ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-445/95-25
50-446/95-25

Licenses: NPF-87
NPF-89

Licensee: TU Electric
Energy Plaza
1601 Bryan Street, 12th Floor
Dallas, Texas

Facility Name: Comanche Peak Steam Electric Station, Units 1 and 2

Inspection At: Grandbury, Texas and Arlington, Texas

Inspection Conducted: September 15, 1995 through January 23, 1996

Inspectors: Linda J. Smith, Reactor Inspector, Engineering Branch
Division of Reactor Safety

Approved: [signature] 1-25-96
Chris VanDenburgh, Chief, Engineering Branch Date
Division of Reactor Safety

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced followup inspection of engineering activities.

Results (Units 1 and 2):

- Licensee personnel effectively responded to diverse turbine-driven auxiliary feedwater pump trips. They developed corrective actions which comprehensively addressed both the identified causes and improvement measures suggested by an industry experience review (Sections 3.2 and 4.3).

- Licensee personnel incorrectly evaluated a design change of the steam supply for the turbine-driven auxiliary feedwater pumps, in that the engineering basis for electrically abandoning a level switch and its controls did not adequately consider the impact of the failed steam trap in all modes. The original plant design included a high condensate level alarm in the turbine high-pressure steamline drain, which was

9602120076 960206
PDR ADOCK 05000445
Q PDR

intended to provide operators indication if the steam traps degraded. Based on the hot functional test results, the licensee incorrectly concluded that the steam traps were not needed in all modes of operation. The failure to perform an adequate safety evaluation of this change is a violation of Technical Specification 6.5.3 (Section 5.2).

Summary of Inspection Findings:

- Unresolved Item 445/9513-02; 446/9513-02 was closed (Section 5).
- Violation 445/9525-01; 446/9525-01 was opened and closed (Section 5.2).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - List of Attendees at the September 15, 1995, Management Meeting
- Attachment 3 - Handout for the September 15, 1995, Management Meeting
- Attachment 4 - Updated Diagram of Planned Condensate Control Modifications

DETAILS

1 INTRODUCTION

NRC Inspection Report 50-445/95-13; 50-446/95-13, dated September 1, 1995, documented a review of the circumstances surrounding the June 11, 1995, failure of the Unit 1 turbine-driven auxiliary feedwater pump to operate on demand. The scope of the inspection was subsequently expanded to include the June 21, 1995, mechanical overspeed trip of the Unit 2 turbine-driven auxiliary feedwater pump during testing. One unresolved item was identified during this inspection concerning the control of condensate in the auxiliary feedwater pump turbine, the steam supply lines, and the steam exhaust lines. At the conclusion of the inspection, the licensee had not completed their review of the control of condensate and its impact on the operability of the turbine-driven auxiliary feedwater pumps. They also had not completed their formal root-cause analysis of the two events. The staff conducted this current inspection to evaluate the results of the licensee's root-cause evaluations for the June 11 and 21, 1995, turbine-driven auxiliary feedwater pump trips and to resolve concerns related to the control of condensate accumulation in the auxiliary feedwater pump turbine steamlines.

2 MANAGEMENT MEETING

The regional staff held a management meeting with TU Electric, the Comanche Peak Steam Electric Station licensee, on September 15, 1995. Those attending this meeting are identified in Attachment 2 of this inspection report. This meeting was conducted to obtain information concerning the June 11 and 21, 1995, overspeed trips of the Unit 1 and 2 turbine-driven auxiliary feedwater pumps. The meeting addressed the results of the licensee's root-cause evaluation of the two trips, including the control of condensate in the turbine steam supply and exhaust lines and the corrective actions taken to preclude recurrence of the trips. The discussion slides are contained in Attachment 3 of this inspection report.

3 UNIT 1 - JUNE 11, 1995, AUXILIARY FEEDWATER PUMP TURBINE MECHANICAL OVERSPEED TRIP

3.1 Cause Determination

At the September 15, 1995, management meeting, the licensee stated that they had determined that the June 11, 1995, overspeed trip was probably caused by corrosion on the auxiliary feedwater pump turbine governor valve stem. The licensee also discovered a slight binding in the governor valve cam linkage.

Licensee personnel contracted for a metallurgical failure analysis of three governor valve stems: the original stem from Unit 1, the stem installed in Unit 1 during the June 11, 1995, reactor trip, and the original stem from Unit 2. The licensee provided the inspectors with a copy of the failure analysis. Based on review of the failure analysis report and visual observation of the corroded valve stem, the inspector concurred that the licensee's probable-cause determination was reasonable. The inspector noted that the licensee concluded that all three valve stems had been manufactured using a liquid nitrided case hardening method.

3.2 Corrective Actions

As discussed in NRC Inspection Report 50-445/95-13; 50-446/95-13, the licensee replaced the Unit 1 corroded valve stem with a new stem manufactured from Inconel 718. They also upgraded the Unit 2 valve stem to Inconel 718. As discussed during the September 15, 1995, management meeting, the licensee also verified that the new valve stem and packing material were metallurgically compatible. The licensee performed two monthly inspections of the Unit 1 Inconel 718 stem to verify adequate performance. In addition, they dynamically monitored governor valve performance with a strain gage to detect binding and established a preventive maintenance activity to routinely check for cam linkage freedom of movement. They also initiated design modifications to improve the drainage from the governor valve stem leak off connection. The inspector concluded that the licensee had aggressively developed corrective actions to preclude an overspeed trip caused by governor valve stem binding.

4 UNIT 2 - JUNE 21, 1995, AUXILIARY FEEDWATER PUMP TURBINE MECHANICAL OVERSPEED TRIP

4.1 Cause Determination

At the September 15, 1995, management meeting the licensee stated that they believed the non-standard warmup run probably caused excess water to accumulate in the system, which resulted in the June 21, 1995, overspeed trip.

During the warmup run, the pump discharge was aligned to the steam generators, with the turbine speed controller set to maximum speed. Both steam admission bypass valves were opened to admit steam to the turbine. This allowed steam to flow to the turbine from two 1-inch lines rather than two 4-inch lines. As a result, turbine acceleration was steam-energy limited, rather than speed-control limited. The licensee believed that in this configuration more energy was removed from the steam, resulting in more condensate accumulation than normal. The inspector concurred with the licensee's conclusion that running the turbine in a steam-limited mode on bypass steam would likely generate more condensate than normal. Licensee personnel stated that they were not able to analytically model the condensate formation and drainage rates because they did not have enough input data.

Thirteen minutes after the warmup run, the licensee attempted to restart the turbine using the main steam supply valves (4-inch), but the turbine tripped on mechanical overspeed. Based on eye witness accounts, excessive water was seen coming from the sentinel valve and coming out of the exhaust stack. The licensee also observed that the governor valve did not move and was not able to control turbine speed. The turbine vendor representative had previously stated that condensate accumulation upstream of the governor valve could bind the valve and result in an overspeed trip.

During followup trouble-shooting activities, licensee personnel identified that degraded steam trap performance reduced the drain system capability and likely contributed to the overspeed trip. They noted that the governor mechanism exhibited stickiness at the full open position. They performed a cam linkage adjustment which significantly reduced governor valve linkage binding. Internal damage was also discovered in the governor valve stem packing assembly during a subsequent valve stem replacement. The licensee noted that this condition may also have increased stem drag. See NRC Inspection Report 50-445/95-14; 50-446/95-14 for a review of this issue.

Following repair of the degraded steam traps and adjustment of the governor mechanism, the licensee successfully demonstrated restart capability 13 minutes following a normal warmup run. The licensee noted that the turbine drain system was not required to be designed or maintained to accommodate condensate generated when operated in an off-normal configuration.

The inspector concurred with the licensee that the overspeed trip was likely caused by a combination of the off-normal warmup run, steam trap degradations, the governor valve stem packing assembly damage and governor linkage misadjustments.

4.2 Past Operability Determination

The licensee determined that the Unit 2 turbine-driven auxiliary feedwater pump was operable for normal steam-line alignments prior to the June 21, 1995, mechanical overspeed trip.

This determination was based primarily on engineering judgement. As stated above, the licensee was not able to analytically model the condensate accumulation from the off-normal steamline configuration. They also did not quantify the impact of the degraded steam traps on the condensate drain rate. The degraded steam traps could have affected draining of condensate initially formed in a cold piping system, draining condensate formed because of leaking steam admission valves or they could have affected draining of condensate which falls back into the turbine following a turbine run.

The licensee asserted that since the traps are controlled by temperature, they close shortly after startup and are not a factor during turbine starts. The inspector agreed that the traps would close after the piping warmed enough so that steam, rather than condensate, was directed at the steam traps. However, the licensee had never performed an analysis or test which supported the assertion that both the exhaust and supply side steam traps can be closed without adverse impact during a cold start. The inspector noted that the licensee had relied on past surveillance test data to confirm that the turbine could cold start and run in a normal configuration with the degraded traps.

