headers may be due to:

Hypothesis #1:

Manual control of the AVVs by the reactor operator. The reactor operator does recall periods of manual control, but not specific times. The pressure swings are larger than desirable or expected for proper manual control of the AVVs.

Hypothesis #2:

The Atmospheric Vent Valves were kept in automatic and controlled at the header pressure dialed by the operator. However, automatic pressure control was then lost intermittently, due to malfunctioning Integrated Control System circuitry and associated hardware. This allowed the Atmospheric Vent Valves to remain open except when controlled by SFRCS or closed manually. Note that actual set pressure dialed by the operator is not recorded. It appears that there were periods when adequate automatic control was maintained.

Hypothesis #3:

Extended blowdown of one or more safety valves on each steam header. This is not expected to be the cause of all observed pressure swings since some were apparently terminated at the same point in time as closure of the AVVs (i.e., when low pressure SFRCS actuation occurred).

Hypothesis #4:

The pressure drops were due to steam flow past the Main Steam Isolation Valves (MSIV). This hypothesis is not considered viable as computer points Z683 and Z686 show MSIVs 1 and 2 to close at 1:35:36 and 1:35:37 and remain closed for several hours. (MSIV 1 was reopened at 6:42:32 and MSIV 2 was reopened at 6:42:56.) It is noted that the Turbine Bypass Valves were closed, isolating the flow path downstream of the MSIV. These steam lines downstream of the MSIVs were also observed to drop in temperature.

Hypothesis #5:

Operating conditions (such as header vibration) contribute to low reseating of safety valves and accelerated degradation of valve components. This degradation contributes to or causes excessive blowdown on one or more main steam safety valves.

LLH:lrh

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
16	1 of 3
DATE PREPARED	PREPARED BY
6/26/85	L. Huston

TITLE
REPORT ON MAIN STEAM HEADER PRESSURE (Rev. 0)

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	ALL STEPS ON THIS ACTION PLAN ARE TO BE PERFORMED IN ACCORDANCE WITH THE LATEST REVISION OF "GUIDELINES TO FOLLOW WHEN TROUBLE-SHOOTING OR PERFORMING INVESTIGATIVE ACTIONS INTO THE ROOT CAUSES SURROUNDING THE JUNE 9, 1985 TRIP".					
	ALL WORK PERFORMED UNDER THIS ACTION PLAN IS TO BE WITNESSED BY LARRY HUSTON OR DESIGNATED SUPPORT PERSONNEL.					
1	Prior to any work of either an investigatory or troubleshooting nature, any unusual, unexpected or abnormal as-found conditions are to be documented, including photographs where necessary.	L. Huston				
2	Perform a stroke test of the Atmospheric Vent Valves (AVVs) in in Mode 3, with steam pressure under the valve. This is to be performed locally from the Control Room using the hand/auto station.	L. Huston	P. Mahoney J. O'Neill			
3	Ensure proper functioning of alarm points Z961 and Z969 that provide position status of AVVs.	L. Huston	J. DeSando K. Yarger J. Narus			

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
16	2 of 3
DATE PREPARED	PREPARED BY
6/26/85	L. Huston

TITLE
REPORT ON MAIN STEAM HEADER PRESSURE (Rev. 0)

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
4	a. Perform a string check of ICS modules providing automatic	L. Huston	J. DeSando			
	control of the AVVs. Any modules in this string found to		K. Yarger			
	be out of order are then to be bench tested.		J. Narus			
	b. Check proper operation of the hand/auto station in the					
	Control Room.					
	c. Check calibration of "dialed in" pressure control.					
	d. Check the ICS to ensure the 145 psi bias is still maintained.					
	e. Perform operability and calibration check of steam header					
	pressure transmitters.					
	Assistance from L. Joyner is expected with Step 4.					
*5	Perform internal inspection of selected MSSVs per Maintenance	P. Mahoney	J. O'Neill			
	Procedure 1401.28, "MSSV Disassembly, Inspection/Repair and		L. Huston			
	Reassembly". This will include recording results of visual					
	inspections, dimensional checks, and ring settings. Vendor					
	engineering & service representatives will provide assistance.					

