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Your ref: Project Number 740
Our ref: DCP/NRC1826

February 8, 2007

Subject: AP1000 COL Standard Technical Report Submittal of APP-GW-GLN-018, Revision 0

In support of Combined License application pre-application activities, Westinghouse is submitting AP1000 Standard Combined License Technical Report Number 86. This report identifies and justifies standard changes to the AP1000 Design Control Document (DCD). These changes impact DCD Chapters 1, 2, 9 and 10 and are related to changes to the Steam & Power Conversion Design. The changes to the DCD identified in Technical Report 86 are intended to be incorporated into FSARs referencing the AP1000 Design Certification or incorporated into the design certification by an amendment to the design certification. This report is submitted as part of the NuStart Bellefonte COL Project (NRC Project Number 740). The information included in this report is generic and is expected to apply to all COL applications referencing the AP1000 Design Certification.

The purpose for submittal of this report was explained in a March 8, 2006 letter from NuStart to the NRC.

Pursuant to 10 CFR 50.30(b), APP-GW-GLN-018, Revision 0, "Alternate Steam & Power Conversion," (Technical Report Number 86), is submitted as Enclosure 1 under the attached Oath of Affirmation.

It is expected that when the NRC review of Technical Report Number 86 is complete, the changes to the DCD identified in Technical Report 86 will be considered approved generically for COL applicants referencing the AP1000 Design Certification.

Westinghouse is hereby requesting review and approval of the design changes associated with the Steam & Power Conversion Design.

Questions or requests for additional information related to content and preparation of this report should be directed to Westinghouse. Please send copies of such questions or requests for additional information to the prospective applicants for combined licenses referencing the AP1000 Design Certification. A representative for each applicant is included on the cc: list of this letter.

D079

Very truly yours,

D. F. Hutchings for

A. Sterdis, Manager
Licensing and Customer Interface
Regulatory Affairs and Standardization

/Attachment

1. "Oath of Affirmation," dated February 8, 2007

/Enclosures

1. APP-GW-GLN-018, Revision 0, "Alternate Steam & Power Conversion," Technical Report Number 86

cc:	S. Bloom	- U.S. NRC		1E	1A
	S. Coffin	- U.S. NRC		1E	1A
	G. Curtis	- TVA		1E	1A
	P. Grendys	- Westinghouse		1E	1A
	P. Hastings	- Duke Power		1E	1A
	C. Ionescu	- Progress Energy		1E	1A
	D. Lindgren	- Westinghouse		1E	1A
	A. Monroe	- SCANA		1E	1A
	M. Moran	- Florida Power & Light		1E	1A
	C. Pierce	- Southern Company		1E	1A
	E. Schmiech	- Westinghouse		1E	1A
	G. Zinke	- NuStart/Entergy		1E	1A

ATTACHMENT 1

"Oath of Affirmation"

ATTACHMENT 1

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

In the Matter of:)

NuStart Bellefonte COL Project)

NRC Project Number 740)

APPLICATION FOR REVIEW OF
"AP1000 GENERAL COMBINED LICENSE INFORMATION"
FOR COL APPLICATION PRE-APPLICATION REVIEW

W. E. Cummins, being duly sworn, states that he is Vice President, Regulatory Affairs & Standardization, for Westinghouse Electric Company; that he is authorized on the part of said company to sign and file with the Nuclear Regulatory Commission this document; that all statements made and matters set forth therein are true and correct to the best of his knowledge, information and belief.

W E Cummins

W. E. Cummins
Vice President
Regulatory Affairs & Standardization

Subscribed and sworn to
before me this 8th day
of February 2007.

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Debra McCarthy, Notary Public
Monroeville Boro, Allegheny County
My Commission Expires Aug. 31, 2009
Member, Pennsylvania Association of Notaries

Debra McCarthy
Notary

ENCLOSURE 1

APP-GW-GLN-018, Revision 0

"Alternate Steam & Power Conversion"

Technical Report 86

AP1000 DOCUMENT COVER SHEET

TDC: ________ Permanent File: ______ APY: ______

RFS#: ________ RFS ITEM #: ________

AP1000 DOCUMENT NO.	REVISION NO.		ASSIGNED TO
APP-GW-GLN-018	0		W-C. Watson

ALTERNATE DOCUMENT NUMBER: TR 86 WORK BREAKDOWN #:

ORIGINATING ORGANIZATION: AP1000

TITLE: **ALTERNATE STEAM AND POWER CONVERSION DESIGN**

ATTACHMENTS:	DCP #/REV. INCORPORATED IN THIS DOCUMENT REVISION:
N/A	
CALCULATION/ANALYSIS REFERENCE: N/A	

ELECTRONIC FILENAME	ELECTRONIC FILE FORMAT	ELECTRONIC FILE DESCRIPTION
APP-GW-GLN-018 RA AP1000 ALTERNATE TURBINE TR.DOC	MicrosoftWord	

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Class 3 Documents being transmitted to the NRC require the following two review signatures in lieu of a Form 36.

LEGAL REVIEW ~~N/A~~	SIGNATURE/DATE	2/8/07
PATENT REVIEW ~~N/A~~	SIGNATURE/DATE	M. M. Corletti 2/7/2007

☐ WESTINGHOUSE PROPRIETARY CLASS 2

ORIGINATOR C. Watson	SIGNATURE/DATE Charles Watson 2/6/07	
REVIEWERS D. Lindgren	SIGNATURE/DATE D. Lindgren 2/6/2007	
VERIFIER D. McDermott	SIGNATURE/DATE D. McDermott 2/6/07	VERIFICATION METHOD
AP1000 RESPONSIBLE MANAGER M. Corletti	SIGNATURE* M. M. Corletti	APPROVAL DATE 2/7/2007

* Approval of the responsible manager signifies that document is complete, all required reviews are complete, electronic file is attached and document is released for use.

AP1000 Standard Combine License Technical Report

Alternate Steam and Power Conversion Design

Technical Report 86

Revision 0

Westinghouse Electric Company LLC
Nuclear Power Plants
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1.0 INTRODUCTION

Chapter 10 of the Design Control Document (DCD) (Reference 1) describes the AP1000 Steam and Power Conversion System Reference Design; however, an alternative Steam and Power Conversion design may need to be considered depending on site specific data, equipment availability, and Utility requirements. This report summarizes the differences of the alternate design from the reference design described in Chapter 10 of the DCD, and includes the DCD mark up. The proposed Addendum 10A is an addition to Chapter 10 of the DCD and describes the AP1000 Alternate Steam and Power Conversion design. Addendum 10A identifies the sections of the DCD impacted by the inclusion of an alternate design. The portions of the AP1000 DCD that are affected by the alternate design are: Tier 1: Chapter 2--Section 2.4.2 / Tier 2: Chapter 1 – Section 1.2.1.3.1, Figure 1.2-27, Table 1.1-1, Table 1.3-1, Table 1.6-1, Appendix 1A Regulatory Guide 115; and Chapter 9 – Section 9.2.8.1.2, Section 9.2.8.2.3, Table 9.2.8-2, Chapter 10 – Sections 10.1, 10.2, 10.3, and 10.4.

Section 10A.2.6 of the Addendum revises one of the COL Information items of the Steam and Power Conversion reference design to reflect the change proposed by Technical Report No. 06, APP-GW-GLR-021 Rev. 0 (Reference 2). This change was enacted because plant-specific turbine rotor test data and calculated toughness curves require the availability of material properties from the fabrication of the turbine rotor. As-fabricated turbine rotor material properties are determined from actual material samples and can not be provided by an applicant for a COL.

The alternative design descibed in Addendum 10A does not decrease the electrical output capability of the AP1000 reference design and has no impact on thermal output or design of the reactor core.

The COL Applicant will determine the turbine design that will be used in licensing their specific plant; either the reference design in Chapter 10, or the alternate design of Addendum 10A.

2.0 APPLICABILITY DETERMINATION

This evaluation is prepared to document that the changes described above are a departure from Tier 1 and Tier 2 information of the AP1000 Design Control Document (DCD) that may be included in plant specific FSARs.

A.	Does the proposed change include a change to:		
	1. Tier 1 of the AP1000 Design Control Document APP-GW-GL-700	☐ NO ☒ YES	(If YES prepare a report for NRC review of the changes)
	2. Tier 2* of the AP1000 Design Control Document, APP-GW-GL-700	☒ NO ☐ YES	(If YES prepare a report for NRC review of the changes)
	3. Technical Specification in Chapter 16 of the AP1000 Design Control Document, APP-GW-GL-700	☒ NO ☐ YES	(If YES prepare a report for NRC review of the changes)
B.	Does the proposed change involve:		
	1. Closure of a Combined License Information Item identified in the AP1000 Design Control Document, APP-GW-GL-700	☒ NO ☐ YES	(If YES prepare a COL item closure report for NRC review.)
	2. Completion of an ITAAC item identified in Tier 1 of the AP1000 Design Control Document,	☒ NO ☐ YES	(If YES prepare an ITAAC completion report for NRC

	APP-GW-GL-700		review.)

☐ The questions above are answered no, therefore the departure from the DCD in a COL application does not require prior NRC review unless review is required by the criteria of 10 CFR Part 52 Appendix D Section VIII B.5.b. or B.5c

3.0 TECHNICAL BACKGROUND

The most significant differences between the Reference Design and the Alternate Design of the Turbine Generator Set are identified in the list below. These differences are elaborated upon in DCD Mark-Up section of this Technical Report.

- Addition of 7th Stage Feedwater Heaters
- 52" LP Turbine Last Stage Blade (LSB) vs. 54" LP Turbine LSB
- Addition of Moisture Extraction Blades (MEB)
- Static Excitation provided via solid-state thyristors vs. Brushless Excitation
- Triplicated channels for turbine speed indication and turbine trip signal vs. Two redundant channels
- Three modes of turbine overspeed protection vs. Two modes
- Hydraulic trip manifold which enables on line testing
- Replacement of the mechanical overspeed protection with a diverse electrical overspeed trip

There is no affect on nuclear safety with the alternative Steam and Power Conversion design. The alternative design conforms to the present reactor interface requirements and does not require a change be made to the Nuclear Island.

This Technical Report contains the DCD Draft for Addendum 10A. The addendum will include the subsections and paragraphs that have been changed to support the specifics of the alternative design. Those sections and subsections that have not been altered are documented as being the same as Chapter 10 of the reference design in the approved DCD. Paragraphs that are not in the design scope are not included in the addendum. The Tables and Figures that have been altered as necessary to reflect the text of the addendum have also been included.

The design of the alternate turbine generator meets the requirement of General Design Criterion 4 and conforms to the guidance provided in NUREG 0800 SRP 10.2 as related to the protection of safety-related structures, systems, and components from the effects of turbine missiles by providing a fully independent, redundant turbine Overspeed Protection System to minimize the probability of turbine missile generation. Also, the turbine is located and oriented to avoid potential impacts on safety-related structures and equipment.

The mechanical overspeed device currently described in the DCD is replaced with an independent, diverse electrical overspeed trip system. The electrical Overspeed Trip System consists of redundant processors, three (3) speed channel circuits, and trip relays, as well as other protective functions such as trip anticipations and power load imbalance. The overspeed controllers execute both Off Line and On-Line testing, both of which are conducted from the control room and require no technicians at the turbine. Off-line testing is performed during start up and trips the turbine based on an internal setpoint rather than actual turbine speed. On-Line testing is automatically executed through the internal injection of a ramping signal into all three independent speed channels at once. This test verifies the proper operation of the software, hardware, and the components of the hydraulic trip manifold. Loss of one signal will neither cause nor prevent a trip; however, a turbine trip is initiated upon failure of two of the three channels.

Additional redundancy is achieved by using three (3) speed channel circuits in the Master Controller of the D-EHC turbine control system. The Master controller is the primary controller for starting, synchronizing, and megawatt loading of the turbine/generator. This Emergency Overspeed Trip System residing in the Master Controller is redundant, independent, and diverse to the Electrical Overspeed Trip System discussed in the paragraph above. Each speed channel also has its own independent tripping relays. Loss of one signal will neither cause nor prevent a trip. Both the Electrical Overspeed Trip System and the Emergency Overspeed Trip Systems in the Master Controller meet the-single failure criterion and are testable when the turbine is in operation.

The turbine Overspeed Protection System is a highly reliable, redundant, non-safety-related system. The overspeed protection instrumentation and controls are acceptable with respect to redundancy, diversity, testability, and reliability.

The inclusion of a diverse electrical overspeed protection function addresses maintenance and serviceability problems experienced with turbine-generators that employ mechanical overspeed devices. The accurate operation of the mechanical overspeed device is dependant on the quality of the oil and turbine age. The oil used in this case is the low pressure bearing oil system which is open to atmosphere and is susceptible to contaminates. Experience shows that as the quality of the oil deteriorates and the turbine components age, the ability to set the trip point accurately decreases. Testing of the mechanical overspeed protection device has contributed to turbine failures; therefore, these devices have been replaced in operating nuclear plants with electrical overspeed protection. Testing of the electrical overspeed protection function can be performed more readily, without the need for operating the turbine generator at an overspeed condition.

The alternative turbine and rotor design described in Section 10A.2 has the same integral mono-block rotor as the reference design. Protection is provided by the orientation of the turbine-generator in relation to safety-related structures and components and by the use of robust turbine rotors as described in Section 10A.2. The rotor design, manufacturing, material specification, and the inspections recommended for the AP1000 provide a very low probability of missile generation (less than 10^{-5} even after 24 years of running time). The potential for a high-trajectory missile to impact safety-related areas of the AP1000 is less than 10^{-7}. Based on this very low probability, the potential damage from a high-trajectory missile is not evaluated. This information is provided in the DCD and the referenced WCAP reports for both turbine designs.

4.0 DCD MARK-UP

Tier 1

2.4.2 Main Turbine System

Design Description

The main turbine system (MTS) is designed for electric power production consistent with the capability of the reactor and the reactor coolant system.

The component locations of the MTS are as shown in Table 2.4.2-2.

1. The functional arrangement of the MTS is as described in the Design Description of this Section 2.4.2.

2. a) Controls exist in the MCR to trip the main turbine-generator.

   b) The main turbine-generator trips after receiving a signal from the PMS.

   c) The main turbine-generator trips after receiving a signal from the DAS.

Inspections, Tests, Analyses, and Acceptance Criteria

Table 2.4.2-1 specifies the inspections, tests, analyses, and associated acceptance criteria for the MTS.

TABLE 2.4.2-2

Component Name	Tag No.	Component Location
HP Turbine	MTS-MG-01	Turbine Building
LP Turbine A	MTS-MG-02A	Turbine Building
LP Turbine B	MTS-MG-02B	Turbine Building
LP Turbine C	MTS-MG-02C	Turbine Building
Gland Steam Condenser	GSS-ME-01	Turbine Building
Gland Condenser Vapor Exhauster 1A	GSS-MA-01A	Turbine Building
Gland Condenser Vapor Exhauster 1B	GSS-MA-01B	Turbine Building
Mechanical Overspeed Trip Device*	--	Turbine Building
Electrical Overspeed Trip Device	--	Turbine Building
Emergency Electrical Overspeed Trip Device*	--	Turbine Building

*Alternate Steam and Power Conversion design of Addendum 10A replaces the mechanical overspeed trip device with a diverse Emergency Electrical Overspeed Trip Device.