However, surveillance testing would not have demonstrated restart capability which was also a required safety function at Comanche Peak Steam Electric Station. The inspector concluded that the licensee's past operability determination was weak in that the determination was based primarily on engineering judgement.

4.3 Corrective Actions

Licensee personnel repaired the steam traps, adjusted the cam plate linkage, and repaired the governor valve stem packing assembly. They also initiated a compensatory action to bypass the steam traps at a frequency sufficient to ensure condensate did not accumulate in the drain system. This compensatory action was in place until level alarms were installed to monitor the effectiveness of the steam traps. The licensee also performed inspections to verify that the turbine casing drain was unobstructed and reworked the steam admission valves to reduce leakage. The licensee also increased the frequency and scope of the steam trap preventive maintenance activity.

During the management meeting, licensee personnel emphasized that they planned to upgrade their design philosophy with respect to condensate accumulation. Prior to this event, the licensee had designed the turbine steam supply and exhaust system with the expectation that significant condensate would be formed during the start sequence and that this condensate could be managed. Following the event, the licensee contacted personnel from other utilities and the Terry Turbine User's Group to determine the best methods for maximizing reliability. Based on those interviews, licensee personnel determined that the best way to maximize reliability was to minimize condensate in the steamlines.

On November 22, 1995, licensee personnel provided a draft of their reliability and performance improvement initiative for the auxiliary feedwater pump turbines (see Attachment 4 to this report). They planned to use a single 4-inch line to provide steam to the turbine. By making the interconnection near the steam admission valve, they would eliminate half of the cold piping and, therefore, half of the condensate formation. They planned to install condensate knock out pots to dynamically remove condensate during cold starts. They also planned to evaluate either: (1) revising the opening characteristics of the steam admission valves or (2) adding startup bypass valves to admit steam to the turbine in a more controlled manner. They also planned to replace the steam traps with a flash tank to improve steamline drain reliability. The inspector concluded that licensee personnel aggressively developed corrective actions to prevent turbine-driven auxiliary feedwater overspeed trips due to condensate accumulation.

5 UNRESOLVED ITEM 445/9513-02; 446/9513-02: POTENTIALLY INADEQUATE CONTROL OF AUXILIARY FEEDWATER PUMP TURBINE STEAM-LINE CONDENSATE

Unresolved Item 445/9513-02; 446/9513-02 involved the potentially inadequate control of auxiliary feedwater pump turbine steamline condensate, in that it was not clear that the licensee personnel had adequately controlled auxiliary feedwater pump turbine steamline condensate prior to the June 25, 1995, mechanical overspeed trip. The capability to control condensate in the auxiliary feedwater pump turbine steam supply and exhaust lines is necessary to assure safe and reliable turbine operation.

5.1 Sentinel Valve Leakage

The inspectors were concerned that licensee personnel did not question that water frequently sprayed from the turbine casing sentinel valves during turbine startup. After investigation, licensee personnel continued to maintain that some sentinel valve leakage was normal for their plant. They contacted six plants of similar design. Three of those plants had noted occasional sentinel valve leakage.

5.2 Design Basis

Licensee personnel did not consider the turbine-driven auxiliary feedwater system drains to have a safety-related function. Consequently, licensee personnel had not demonstrated if the nonsafety-related drains and steam traps failed, that condensate accumulation was adequately controlled to achieve satisfactory operation of the turbine. During the inspection, licensee personnel acknowledged that functioning steam traps and drains were necessary for reliable turbine operation.

The original plant design included a high condensate level alarm in the turbine high-pressure steamline drain, which was intended to provide operators indication if the steam traps degraded. However, Design Change Notice DCN 4082, dated May 7, 1992, disabled the Unit 1 Level Switch 1-LS-2383 associated with this high condensate level alarm.

The engineering basis specified on Design Change Notice DCN 4082 for electrically abandoning Level Switch 1-LS-2383 and controls for 1-LV-2383 did not adequately consider the impact of a failed steam trap in all modes. From hot functional test results, the licensee incorrectly extrapolated, that the steam traps were not needed in all modes. The hot functional test only provided information about failure of the supply side steam trap just prior to a cold start. The test did not address exhaust side trap and drain failures, nor did it address the standby mode or the restart mode.

Licensee personnel made a similar reasoning error during the associated 10 CFR 50.59 evaluation. The response to Question 3 on Form STA-707-2 for Design Change Notice DCN 4082 was inaccurate in that it inappropriately concluded that the drain function was not required during all operating modes. This design error was carried forward to Unit 2. As a result, a condensate level alarm was not available to warn operators of steam trap degradations which contributed to the spurious trip of the Unit 2 turbine-driven auxiliary feedwater pump during testing on June 25, 1995. The failure to correctly evaluate Design Change Notice DCN 4082 was a violation of Technical Specification 6.5.3 (445/9525-01; 446/9525-01).

Licensee personnel implemented Design Change Notices DCN 9498 and DCN 9499 to restore the supply side steamline drain level alarm for Unit 1 and 2, respectively. They have scheduled the implementation of Design Change Notices DCN 9646 and DCN 9647 to install level alarms on the exhaust side steam line drains for Unit 1 and 2, respectively.

5.3 Maintenance Prioritization

The inspectors concluded that past prioritization for repairing leaking steam admission valves was not consistent with the classification of the condensate drain function as nonsafety-related in the absence of a level alarm. Licensee personnel aggressively addressed this weakness and scheduled the appropriate repairs.

5.4 Experience Review

The inspectors were concerned that the licensee's review of Information Notice 94-66 did not address the fact that admission valve leakage exacerbated governor valve stem corrosion for susceptible materials. The licensee had noted that corrosion could happen with the susceptible material in less than a month; however, the licensee relied on quarterly monitoring for steam admission valve leaking. The inspectors were also concerned that quarterly monitoring was not sufficient to prevent this degradation. As discussed above, the licensee upgraded the design of the governor valve stem leakoff drain and replaced the stem with one constructed of a more corrosion resistant material.

The inspectors noted that the licensee's review of industry events did not alert them to the importance of assuring the operability of steam traps, drains, and turbine exhaust. As described above, licensee personnel plan design, maintenance, and operating changes to improve the effectiveness of the condensate removal function.

Licensee personnel indicated that they also re-reviewed 58 other industry events and re-evaluated their applicability. The inspector reviewed the implementation of other aspects of the licensee's controls for turbine reliability during performance of NRC Inspection 50-445/95-98; 50-446/95-98. Licensee personnel added governor preventive maintenance requirements. They also worked with the vendor to confirm that the buffer spring installed in the governor was correctly specified. The inspector concluded that licensee personnel had comprehensively reviewed related industry experience information and implemented appropriate turbine reliability improvements.

5.5 Conclusion

The failure to correctly evaluate Design Change Notice DCN 4082 was a violation of Technical Specification 6.5.3. The violation is of concern because, prior to the June 25, 1995, Unit 2 mechanical overspeed trip, licensee personnel did not recognize that the steam trap drain function was important to safety. As a result, they deleted condensate level alarm instrumentation which provided valuable operating status information for the turbine-driven auxiliary feedwater pumps. Licensee personnel have since restored the condensate level alarm instrumentation and have developed corrective action plans which broadly address the control of condensate as discussed in Sections 5.1-5.4. Unresolved Item 445/9513-02; 446/9513-02 is closed.

ATTACHMENT 1

EXIT MEETING AND ATTENDEES

1 PERSONS CONTACTED

1.1 Comanche Peak

D. Depierro, Balance-of-Plant Systems Supervisor
C. Feist, Consulting Engineer
R. Flores, System Engineering Manager
T. Hope, Regulatory Compliance Manager
G. Merka, Senior Nuclear Specialist
J. Muffett, Station Engineering Manager
L. Terry, Group Vice President

1.2 NRC Personnel

L. Smith, Reactor Inspector

The above personnel attended the exit meeting. In addition to the personnel listed above, the inspector contacted other personnel during this inspection.