ACTION PLAN
ED 6408

PLAN NUMBER	PAGE
16	3 of 3
DATE PREPARED	PREPARED BY
6/26/85	L. Huston

TITLE

REPORT ON MAIN STEAM HEADER PRESSURE (Rev. 0)

SPECIFIC OBJECTIVE

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
*6	Evaluate whether steam testing of selected valves should be performed, and perform as required.	L. Huston	P. Mahoney T. Hiss J. O'Neill			
*7	If root cause is not found through above steps, develop program for monitoring and analyzing operating conditions which could be contributing to accelerated degradation.	L. Huston	T. Hiss P. Mahoney D. Wilczynski			
*	Steps 5, 6, & 7 may be performed in any sequence.					

MR. BEARD: The date on this is Rev. 0, dated 6/25/85.

MR. WOOD: And the second is Action Plan No. 26.

MR. LANNING: It's entitled "Inadvertent Auxiliary Feedwater Pump No. 1 Suction Supply Transfer from Condensate Storage Tank to Service Water Supply," dated June 26, 1985, which is Exhibit No. 10.

[The document referred to, marked Exhibit No. 10, follows:]

#10

ACTION PLAN # 26

TITLE: Inadvertent Auxiliary Feedwater Pump #1 Suction Supply Transfer from Condensate Storage Tank to Service Water Supply

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE	APPR. FOR IMPL.
0	6/26/85	Initial Issue	Timothy [signature]	[signature]	

TITLE: Inadvertent Auxiliary Feedwater Pump #1 Suction Supply Transfer from Condensate Storage Tank to Service Water Supply

REPORT BY: Timothy Czuba PLAN NO: 26

DATE PREPARED: June 26, 1985

INTRODUCTION:

The following is the analysis and evaluation to support the action plan for determining the root cause for the auxiliary feedwater pump #1 suction supply transfer from the condensate storage tank to service water. This report has been prepared in accordance with the "Guidelines to Follow when Troubleshooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip," Rev. 4.

SUMMARY OF DATA:

This plant has experienced inadvertent auxiliary feedwater suction supply transfers on auxiliary feedpump #1 during pump startups. An analysis of this situation had been initiated prior to the June 9, 1985 reactor trip. The analysis had indicated a need for a time delay in initiating suction transfer due to transients in the auxiliary feedwater supply header on auxiliary feedpump start-up.

A. June 9, 1985 Sequence of Events:

1. The #1 auxiliary feedpump turbine speed was approximately 3625 rpm. The Auxiliary Feedpump #1 low suction pressure alarm actuated. This alarm will actuate on 11 psi decreasing. (See time 1:57:53 in Section B.)

2. The auxiliary feedpump #1 low suction pressure alarm cleared. (See time 1:58:27 in Section B.)

3. The auxiliary feedpump turbine #1 stop valve closed. (See time 1:58:34 in Section B.)

4. The auxiliary feedpump #1 suction supply transferred from the condensate storage tank to service water. (See time 1:58:40 in Section B.)

5. The auxiliary feedpump #1 suction supply was manually reset which returns suction to the condensate storage tanks. (See time 2:00:31 in Section B.)

B. Computer Alarm Printout Data:

TIME	EVENT	REF.	PUMP SPEED (RPM)
1:57:53	APF 1 Suction Pressure Low	P006	3623
1:58:27	AFP 1 Suction Pressure Norm	P006	3471
1:58:34	AFPT 1 Stop Valve No	Z001	2707

TIME	EVENT	REF.	PUMP SPEED (RPM)
1:58:40	AFPT Suct Xfer to SW or PSL	P008	2706
2:00:31	AFPT Suct Xfer to SW or PSL Norm	P008	1767

C. Maintenance and Surveillance/Testing History of Transfer Schemes:

3/25/85 ST 5071.03, Section 6.6 (Calibration of the Auxiliary Feedpump 1-2 Suction Pressure Switches) was performed. The calibration was within tolerance. No adjustments were made.

4/8/85 ST 5071.03 Section 6.2 (Calibration of the Auxiliary Feedpump 1-1 Suction Pressure Switches) was performed. The calibration was within tolerance. No adjustments were made.

4/22/85 ST 5071.03, Section 6.6 (Calibration of the Auxiliary Feedpump 1-2 Suction Pressure Switches) was performed. The calibration was within tolerance. No adjustments were made.

5/6/85 ST 5071.03 Section 6.2 (Calibration of the Auxiliary Feedpump 1-1 Suction Pressure Switches) was performed. The calibration was within tolerance. No adjustments were made.