Tier 2

CHAPTER 1
INTRODUCTION AND GENERAL DESCRIPTION OF THE PLANT

1.2.1.3.1 Turbine Design

- The turbine is a power conversion system designed to change the thermal energy of the steam flowing through the turbine into rotational mechanical work which rotates a generator to provide electrical power. It consists of a double flow high pressure cylinder (high pressure turbine) and three double flow low pressure cylinders (low pressure turbines) which exhaust to the condenser. It is a six flow tandem compound, 1800 rpm machine. The turbine system includes stop, control and intercept valves directly attached to the turbine and in the steam flow path, crossover and crossunder piping between the turbine cylinders and the moisture separator reheaters.

- The high pressure turbine has a connection for one stage of feedwater heating (connections for two stages of feedwater heating on the alternate steam and power conversion design). The high pressure turbine exhaust steam provides steam for one stage of feedwater heating in the deaerator. The low pressure turbines have extraction connections for four stages of feedwater heating.

- The moisture separator reheater is an integral component of the turbine system which extracts moisture from the steam and reheats the steam to improve the turbine system performance. There are two moisture separator reheaters located between the high pressure turbine exhaust and the low pressure turbine inlet. The reheater has ~~a single stage~~two stages of reheat.

- The turbine orientation minimizes potential interaction between turbine missiles and safety-related structures and components.

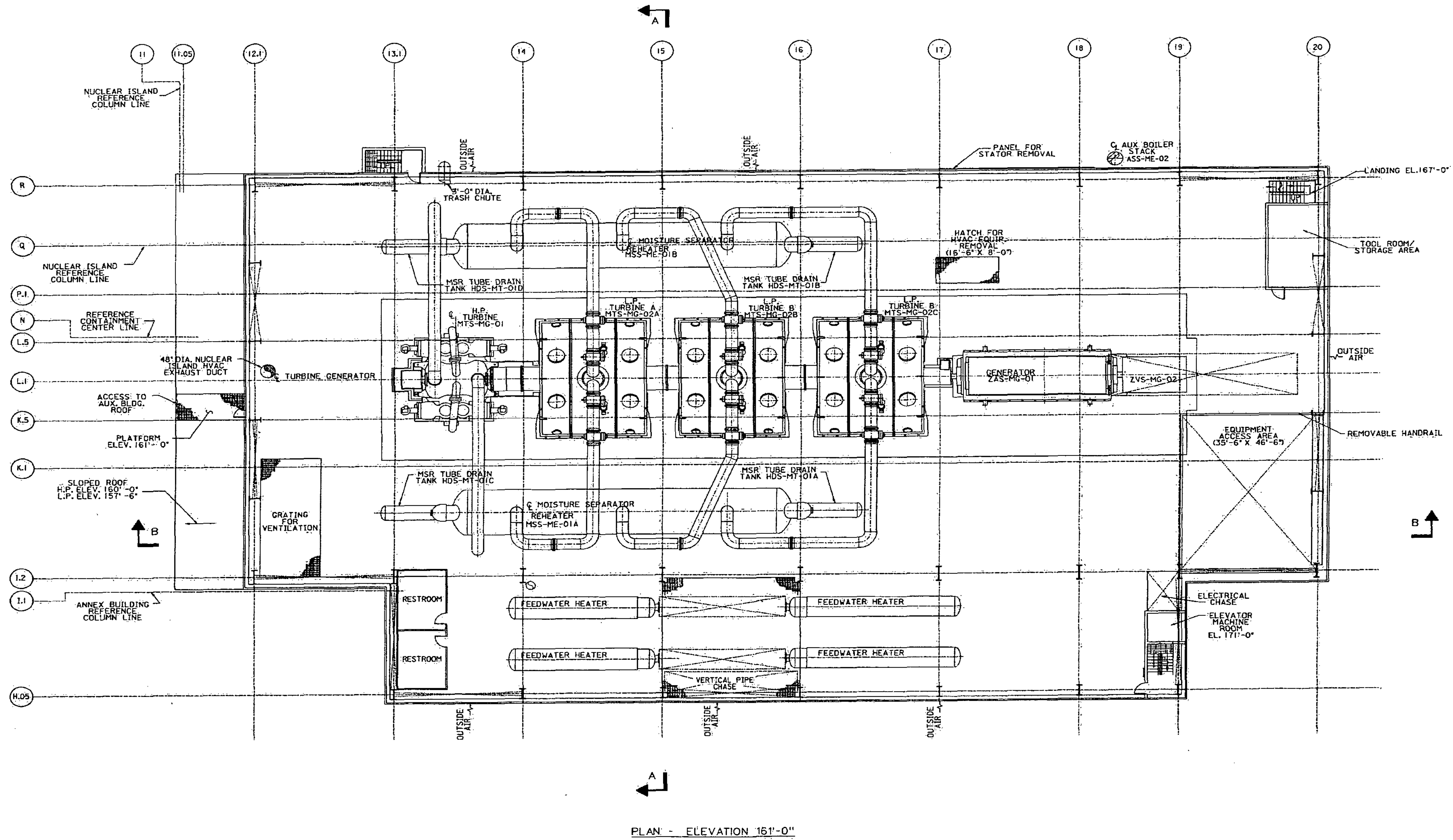

Figure 1.2-27

Turbine Building General Arrangement Plan at Elevation 161′-0″ with Equipment

Table 1.1-1 (Sheet 1 of 4)
AP1000 DCD ACRONYMS

ac	-	Alternating Current
ACI	-	American Concrete Institute
ACRS	-	Advisory Committee on Reactor Safeguards
ADS	-	Automatic Depressurization System
AISC	-	American Institute of Steel Construction
AISI	-	American Iron and Steel Institute
ALARA	-	As-Low-As-Reasonably Achievable
ALWR	-	Advanced Light Water Reactor
AMCA	-	Air Movement and Control Association
ANS	-	American Nuclear Society
ANL	-	Argonne National Laboratory
ANSI	-	American National Standards Institute
API	-	American Petroleum Institute
ARI	-	Air Conditioning and Refrigeration Institute
ASCE	-	American Society of Civil Engineers
ASHRAE	-	American Society of Heating, Refrigeration and Air-Conditioning Engineers
ASME	-	American Society of Mechanical Engineers
ASTM	-	American Society for Testing and Materials
ATWS	-	Anticipated Transient Without Scram
AWS	-	American Welding Society
BEACON	-	Best Estimate Analyzer for Core Operations - Nuclear
BOL	-	Beginning of Life
BOP	-	Balance of Plant
BTP	-	Branch Technical Position
CFR	-	Code of Federal Regulations
CHF	-	Critical Heat Flux
CMAA	-	Crane Manufacturers Association of American
CMT	-	Core Makeup Tank
CRD	-	Control Rod Drive
CRDM	-	Control Rod Drive Mechanism
CVS	-	Chemical and Volume Control System
DAC	-	Design Acceptance Criteria
dc	-	Direct Current
DBA	-	Design Basis Accident
DBE	-	Design Basis Event
DCD	-	Design Control Document
DEH	-	Digital Electrohydraulic
D-EHC	-	Digital Electrohydraulic Control
DEMA	-	Diesel Engine Manufacturers Association
DNB	-	Departure from Nucleate Boiling
DNBR	-	Departure from Nucleate Boiling Ratio
DOE	-	Department of Energy
DPU	-	Distributed Processing Unit

Table 1.1-1 (Sheet 2 of 4)

AP1000 DCD ACRONYMS

EFPD	-	Effective Full Power Days
EIS	-	Environmental Impact Statement
EMI	-	Electromagnetic Interference
EOF	-	Emergency Offsite Facility
EPA	-	Environmental Protection Agency
EPRI	-	Electric Power Research Institute
ER	-	Environmental Report
ERF	-	Emergency Response Facility
ESF	-	Engineered Safety Features
ESFAS	-	Engineered Safety Features Actuation System
FID	-	Fixed Incore Detector
FM	-	Factory Mutual Engineering and Research Corporation
FMEA	-	Failure Modes and Effects Analysis
FWPCA	-	Federal Water Pollution Control Act
GDC	-	General Design Criteria
GSI	-	Generic Safety Issues
HEPA	-	High Efficiency Particulate Air
HFE	-	Human Factors Engineering
HVAC	-	Heating, Ventilation and Air Conditioning
I&C	-	Instrumentation and Control
ICEA	-	Insulated Cable Engineers Association
IDCOR	-	Industry Degraded Core Rulemaking
IEEE	-	Institute of Electrical and Electronics Engineers
IES	-	Illumination Engineering Society
ILRT	-	Integrated Leak Rate Test
INEL	-	Idaho National Engineering Laboratory
I/O	-	Input/Output
IRWST	-	In Containment Refueling Water Storage Tank
ISA	-	Instrument Society of America
ISI	-	Inservice Inspection
IST	-	Inservice Testing
ITAAC	-	Inspections, Tests, Analyses and Acceptance Criteria
LBB	-	Leak-Before-Break
LOCA	-	Loss of Coolant Accident
LOF	-	Loss-of-Flow with Failure to Scram
LOFT	-	Loss of Flow Test
LOOP	-	Loss of Offsite Power
LOSP	-	Loss of System Pressure with Degraded ECCS Operation
LPZ	-	Low Population Zone
LSB		Last Stage Blade
LWR	-	Light Water Reactor
MAAP	-	Modular Accident Analysis Programs
MCC	-	Motor Control Center
MCR	-	Main Control Room

Table 1.3-1 (Sheet 3 of 6)

AP1000 PLANT COMPARISON WITH SIMILAR FACILITIES

Systems – Components	DCD	AP1000	AP600	Reference 2 Loop
Pressurizer	5.4.5			
Total volume		2,100 ft^3	1,600 ft^3	1,500 ft^3
Volume/MWt		0.618 ft^3/MWt	0.825 ft^3/MWt	0.440 ft^3/MWt
Safety valves #/size		2 – 6"x8"	2 – 6"x6"	3 – 6"
PORV #/size		no	no	no
PRT volume		no	no	2,400 ft^3
Auto depressurization		yes	yes	no
Turbine Island	10.2			
Turbine – # HP cylinder		1	1	1
# LP cylinders		3	2	3
Max blade length		54 in | 52 in*	47 in	40 in
Number reheat stages		2	1	1
Feedwater heating stages				
– # LP stages		4	4	5
– # HP stages		1 | 2*	2	1
Deaerator		yes	yes	no
Main feedwater pumps		3 motor driven	2 motor driven	2 turbine driven
Condensate pumps		3	3	3
Condenser tube material		Ti	Ti	SS
Condensate polishing		0–33%	33%	0–100%

* Designates Alternate Steam and Power Conversion design configuration

Table 1.6-1 (Sheet 3 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
1.9	WCAP-15993	Evaluation of the AP1000 Conformance to Inter-System Loss-of-Coolant Accident Acceptance Criteria, Revision 1, March 2003
	WCAP-15799	AP1000 Compliance with SRP Acceptance Criteria, Revision 1, August 2003
	WCAP-15800	Operational Assessment for AP1000, Revision 3, July 2004
	WCAP-15992	AP1000 Adverse Systems Interactions Evaluation Report, Revision 1, February 2003
	WCAP-15776	Safety Criteria for the AP1000 Instrumentation and Control Systems
1A	WCAP-8577	The Application of Pre-Heat Temperature After Welding of Pressure Vessel Steels, September 1975
	WCAP-15783-P (P) WCAP-15783-NP	Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines, Revision 2, August 2003
	WCAP-16650-P (P) WCAP-16650-NP	Analysis of the Probability of Generation of Missiles for AP1000 Alternate Fully Integral Low Pressure Turbines, Revision 0, February 2007.
3.3	WCAP-13323 (P) WCAP-13324	Phase II Wind Tunnel Testing for the Westinghouse AP600 Reactor, August 1992
	WCAP-14068 (P) WCAP-14084	Phase IVA Wind Tunnel Testing for the Westinghouse AP600 Reactor, May 1994
	WCAP-14169 (P) WCAP-14170	Phase IVA Wind Tunnel Testing for the Westinghouse AP600 Reactor, Supplemental Report, September 1994
	WCAP-13294-P (P) WCAP-13295-NP	Phase I Wind Tunnel Testing for the Westinghouse AP600 Reactor, April 1992
3.6	WCAP-8077 (P) WCAP-8078	Ice Condenser Containment Pressure Transient Analysis Methods, March 1973
	WCAP-8708 (P) WCAP-8709-A	MULTIFLEX A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics, February 1976
	WCAP-8252	Documentation of Selected Westinghouse Structural Analysis Computer Codes, Revision 1, May 1977

(P) Denotes Document is Proprietary

Table 1.6-1 (Sheet 13 of 20)

MATERIAL REFERENCED

DCD Section Number	Westinghouse Topical Report Number	Title
9.5	WCAP-15871	AP1000 Assessment Against NFPA 804, Revision 1, December 2002
10.2	WCAP-15783-P (P) WCAP-15783-NP	Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines, Revision 2, August 2003
	WCAP-15785 (P) WCAP-15786	Probabilistic Evaluation of Turbine Valve Test Frequency, April 2002
10A.2	WCAP-16650-P (P) WCAP-16650-NP	Analysis of the Probability of Generation of Missiles for AP1000 Alternate Fully Integral Low Pressure Turbines, Revision 0, February 2007.
	WCAP-16651-P (P) WCAP-16651-NP	Probabilistic Evaluation of AP1000 Alternate Turbine Valve Test Frequency, Revision 0, February 2007.
13	WCAP-14690	Designer's Input to Procedure Development for the AP600, Revision 1, June 1997
	WCAP-13864	Rod Control System Evaluation Program, Revision 1-A, November 1994
15.0	WCAP-11397-P-A (P) WCAP-11397-A	Revised Thermal Design Procedure, April 1989
	WCAP-10054-P-A (P) WCAP-10081	Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code, August 1985
	WCAP-12945-P-A (P) WCAP-14747	Code Qualification Document for Best Estimate LOCA Analysis, Revision 1, March 1998
	WCAP-7908-A	FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod, December 1989
	WCAP-7907-P-A (P) WCAP-7907-A	LOFTRAN Code Description, April 1984
	WCAP-7979-P-A (P) WCAP-8028-A	TWINKLE – A Multi-Dimensional Neutron Kinetics Computer Code, January 1975
	WCAP-10698-P-A (P) WCAP-10750-A	SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill, August 1987
	WCAP-14234 (P) WCAP-14235	LOFTRAN and LOFTTR2 AP600 Code Applicability Document, Revision 1, August 1997
	WCAP-15644-P (P) WCAP-15644-NP	AP1000 Code Applicability Report, Revision 2, March 2004

(P) Denotes Document is Proprietary

APPENDIX 1A
CONFORMANCE WITH REGULATORY GUIDES

Criteria Section	Referenced Criteria	AP1000 Position	Clarification/Summary Description of Exceptions
DIVISION 1 – Power Reactors			
Reg. Guide 1.115, Rev. 1, 1/77 – Protection Against Low-Trajectory Turbine Missiles			
General		Conforms	The SRP 3.5.1.3 issued in 1981 and Regulatory Guide 1.115, issued in 1977, provide criteria for protection against the effects of potential turbine missiles. Reference 28 issued in 1984 states that "the Nuclear Regulatory Commission staff has shifted emphasis in the reviews of the turbine missile issue from the strike and damage probability (P_2xP_3) to the missile generation probability (P_1) and, in the process, has attempted to integrate the various aspects of the issue into a single coherent evaluation." The AP1000 turbine is arranged in a radial orientation. The ~~two~~ low pressure turbines incorporate fully integral rotors. The turbine conforms ~~with~~to the criteria given in References 28 ~~and~~, WCAP-15783 (Reference 29), and WCAP-16650 (Reference 52 for the alternate Steam and Power Conversion design in Addendum 10A).