2 EXIT MEETING

An exit meeting was conducted by telephone on January 23, 1996. During this meeting, the inspector summarized the scope and findings of the inspection. The licensee acknowledged the findings presented at the exit meeting. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

Attachment 2

List of Attendees at the
September 15, 1995
Management Meeting

MEETING: TU ELECTRIC (COMANCHE PEAK)

SUBJECT: DISCUSSION OF SPECIAL INSPECTION 50-445/95-13; 50-446/95-13

DATE: SEPTEMBER 15, 1995

ATTENDANCE LIST
(PLEASE PRINT CLEARLY)

NAME	ORGANIZATION	POSITION TITLE
Linda Smith	NRC	Reactor Inspector
C.J. Paulk	NRC	Reactor Inspector
L. J. CALLAN	NRC	RA
T. P. GWYNN	NRC	Dir, Div of Rx Safety
K. E. BROCKMAN	NRC	Dep Dir, Div Rx Safety
HARRY FREEMAN	NRC	RESIDENT INSPECTOR
T. J. POLICH	NRC	PROJECT MANAGER NRR/DRPW/PD 4-1
D.R. MOORE	TUE	OPERATIONS MGR
T.A. Hope	TUE	Regulatory Compliance Mgr
J. L. Barker	TUE	Mech Eng MGR
DAVID A. BERSI	TUE	MECH. DESIGN ENGR
M. L. LUCAS	TUE	MAINTENANCE MANAGER
DL DAVIS	TUE	Nuc OVERVIEW MANAGER
G.L. MERKA	TUE	REGULATORY AFFAIRS
ALAN B. HALL	TUE	SHIFT MANAGER
MORRISON, WILLIAM R	TUE	DESIGN MODIFICATION DESIGN LEADER
Donald R. Woodlan	TU Electric	Docket Licensing Manager
Eric Schmitt	TU Services	Commun. Support Mgr.
Roger D. Walker	TUE	Regulatory Affairs Mgr.
M. R. Blevins	TUE	Plant Manager
R. Flores	TUE	Systems Engineering Mgr
J.J. Kelley	TUE	V.P Engineering and Support
C.L. Terry	TUE	Group Vice President Nuclear

NAME	ORGANIZATION	POSITION TITLE
W. M. Taylor	TUE	Executive Vice President Production
W Reppa	TUE	Systems Engineer
S. Muffett	TUE	Station Engineering MGR.
T. Depierro	TUE	Systems Engineer
D. Moore	TUE	Operations Manager

Attachment 3

Handout for the
September 15, 1995
Management Meeting

TEXAS UTILITIES COMANCHE PEAK STEAM ELECTRIC STATION

TURBINE DRIVEN AUXILIARY FEEDWATER PUMP OVERSPEED EVENTS OF JUNE, 1995

PRESENTATION FOR MANAGEMENT MEETING WITH USNRC

SEPTEMBER 15, 1995

Table of Contents

Corrective Actions

Industry Experience

Long Term Corrective Actions

Conclusions

System Design

Turbine Driven Auxiliary Feed Water

Functional Requirements

- Auxiliary Feedwater provides emergency source of cooling water to Steam Generators for RCS heat sink in case of loss of main feedwater

- Turbine Driven Pump (TDAFWP) provides system redundancy independent of normal or emergency power supplies (Station Blackout)

- TDAFWP is required to respond to an actuation signal within 85 seconds

Turbine Driven
Auxiliary Feed Water

System Layout (Refer to Sketches)

- Two steam admission lines branch off the main steam headers from steam generators #1 & #4

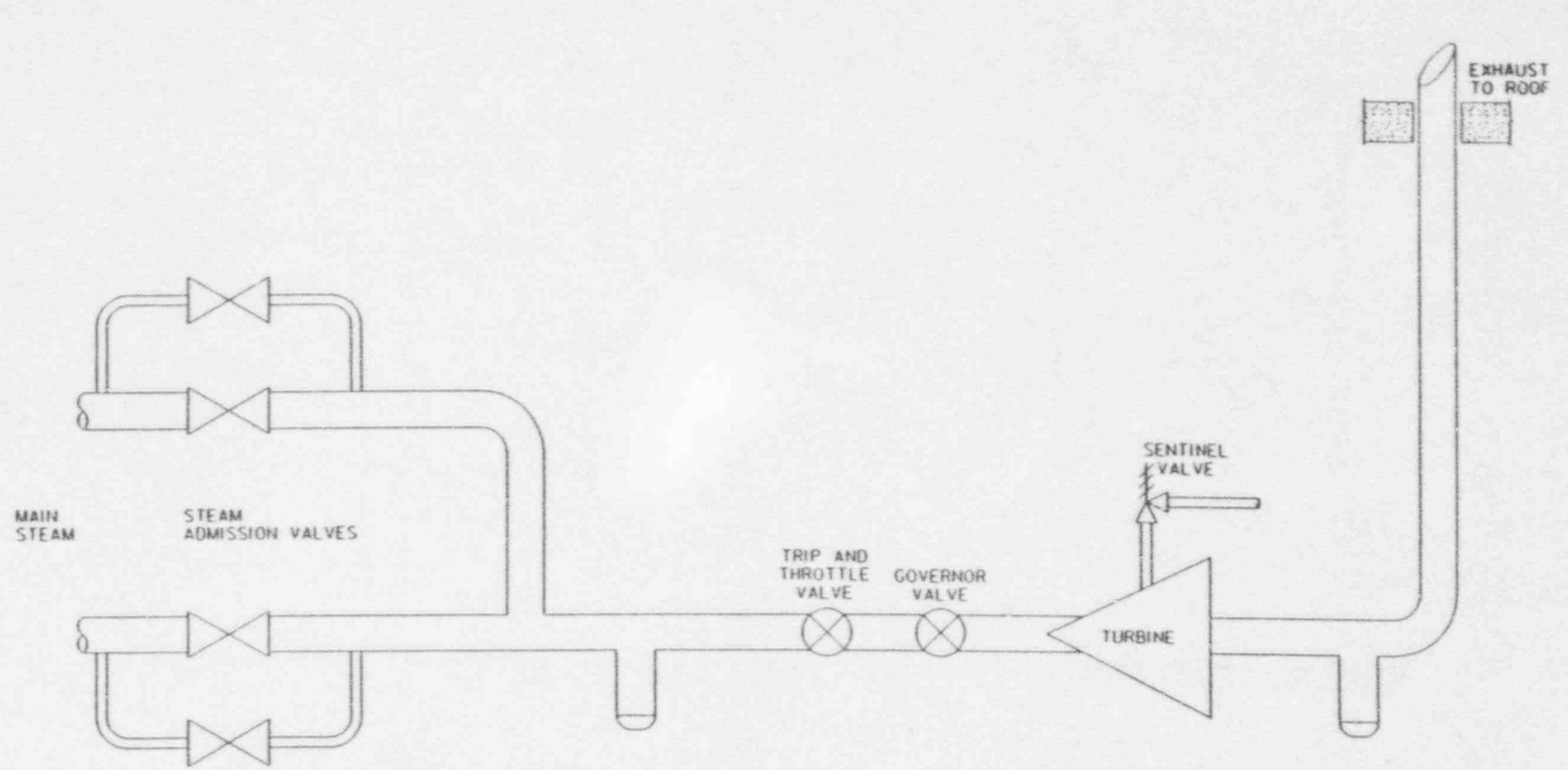
- A steam admission valve is located in each line ~250' upstream of the turbine

- The two lines tie together just upstream of the trip and throttle valve

- The normally open trip and throttle valve and governor valve are located just upstream of the turbine

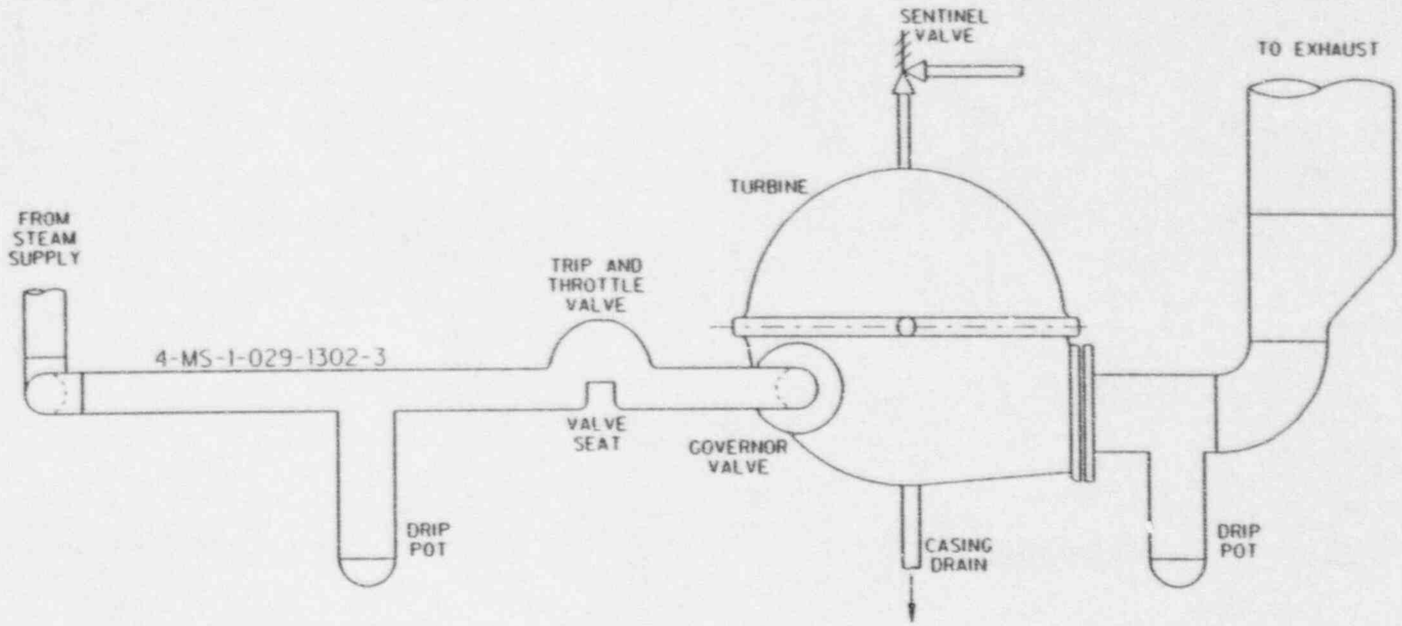
- The turbine drives the pump. The turbine is controlled by a mechanical governor via the governor valve.