5/20/85 ST 5071.03, Section 6.6 (Calibration of the Auxiliary Feedpump 1-2 Suction Pressure Switches) was performed. The calibration was within tolerance. No adjustments were made.

6/4/85 ST 5071.03 Section 6.2 (Calibration of the Auxiliary Feedpump 1-1 Suction Pressure Switches) was performed. The calibration was within tolerance. No adjustments were made.

CHANGE ANALYSIS:

According to the maintenance history taken from instrumentation and controls equipment records and from Davis-Besse Maintenance Management System, modifications of the system are as follows:

9/1/81 Auxiliary Feedpump Suction Line Strainers S-201 and S-206 were modified to prevent plugging per FCR 79-0215.

HYPOTHESES:

Hypotheses for the auxiliary feedwater pump #1 inadvertent suction transfer are based on information received during the transfer, information obtained from equipment records, DBMMS, and the computer alarm printout.

A. Hypothesis #1:

Suction header pressure switches PSL 4928A and PSL 4928B setpoints are out of specification.

B. Hypothesis #2:

The low suction pressure alarm pressure switch PSL 503 is out of specification and failed to alarm on an actual low suction pressure condition.

C. Hypothesis #3:

Pressure switches PSL 4928A and PSL 4928B were inadvertently actuated by vibration.

D. Hypothesis #4:

Momentary loss of power to motor operated valves AF 786 and SW 1382 and their control circuits.

This hypothesis is considered infeasible for the following reason:

This system is fail safe and upon loss of power the valves will not transfer. The computer alarm point (P008) indicated that the valves did transfer. Therefore, there could not have been any loss of power to motor operated valves AF786 and SW 1382 and their control circuits.

E. Hypothesis #5:

Operators may have manually transferred suction supply to service water after seeing the low suction pressure alarm.

The scenario was discussed with the operators who were on duty during the transfer and no one recalled manually transferring auxiliary feedpump suction supply to service water. No log entries were made concerning a manual transfer. Due to the nature of this hypothesis, no work can be performed to prove or disprove this hypothesis.

F. Hypothesis #6:

Auxiliary feedpump suction line strainer S-201 was clogged during the transient and caused inadvertent transfer of auxiliary feedpump #1 suction transfer.

This hypothesis is considered infeasible for the following reason:

The pressure switches PSL 4928A and 4928B are located upstream of the strainer and would not see the pressure drop of a clogged strainer. The computer point (P002) for the differential pressure across the strainer was not indicating an alarm condition during the transient.

G. Hypothesis #7:

A low suction pressure transient was induced into the system causing suction supply to be transferred to service water supply. In my discussion with the operator on shift on June 9, 1985, he stated that he saw the station annunciator alarm for low suction pressure for auxiliary feedpump #1. Then he saw that valve transfer to service water had taken place.

If the time response of the interlock control circuit is faster than the computer scan rate, it is possible that a low suction pressure transient could have caused the transfer without the computer seeing the transient, but the station annunciator would.

H. Hypothesis #8:

A low suction pressure was caused by strainer S-257 being clogged. The low suction pressure was properly sensed in the auxiliary feedpump #1 piping causing suction transfer to occur. S-257 is located in the condensate suction header which is common to both feedpumps during normal suction lineup. A suction transfer did not occur in the auxiliary feedpump #2 supply because PSL 4929A and PSL 4929B did not actuate due to their setpoints being out of specification.