1A.1 References

52. WCAP-16650-P (Proprietary) and WCAP-16650-NP (Non-Proprietary), "Analysis of the Probability of Generation of Missiles for AP1000 Alternate Fully Integral Low Pressure Turbines," Revision 0, February 2007.

CHAPTER 9
AUXILIARY SYSTEMS

9.2.8.1.2 Power Generation Design Basis

The turbine building closed cooling water system provides corrosion-inhibited, demineralized cooling water to the equipment shown in Table 9.2.8-1 (Table 9.2.8-2 for the alternate steam and power conversion design of Addendum 10A) during normal plant operation.

During power operation, the turbine building closed cooling water system provides a continuous supply of cooling water to turbine building equipment at a temperature of ~~95~~96°F or less assuming a circulating water temperature of ~~90~~91°F or less.

The cooling water is treated with a corrosion inhibitor and uses demineralized water for makeup. The system is equipped with a chemical addition tank to add chemicals to the system.

The heat sink for the turbine building closed cooling water system is the circulating water system. The heat is transferred to circulating water through plate type heat exchangers which are components of the turbine building closed cooling water system.

A surge tank is sized to accommodate thermal expansion and contraction of the fluid due to temperature changes in the system.

One of the turbine building closed cooling system pumps or heat exchangers may be unavailable for operation or isolated for maintenance without impairing the function of the system.

The turbine building closed cooling water pumps are provided ac power from the 6900V switchgear bus. The pumps are not required during a loss of normal ac power.

9.2.8.2 System Description

The entirety of Chapter 9, Section 2.8.2, System Description, is the same as the DCD reference Chapter 9 with the exception of the section identified below.

9.2.8.2.3 System Operation

Normal Operation

During normal operation, one turbine building closed cooling water system pump and two heat exchangers provide cooling to the components listed in Table 9.2.8-1 (Table 9.2.8-2 for the alternate steam and power conversion design of Addendum 10A). The other pump is on standby and aligned to start automatically upon low discharge header pressure.

During normal operation, leakage from the system will be replaced by makeup from the demineralized water transfer and storage system through the automatic makeup valve. Makeup can be controlled either manually~~,~~ or automatically, upon reaching low level in the surge tank.

Table 9.2.8-1

TURBINE BUILDING CLOSED COOLING WATER SYSTEM
~~NORMAL POWER OPERATION~~
~~NOMINAL VALUES~~EQUIPMENT LOAD LIST

Component
Main turbine lube oil coolers
Main feedwater pump lube oil coolers
Air side seal oil cooler
Hydrogen side seal oil cooler
Exciter air coolers
Generator hydrogen coolers
Generator stator cooling water cooler
Isolated phase bus coolers
CT case and neutral enclosure
Low pressure feedwater heater drain pump
MSR drain pump
Condenser vacuum pump
EH control coolers
Secondary sampling system coolers
~~Total~~

Table 9.2.8-2 **TURBINE BUILDING CLOSED COOLING WATER SYSTEM EQUIPMENT LOAD LIST FOR THE ALTERNATE STEAM AND POWER CONVERSION DESIGN**
Component
Main turbine lube oil coolers
Main feedwater pump lube oil coolers
Generator hydrogen coolers
Generator stator cooling water cooler
Isolated phase bus coolers
Condensate pump motor air cooler Condensate pump bearing oil cooler
Feedwater pump motor air cooler
MSR drain pump
Condenser vacuum pump
EH control coolers
Secondary sampling system coolers

CHAPTER ~~10~~10A ALTERNATE STEAM AND POWER CONVERSION

~~10~~10A.1 Summary Description

The steam and power conversion system is designed to remove heat energy from the reactor coolant system via the two steam generators and to convert it to electrical power in the turbine-generator. The main condenser deaerates the condensate and transfers heat that is unusable in the cycle to the circulating water system. The regenerative turbine cycle heats the feedwater, and the main feedwater system returns it to the steam generators.

Table ~~10~~10A.1-1 gives the significant design and performance data for the major system components. Figure ~~10~~10A.1-1 shows the rated heat balance for the turbine cycle process.

~~10~~10A.1.1 General Description

The steam generated in the two steam generators is supplied to the high-pressure turbine by the main steam system. After expansion through the high-pressure turbine, the steam passes through the two moisture separator/reheaters (MSRs) and is then admitted to the three low-pressure turbines. A portion of the steam is extracted from the high- and low-pressure turbines for ~~six~~ seven stages of feedwater heating.

Exhaust steam from the low-pressure turbines is condensed and deaerated in the main condenser. The heat rejected in the main condenser is removed by the circulating water system (CWS). The condensate pumps take suction from the condenser hotwell and deliver the condensate through four stages of low-pressure closed feedwater heaters to the fifth stage, open deaerating heater. Condensate then flows to the suction of the steam generator feedwater booster pump and is discharged to the suction of the main feedwater pump. The steam generator feedwater pumps discharge the feedwater through ~~one stage~~two stages of high-pressure feedwater heating to the two steam generators.

~~The moisture separator drains are pumped to the deaerator. The reheater drains and high-pressure feedwater heater drains cascade into the deaerator. Drains from the low-pressure feedwater heaters are cascaded through successively lower pressure feedwater heaters to the main condenser.~~

The turbine-generator has an output of ~~about~~approximately 1,199,500 kW for the Westinghouse nuclear steam supply system (NSSS) thermal output of 3,415 MWt. The principal turbine-generator conditions for the turbine rating are listed in Table ~~10~~10A.1-1. The rated system conditions for the NSSS are listed in Table ~~10~~10A.1-1. The systems of the turbine cycle have been designed to meet the maximum expected turbine generator conditions.

Instrumentation systems are designed for the normal operating conditions of the steam and condensate systems. The systems are designed for safe and reliable control and incorporate requirements for performance calculations and periodic heat balances. Instrumentation for the secondary cycle is also provided to meet recommendations by the turbine supplier and ANSI/ASME TDP-2-1985, "Recommended Practices for the Prevention of Water Damage to Steam Turbines Used for Electric Power Generation." Design features for prevention of water hammer in the steam generator are described in subsection 5.4.2.2. Continuous sampling instrumentation and grab sample points are provided so that water chemistry in the secondary cycle can be maintained within acceptable limits, as required by the nuclear steam system and turbine suppliers (see subsections 9.3.4 and 10.3.5). Condenser tube/tube sheet leakage can be identified and isolated by using condenser conductivity sampling provisions.

Criteria and bases for safety-related instrumentation for main steam isolation are discussed in Section 7.3.

~~10~~10A.1.2 Protective Features

Loss of External Electrical Load and/or Turbine Trip Protection

Same as reference Chapter 10 section.

Overpressure Protection

Same as reference Chapter 10 section.

Loss of Main Feedwater Flow Protection

Same as reference Chapter 10 section.

Turbine Overspeed Protection

During normal operations, turbine overspeed protection is provided by the ~~governing~~ action of the Master Controller of the electro-hydraulic control system. Additional protection is provided by an Overspeed Protection ~~emergency trip~~ ~~s~~System which continuously monitors critical turbine parameters on a ~~multi~~three-channel basis. Each of the channels is independently testable under load with overspeed protection during testing provided by the channels not being tested. If turbine speed exceeds 110 percent of rated speed, the electronic ~~emergency~~ trip system causes steam supply valves to close, tripping the unit. This system is described in subsection ~~10~~10A.2.2.5.

Turbine Missile Protection

Turbine ~~disk~~ rotor integrity minimizes the probability of generating turbine missiles and is discussed in subsection ~~10~~10A.2.3. Turbine missiles are addressed in subsection 3.5.1.3. The favorable orientation of the turbine-generator directs potential missiles away from safety-related equipment and structures.

Radioactivity Protection

Same as reference Chapter 10 section.

Erosion-Corrosion Protection

Same as reference Chapter 10 section.

~~10~~10A.1.3 Combined License Information on Erosion-Corrosion Monitoring

Same as reference Chapter 10 section.

Table ~~10~~10A.1-1

SIGNIFICANT DESIGN FEATURES AND PERFORMANCE CHARACTERISTICS FOR MAJOR STEAM AND POWER CONVERSION SYSTEM COMPONENTS

Nuclear Steam Supply System, Full Power Operation

Rated NSSS power (MWt)	3415
Steam generator outlet pressure (psig)	823
Steam generator inlet feedwater temperature (°F)	440
Maximum steam generator outlet steam moisture (%)	0.25
Steam generator outlet steam temperature (°F)	523
Quantity of steam generators	2
Flow rate per steam generator (lb/hr)	7.49×10^6

Turbine

Nominal Output (kW)	1,199,500 kW (rated heat balance value)
Turbine type	Tandem-compound, 6-flow, 52~~54~~-in. last-stage blade
Turbine elements	1 high pressure 3 low pressure
Operating speed (rpm)	1800

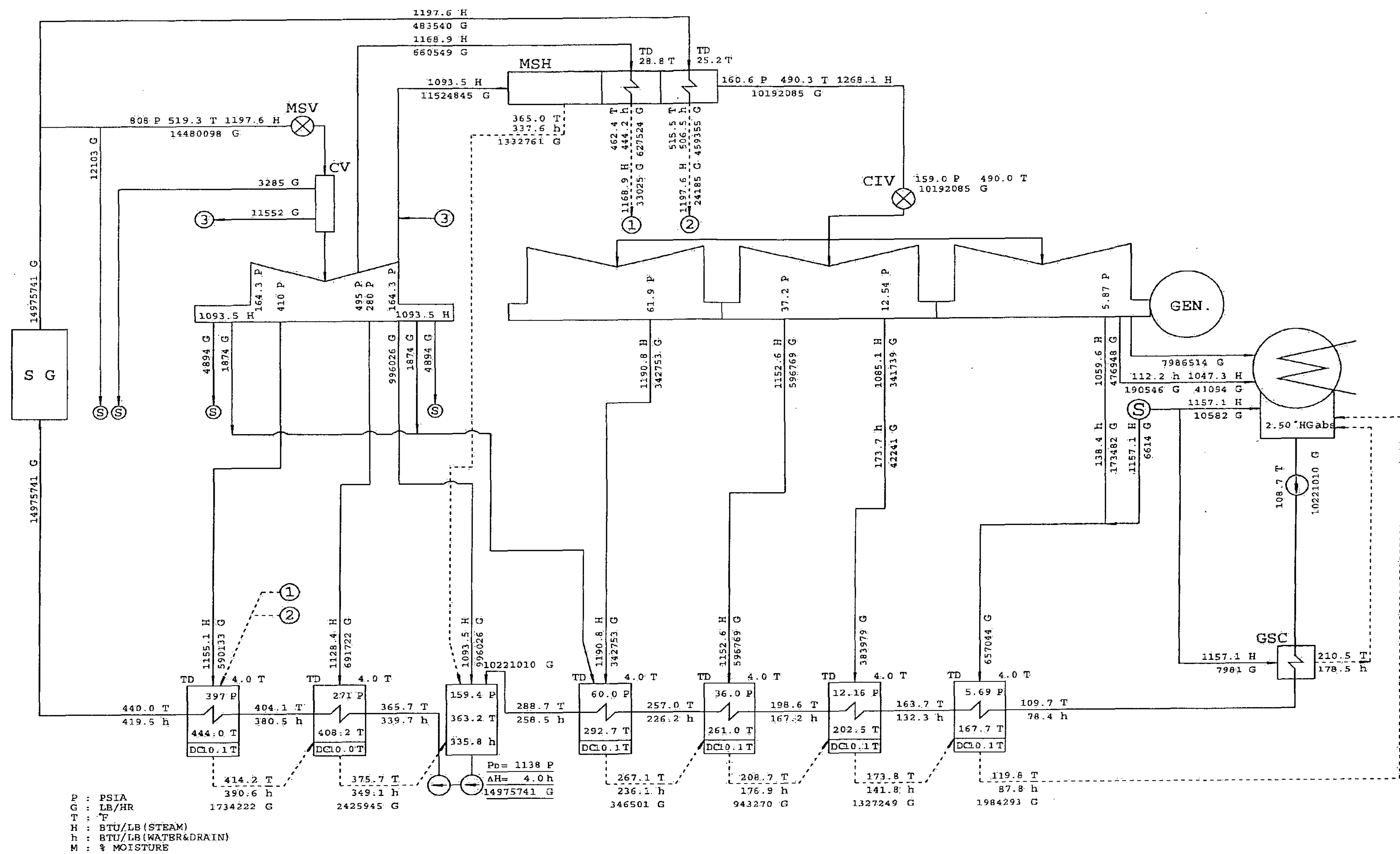

Figure 10A.1-1
Rated Heat Balance

~~10~~10A.2 Turbine-Generator

The function of the turbine-generator is to convert thermal energy into electric power.

~~10~~10A.2.1 Design Basis

~~10~~10A.2.1.1 Safety Design Basis

The turbine-generator serves no safety-related function and therefore has no nuclear safety design basis.

~~10~~10A.2.1.2 Power Generation Design Basis

Same as reference Chapter 10 section.

~~10~~10A.2.2 System Description

The turbine-generator is designated as a TC6F 52 inch last-stage blade unit~~TC6F 54 inch last-stage blade unit~~ consisting of turbines, a generator, external moisture separator/reheaters, ~~exciter,~~ controls, and auxiliary subsystems. (See Figure ~~10~~10A.2-1.) The major design parameters of the turbine-generator and auxiliaries are presented in Table ~~10~~10A.2-1. The piping and instrumentation diagram containing the stop, ~~governing~~ control, intercept, and reheat valves is shown in Figure 10.3.2-2.

The turbine-generator and associated piping, valves, and controls are located completely within the turbine building. There are no safety-related systems or components located within the turbine building. The probability of destructive overspeed condition and missile generation, assuming the recommended inspection and test frequencies, is less than 1 x 10^{-5} per year. In addition, orientation of the turbine-generator is such that a high-energy missile would be directed at a 90 degree angle away from safety-related structures, systems, or components. Failure of turbine-generator equipment does not preclude safe shutdown of the reactor. The turbine-generator components and instrumentation associated with turbine-generator overspeed protection are accessible under operating conditions.

~~10~~10A.2.2.1 Turbine-Generator Description

The turbine is an 1800-rpm, tandem-compound, six-flow, reheat unit with 52 inch last stage blades (TC6F 52 inch LSB). ~~54 inch last-stage blades (TC6F 54 inch LRB).~~ The high-pressure turbine element includes one double-flow, high-pressure turbine. The low-pressure turbine elements include three double-flow, low-pressure turbines and two external moisture separator/reheaters (MSRs) with two stages of reheating. The single direct-driven generator is hydrogen gas and de-ionized water ~~water~~ cooled and rated at 1375 MVA at 0.90 PF. Other related system components include a complete turbine-generator bearing lubrication oil system, a digital electrohydraulic (D-EHC~~DEH~~) control system with supervisory instrumentation, a turbine steam sealing system (refer to subsection ~~10~~10A.4.3), overspeed protective devices, turning gear, a stator cooling water system, a generator hydrogen and seal oil system, a generator CO_2 system, ~~an exciter cooler,~~ a rectifier section, an excitation transformer~~an exciter,~~ and a voltage regulator.

The turbine-generator foundation is a spring-mounted support system. A spring-mounted turbine-generator provides a low-tuned, turbine-pedestal foundation. The springs dynamically isolate the turbine-generator deck from the remainder of the structure in the range of operating frequencies, thus allowing for an integrated structure below the turbine deck. The condenser is supported on springs and attached rigidly to the low-pressure turbine exhausts.