- Turbine exhaust passes straight to atmosphere



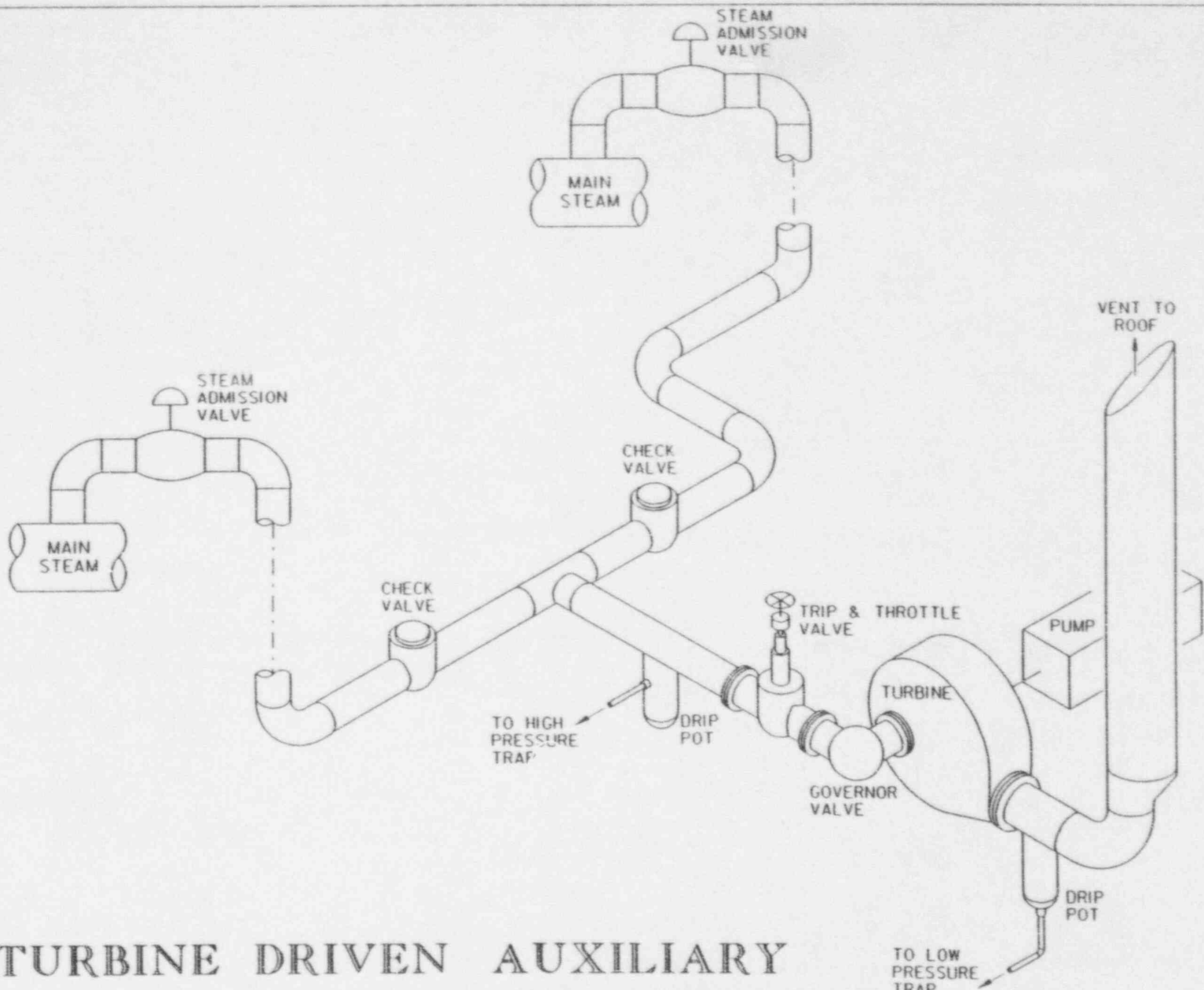
SYSTEM ARRANGEMENT (STEAM SIDE)

SKETCH NO. 1



TDAFW TURBINE STEAM INLET ARRANGEMENT

SKETCH NO. 2



TURBINE DRIVEN AUXILIARY FEED PUMP SYSTEM ARRANGEMENT

SKETCH NO. 3

Turbine Driven
Auxiliary Feed Water System

Design Features

- Steam admission valves open and turbine starts on Blackout, Steam Generator Lo-Lo or AMSAC Signal
- Steam admission lines are normally dry and de-energized
- Turbine speeds up quickly (3-5 seconds) and initially overshoots the speed setting (idle)
- Governor takes control and reduces speed to idle then ramps turbine up to full speed
- Sequence is required to take place within 85 seconds

Turbine Driven
Auxiliary Feed Water System

Drain System Function

- Drains condensate from inlet, exhaust and turbine when system is in standby
- Prevents live steam from entering floor drains/room when turbine is operating
- Drain system **IS NOT** designed to remove condensate from steam during startup
- Due to the configuration of the drip pots the drain system **DOES NOT** remove condensate from the inlet and exhaust lines during steady state operation

Turbine Driven Auxiliary Feed Water

Drains System Layout and Design Features

- Piping upstream of turbine is sloped to the inlet drip pot. downstream of turbine is sloped to the exhaust drip pot

- Inlet drip pot drains through orifices and steam trap to floor drain the exhaust drip pot drains through trap to floor drain

- The turbine casing drains directly (no trap)

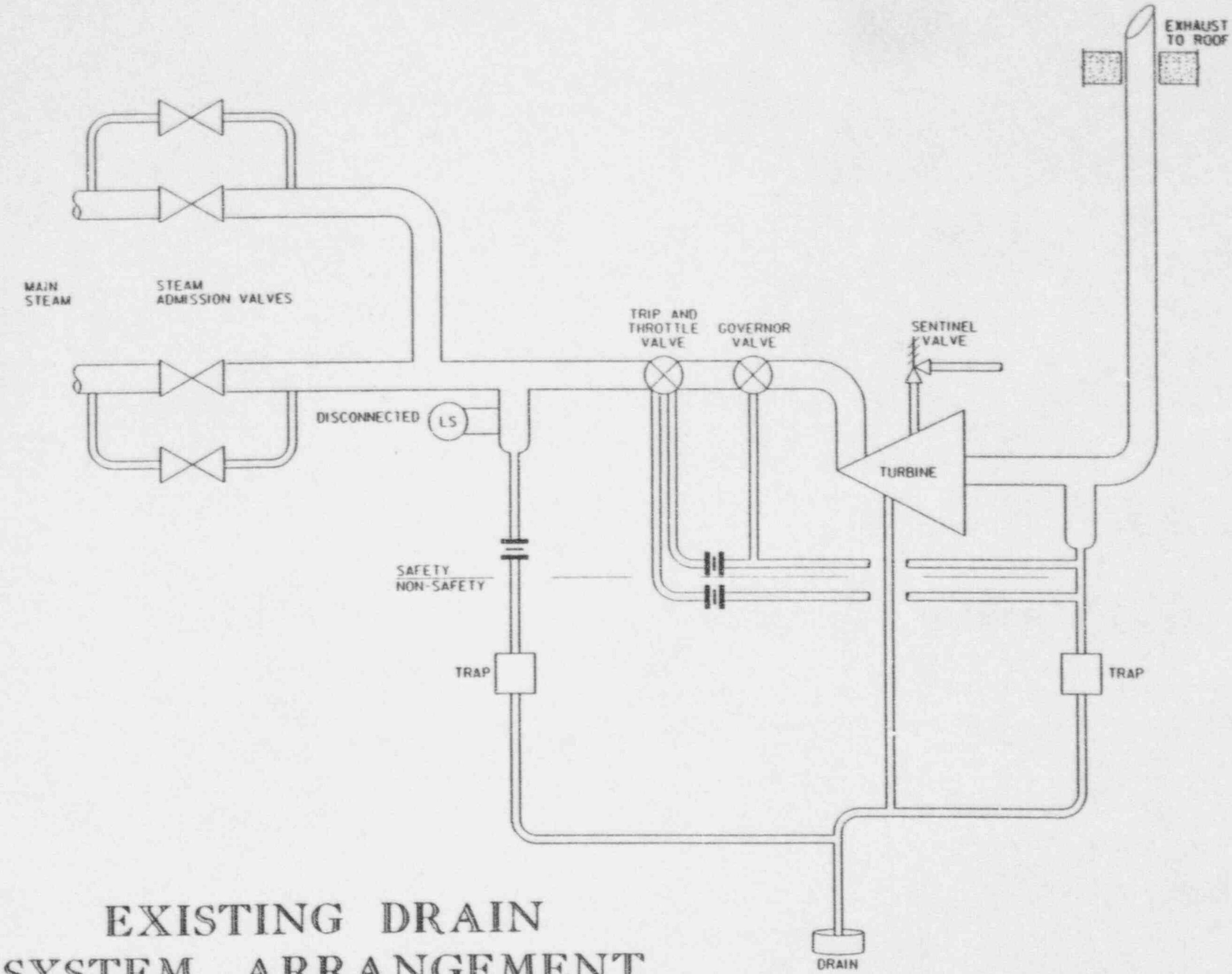
- The drain system was sized based on the capacity required to remove the steady state condensate generated during turbine operation