ACTION PLAN
ED 6408

Rev. 0

PLAN NUMBER	PAGE	DATE PREPARED	PREPARED BY
26	1 of 2	6/26/85	T. Czuba

TITLE

INADVERTENT AUXILIARY FEEDWATER PUMP #1 SUCTION SUPPLY TRANSFER

SPECIFIC OBJECTIVE

To determine root cause of the Auxiliary Feedwater Pump #1 transfer to service water.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	ALL STEPS OF THIS ACTION PLAN ARE TO BE PERFORMED IN ACCORDANCE WITH THE LATEST REVISION OF "GUIDELINES TO FOLLOW WHEN TROUBLE-SHOOTING OR PERFORMING INVESTIGATIVE ACTIONS INTO THE ROOT CAUSES SURROUNDING THE JUNE 9, 1985, REACTOR TRIP."					
1.	Independently verify by a calibration check the setpoint at which the pressure switches (PSL 4928A and PSL 4928B) actuate.	T. Czuba	T. Czuba K. Yarger			
2.	Simulate a low suction pressure on both pressure switches PSL 4928A and PSL 4928B simultaneously, and verify proper valve actuation occurs on AF 786 and SW 1382. Monitor PSL4928A and PSL4928B for actuation during auxiliary feedpump testing, which is being performed by action plans 1A and 1B. Steps 1 and 2 address Hypothesis #1.	T. Czuba	T. Czuba K. Yarger			
3.	Check the calibration of PSL 503 and verify actuation occurs at the required setpoint. This step addresses Hypothesis #2.	T. Czuba	T. Czuba K. Yarger			
4.	Perform a seismic analysis on PSL 4928A and PSL 4928B mounting. This step addresses Hypothesis #3.	Kanut Sagooleim	T. Czuba K. Yarger			

ACTION PLAN

ED 6408

TITLE	Rev. 0	PLAN NUMBER	PAGE
INADVERTENT AUXILIARY FEEDWATER PUMP #1 SUCTION SUPPLY TRANSFER		26	2 of 2
		DATE PREPARED	PREPARED BY
		6/26/85	T. Czuba

SPECIFIC OBJECTIVE

To determine root cause of the Auxiliary Feedwater Pump #1 transfer to service water.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
5.	Perform response time on the interlock control circuit.	T. Czuba	T. Czuba			
	This step addresses Hypothesis #7.		K. Yarger			
6.	Independently verify by a calibration check the setpoint	T. Czuba	T. Czuba			
	at which the pressure switches (PSL 4929A and PSL 4929B)		K. Yarger			
	actuate. Monitor PSL 4929A and PSL 4929B for actuation					
	during auxiliary feedpump testing, which is being performed					
	by action plans 1A and 1B.					
7.	Check the calibration of PSL 509 and verify the actuation	T. Czuba	T. Czuba			
	occurs at the required setpoint. Steps 6 and 7 address		K. Yarger			
	Hypothesis #8.					
	NOTE: The action steps may be performed in any sequence.					

MR. LANNING: And the last one that you are transmitting to us is Action Plan No. 27, entitled "Auxiliary Feed Pump Turbine Main Steam Inlet Isolation Valve (MS-106) Problem Analysis." That is dated June 25, 1985 and designated Exhibit No. 11.

[The document referred to, marked Exhibit No. 11, follows:]

#11

ACTION PLAN # 27

TITLE: AUXILIARY FEED PUMP TURBINE MAIN STEAM INLET ISOLATION VALVE (MS-106) PROBLEM ANALYSIS

REV	DATE	REASON FOR REVISION	BY	CHAIRMAN TASK FORCE	APPR. FOR IMPL.
0	6/25/85	Initial Issue	N. Bonner	[signature]	

Title: Auxiliary Feed Pump Turbine Main Steam Inlet Isolation Valve (MS-106) Problem Analysis

Report by: Neal L. Bonner Plan No. 27

Date prepared: June 26, 1985 Page 1 of 3

This report has been prepared in accordance with the "Guidelines to Follow When Troubleshooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip," Rev. 4.

INTRODUCTION

This report is intended to analyze known information concerning the apparent interruption of the open control circuit to Auxiliary Feed Pump Turbine 1-1 Main Steam Inlet Isolation Valve (MS-106). During the event, MS-106 apparently cycled in about one third of the expected stroke time. It will be the intent of this report to support the action plan for determining the root cause of the anomalous operation of MS-106.

SUMMARY OF DATA

Valve MS-106 is a normally closed valve and was closed prior to the transient.

Early into the transient steam generator levels decreased to the Steam Feedwater Rupture Control System (SFRCS) low level trip setpoint. From this SFRCS steam generator low level trip the open circuitry to MS-106 received an initiation. Activation of the SFRCS trip and indication of MS-106 opening is indicated by the alarm printout respectively. Approximately two seconds after MS-106 showed position change, the operator action of manually tripping the SFRCS on main steam line low pressure occurred and is also recorded on the alarm printout. From the initial activation of SFRCS, MS-106 should have gone open to the full open position. The operator initiation of SFRCS should have given MS-106 a close circuit permissive. Once MS-106 had reached full open, its close circuitry would have been completed via one of its own limit switch contacts. MS-106 would then have started in the close direction. MS-106 was indicated closed by the alarm printout approximately 19 seconds after the original SFRCS steam generator level signal to the alarm printout was received.