The foundation design consists of a reinforced concrete deck mounted on springs and supported on a structural steel frame that forms an integral part of the turbine building structural system. The lateral bracing under the turbine-generator deck also serves to brace the building frame. This "integrated" design reduces the bracing and number of columns required in the building. Additionally, the spring-mounted design allows for dynamic uncoupling of the turbine-generator foundation from the substructure. The spring mounted support system is much less site dependent than other turbine pedestal designs, since the soil structure is decoupled from turbine dynamic effects. The turbine-generator foundation consists of a concrete table top while the substructure consists of supporting beams and columns. The structure below the springs is designed independent of vibration considerations. The turbine-generator foundation and equipment anchorage are designed to the same seismic design requirement as the turbine building. See subsection 3.7.2.8 for additional information on seismic design requirements. See subsection 10.4.1.2 for a description of the support of the condenser.

~~10~~10A.2.2.2 Turbine-Generator Cycle Description

Steam from each of two steam generators enters the high-pressure turbine through four stop valves and four governing control valves; each stop valve is in series with one control valve. Crossties are provided upstream of the turbine stop valves to provide pressure equalization with one or more stop valves closed. After expanding through the high-pressure turbine, exhaust steam flows through two external moisture separator/reheater vessels. The external moisture separators reduce the moisture content of the high-pressure exhaust steam from approximately 10 to 13 percent at the rated load to ~~approximately 0.17~~0.5 percent moisture or less.

The AP1000 employs a 2 stage reheater, of which the first stage reheater uses the extraction steam from the high pressure turbine and the second reheater uses a portion of the main steam supply to reheat the steam to superheated conditions. The reheated steam flows through separate reheat stop and intercept valves in each of six reheat steam lines leading to the inlets of the three low-pressure turbines. Turbine steam extraction connections are provided for ~~six~~ seven stages of feedwater heating. Steam from the extraction point of the high-pressure turbine is supplied to high-pressure feedwater heater No. 6 and No. 7. The high-pressure turbine exhaust supplies steam to the deaerating feedwater heater. The low-pressure turbine third, fourth, fifth, and sixth extraction points supply steam to the low-pressure feedwater heaters No. 4, 3, 2, and 1, respectively.

Moisture is removed at a number of locations in the blade path. The no-return drain catchers provided at the nozzle diaphragms (stationary blade rings) accumulate the water fraction of the wet steam, and the accumulated water discharges into each extract, reheat and exhaust lines directly or through drainage holes drilled through the nozzle diaphragms. A few grooves are provided on the rotating blades near the last stage of the low-pressure turbine to capture the large water droplets of the wet steam and to enhance the moisture removal effectiveness.~~Drainage holes drilled through the blade rings provide moisture removal from blade rings located in high moisture zones. The effectiveness of moisture removal at these locations is enhanced by moisture nonreturn catchers which trap a large portion of the water from the blade path and direct it to the moisture removal system.~~

The external moisture separator/reheaters use multiple vane chevron banks (shell side) for moisture removal. The moisture removed by the external moisture separator/reheaters drain to a moisture separator drain tank and is pumped to the deaerator.

Condensed steam in the reheater (tube side) is drained to the reheater drain tank, flows into the shell side of the ~~No. 6~~No. 7 feedwater heater~~,~~ and cascades to the ~~deaerator~~No. 6 feedwater heater.

~~10~~10A.2.2.3 ~~Exciter Description~~Excitation System

The excitation system is static excitation system using the thyristor full bridge rectifier.

Excitation power used in this system is fed from the generator main lead through the excitation transformer. The excitation transformer is of outdoor use type, and will be located adjacent to the turbine building. After stepping down the voltage at the excitation transformer, ac current from the generator main lead will be rectified by the thyristor rectifier.

Voltage control system utilizes the digital controller for major control function. The system has two master controller configurations (i.e. one is for normal operation and the other is stand-by). The voltage setting range of the automatic voltage regulator is +/- 10% of the generator rated voltage; however, the operating range of the generator is +/- 5% of the generator rated voltage. The excitation system will include a power system stabilizer. The standard type power system stabilizer is single input type, utilizing the generator output power deviation as the input signal.~~The excitation system is a brushless exciter with a solid-state voltage regulator. Excitation power is obtained from the rotating shaft, which is directly connected to the main generator shaft. The brushless exciter consists of three parts: a permanent magnet pilot exciter, a main ac exciter, and a rectifier wheel. The exciter rectifiers are arranged in a full wave bridge configuration and protected by a series connected fuse. The turbine building closed cooling water system (TCS) provides cooling water to the exciter air-to-water heat exchangers.~~

~~10~~10A.2.2.4 Digital Electrohydraulic System Description

The turbine-generator is equipped with a digital electrohydraulic (D-EHC~~DEH~~) system that combines the capabilities of redundant processors and high-pressure hydraulics to regulate steam flow through the turbine. The control system provides the functions of speed control, load control, and automatic turbine control (ATC), which may be used, either for control or for supervisory purposes, at the option of the plant operator.

The D-EHC~~DEH~~ system employs three electric speed inputs whose signals are processed in redundant processors. Valve opening actuation is provided by a hydraulic system that is independent of the bearing lubrication system. Valve closing actuation is provided by springs and steam forces upon reduction or relief of fluid pressure. The system is designed so that loss of fluid pressure, for any reason, leads to valve closing and consequent turbine trip.

Steam valves are provided in series pairs. A stop valve is tripped by the overspeed trip system; the control valve is modulated by the ~~governing~~ control system and is actuated by the trip system.

~~10~~10A.2.2.4.1 Speed Control

The D-EHC's Master Controller's speed control function ~~of the DEH~~ provides speed control, acceleration, and overspeed protection functions. ~~The speed control function produces a speed error signal, which is fed to the load control unit.~~ The speed error signal is derived by comparing the desired setpoint speed with the actual speed of the turbine. This error drives an algorithm that positions the control valves at the desired set point. Acceleration rates can also be entered by the operator or calculated by D-EHC in auto Start-up Mode. ~~at steady state conditions or by comparing the desired acceleration rate with the actual acceleration rate during startup.~~

~~The speed select algorithm receives three speed signals, performs a two out of three comparison, compares the result to the speed reference signal, and transmits the error signal demanding the appropriate speed to the speed controller.~~ A failure of one speed input generates an alarm. Failure of two or more speed inputs also generates an alarm and trips the turbine.~~changes speed control to a manual mode of operation where automatic compensation for speed changes (except overspeed protection) will not occur.~~

The speed control function exists in triplicate ~~two redundant~~ channels, which include the load control function if the Main generator breaker is closed. If one channel fails, the lower signal of the remaining two channels is selected by the Medium Value Gate (MVG) and fed into the valve positioning control function.~~a primary and a backup. If the primary channel fails, the backup channel takes over automatically. If the backup channel fails, the primary channel will maintain control. In the event that both channels are lost, the turbine trips.~~

The Master Controller speed control function also contains the redundant 110% and the 111% overspeed trips. The 110% ~~A~~ trip signal is sent to a fast acting solenoid valve in the hydraulic trip manifold which actuates closure of the stop, control, intercept, and reheat ~~each control valve and intercept valve. Energizing these solenoid~~ valves by releasing~~es~~ the hydraulic fluid pressure in the valve actuators, allowing springs to close each valve. An independent emergency electrical trip is available at 111% turbine speed to backup the 110% electrical overspeed trip.

The speed control function is designed to slowly vary the rotor speed above and below critical frequencies when operating near critical speed. This will prevent the turbine from running at a constant speed near critical blade resonances.

~~10~~10A.2.2.4.2 Load Control

The load control function of the D-EHC~~DEH~~ develops signals that are used to regulate unit load. Signal outputs are based on a proper combination of the speed error, ~~impulse pressure,~~ and actual load (turbine megawatt) setpoints to generate a flow demand to the control valves~~reference signals~~.

Steam flow is not controlled by feedback, ~~directly~~ but rather by a characterization of maximum nozzle flow per valve verses control ~~turbine megawatt and~~ valve position. Under normal conditions, the turbine requests a certain megawatt load target. Through a coordinated mode of control, the turbine valves adjust the steam flow from the steam generators supplied to the turbine.

~~10~~10A.2.2.4.3 Valve Control

The flow of the main steam entering the high-pressure turbine is controlled by four stop valves and four ~~governing~~ control valves. Each stop valve is controlled by an electrohydraulic actuator, so that the stop valve is either fully open or fully closed. The function of the stop valves is to shut off the steam flow to the turbine when required. The stop valves are closed by actuation of the emergency trip system devices. These devices are independent of the electronic flow control unit. The #2 and #4 stop valves have the bypass valve, which is controlled by an electro-hydraulic servo actuator for control valve warming.

The turbine control valves are positioned by electrohydraulic servo actuators in response to signals from their respective flow control unit. The flow control unit signal positions the control valves for wide-range speed control through the normal turbine operating range, and for load control after the turbine-generator unit is synchronized.

The reheat stop and intercept valves, located in the hot reheat lines at the inlet to the low-pressure turbines, control steam flow to the low-pressure turbines. During normal operation of the turbine, the reheat stop and intercept valves are wide open. The intercept valve flow control unit positions the valve during startup and normal operations and closes the valve rapidly on loss of turbine load. The reheat stop valves close completely on ~~turbine overspeed and~~a turbine trip.

The control, stop, reheat stop, and intercept valves have dump valves connected to the hydraulic portion of their respective valve actuators. Opening a dump valve causes the connected control or stop valve to rapidly close. The dump valve actuators are connected to trip headers and open in response to loss of pressure in the connected trip header. The control and intercept dump valves are connected to the ~~DEH overspeed protection control trip header and the stop~~relay trip header and reheat stop dump valves are connected to the auto stop emergency trip header.

~~10~~10A.2.2.4.4 Power/Load Unbalance

A rate sensitive power/load unbalance circuit initiates fast closing intercept valve action under load rejection conditions that might lead to rapid rotor acceleration and consequent overspeed.

Valve action occurs when the power exceeds the load by 30 percent or more, and when the generator current is lost in a time span of 10 ~~35~~ milliseconds or less. Cold reheat pressure is used as a measure of power. Generator current is used as a measure of load to provide discrimination between loss of load incidents and occurrences of electric system faults.

When the detection circuitry provides a signal indicating a power/load unbalance condition, the load reference signal is set to zero~~grounded~~, and the ~~intercepter~~intercept valve, which is a solenoid operated valve with quick response characteristics, is closed immediately. Should the condition disappear quickly, the power/load unbalance circuitry resets automatically, and the load reference signal is recalculated based on new calculation of flow demand~~reestablished near its value prior to the loss of load~~.

~~10~~10A.2.2.4.5 Overspeed Protection

The D-EHC~~DEH~~ has three~~two~~ modes of operation to protect the turbine against overspeed. The first is the Intercept Valve ~~speed~~ control function, which initiates closure of the intercept valves when the error between the demand position signal and actual position signal of the Intercept Valve exceeds the setpoint. ~~that functions to maintain the desired speed as discussed in subsection 10.2.2.4.1.~~ The second mode is Load Unbalance ~~the overspeed protection control~~ which operates at more than or equal to 30% load rejection. This causes all Control and Intercept valves to close quickly. ~~if the normal speed control should fail or upon a load rejection. The overspeed protection control opens a drain path for the hydraulic fluid in the overspeed protection control header if the turbine speed exceeds 103 percent of rated speed.~~ The third mode is the 110% overspeed trip. All CVs and IVs are fully closed quickly by the actuation of each fast acting solenoid valve of the ~~loss of fluid pressure in the header causes the control and intercept valves to close. If the speed falls below rated speed following an overspeed protection controller action, the header pressure is reestablished, the control and intercept valves are reopened, and the unit resumes speed control. Refer to Table 10.2-2 for a description of the sequence of events following a full load rejection and the nominal trip setpoints. An emergency trip system is also provided to trip the turbine in the event that speeds in excess of the overspeed protection control trip points are reached. The~~ Electrical Overspeed Trip System,~~emergency trip system is~~ discussed in subsection ~~10~~10A.2.2.5.1.

Redundancy is built into the D-EHC ~~DEH~~ overspeed protection control. The failure of a single valve will not disable the trip functions. The overspeed protection components are designed to fail in a safe position. Loss of the hydraulic pressure in the emergency trip system causes a turbine trip. Therefore, damage to the overspeed protection components, results in the closure of the valves and the interruption of steam flow to the turbine.

Quick closure of the steam valves prevents turbine overspeed. Valve closing times are given in Table 10.2-4.

~~10~~10A.2.2.4.6 Automatic Turbine Control

Automatic turbine control provides safe and proper startup and loading of the turbine generator. The applicable limits and precautions are monitored by the automatic turbine control programs even if the automatic turbine control mode has not been selected by the operator. When the operator selects automatic turbine control, the programs both monitor and control the turbine. The D-EHC~~DEH~~ controller takes advantage of the capability of the computer to scan, calculate, make decisions, and take positive action.

The automatic turbine control is capable of automatically:

- Changing speed
- Changing acceleration
- Generating speed holds
- Changing load rates
- Generating load holds

The thermal stresses in the rotor are calculated by the automatic turbine controls programs based on actual turbine steam and metal temperatures as measured by thermocouples or other temperature measuring devices. Once the thermal stress (or strain) is calculated, it is compared with the allowable value, and the difference is used as the index of the permissible first stage temperature variation. This permissible temperature variation is translated in the computer program as an allowable speed or load or rate of change of speed or load.

Values of some parameters are stored for use in the prediction of their future values or rates of change, which are used to initiate corrective measures before alarm or trip points are reached.

The rotor stress (or strain) calculations used in the program, and its decision-making counterpart are the main controlling sections. They allow the unit to roll with relatively high acceleration until the anticipated value of stress predicts that limiting values are about to be reached. Then a lower acceleration value is selected and, if the condition persists, a speed hold is generated. The same philosophy is used on load control in order to maintain positive control of the loading rates.

The automatic turbine controls programs are stored and executed in redundant distributed processing units, which contain the rotor stress programs and the majority of the automatic turbine controls logic programs. Once the turbine is latched, the automatic turbine controls programs are capable of rolling the turbine from turning gear to synchronous speed with supervision from a single operator.

Once the turbine-generator reaches synchronous speed, the startup or speed control phase of automatic turbine control is completed and no further action is taken by the programs. Upon closing the main generator breaker, the D-EHC~~DEH~~ automatically picks up approximately 5 percent of rated load to prevent motoring of the generator. At this time, the D-EHC~~DEH~~ is in load control.

The ~~DEH~~D-EHC unit is equipped with a remote control interface. Selection of the remote mode provides for control of the turbine-generator from an operator console. In the remote mode of control, the rate of this load change is controlled by the amount of this load change.

In the combined mode of both remote control and automatic turbine control, the automatic turbine control allows the remote control system control of load changes until an alarm condition occurs. If the operating parameters being monitored (including rotor stress) exceed their associated alarm limit, a load hold is generated in conjunction with the appropriate alarm message. The D-EHC~~DEH~~ generates the load hold by ignoring any further load increase or decrease until the alarm condition is cleared or until the operator overrides the alarm condition. At the same time that the ~~DEH~~D-EHC generates the load hold based on the automatic turbine control alarm condition, the ~~DEH~~D-EHC also informs the remote control system of its action. In the combined mode of control, both the load reference and the load rate are implicitly controlled by the remote control system while the automatic turbine control supervises the load changes with overriding control capability.

The operator may remove the turbine-generator from automatic turbine control. This action places the automatic turbine control in a supervisory capacity.

~~10~~10A.2.2.5 Turbine Protective Trips

Same as reference Chapter 10 section.

~~10~~10A.2.2.5.1 ~~Emergency~~ Overspeed Trip System

The purpose of the electrical Overspeed Trip System~~emergency trip system~~ is to detect undesirable operating conditions of the turbine-generator, take appropriate trip actions, and provide information to the operator about the detected conditions and the corrective actions. In addition, means are provided for testing emergency trip equipment and circuits.