- However, the physical arrangement of the piping and drain connections in addition to the steam conditions results in minimal accumulations of condensate in the drains during cold starts and steady state operation.

- The condensate generated during cold starts was intended to be driven through the turbine. Steady state condensate also carries through the turbine

Steam Trap Function

System Operating Mode	Steam Trap Function
System Standby	Traps Drain condensate accumulation from any source
Turbine Cold Demand Start	Traps close shortly after steam admission valves open and line heats up. Trap function in this mode has no impact on system operation.
Steady State Operation	Cycle open/close. Trap function during this mode has no impact on system operation



EXISTING DRAIN SYSTEM ARRANGEMENT

SKETCH NO. 4

Unit 1 and 2 Overspeed Trip Events

June 11,1995 Unit 1 Overspeed Trip

Chronology

- On June 11, 1995 the TDAFWP was started on a demand signal due to Lo-Lo Steam Generator level, 28 seconds later the turbine tripped on overspeed
- TDAFWP was declared inoperable
- On June 14, 1995 TU Electric requested and was granted a notice of enforcement discretion by the NRC to remain in mode 3 while repairs and testing were performed
- Trouble shooting, repairs and system operability testing (including cold start) were performed during the 4 ½ days following the overspeed event
- On June 15, 1995 the system was declared operable

June 21, 1995 Unit 2 Overspeed Trip

Chronology

- Unit 2 TDAFWP was run on June 21, 1995 to investigate a reported system noise
- Turbine warm-up was performed for four minutes using a non-standard system alignment.
- The turbine was restarted 13 minutes later following valve re-alignment, ran for 13 seconds and tripped on overspeed
- Personnel noted more water than usual discharged from sentinel valve and the governor valve packing area. No movement of governor valve was noted
- TDAFWP was declared inoperable
- During the following three days trouble shooting, repairs and operability testing were performed. The turbine was run, shut down, and started after 13 minutes to verify restart capability
- On June 24, 1995 the system was declared operable

Probable Causes

June 11, 1995 Unit 1 Overspeed Trip

Probable Causes

- The governor valve stem corroded to the point of binding with the valve stem packing

- A slight binding was discovered in the governor valve cam linkage

Contributing Factors

- New valve stem was installed during march, 1995 outage. Replacement stem (liquid nitrided 410ss) is susceptible to accelerated corrosion.

- Stem to packing clearances were reduced (while still within spec) when new materials were installed

- Governor valve leakoff line is oriented horizontally by the vendor's design, which may contribute to a wet environment in the stem packing area

June 21, 1995 Unit 2 Overspeed Trip

Probable Cause

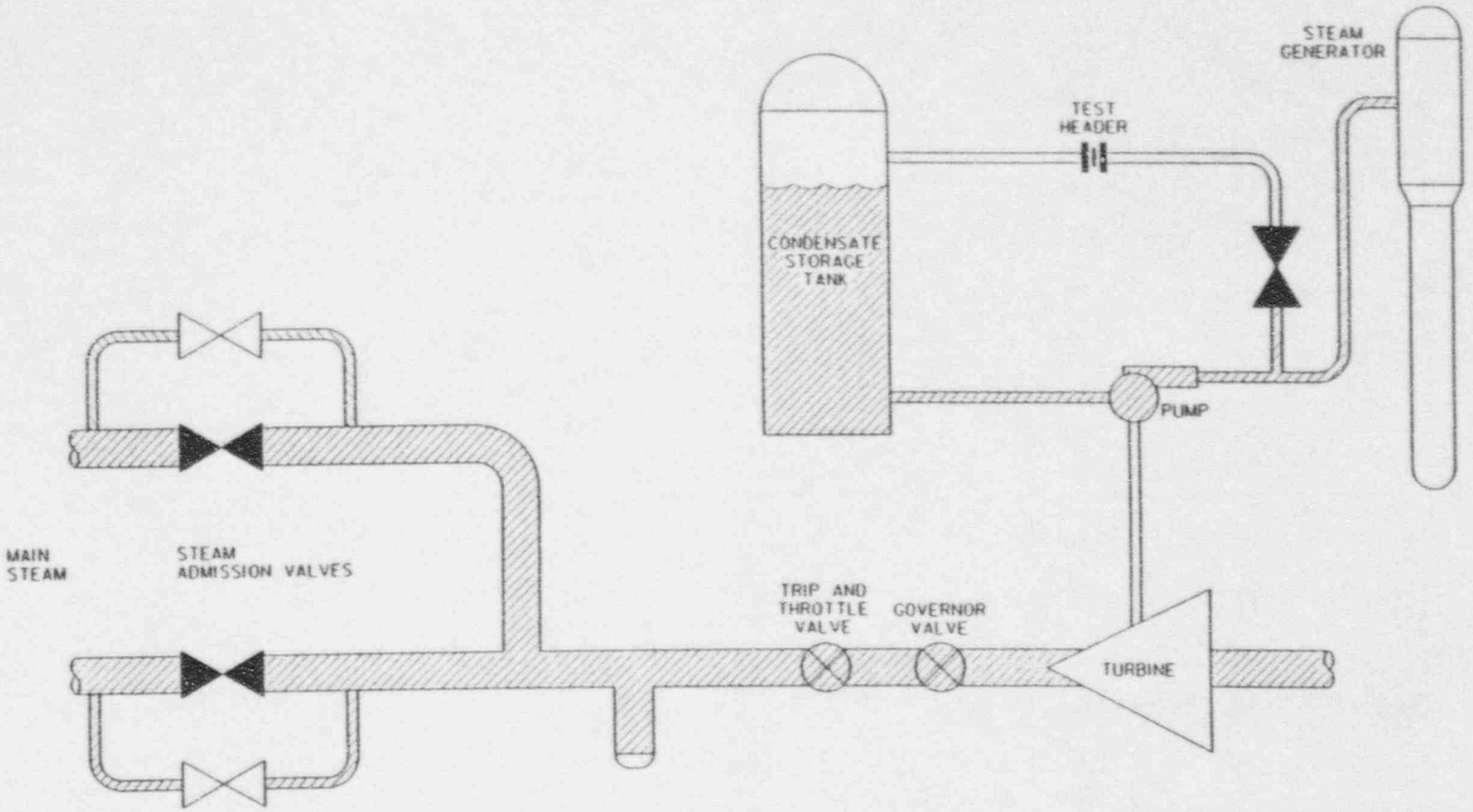
- The non-standard warm up run is believed to have caused excess water to accumulate in the system, based on eyewitness accounts. The governor valve was not able to control turbine speed.