MAINTENANCE AND SURVEILLANCE/TESTING HISTORY

Based upon a review of data from ST 5071.01 it was determined that MS-106 normal stroke time from closed to open is approximately 25 seconds. Likewise, the open to close cycle occurs in approximately 25 seconds.

In a review of past maintenance data both on Davis-Besse Maintenance Management System (DBMMS) and from Records Management the most recent Maintenance Work Orders (MWO) were 2-82-0119-00 and 1-82-2787-00. Both of these MWOs were completed in 1983.

Based on the review of the above mentioned MWO's and that of recent ST 5071.01 data (5-23-85), there is no information which would indicate that MS-106 should perform other than as designed.

CHANGE ANALYSIS

The operation of MS-106, in the manner observed during the transient, apparently went from closed to open to closed position in approximately 19 seconds. The most recent test data from ST 5071.01, which was reviewed, indicates a time of approximately 25 seconds for MS-106 to open and approximtaely 25 seconds to close. A total time of approximately 50 seconds for a close to open to close operation. It is the evident difference between operating times (19 seconds versus 50 seconds) which will be the basis for hypotheses. These hypotheses will be contingent upon one of two assumptions:

1. The valve operator motor for MS-106 significantly increased in speed (rpm).

2. The open control circuit failed in such a manner to preclude MS-106 from going to full open. Thus MS-106 would have stopped in some intermediate position and then returned closed. This would decrease the overall time for close to open to close operation.

HYPOTHESES

The information collected and reviewed from before, during and after the transient, indicates that a much shorter (~1/3 the normal time or ~19 seconds) time elapsed for the close to open to close cycle of MS-106. The following is a list of the hypotheses which could cause MS-106 to act in this manner. These hypotheses were reviewed and discussed for plausability with F. R. Miller, Nuclear Systems and Analysis Engineer, and S. C. Jain, Davis-Besse staff Senior Nuclear Engineer.

1. An open in the field circuit to the compound wound dc motor driving the operator of MS-106.

2. An open or misoperation in the 42a/0 contact seal in circuit.

3. Improper operation of pressure switch PSL 4930A and/or its auxiliary relay PSL 4930X1 which provides a permissive for both the SFRCS open initiation and the 42a/0 seal in contact.

4. Improper operation of either relay R1 or R3 contacts 2-7 or their associated coils. These are auxiliary relays in the main steam line pressure switch logic which provides a permissive to the SFRCS open circuit logic and the 42a/0 open seal-in. This particular hypothesis may be discounted based on the following reasons.

   a. The low steam line pressure logic takes 25 seconds to pick up after MS-106 has given the logic a full open permissive. As has been shown previously MS-106 opened and closed in ~19 seconds. Therefore, MS-106 was never open long enough to maintain the permissive to allow the logic time to pick up.

b. MS-106 opened successfully after the improper manual operation of SFRCS was reset and SFRCS returned to its previous trip state. This would not have happened if either R1 or R3 contact 2-7 had failed opened during a previous operation of the logic. This would require a one time only failure of one of the two contacts.

c. Since the pressure switch logic is normally deenergized (with pressure available) there is no reason to believe that the 2-7 contacts of relays R1 and R3 ever changed state to provide for a mode of failure.

d. No alarm was received giving an indication of activation of logic.

5. Improper operation (opening) of the torque switch open, due to improper setting of the torque switch 33/tO.

6. Out of adjustment setting on the open limit switch contact No. 4 (33/bO).

Hypothesis #1 deals with the assumption of the valve motor increasing in speed.