The system hydraulic manifold ~~system utilizes a two channel~~ configuration ~~which~~ permits on line testing with continuous protection afforded during the test sequence. ~~A mechanical overspeed trip is also provided as described in 10.2.2.5.3.~~

The ~~emergency~~ trip system includes an on line testable hydraulic manifold,~~the emergency trip control block, trip solenoid valves, test panel, the mechanical overspeed trip device~~, speed sensors, trip relays, independent power supplies, and a test panel. These items and the function of the overspeed trips are describe in the following three subsystems.

~~10~~10A.2.2.5.2 Master Trip Device~~Emergency Trip Control Block~~

The emergency trip supply ~~The auto stop emergency trip header~~ pressure is established when the master trip solenoid ~~auto stop trip solenoid~~ valves are ~~energized~~ closed. The valves are arranged in two channels for testing purposes~~, the odd numbered pair correspond to channel 1, and the even numbered pair correspond to channel 2. This convention is carried throughout the emergency trip system in designating devices; e.g., channel 1 devices are odd numbered, and channel 2 devices are even numbered~~. Both valves in a channel will open to trip that channel. Both channels must trip before the emergency trip supply ~~the auto stop trip header~~ pressure collapses to close the turbine steam inlet valves. Each tripping function of the electrical emergency trip system can be individually tested from the operator/test panel without tripping the turbine by separately testing each channel of the appropriate trip function. The solenoid valves may be individually tested. ~~Spool type solenoid valves are not used in the emergency trip control block.~~

A trip of the emergency trip system opens a drain path for the hydraulic fluid in the emergency trip supply~~the auto stop emergency trip header~~. The loss of fluid pressure in the trip header will cause~~s~~ the main stop and reheat stop valves to close. Also, a relay trip valve~~check valves~~ in the connection to the emergency trip supply ~~the overspeed protection control header~~ opens to drop the pressure in the relay emergency trip supply ~~the overspeed protection control header~~ and cause the control and intercept valves to close. The control and intercept valves are redundant to the main stop and reheat stop valves respectively.

~~10~~10A.2.2.5.3 Overspeed Trip Functions and Mechanisms

The ~~emergency~~ overspeed trips for the AP1000 turbine consist of a 110% ~~a mechanical and an~~ electrical trip and a 111% emergency electric trip. ~~The mechanical emergency overspeed trip trips before the electrical emergency trip.~~ The ~~emergency~~ overspeed trip setpoints are identified in Table ~~10~~10A.2-2.

~~The mechanical overspeed trip device consists of a spring-loaded trip weight mounted in the rotor extension shaft. At normal operating speed, the weight is held in the inner position by the spring. When the turbine speed reaches the trip setpoint, the centrifugal force overcomes the compression force of the spring and throws the trip weight outward striking a trigger. As the trigger moves, it unseats a cup valve which drains the mechanical overspeed and manual~~

~~trip header. The mechanical overspeed and manual trip header can be tripped manually via a trip handle mounted on the governor pedestal.~~

The electrical overspeed trip system has ~~separate, redundant~~triplicated speed sensors, separate from the emergency electric overspeed trip speed sensors, ~~and provides~~which provide backup overspeed protection utilizing the master trip solenoid valves ~~trip solenoid valves~~ in the master trip device ~~emergency trip control block~~ to drain the emergency trip hydraulic supply~~header~~. The hydraulic fluid in the trip and overspeed protection control headers is independent of the bearing lubrication system to minimize the potential for contamination of the fluid.

The Master Controller speed control and overspeed protection function of the ~~DEH~~D-EHC combined with the Overspeed Protection System and hydraulic manifold ~~emergency trip system electrical and mechanical overspeed~~ trips provide a level of redundancy and diversity at least equivalent to the recommendations for turbine overspeed protection found in III.2 of Standard Review Plan (NUREG-0800) Section 10.2. Additionally, the issues and problems with overspeed protection systems identified in NUREG-1275 (Reference 3) have been addressed.

~~10~~10A.2.2.5.4 Trip Instrumentation~~Test Blocks~~

Low bearing oil pressure, low electrohydraulic fluid pressure, and high condenser back pressure are each sensed by separate ~~test block~~ instrumentation. Each ~~test block~~ assembly consists of triplicate pressure~~a steel test block, two pressure~~ transmitters with instrument valves~~, two shutoff valves, two solenoid valves, and three needle valves~~. Each assembly is arranged into ~~two~~ three channels. ~~The assemblies, mounted on the governor pedestal, are connected to pressure sensors mounted in a nearby terminal box. The assemblies have an orifice on the system supply side and are connected to a drain or vent on the other side. An orifice is provided in each channel so that the measured parameter is not affected during testing. An isolation valve on the supply side allows the test block assembly to be serviced.~~

If two of the three signals~~the medium~~ (pressure or vacuum) ~~reaches~~reach a trip setpoint, then the pressure sensors cause the master trip device ~~the auto stop emergency trip header mechanism~~ to operate. ~~When functionally testing an individual trip device, the medium is reduced to the trip setpoint in one channel either locally through the hand test valves or remotely from the trip test panel via the test solenoid valves.~~

The trip function can be checked by a test device that simulates pressure to activate the trip outputs from the modules.

~~10~~10A.2.2.5.5 Thrust Bearing Trip Device

Same as reference Chapter 10 section.

~~10~~10A.2.2.5.6 Remote Trip

Same as reference Chapter 10 section.

~~10~~10A.2.2.6 Other Protective Systems

Same as reference Chapter 10 section.

~~10~~10A.2.2.7 Plant Loading and Load Following

Same as reference Chapter 10 section.

~~10~~10A.2.2.8 Inspection and Testing Requirements

Major system components are readily accessible for inspection and are available for testing during normal plant operation. Turbine trip circuitry is tested prior to unit startup. ~~To test governor valves with minimal disturbance, the load is reduced to that capable of being carried with one governor valve closed.~~

~~10~~10A.2.3 Turbine Rotor Integrity

Same as reference Chapter 10 section.

~~10~~10A.2.3.1 Materials Selection

Same as reference Chapter 10 section.

~~10~~10A.2.3.2 Fracture Toughness

Same as reference Chapter 10 section.

~~10~~10A.2.3.2.1 Brittle Fracture Analysis

Same as reference Chapter 10 section.

~~10~~10A.2.3.2.2 Rotor Fatigue Analysis

A fatigue analysis is performed for the turbine rotors to show that the cumulative usage is acceptable for expected transient conditions including normal plant startups, load following cycling, and other load changes. The fatigue design curves are based on mean values of fatigue test data. Margin is provided by assuming a conservatively high number of turbine start and stop cycles. The ~~Westinghouse/Mitsubishi~~Toshiba-designed turbine rotors in operating nuclear power plants were designed using this methodology and have had no history of fatigue crack initiation due to duty cycles.

In addition to the low cycle fatigue analysis for transient events, an evaluation for high cycle fatigue is performed. This analysis considers loads due to gravity bending, bearing elevation misalignment, control stage partial arc admission bearing reactions, and steady-state unbalance stress. The local alternating stress is calculated at critical rotor locations considering the bending moments due to the loads described above. The maximum alternating stress is less than the smooth bar endurance strength modified by a size factor.

The AP1000 turbine generator is supported by a spring-mounted system to isolate the dynamic behavior of the turbine-generator equipment from the foundation structure. The support system includes a reinforced concrete deck on which the turbine generator is mounted. The deck is sized to maintain the gravity load and misalignment load bending stresses within allowable limits. The evaluation of the loads includes a dynamic analysis of the combined turbine-generator and foundation structure.

~~10~~10A.2.3.3 High Temperature Properties

Same as reference Chapter 10 section.

~~10~~10A.2.3.4 Turbine Rotor Design

Same as reference Chapter 10 section.

~~10~~10A.2.3.5 Preservice Tests and Inspections

Same as reference Chapter 10 section.

~~10~~10A.2.3.6 Maintenance and Inspection Program Plan

The maintenance and inspection program plan for the turbine assembly and valves is based on turbine missile probability calculations, operating experience of similar equipment, and inspection results. The methodology for analysis of the probability of generation of missiles for fully integral rotors was submitted in WCAP-~~15783~~16650-P (Reference 1). The methodology used for analysis of the missile generation probability calculations used to determine turbine valve test frequency is described in WCAP-~~15785~~16651-P (Reference 2). The maintenance and inspection program includes the activities outlined below:

- Disassembly of the turbine is conducted during plant shutdown. Inspection of parts that are normally inaccessible when the turbine is assembled for operation (couplings, coupling bolts, turbine rotors, and low-pressure turbine blades) is conducted.

  This inspection consists of visual, surface, and volumetric examinations as indicated below:

  - Each rotor and stationary and rotating blade path component is inspected visually and by magnetic particle testing on accessible surfaces. Ultrasonic inspection of the ~~side entry blade grooves~~outer dovetail and the bucket pin is conducted. These inspections are conducted at intervals of about 10 years for low-pressure turbines and about 8 years for high-pressure turbines.

  - A 100 percent surface examination of couplings and coupling bolts is performed.

  - Fluorescent penetrant examination is conducted on nonmagnetic components.

- At least one main steam stop valve, one main steam control valve, one reheat stop valve, and one intercept valve are dismantled approximately every 3 years during scheduled refueling or maintenance shutdowns. A visual and surface examination of valve internals is conducted. If unacceptable flaws or excessive corrosion are found in a valve, the other valves of its type are inspected. Valve bushings are inspected and cleaned, and bore diameters are checked for proper clearance.

- Main stop valves, control valves, reheat stop and intercept valves may be tested with the turbine online. The ~~DEH~~D-EHC control test panel is used to stroke or partially stroke the valves.

- Extraction nonreturn valves are tested prior to each startup.

- Turbine valve testing is performed at ~~quarterly~~ six month intervals. The ~~quarterly~~ semi-annual testing frequency is based on nuclear industry experience that turbine-related tests are the most common cause of plant trips at power. Plant trips at power may lead to challenges of the safety-related systems. Evaluations show that the probability of turbine missile generation with a ~~quarterly~~ semi-annual valve test is less than the evaluation criteria.

- Extraction nonreturn valves are tested locally by stroking the valve full open with air, then equalizing air pressure, allowing the spring closure mechanism to close the valve. Closure of each valve is verified by direct observation of the valve arm movement.

The valve inspection frequency of three years noted above is consistent with a 18-month fuel cycle for AP1000 and is based on evaluations performed to support this valve inspection interval at operating plants with 18-month fuel cycles. A monitoring program is in place at operating nuclear power plants to verify the success of longer valve inspection intervals. A Combined License holder recommendation for a valve inspection frequency longer than three years may be justified when a longer interval is supported by operating and inspection program experience and supported by the missile generation probability calculations.

~~10~~10A.2.4 Evaluation

Same as reference Chapter 10 section.

~~10~~10A.2.5 Instrumentation Applications

The turbine-generator is provided with turbine supervisory instrumentation including monitors for the following:

- Speed
- Stop valve position
- Control valve position
- Reheat intercept and stop valve positions
- Temperatures as required for controlled starting, including:
  - External valve chest inner surface
  - External valve chest outer surface
  - First-stage shell lower inner surface
  - Crossover pipe downstream of reheat stop valve No. 1
  - Crossover pipe downstream of reheat stop valve No. 2
  - Crossover pipe downstream of reheat stop valve No. 3
  - Crossover pipe downstream of reheat stop valve No. 4
  - Crossover pipe downstream of reheat stop valve No. 5
  - Crossover pipe downstream of reheat stop valve No. 6
- Casing and shaft differential expansion
- Vibration of each bearing
- Shaft eccentricity
- Bearing metal temperatures

Alarms are provided for the following abnormal conditions:

- High vibration
- Turbine supervisory instruments common alarm

In addition to the turbine protective trips listed in subsection ~~10~~10A.2.2.5, the following trips are provided:

- High exhaust hood temperature
- Low emergency trip system pressure
- Low shaft-driven lube oil pump discharge pressure
- High or low level in moisture separator drain tank

Indications of the following miscellaneous parameters are provided:

- Main steam throttle pressure
- Steam seal supply header pressure
- Steam seal condenser vacuum
- Bearing oil header pressure
- Bearing oil coolers coolant temperature
- ~~DEH~~D-EHC control fluid header pressure
- ~~DEH~~D-EHC control fluid temperature
- Crossover pressure
- Moisture separator drain tank level
- First-stage pressure
- High-pressure turbine exhaust pressure
- Extraction steam pressure, each extraction point
- Low-pressure turbine exhaust hood pressure
- Exhaust hood temperature for each exhaust

Generator supervisory instruments are provided, with sensors and/or transmitters mounted on the associated equipment. These indicate or record the following:

- Multiple generator stator winding temperatures; the detectors are built into the generator, protected from the cooling medium, and distributed around the circumference in positions having the highest expected temperature

- Stator coil cooling water temperature (one detector per coil)

- Hydrogen cooler inlet gas temperature (two detectors at each point)

- Hydrogen gas pressure

- Hydrogen gas purity

- Generator ampere, voltage, and power

Additional generator protective devices are listed in Table ~~10~~10A.2-3.

~~10~~10A.2.6 Combined License Information on Turbine Maintenance and Inspection

The Combined License holder will submit to the NRC staff for review ~~and approval within 3 years of obtaining a Combined License~~ prior to fuel load, and then implement a turbine maintenance and inspection program. The program will be consistent with the maintenance and inspection program plan activities and inspection intervals identified in subsection ~~10~~10A.2.3.6.

The Combined License holder will have available plant-specific turbine rotor test data and calculated toughness curves that support the material property assumptions in the turbine rotor analysis after the fabrication of the turbine and prior to fuel load.

~~10~~10A.2.7 References

1. WCAP-16650-P, Proprietary and WCAP-16650-NP, Nonproprietary, "Analysis of the Probability of Generation of Missiles for AP1000 Alternate Fully Integral Low Pressure Turbines," Revision 0, February 2007.

~~1. WCAP-15783-P, Proprietary and WCAP-15783-NP, Nonproprietary, "Analysis of the Probability of the Generation of Missiles from Fully Integral Nuclear Low Pressure Turbines," Revision 2, August 2003.~~

2. WCAP-16651-P, Proprietary and WCAP-16651-NP, Nonproprietary, "Probabilistic Evaluation of AP1000 Alternate Turbine Valve Test Frequency," Revision 0, February 2007.

~~2. WCAP-15785, Proprietary and WCAP-15786, Nonproprietary, "Probabilistic Evaluation of Turbine Valve Test Frequency," April 2002.~~

3. NUREG-1275, Vol. 11, Operating Experience Feedback Report - Turbine-Generator Overspeed Protection Systems, Commercial Power Reactors, H. L. Ornstein, Nuclear Regulatory Commission, April 1995.