Warm Up Run Alignment

- Pump discharge was lined up to Steam Generators (normal warm up run is lined up on test line to condensate storage tank)

- Turbine speed controller set to maximum speed (normal warm up run is set to minimum speed)

- Both Steam Admission bypass valves were opened to admit steam to turbine (normal warm up run is performed with one bypass valve open)



WARM-UP RUN (4 MIN ELAPSED TIME)
SYSTEM ARRANGEMENT

SKETCH NO. 5

June 21, 1995 Unit 2 Overspeed Trip

Contributing Factors

- Degraded steam trap performance reduced the drain system capability.
- Alarms for water level in the drain system are not part of the current design
- Slight binding was detected in the governor valve cam linkage
- Inboard packing bushing damage may have increased stem drag

Corrective Actions

June 11, 1995 Unit 1 Overspeed Trip

Immediate Corrective Actions to Return Equipment to Service

- Installed inconel valve stem
- Verified packing material composition
- Repaired cam plate washers to allow smooth operation of cam plate

June 21, 1995 Unit 2 Overspeed Trip

Immediate Corrective Actions to Return Equipment to Service

- Reworked steam traps
- Adjusted cam plate linkage to eliminate binding
- Performed test in which turbine was run under normal conditions, stopped for 13 minutes and restarted
- Initiated compensatory action to bypass steam traps at a frequency sufficient to insure no back up of condensate in the drain system

Additional Short Term Corrective Actions

Because the systems/equipment are nearly identical, corrective actions have been applied in both units except as noted

- Performed two monthly inspections of Unit 1 Inconel stem to verify adequate performance

- Monitor governor valves with strain gauges

- Established preventive maintenance (PM) activity to check cam linkage freedom of movement

- Performed metallurgical evaluation of Unit 1 valve stems which concluded that corrosion was the key contributing cause of stem binding

- Initiated Design Modifications to re-orient governor valve stem leak off connection

- Issued Design Modifications to install level alarms, this work is currently in process

- Issued Operations direction to bypass the steam traps, verify drain system level and quantify steam admission valve leakage periodically until alarms are installed

- Initiated Design Modifications to modify drain system to improve reliability

Additional Short Term Corrective Actions

- Verified the drain system is unobstructed

- Redesigned the Unit 2 inboard packing bushing. Replaced bushing and valve stem with a new inconel stem

- Reworked one Unit 2 steam admission valve to reduce leakage and scheduled remaining valves

- Changed frequency and scope of trap PM

- Reevaluated industry experience

  - Met with personnel from South Texas Project

  - Attended Terry Turbine Users Group meeting

  - Communicated with Millstone Unit 3 following the overspeed trip of their Terry turbine

Industry Experience

Industry Operating Experience

- During Start Up, the following measures were incorporated into the design and testing as a direct result of review of existing industry experience and recommendations (see Unit 1 start up issues)
  - Sloped piping
  - Installed governor modifications
  - Performed cold start Pre-0p testing
  - Replaced overspeed trip tappet
  - Worked with turbine and governor vendor to provide a reliable turbine control design

- The following are some of the measures that have been taken to address industry operating experience reports (IOER) since commercial operation and prior to the June, 1995 events

  - Perform cold start surveillance testing

  - Established PMs for trip and throttle valve lubrication and testing, turbine five year inspection, steam trap inspection and trip tappet inspection

  - Performed inspections of trip and throttle valve stem coupling

  - Incorporated governor oil; and turbine lube oil recommendations into the lube oil program

Industry Operating Experience

- Initiated governor valve stem inspections and strain gauge monitoring of stem forces

- Initiated purchasing documents to buy inconel stems from the turbine manufacturer when they become available

- Scheduled attendance at June, 1995 Terry Turbine Users Group meeting

- After the June, 1995 events, under PIR 95-657, an IOER reevaluation was performed.

  The team reviewed 58 industry events categorized them and reevaluated their applicability to CPSES

  The product of the review is an attachment to PIR 95-657

  The review confirmed that actions being taken after the June events incorporated industry information.

  Applicable CPSES IOER files will be updated to add current information

Design/Construction and Start-Up History

Unit 1 Start Up Issues

To address industry experience and CPSES specific start up problems the following changes were made to the system during Unit 1 completion

- Inlet and exhaust piping was sloped to drip pots to provide for proper standby drainage
- A pressure activated shutdown device was added to the governor to allow for quick restart of turbine
- The 30 sec. speed bushing was replaced with a 15 sec. bushing
- The overspeed trip tappet was replaced with the newer model
- Air diaphragm vent valves were modified to increase stroke time and equal percentage cages were installed
- Steam traps were added to the drain lines from the inlet and exhaust lines

Unit 1 Startup Issues continued

- Overspeed trip setpoint was revised and retested

- The Pre-Op test procedure was changed to perform the timed cold start testing with the steam admission line drip pot drain valves isolated (the steam traps were installed following hot functional testing). The turbine exhaust line drains were in operation during the Unit 1 timed cold start testing.

Unit 2 Design and Start Up Issues

- Philosophy: design, build and test similar to Unit 1
- Design Modifications performed on Unit 1 were incorporated in the Unit 2 design with few exceptions.
- Pre-Op test procedures for Unit 2 were developed from the Unit 1 procedures
- Successful Pre-Op testing would confirm system function and operation
- Steam Traps were installed in the steam admission line and exhaust line drains prior to the start of the timed cold start response testing
- The steam admission line drip pot level instrumentation was deleted from the original Unit 2 design because this change had been made in Unit 1 (after commercial operation)
- The physical differences between Unit 1 and 2 are evaluated in station procedure STA-504. A Unit Difference is determined to exist if operation, maintenance or surveillance testing are affected.

Unit 2 Design and Start Up Issues

- Lack of an additional drain pot in the Unit 2 exhaust line and quick opening trim in the steam admission valves were determined to be in accordance with the criteria for a non unit difference. (Note: a one-form has been initiated to address the design document discrepancy associated with the steam admission valve trim)

- Steam admission and exhaust line drains were not isolated during Unit 2 timed cold start testing, steam traps by nature of their operation (traps close when hot) would effectively isolate the drain lines during cold starts

System Design and Startup Conclusions

- CPSES TDAFW systems were designed, installed and tested in accordance with the criteria and standards that existed at the time of licensing. The NRC noted its concurrence in the CPSES Supplemental Safety Evaluation Report, SSER-22.

- The affect of excess condensate on the ability of the turbine start is understood qualitatively. There is no criteria which establishes the allowable condensate for the turbine, therefore the benefit of a comprehensive analysis is limited.

- The existing analytical models are complicated and very sensitive to minor changes in input parameters. The standard approach has been to test the system to prove functional capability and reliability. We believe CPSES testing met the existing industry standard.

Turbine Driven Auxiliary Feedwater Pump Operating History

Operating History

Testing Activity	Unit 1 Starts	Unit 2 Starts	Total Starts
Cold Quick Starts	20	10	30
Pre-warmed Quick Starts	40	20	60
Response Time Tests	6	3	9
Slave Relay Tests	10	4	14
Unscheduled Tests (2)	29	20	49
Demand Starts	9	4	13
	114	61	175

Note: 1. Actual number of starts may exceed totals shown. Numbers were extracted from operating logs or conservatively estimated from minimum test frequencies.

2. Includes Unit 2 Pre-Op testing

Operating History Conclusions

- From licensing until June, 1995 the Terry turbines have been tested similarly to the rest of the industry

- Until June, 1995 there has been no history of overspeed trips of the CPSES Terry turbines

- Operating history indicates that this equipment has performed reliably

- The Individual Plant Examination (IPE) for CPSES assesses the impact of the TDAFWP pump with respect to core damage frequency. The IPE uses generic industry data as its basis for reliability values. The value used for the TDAFWP pump failures upon any initiation signal is 1 failure per 30.3 starts. The failure rates used in the IPE are therefore conservative with respect to the actual performance of 2 failures to start in 175 attempts, for a failure rate of 1 per 87.5 attempts to start.

Steam Trap Installation and Classification

- Steam traps were added to the steam inlet and exhaust drain lines (Unit 1 during startup, Unit 2 pre-startup)

- The steam traps were classified as non-safety related based on:

  - During testing it was demonstrated that drain function was not required.