Hypotheses #2-#6 deal with the assumption that MS-106 open circuitry malfunctioned causing the valve to reverse direction at some intermediate position.

sm d/11

ACTION PLAN
ED 6408

REV. 0

PLAN NUMBER	PAGE
27	1 of 5

TITLE	DATE PREPARED	PREPARED BY
AUXILIARY FEED PUMP TURBINE MAIN STEAM INLET ISOLATION (MS-106) PROBLEM ANALYSIS	6/20/85	N. Bonner

SPECIFIC OBJECTIVE

To determine the root cause of motor operated valve MS106 to operate in a shorter amount of time, during the transient of June 9, 1985, than the recorded stroke test data.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	All steps of this action plan are to be performed in accordance with the latest revision of "Guidelines to Follow When Trouble-shooting or Performing Investigative Actions into the Root Causes Surrounding the June 9, 1985 Reactor Trip".					
	NOTE: All steps to be performed in sequence.					
	NOTE: Vendor support from MOVATS is required for steps 11,12&13					
1	Before beginning troubleshooting work at the MCC D1NA starter D135, document the as-found conditions of the starter. In performing this step, it will require that the door to the starter be opened. In performing this step, limit the gathering of the as-found information to that which can be recorded without changing conditions, i.e., general conditions, environmental conditions, etc.	N. Bonner				
2	Before beginning troubleshooting work at the valve, document the as-found condition of the valve and operator MS106. In performing this step limit the gathering of the as-found information to that which can be recorded without changing condi-	N. Bonner				

ACTION PLAN
ED 6408

REV. 0

PLAN NUMBER	PAGE
27	2 of 5

TITLE AUXILIARY FEED PUMP TURBINE MAIN STEAM INLET ISOLATION (MS-106) PROBLEM ANALYSIS

DATE PREPARED	PREPARED BY
6/20/85	N. Bonner

SPECIFIC OBJECTIVE

To determine the root cause of motor operated valve MS106 to operate in a shorter amount of time, during the transient of June 9, 1985, than the recorded stroke test data.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	tions, i.e., valve position, general condition, environmental conditions, etc.					
3	Remove the cover on MS106 valve operator and inspect the operator limit switches, torque switch and all wiring. Record the torque switch settings. These settings should be 2.5 open and 1.5 close.	N. Bonner				
4	Perform a wiring check of the valve operator compartment. Verify the wiring with Bechtel drawing E-557A, sheets 77A and 77B. Pay particular attention to possible bad connections.	N. Bonner				
5	Perform a wiring check at MCC D1NA of starter D135. Verify the wiring using Bechtel drawing E280A, sheets 29 and 29A and the Westinghouse starter internal wiring diagram 6798A39WD-1 (Bechtel vendor drawing #7749-E-8-139-3). Pay particular attention to loose connections or broken wires.	N. Bonner				
6	Perform bridge resistance readings of the series and shunt field windings. These readings are to be taken (if practical) at the MCC starter D135.	N. Bonner				

TITLE AUXILIARY FEED PUMP TURBINE MAIN STEAM INLET ISOLATION (MS-106) PROBLEM ANALYSIS

SPECIFIC OBJECTIVE

To determine the root cause of motor operated valve MS106 to operate in a shorter amount of time, during the transient of June 9, 1985, than the recorded stroke test data.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
7	Perform a visual inspection of PSL4930A and document the as-found condition of this pressure switch. In performing this step, limit the gathering of the as-found information to that which can be recorded without changing conditions, i.e. general condition, environmental conditions, or system conditions, etc.	N. Bonner				
8	Perform a wiring check of PSL4930A. Verify the wiring using Bechtel drawing E632B, sheets 2 and 6. Pay particular attention to bad connections.	N. Bonner				
9	Perform a calibration check of PSL4930A.	N. Bonner				
10	Perform a functional check of PSL4930A and its auxiliary relay PSL4930X1. This step will require that starter D135 control circuit power be made available by closing the main disconnect to D135. This step includes, but is not limited to the following:	N. Bonner				
	a. Activate PSL4930A by means of an appropriate pressure source.					
	b. Monitor and time contact 4-6 of relay PSL4930X1 upon depressurizing of the source to PSL4930A. This monitoring and					