Table ~~10~~10A.2-1

TURBINE-GENERATOR AND AUXILIARIES DESIGN PARAMETERS

Manufacturer Toshiba~~Mitsubishi~~	
Turbine	
Type	TC6F 52-in. LSB~~TC6F 54 in. last row blades~~
No. of elements	1 high pressure; 3 low pressure
Last-stage blade length (in.)	52~~54~~
Operating speed (rpm)	1800
Condensing pressure (in. HgA)	~~2.5~~2.9
~~Turbine cycle heat rate (Btu/kWh)~~	~~9715~~
Generator	
Generator rated output (kW)	1,237,500~~(nominal)~~
Power factor	0.90
Generator rating (kVA)	1,375,000~~(nominal)~~
Hydrogen pressure (psig)	75
Moisture separator/reheater	
Moisture separator	Chevron vanes
Reheater	U-tube
Number	~~1~~2 shell
Stages of reheating	2

Table ~~10~~10A.2-2

TURBINE OVERSPEED PROTECTION

Percent of Rated Speed (Approximate)	Event
100	Turbine is initially at valves wide open. Full load is lost. Speed begins to rise. When the breaker opens, the load drop anticipator immediately closes the control and intercept valves if the load at time of separation is greater than 30 percent.
101	Control and intercept valves begin to close.
~~103~~	~~The overspeed protection controller closes the control and intercept valves until the speed drops below 103 percent.~~
108	Peak transient speed with normally operating speed control system. If the power/load unbalance and speed control systems had failed prior to loss of load, then:
110	A trip signal is sent by the overspeed trip system to actuate closure of the stop, control, intercept, and reheat valves by releasing the hydraulic fluid pressure in the valve actuators.~~The mechanical overspeed trip device closes the turbine stop and reheat valves.~~
111	The emergency electrical overspeed trip system closes the main stop and reheat stop valves based on a two-out-of-three trip logic system.

Note:
Following the above sequence of events, the turbine ~~will~~ may approach but not exceed 120 percent of rated speed.

Table ~~10~~10A.2-3 (Sheet 1 of 2)

GENERATOR PROTECTIVE DEVICES FURNISHED WITH THE VOLTAGE REGULATOR PACKAGE

Device	Action	
• Generator Minimum Excitation Limiter	Limiter	- maintains generator reactive power output above certain level (normally steady-state stability limit level)
	Alarm	- when limiter is limiting
• Generator Maximum Excitation Limiter	Limiter	- maintains generator field voltage below certain voltage inverse time characteristics
	Alarm	- when limiter is timing
	Alarm	- when limiter is limiting
• Generator Overexcitation Protection	Alarm	- The system has two master controller configurations i.e. one is for normal operations and the other is stand-by. - Changes the stand-by controller ~~repositions the dc regulator adjuster to a preset position~~ when overexcitation protection pickup level is exceeded
Inverse Timer	Alarm	- when timing commences
	~~ac r~~Regulator trip	- when timed out
Fixed Timer	Alarm	- when timing
	Unit trip	- when timed out
• Generator Volts/Hertz Limiter	Limiter	- maintains machine terminal volts/Hertz ratio below certain level
	Alarm	- when limiter is limiting
• Generator Dual Level Volts/Hertz Protection	Alarm	- when above either preset volts/Hertz level
	Unit trip	- if timed out at either alarm level
• Generator Automatic Field Ground Detection	~~Alarm~~	~~- brush failure (alarms about 20 seconds)~~
	Alarm	- ground
• Regulator Firing Circuit - Loss of Thyristor Firing Pulse Protection	Alarm	- loss of one firing circuit
	Unit Trip	- loss of both firing circuits
• Thyristor Blown Fuse Detection	Alarm	- When one or more thyristor fuses in power drawers open

Table ~~10~~10A.2-3 (Sheet 2 of 2)

GENERATOR PROTECTIVE DEVICES FURNISHED WITH THE VOLTAGE REGULATOR PACKAGE

Device	Action	
• Regulator Forcing Indication	Alarm	- online forcing
	Alarm	- offline forcing (blocks "Raise" controls of dc regulator and ac regulator adjusters)
• Regulator Loss of Power Supply (s) Protection	Alarm	- loss of one power supply
	Unit trip	- loss of both power supplies
• Regulator Loss of Sensing Protection	Alarm and ~~AC~~ ac regulator trip	- when regulator voltage transformer changes the stand-by controller. The systems has two master controller configurations, i.e. one is for normal operation and the other is for stand-by~~sensing is lost~~
• Excitation Supply Breaker	Alarm Excitation trip	
~~• Alternate Excitation Removal Equipment~~	~~Alarm~~	~~- For fast de-excitation, phase back thyristor firing pulses for specified time, then trip excitation supply breaker~~
• Power System Stabilizer (PSS) Excessive Output Protection	Alarm Power System Stabilizer trip	- When PSS output exceeds specified level for specified time
• Power System Stabilizer Inservice Instrumentation Indication	Indicator	- lamps and contacts
~~• Exciter - Air Temperature Detection~~	~~Alarm~~	
~~• Exciter - Rotation Vibration Pick-up~~	~~Alarm~~ ~~Unit Trip~~	
~~• Exciter - Bearing Metal Detection~~	~~Alarm~~	
• Generator - Overvoltage Protection	Alarm	- Phase-back thyristor firing pulses if overvoltage condition persists for a specified time
~~• Exciter Diode Fuse Detection~~	~~Indicator~~	~~- Flag on rotating fuse raises when fuse opens; detected by periodic checks with strobe light.~~

Table ~~10~~10A.2-4 **TURBINE-GENERATOR VALVE CLOSURE TIMES**
SAME AS REFERENCE TABLE

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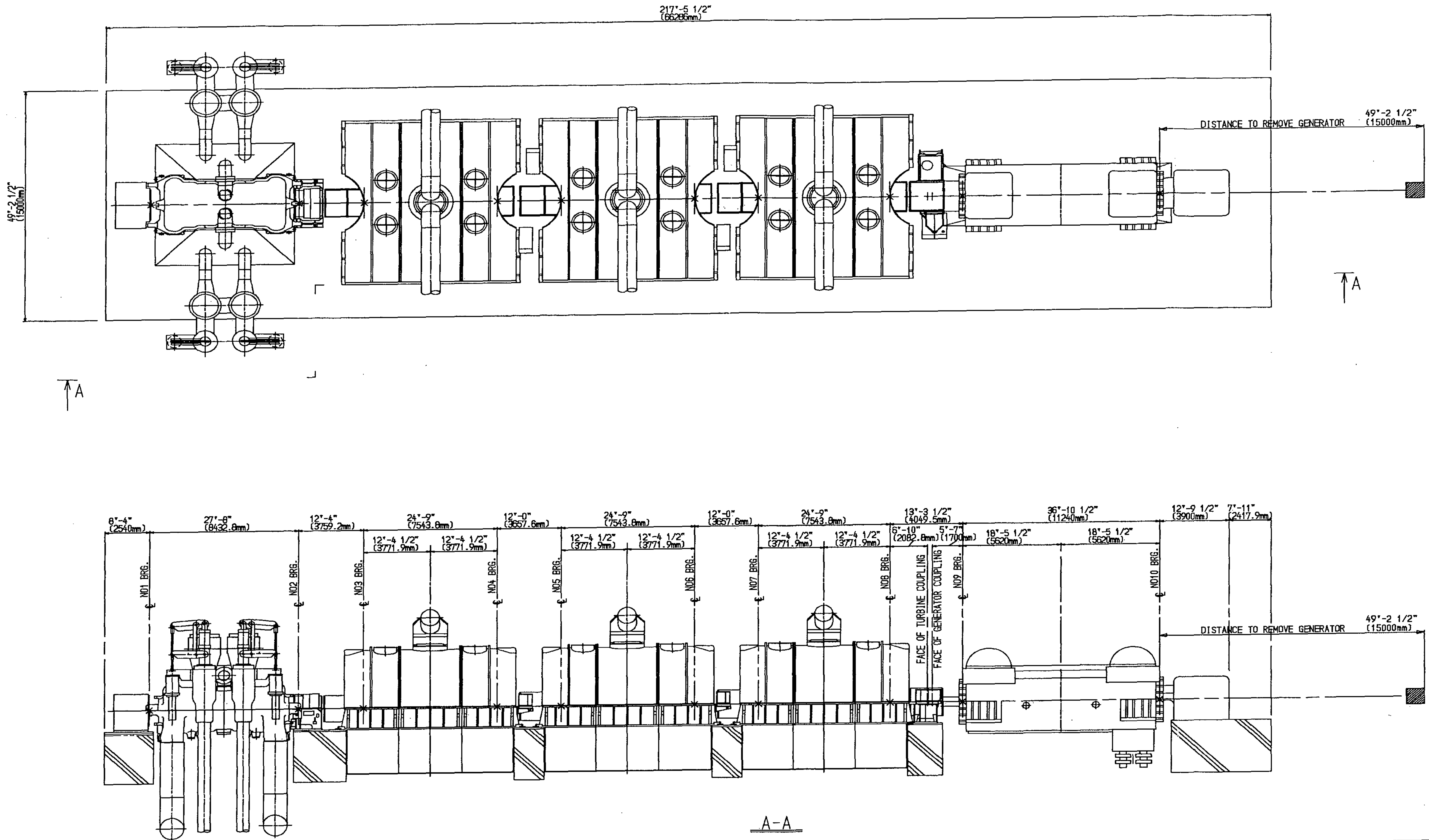


Figure 10A.2-1 (Sheet 1 of 2)

Turbine Generator Outline Drawing

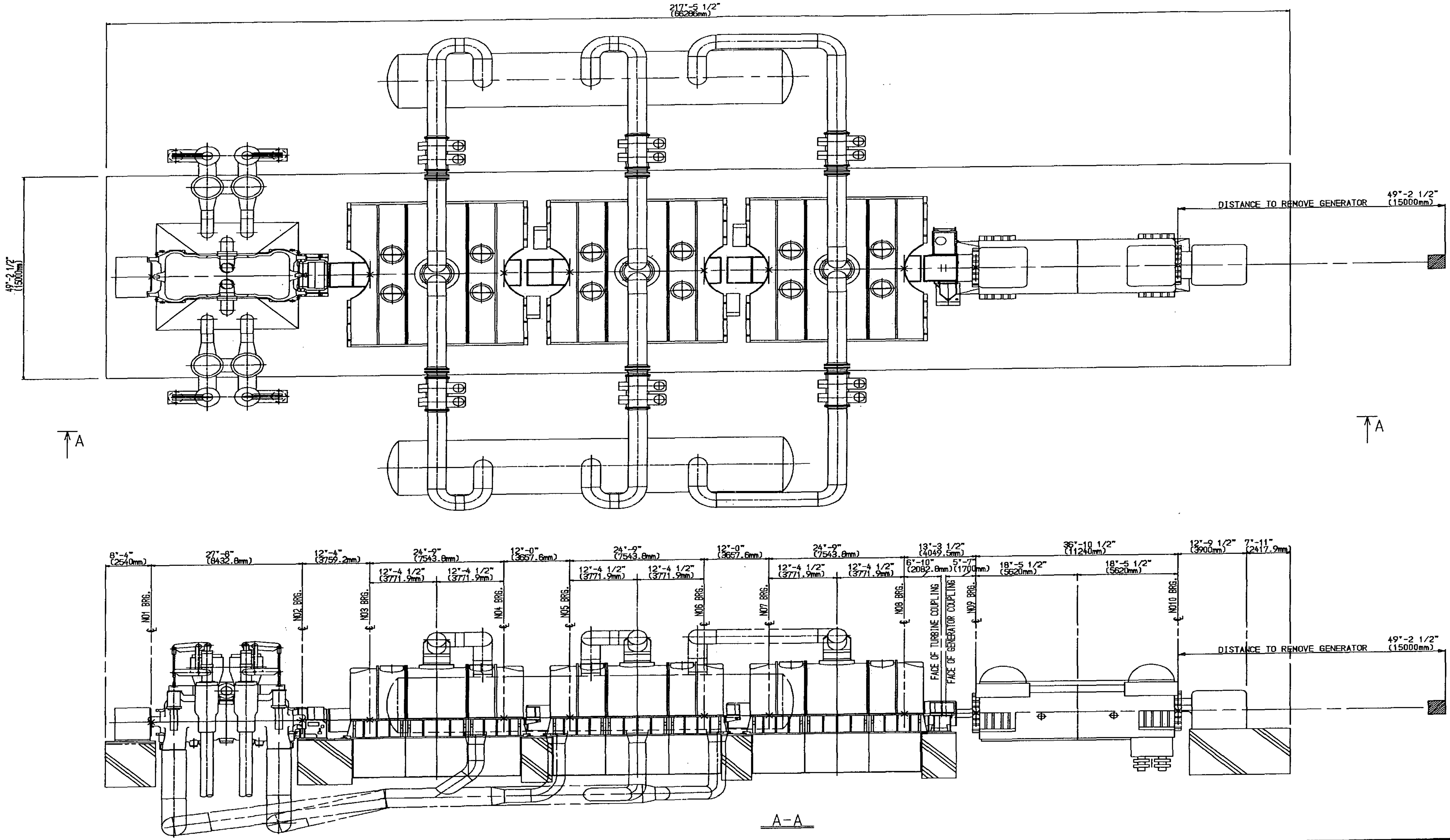
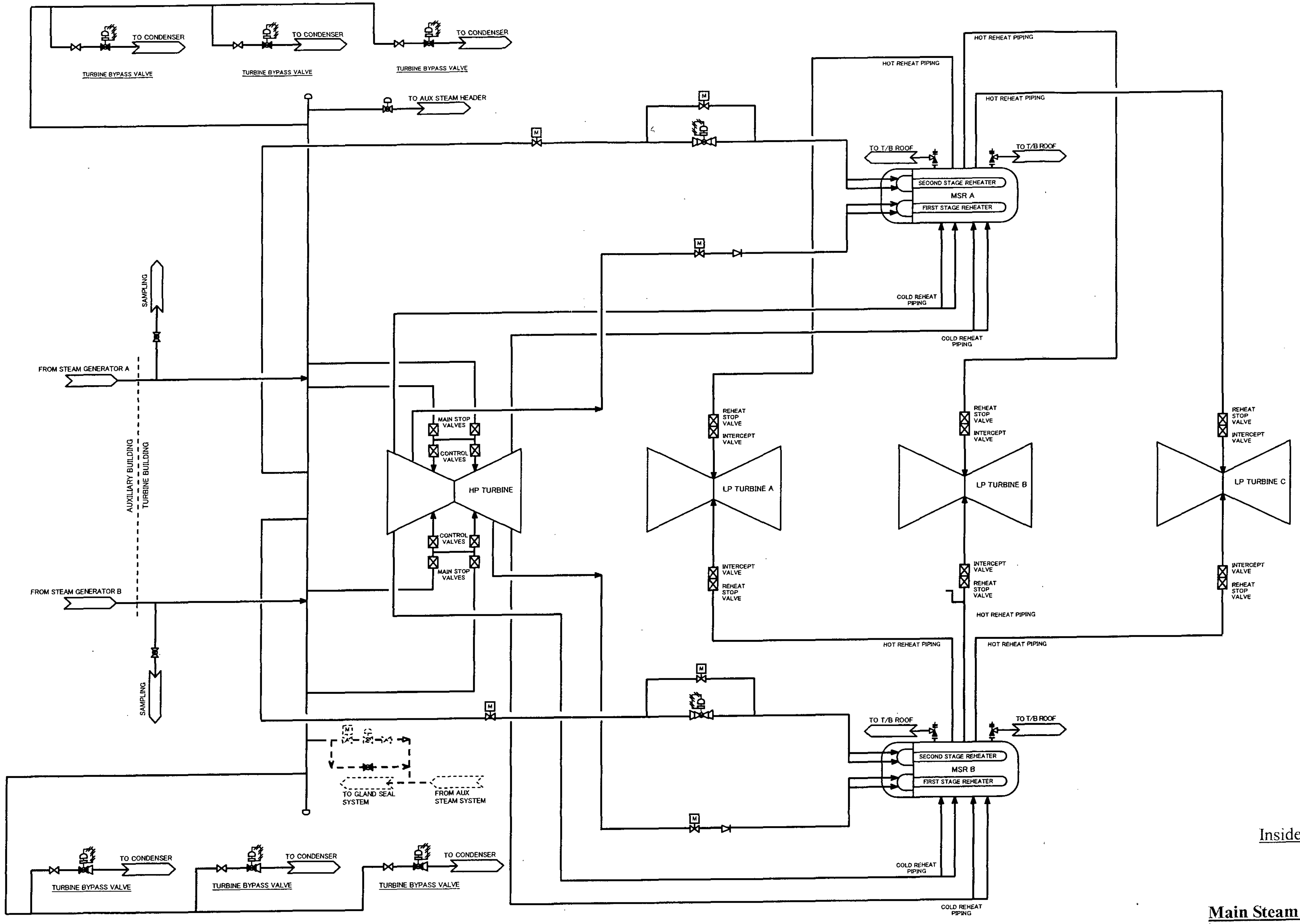


Figure 10A.2-1 (Sheet 2 of 2)

Turbine Generator Outline Drawing



Inside Turbine Building

Figure 10.3.2-2

Main Steam System Diagram
(REF)MSS 001

10A.4 Other Features of Steam and Power Conversion System

This section provides descriptions of each of the principal design features of the steam and power conversion system not in Sections ~~10~~10A.2 and 10.3.