  - Testing demonstrated that condensate does not accumulate in inlet line or exhaust line during steady state system operation

  - Safety related orifices in the high pressure drains upstream of the traps were analyzed to restrict steam flow in event of a trap or line failure

  - Level instrumentation and alarm in the inlet line drip pot was available to indicate degradation or failure of the inlet line trap

Steam Trap Installation and Classification

- The level instrumentation and alarm were deleted by a Design Modification in 1992

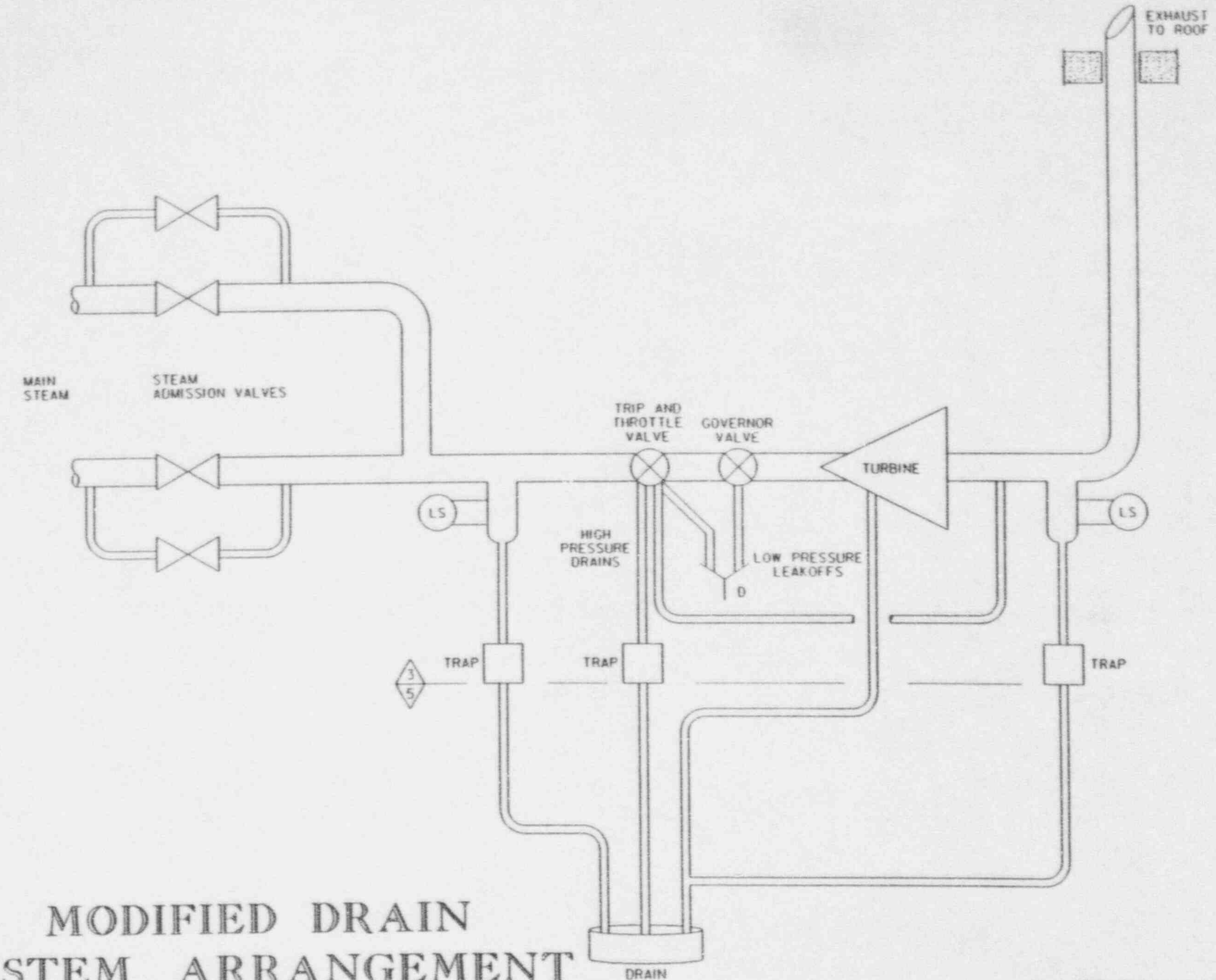
- The Safety Evaluation for Design Modification inappropriately concluded the drain function (i.e. trap function) is not required during all operating modes.

- Design Modifications are in process to modify the drain system as follows:

  - Level instrumentation and alarms will be installed in the inlet and exhaust steam lines

  - The high pressure and low pressure drains will be segregated

  - The orifices are being deleted from the drain lines and the steam traps are being conservatively classified as safety related (traps provide steam isolation function)



MODIFIED DRAIN
SYSTEM ARRANGEMENT

SKETCH NO. 6

Control of Condensate During Turbine Starts

- Our design consists of cold runs of pipe that condense water <u>during</u> a cold (demand) start. This is the primary source of water during the start

- Vendor (and other plants) have been unable to quantify how much water will adversely impact turbine control in order to establish the acceptability of the system through analysis

- Current approach for plants that have experienced overspeed trips is to maximize reliability by minimizing water

- Our design incorporates proper sloping of lines to facilitate draining and minimize water accumulation during standby

- Sentinel valve lifting is normal

  - Unit 1 start up engineer confirms that this was normal during Start Up

  - The valve has lifted in each cold start test since the June events

  - Other plants contacted have reported sentinel valves lifting

- Current compensatory measures and in process Design Mods to install level alarms will ensure lines dry at standby

- The Design Modifications section addresses our plan to minimize this water

Design Features of other Domestic Nuclear Plants

Summary

A survey of several domestic nuclear facilities similar to CPSES was performed. The following summarizes some of the pertinent findings.

1) The design of auxiliary feedwater systems throughout the industry varies significantly.

2) Several plants experience the sentinel valve lifting during startup of the TDAFWP.

3) Operability of the TDAFWP and of the non safety portions of the drain system is demonstrated through testing, surveillance, preventative maintenance, and operator actions.

Turbine Driven Auxiliary Feedwater System Design Features

Utility	Design Features
1	Trapped and/or orificed drains at critical locations: - Upstream of admission valve, - Upstream of check valves - Upstream of T&T valve, - Above and below seat of T&T valve, - On governor valve gland, - On turbine steam chest, - On exhaust line.
2	Electric heat traced lines from steam admission valves to T&T valve with temperatures maintained at 350-500 F. HELB considered for line where required.
3	Condensate collection tank installed downstream of steam admission valves. Tank is manually drained.
4	Drains for above seat drain, below seat drain, casing drain, and exhaust drain are valved and the valves close on turbine start.
5	T&T Valve is used as steam admission valve. T&T valve is very close to Turbine.
6	Main steam to steam admission valve is a relatively long run of piping, but distance from steam admission valve to T&T Valve is short.
7	Steam admission valves to T&T Valve is relatively long run of piping. After steam lines join, condensate knockout pots with orificed drain lines are provided at changes in direction.

8	Utilizing inconel governor valve stem.
9	Using T&T valve to shut down turbine, then close steam admission valves against low differential pressure to minimize valve seat wear.
10	Steam admission valve seat to body seal replaced with spiral wound style gasket with good results to date.
11	Trapped drains upstream and downstream of admission valves discharge to condenser.
12	Operation of traps verified with portable temperature indication on monthly basis.
13	Replaced Governor Valve and Governor with Electro-Hydraulically controlled system.

Long Term
Corrective Actions

Design Modifications

Criteria for Development of Design Modifications

- Remove condensate during system standby operation
- Minimize condensate passed through turbine during cold starts.
- Remove condensate during steady state turbine operation

Design Modifications

Design Options Considered

1 Maintain the steam admission lines hot during system standby operation using main steam

2 Heat trace the steam admission lines

3 Install condensate drain points along the steam admission line runs

4 Replace existing mechanical governor with a digital controller

5 Modify steam admission valve opening characteristic or add start up bypass steam admission valve

Options 3 and 5 are Selected

Option 3: **Modify Steam Admission Lines to Install Condensate Knock Out Pots**

Scope: The steam admission line piping will be modified to install a run tee and a drain pot in selected sections of the piping run to dynamically remove condensate from the lines during cold start conditions. The condensate will be continuously drained during standby, startup and steady state operation.

Pros: Steam admission lines can be normally de-energized, HELB analysis not impacted.