ACTION PLAN
ED 6408

REV. 0

PLAN NUMBER	PAGE
27	4 of 5
DATE PREPARED	PREPARED BY
6/20/85	N. Bonner

TITLE: AUXILIARY FEED PUMP TURBINE MAIN STEAM INLET ISOLATION (MS-1( ) PROBLEM ANALYSIS

SPECIFIC OBJECTIVE

To determine the root cause of motor operated valve MS106 to operate in a shorter amount of time, during the transient of June 9, 1985, than the recorded stroke test data.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
	timing of contact 4-6 of relay PSL4930X1 should be done at					
	MCC D1NA starter D135.					
11	Stroke MS106 and monitor the operation of the valve using	N. Bonner				
	Motor Operated Valve Analysis and Test System (MOVATS). During					
	the operation of the valve MS106 the following should be done:					
	a. Set the control circuit up to cause the valve to cycle open					
	and then shut using a momentary initiation of the open					
	circuit and immediately followed by a maintained close					
	circuit contact.					
	b. Record time required for the closed to open to closed					
	operation of MS106.					
	c. Observe operation of the limit switches and torque switches.					
12	Stroke MS106 open and monitor the operation of the valve using	N. Bonner				
	MOVATS. (See NOTE on page 1)					
13	Stroke MS106 close and monitor the operation of the valve using	N. Bonner				
	MOVATS. (See NOTE on page 1)					

ACTION PLAN
ED 6438

REV. 0	PLAN NUMBER 27	PAGE 5 of 5	
TITLE AUXILIARY FEED PUMP TURBINE MAIN STEAM INLET ISOLATION (MS-106) PROBLEM ANALYSIS	DATE PREPARED 6/20/85	PREPARED BY N. Bonner	

SPECIFIC OBJECTIVE

To determine the root cause of motor operated valve MS106 to operate in a shorter amount of time, during the transient of June 9, 1985, than the recorded stroke test data.

STEP NUMBER	ACTION STEPS	PRIME RESPONSIBILITY	ASSIGNED TO	START DATE	TARGET DATE	DATE COMPLETED
14	Manually operate the valve MS106 from close to open counting the number of turns to each of the following:	N. Bonner				
	a. Torque switch 33/TO bypass contact 33/aC-#5.					
	b. Limit switch contact 33/bO-#4 contact to drop out open circuitry.					
	c. Valve full open.					
15	Open connections to isolate the series field winding, shunt field winding and shunt field resistor. Measure resistance of each of these components. This may be done at the starter D135.	N. Bonner				
16	If the above steps do not produce a root cause, additional valve exercising and testing may be conducted with the system pressurized.					

MR. ROSSI: So we have four now that we have received today, four new ones.

One other point I would like to make is that when these things are revised for any reason, both Region III and this team ought to get the revision as soon as it is issued.

MR. BEARD: I think that is just a reminder of what we said earlier.

MR. WOOD: That's correct. And as a result of our meeting today, we realized we need to get to you Rev. 1 of Action Item No. 12 dealing with AF-599 and 608. We had given you Rev. 2 today, and we also need to come back with a revision to the joint one covering 5, 6 and 7 dealing with SFARCS and MSIV.

MR. BEARD: Well, send us copies. I don't know whether you mean come back in the sense of a meeting.

MR. WOOD: I meant come back in the sense of providing you a revision to that.

MR. SHAFER: May I ask again, now, how do you feel about being held to three working days now that you have four?

MR. ROSSI: To decide whether we want to have a meeting or whether we have comments? Do you guys have any problem with it?

MR. BEARD: Three working days not counting today for this batch would be fine.

MR. WOOD: Okay. So Wednesday.

MR. BEARD: Yes. Check with the Region on Wednesday morning.

We are about to adjourn here, which is what I sense. I would like to ask another question about the Steam Feed Rupture Control System, if I could, just to get a general understanding from one of you.

If, in fact, this pressure wave occurs upon turbine trip, and if, in fact, it upsets the level instruments which in turn cause spurious actuation, would that not be a common mode problem in that it would affect all level transmitters to some degree and incense various signals down and cause a premature actuation?

Now, not getting into the significance of it, but it would cause an undesired actuation of a common single origin, would it not?

MR. JAIN: Yes, that would be true. Yes.

MR. ROSSI: Okay. Unless somebody has something else they want to talk about, I guess we are ready to adjourn the meeting.

Does anybody have anything?

[No response.]

MR. ROSSI: Okay. Then why don't we bring the meeting to a close.

[Whereupon, at 4:03 p.m. the meeting was concluded.

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Before the Fact-Finding Task Force
RE: Davis-Besse Event of June 9, 1985
(Closed Session)

Docket No.:

Place: Bethesda, Maryland

Date: Thursday, June 27, 1985

were held as herein appears and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission.

(Signature) Suzanne B. Young

(Typed Name of Reporter) Suzanne B. Young

Ann Riley & Associates, Ltd.