~~10~~10A.4.1 Main Condensers

The entirety of Chapter 10, Section 4.1, Main Condensers, is the same as the DCD reference Chapter 10 with the exception of the section paragraph identified below.

~~10~~10A.4.1.2 System Description

The main condenser is part of the AP1000 condensate system (CDS). The condensate system is described in subsection ~~10~~10A.4.7 and shown in Figure ~~10~~10A.4.7-1. Classification of equipment and components is given in Section 3.2. Table 10.4.1-1 provides main condenser design data.

The main condenser is a three-shell, single-pass, multipressure, spring-supported unit. Each shell is located beneath its respective low-pressure turbine. The condenser is equipped with titanium or stainless steel tubes. The titanium material provides good corrosion and erosion resisting properties. Freshwater cooled plants do not require the high level corrosion and erosion resistance provided by titanium; therefore, 304L, 316L, 904L or AL-6X may be substituted if desired.

In a multipressure condenser, the condenser shells operate at slightly different pressures and temperatures. Condensate that is condensed in the low pressure condenser shell drains through internal piping to the high pressure (hottest) shell where it is slightly heated and mixed with condensate of the high pressure shell. Condensate then flows through a single outlet to the suction of the condensate pumps.

The condenser shells are located below the turbine building operating floor and are supported on a spring-mounted foundation from the turbine building basemat. A rigid connection is provided between each low-pressure turbine exhaust opening and the steam inlet connections of the condenser. Two low-pressure feedwater heaters are located in the neck area of each condenser shell. Piping is installed for hotwell level control and condensate sampling.

~~10~~10A.4.2 Main Condenser Evacuation System

The entirety of Chapter 10, Section 4.2, Main Condenser Evacuation System, is the same as the DCD reference Chapter 10.

~~10.~~10A4.3 Gland Seal System

~~10~~10A.4.3.1 Design Basis

~~10~~10A.4.3.1.1 Safety Design Basis

Same as reference Chapter 10 section.

~~10~~10A.4.3.1.2 Power Generation Design Basis

Same as reference Chapter 10 section.

~~10~~10A.4.3.2 System Description

~~10~~10A.4.3.2.1 General Description

The gland seal system consists of the following items and assemblies:

- Steam supply header
- Steam drains/noncondensable gas exhaust header
- Two motor driven gland seal condenser exhaust blowers
- Associated piping, valves, and controls
- Gland seal condenser
- Vent and drain lines

The quality group standards for the gland seal system are provided in Section 3.2. The gland seal system is shown in Figure ~~10~~10A.4.3-1.

~~10~~10A.4.3.2.2 System Operation

The annular space through which the turbine shaft penetrates the turbine casing is sealed by steam supplied to the rotor glands. Where the packing seals against positive pressure, the sealing steam connection acts as a leakoff. Where the packing seals against vacuum, the sealing steam either is drawn into the casing or leaks outward to a vent annulus maintained at a slight vacuum. The vent annulus receives air leakage from the outside. The air-steam mixture is drawn to the gland seal condenser.

Sealing steam is distributed to the turbine shaft seals through the steam-seal header. This sealing steam is supplied from either the auxiliary steam system (ASS), or from main steam (MSS), extracted ahead of the high-pressure turbine throttle valves. Steam flow to the header is controlled by the steam-seal feed valve which responds to maintain the steam-seal supply header pressure. The low and high pressure turbine ~~sealing systems each have~~gland steam pressures are maintained ~~a separate steam~~by pressure regulating valves ~~which provides sealing steam~~provided in both Main Steam and Auxiliary Steam System piping. Excess steam is returned to the No. 1 feedwater heaters via the spillover control valve which automatically opens to bypass excess steam from the GSS.

During the initial startup phase of turbine-generator operation, steam is supplied to the gland seal system from the auxiliary steam header which is supplied from the auxiliary boiler. At times other than initial startup, turbine-generator sealing steam is supplied from ~~either the~~MSV and CV gland steam leak-off, the auxiliary steam system, or from main steam.
At the outer ends of the glands, collection piping routes the mixture of air and excess seal steam to the gland seal condenser. The gland seal condenser is a shell and tube type heat exchanger where the steam-air mixture from the turbine seals is discharged into the shell side and condensate flows through the tube side as a cooling medium. The gland seal condenser internal pressure is maintained at a slight vacuum by a motor-operated blower. There are two 100-percent blowers mounted in parallel. Condensate from the steam-air mixture drains to the main condenser while noncondensables are exhausted to the turbine island vents, drains, and relief system through a common discharge line shared by the vapor extractor blowers.

The mixture of noncondensable gases discharged from the gland seal condenser blower is not normally radioactive; however, in the event of significant primary-to-secondary system leakage due to a steam generator tube leak, it is possible ~~for the mixture~~to discharge~~d to be~~ radioactively contaminated gases. The headered discharge line vents to the turbine vents, drains, and relief system which contains a radiation monitor for detection of radioactivity. Upon detection of unacceptable levels of radiation, operating procedures are implemented. A description of the radiological aspects of primary-to-secondary system leakage is included in Chapter 11.

Failure of the gland seal system normally results in no release of radioactivity to the atmosphere.

~~10~~10A.4.3.3 Safety Evaluation

Same as reference Chapter 10 section.

~~10~~10A.4.3.4 Tests and Inspections

Same as reference Chapter 10 section.

~~10~~10A.4.3.5 Instrumentation Applications

A pressure controller is provided to maintain the steam-seal supply header pressure by providing signals to the steam-seal feed valve. ~~Pressure control valves are used to provide appropriate pressures to operate both the low and high pressure turbine steam seals.~~ Excess steam flow is handled by the gland spillover control valve which discharges to the No. 1 feedwater heaters.

The gland seal condenser is monitored for shell side pressure and internal liquid level.

Pressure indication with appropriate alarm is provided for monitoring the operation of the system. A radiation detector with an alarm is provided in the turbine island vents, drains, and relief system to detect radiation associated with primary-to-secondary side leakage in the steam generators.

~~10~~10A.4.7 Condensate and Feedwater System

The entirety of Chapter 10, Section 4.7, Condensate and Feedwater System, is the same as the DCD reference Chapter 10 with the exception of the section paragraph identified below.

~~10~~10A.4.7.2.1 General Description

The condensate and feedwater system is shown schematically in Figure ~~10.4.7-1~~10A.4.7-1, and in Figure 10.3.2-1. Classification of equipment and components is given in Section 3.2.

The condensate and feedwater system supplies the steam generators with heated feedwater in a closed steam cycle using regenerative feedwater heating. The condensate and feedwater system is composed of the condensate system, the main feedwater system, and portions of the steam generator system. The condensate system collects condensed steam from the condenser and pumps condensate forward to the deaerator. The feedwater system takes suction from the deaerator and pumps feedwater forward to the steam generator system utilizing high-pressure main feedwater pumps. The steam generator system contains the safety-related piping and valves that deliver feedwater to the steam generators. The condensate and feedwater systems are located within the turbine building, and the steam generator system is located within the auxiliary building and containment.

The main portion of the feedwater flow originates from condensate pumped from the main condenser hotwell by the condensate pumps. The main condenser hotwell receives makeup from the condensate storage tank. (Refer to subsection 9.2.4 for a description of the condensate storage system.) The condensate passes in sequence through: the condensate polishing system or condensate polishing bypass (described in subsection 10.4.6); the gland steam condenser; three strings of low-pressure heaters, each string consisting of a No. 1 and No. 2 low-pressure heater; two strings of low-pressure heaters No. 3 and No. 4; the No. 5 open low pressure heater (deaerator); the three parallel booster/main feedwater pumps; and two strings of high-pressure heaters, No. 6 and No. 7. Feedwater is pumped to the plant's two steam generators through each generator's respective flow element, control valve, feedwater isolation valve, and check valve. The balance of the plant's feedwater flow is provided by drains from the main steam system moisture separator reheater, drains from the No. 6 and No. 7 feedwater heaters, and steam condensed in the deaerator. These flows are collected in the deaerator and pumped forward in the feedwater cycle. A portion of the condensate flow downstream of the condensate polishers is diverted to provide cooling to the steam generator blowdown system heat exchangers before returning to the main condensate flow at the deaerator.

During plant startup, three recirculation paths facilitate system cleanup and adjustment of water quality prior to initiating feed to the steam generators. These cleanup loops are designed for approximately 33 percent of design condensate flow and include a hotwell recirculation loop, a deaerator recirculation loop, and a third recirculation loop from downstream of the ~~No. 6~~ No. 7 feedwater heaters. Steam is provided to the deaerating feedwater heater from the auxiliary steam supply system to preheat the feedwater to over 200°F during the initial cleanup and startup recirculation operations. This preheating action, along with chemical addition, minimizes formation of iron oxides in the condensate system. The condensate polishing system is described in subsection 10.4.6 and may be in service or bypassed. Each of the two main feedwater lines to the two steam generators contains a feedwater flow element, a main feedwater control valve, a main feedwater isolation valve, and a check valve.

The turbine island chemical feed system (CFS) described in subsection 10.4.11 is provided to inject an oxygen scavenging agent and a pH control agent into the condensate pump discharge downstream of the condensate polishers and an oxygen scavenging agent and pH control agent into the feedwater booster pump suction piping. Injection points are shown in Figure ~~10~~10A.4.7-1. During normal power operation, the addition of an oxygen scavenging agent and pH control agent to the condensate system downstream of the condensate demineralizers is in automatic control, with manual control available. The added chemicals control pH according to the condensate and feedwater system chemistry requirements and establish an oxygen scavenging agent residual in the feedwater system. The oxygen scavenger agent and pH control agent will be selected by the Combined License applicant.

A cross connection from the main feedwater pump discharge header to the startup feedwater header allows any booster/main feedwater pump to supply feedwater to the startup feedwater control valves. The startup feedwater system is described in subsection 10.4.9. Thus, feedwater from the deaerator storage tank can be supplied by the booster/main feedwater pumps through the startup feedwater connections to the steam generators during hot standby, plant startup and low power operation. A check valve in the cross connection piping prevents the startup feedwater pumps from supplying the main feedwater header, and a nonsafety-related isolation valve in the cross connection piping automatically closes upon the feedwater isolation signal that trips the main feedwater pumps.

A condensate and feedwater failure analysis for safety-related components is presented in Table 10.4.7-1. Occurrences which produce an increase in feedwater flow or decrease in feedwater temperature result in increased heat removal from the reactor coolant system which is compensated for by control system action, as described in subsection 10.4.7.5. Events which produce the opposite effect (i.e., decreased feedwater flow or increased feedwater temperature) result in reduced heat transfer in the steam generators. Normally, automatic control system action is available to adjust feedwater flow to prevent excess energy accumulation in the reactor coolant system, and the increasing reactor coolant temperature provides a negative reactivity feedback, reducing reactor power. In the absence of normal control action, either the high-outlet temperature or the high-pressure trips of the reactor protection system are available to provide reactor safety. Loss of all feedwater is examined in Section 15.3.

Refer to subsection 5.4.2.2 for a description of steam generator design features to prevent fluid flow water hammer. The main feedwater connection on each of the steam generators is the highest point of each feedwater line downstream of the MFIV. The feedwater lines contain no high-point pockets that could trap steam and lead to water hammer. The horizontal pipe length from the main nozzle to the downward turning elbow of each steam generator is minimized.

~~10~~10A.4.7.2.2 Component Description

Low-Pressure Feedwater Heaters

These heaters are shell and tube heat exchangers with the heated condensate flowing through the tube side and the extraction steam condensing on the shell side. Parallel strings of low-pressure feedwater heaters No. 1 and 2 are located in each of three condenser necks. Feedwater heaters No. 3 and 4 are also parallel strings of heaters. ~~Except for the No. 1 feedwater heaters, t~~The closed low-pressure feedwater heaters ~~have integral~~utilize drain coolers~~, and their shell side drains cascade to the next lower stage feedwater heater~~. The cascaded drains from the ~~No. 1~~ heaters are dumped to their respective condenser shell.

A drain line from ~~each~~ the heater allows direct discharge of the heater drains to the condenser in the event the normal drain path is not available or flooding occurs in the heater.

The low-pressure feedwater heater shells are carbon steel, and the tubes are stainless steel.

High-Pressure Feedwater Heater

The main feedwater pumps discharge into a parallel string of No. 6 and No. 7 high-pressure feedwater heaters. These heaters are shell and tube heat exchangers ~~with integral drain coolers~~. Heated feedwater flows through the tubes and extraction steam condenses in the shell. The No. 6 and No. 7 heaters drain into low-pressure heater No. 5 (deaerator).

A drain line from each heater allows direct discharge of the heater drains to the condenser in the event the normal drain path is not available or flooding occurs in the heater.

The high-pressure feedwater heater shells are carbon steel, and the tubes are stainless steel.

Table 10A.4.1-1

MAIN CONDENSER DESIGN DATA

Condenser Data	
Condenser type	Multipressure, Single pass
Hotwell storage capacity	3 min
Heat transfer	~~7,540~~7,630 x 10^6 Btu/hr
Design operating pressure (average of all shells)	~~2.7~~2.9 in.-Hg
Shell pressure (design)	0 in.-Hg absolute to 15 psig
[[Nominal Circulating water flow]]	[[~~600,000~~625,000 gpm]]
Water box pressure (design)	~~60~~ 90 psig
Tube-side inlet temperature	~~87~~91°F
Approximate Tube-side temperature rise	25.2°F
Condenser outlet temperature	~~116.8~~116.2°F
Waterbox material	Carbon Steel
Condenser Tube Data	
Tube material (main section)	Titanium*
Tube size	~~1-3/8~~1" O.D. – ~~.5 mm~~23BWG
Tube material (periphery)	Titanium*
Tube size	~~1-3/8~~1" O.D. – ~~.7 mm~~23BWG
Tube sheet material	Titanium or Titanium Clad Carbon Steel
Support plates	Modular Design/Carbon Steel

* For fresh water plants, an equivalent tube material such as 304L, 316L, 904L or AL-6X may be substituted.