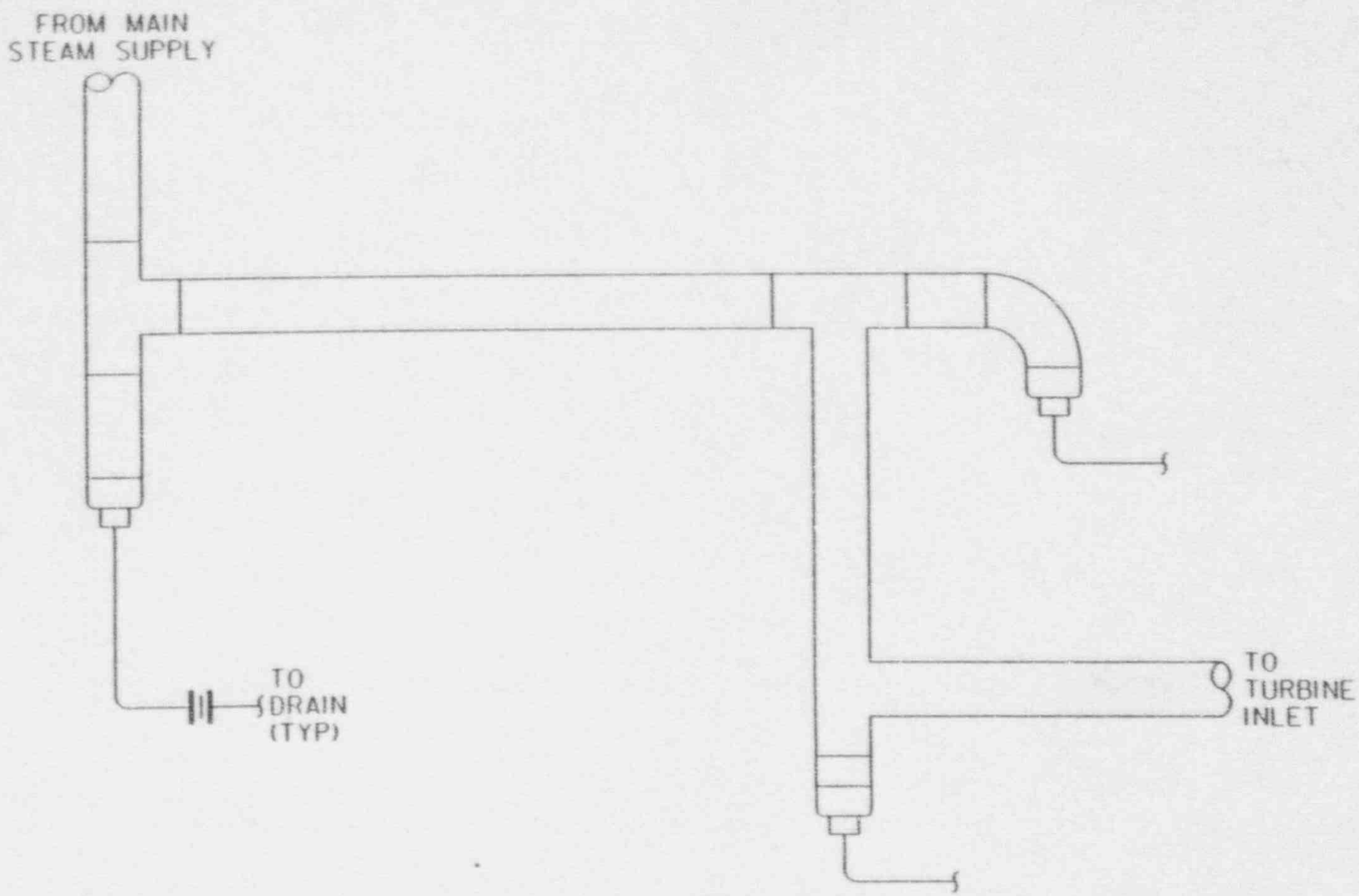
Will remove most condensate during standby, startup and steady state operation.

Relatively low cost

Cons: Knock out pot can not remove <u>all</u> entrained water

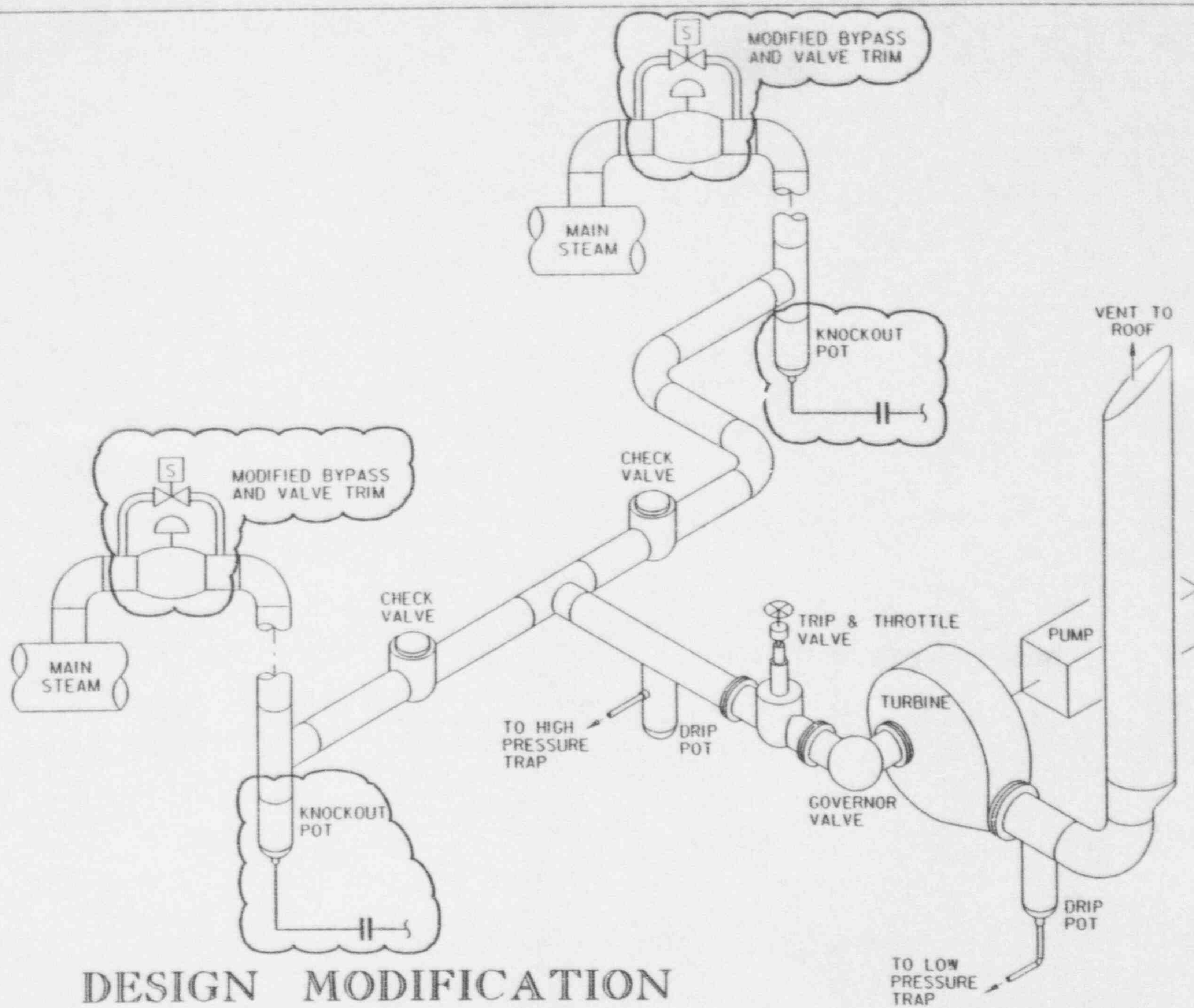
Knock out pot drain lines must be monitored for clogging

Option 5:	**Revise Opening Characteristic for Steam Admission Valves or Add Startup Bypass Steam Admission Valve** (combine with other options)
Scope:	Modify the steam admission valve internals and controls to admit steam to the turbine in a more controlled manner or add bypass steam admission valve
Pros:	Steam lines are energized gradually during cold starts allowing the governor to gain control while the steam conditions are insufficient to over speed the turbine. Steam lines are de-energized during normal operation, HELB analysis is not impacted
Cons:	Does not address condensate problem, must be combined with other modifications



TYPICAL CONDENSATE KNOCKOUT POT

SKETCH NO. 7



DESIGN MODIFICATION OPTIONS 3 & 5

SKETCH NO. 8

Conclusions

Unit 2 Operability

- Pre-op test program verified that turbine could successfully cold start on demand as designed.
- Surveillance testing verified that drains (as found) provided sufficient capacity to remove condensate during normal standby conditions.
- Steam side system configuration during Pre-Op and surveillance testing is identical to the as designed safeguards operating mode for demand operation (system is tested as-it-operates)
- Pre-Op testing and continued surveillance testing verified that condensate generation during steady state turbine operation does not impact the ability of the system to perform its intended function, cold start on demand and re-start.
- Follow up diagnostic testing has revealed that minimal quantities of condensate are accumulated in the drain system during cold starts and steady state turbine operation.
- The non-standard warmup run performed prior to the overspeed trip event is the probable cause . The system was not normally operated in this manner prior to this specific event. The systems functioned reliably when operated as designed as is evident by the previous 175 successful starts without an overspeed trip.

Therefore the TDAFWP was operable and capable of performing its intended function.

Summary

Unit 2 Overspeed Trip Summary

- Turbine Driven Auxiliary Feed Pump was always operable
- Functional capability of TDAFWP to perform as intended was adequately demonstrated by Pre-Operational and Surveillance Testing
- Probable causes of overspeed trips has been determined. Corrective and preventative action is complete or ongoing
- Drain system function is essential during system standby operation
- Minimal amounts of condensate accumulate in system drains during cold starts or steady state system operation
- Absence of drain function does not impact system operation during demand cold starts or steady state system operation
- Deletion of level instrumentation was inappropriate. Level instrumentation is being installed in inlet and exhaust lines.
- Running the TDAFWP in a non-standard warmup configuration likely resulted in the overspeed trip.

<u>Attachment 4</u>

Updated Diagram of
Planned Condensate Control
Modifications

Auxiliary Feedwater Pump Turbine Supply and Drain line Modification DM 95-054, 95-055 ATTACHMENT 4