Table 10A.4.5-1

[[DESIGN PARAMETERS FOR MAJOR CIRCULATING WATER SYSTEM COMPONENTS]]

(Conceptual Design)

Circulating Water Pump	
Quantity	Three per unit
Flow rate (gal/min)	200,000
Natural Draft Cooling Tower	
Quantity	One per unit
Approach temperature (°F)	10
Inlet temperature (°F)	~~112.2~~116.2
Outlet temperature (°F)	~~87~~91
Approximate Temperature range (°F)	25.2
Flow rate (gal/min)	~~600,000~~625,000
Heat transfer (Btu/hr)	~~7,540~~7,630 x 10^6
Wind velocity design (mph) Seismic design criteria per Uniform Building Code	110
~~Predicted performance during limiting site conditions:~~ ~~Outlet temp @ wet bulb temp of 80°F (1% exceedance)~~	~~90°F~~

Table ~~10~~10A.4.7-1 (Sheet 1 of 2)

CONDENSATE AND FEEDWATER SYSTEM COMPONENT FAILURE ANALYSIS

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
SAME AS REFERENCE TABLE			

Table ~~10~~10A.4.9-1 (Sheet 1 of 2)

STARTUP FEEDWATER SYSTEM COMPONENT FAILURE ANALYSIS

Component	Failure Effect on Train	Failure Effect on System	Failure Effect on RCS
SAME AS REFERENCE TABLE			

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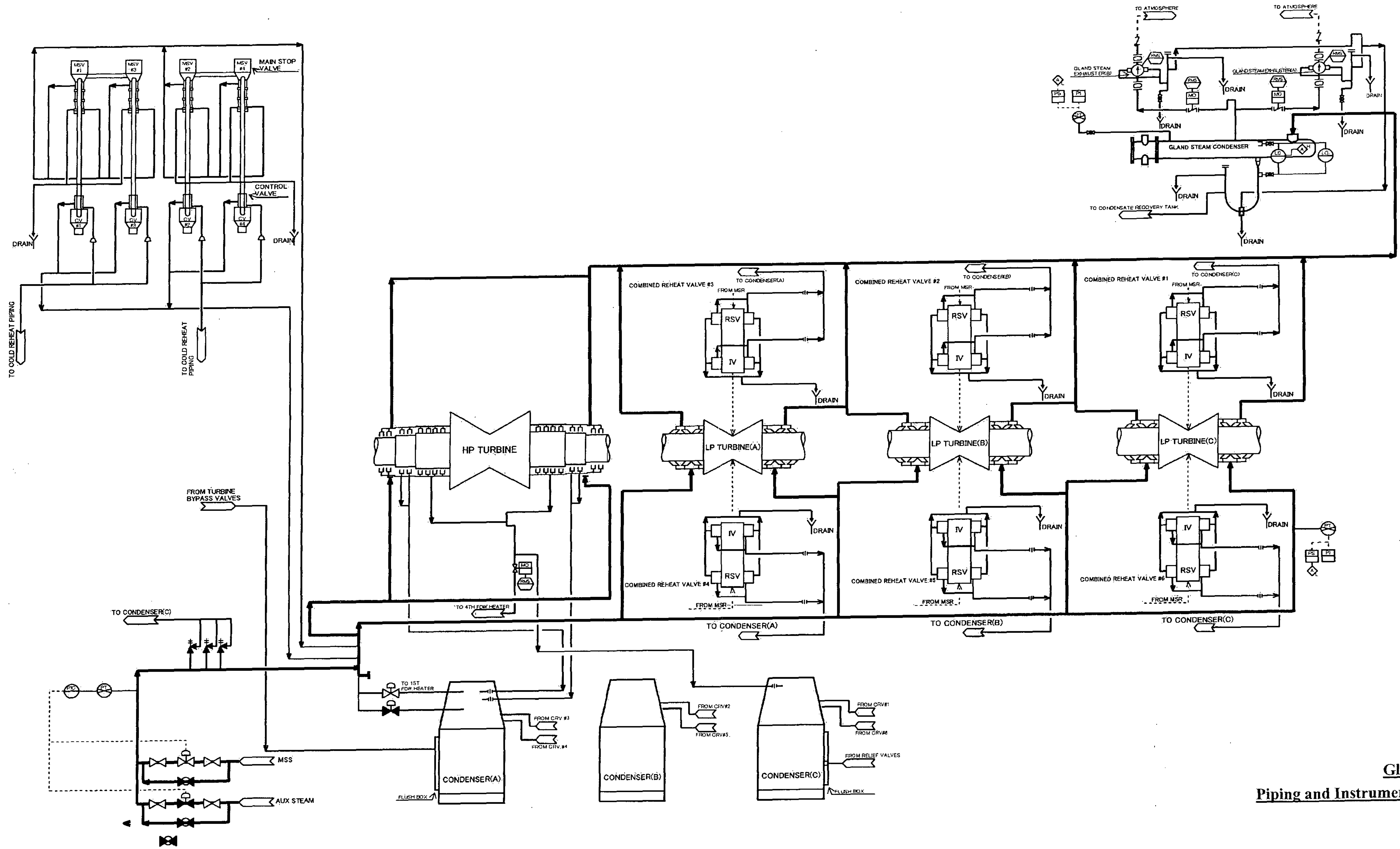

Figure 10A.4.3-1

Gland Seal System

Piping and Instrumentation Diagram

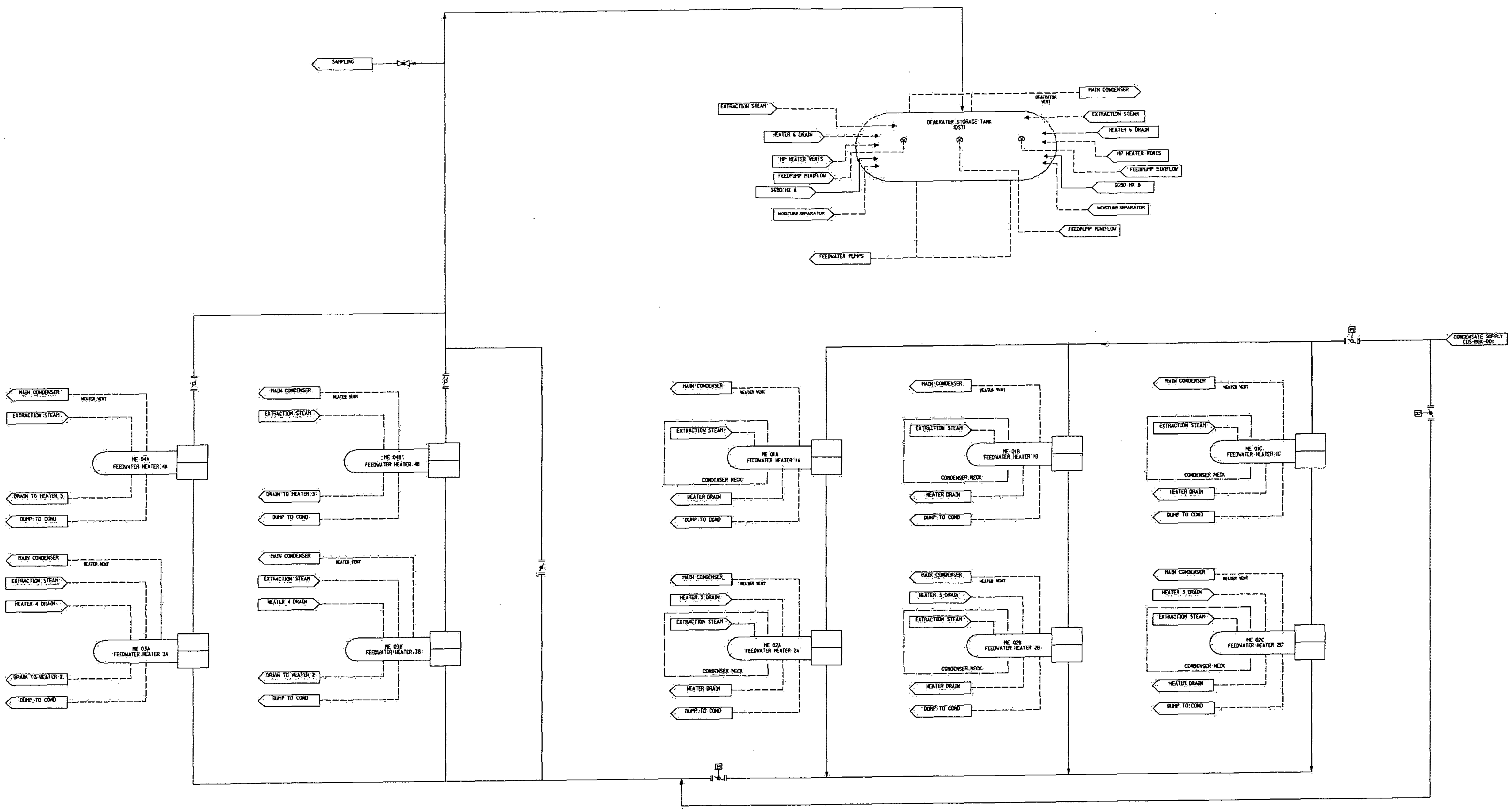

Figure 10A.4.7-1 (Sheet 2 of 4)

Condensate and Feedwater System Piping and Instrumental Diagram

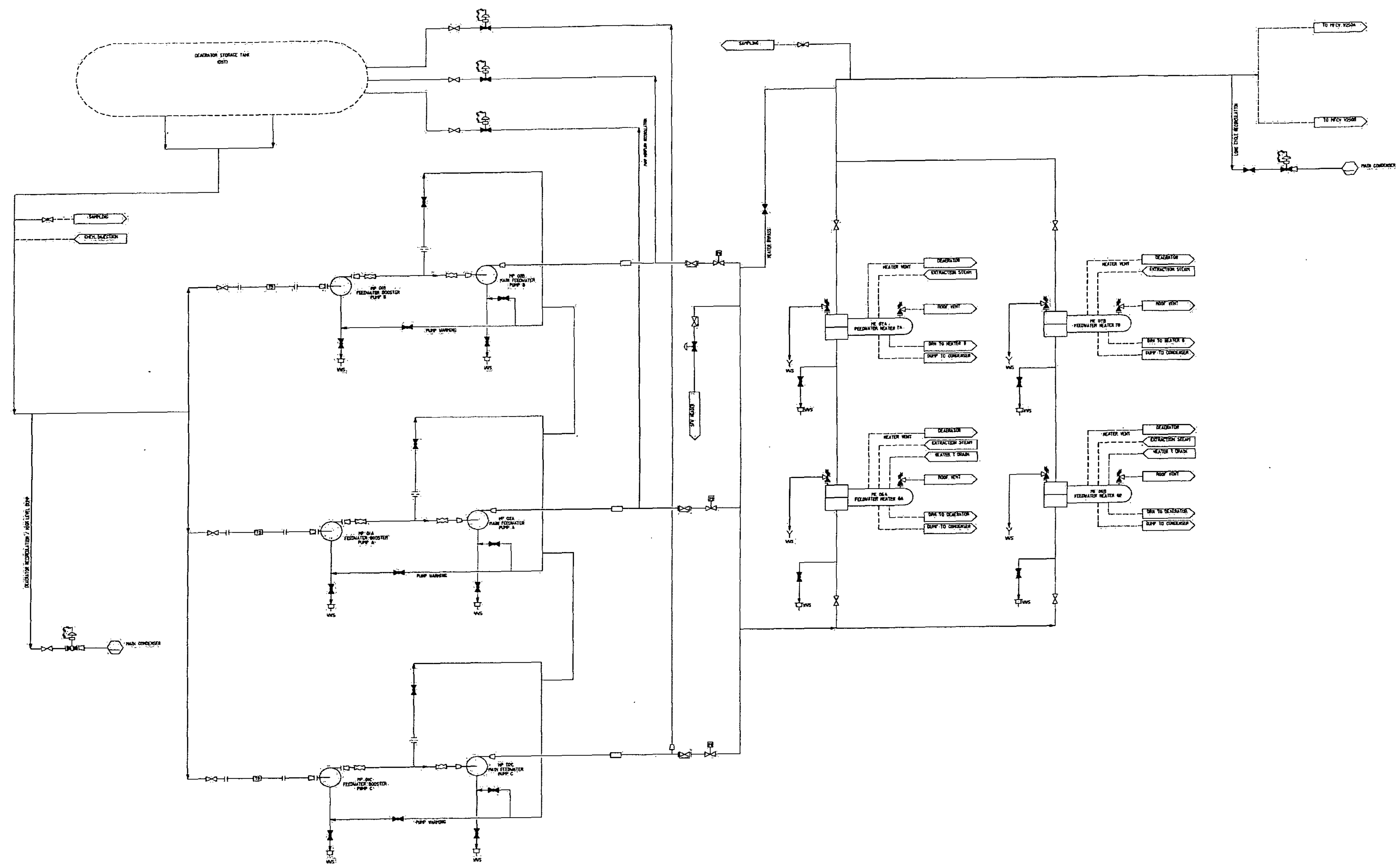

Figure 10A.4.7-1 (Sheet 3 of 4)

Condensate and Feedwater System
Piping and Instrumental Diagram

5.0 REGULATORY IMPACT

A. FSER IMPACT

There is no impact on the FSER. The changes in the equipment qualification methodology have no effect on design function. This change has no effect on analysis or analysis method.

B. SCREENING QUESTIONS

1. Does the proposed change involve a change to an SSC that adversely affects a DCD described design function?	☐ YES ☒ NO
There is no change to a design function of any related equipment.	
2. Does the proposed change involve a change to a procedure that adversely affects how DCD described SSC design functions are performed or controlled?	☐ YES ☒ NO
The alternate Steam and Power Conversion design has no effect on the function of a DCD described SSC.	
3. Does the proposed activity involve revising or replacing a DCD described evaluation methodology that is used in establishing the design bases or used in the safety analyses?	☒ YES ☐ NO
The alternate Steam and Power Conversion design requires changes to the Maintenance and Inspection Program Plan. Specifically, the alternate design changes the turbine valve test frequency to semi-annual versus the previous quarterly requirement. The alternate design also replaces the existing mechanical overspeed with a redundant, diverse emergency electrical overspeed turbine trip device..	
4. Does the proposed activity involve a test or experiment not described in the DCD, where an SSC is utilized or controlled in a manner that is outside the reference bounds of the design for that SSC or is inconsistent with analyses or descriptions in the DCD?	☐ YES ☒ NO
The alternate Steam and Power Conversion design does not require an additional test or experiment or changes to testing for an SSC.	

C. EVALUATION OF DEPARTURE FROM TIER 2 INFORMATION

10 CFR Part 52, Appendix D, Section VIII. B.5.a. provides that an applicant for a combined licensee who references the AP1000 design certification may depart from Tier 2 information, without prior NRC approval, if it does not require a license amendment under paragraph B.5.b. The questions below address the criteria of B.5.b.

1. Does the proposed activity result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the plant-specific DCD?	☐ YES ☒ NO
Since there is no change from the alternate Steam and Power Conversion design that could affect the plant design or operations, there are no new accident initiators and no effect on the frequency of evaluated accidents.	
2. Does the proposed activity result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety and previously evaluated in the plant-specific DCD?	☐ YES ☒ NO
The alternate Steam and Power Conversion design does not increase the likelihood of a malfunction of	

any SSC important to safety. The replacement of the mechanical overspeed trip device with an emergency electrical overspeed trip device on the turbine will not increase this likelihood of a malfunction due to the redundancy and diversity built into the trip device design.	
3. Does the proposed activity result in more than a minimal increase in the consequences of an accident previously evaluated in the plant-specific DCD?	☐ YES ☒ NO
The alternate Steam and Power Conversion design has no effect on the operation, performance, and pressure boundary integrity of the safety related equipment. Therefore, there is no increase in the calculated release of radioactive material during postulated accident conditions.	
4. Does the proposed activity result in more than a minimal increase in the consequences of a malfunction of an SSC important to safety previously evaluated in the plant-specific DCD?	☐ YES ☒ NO
The alternate Steam and Power Conversion design has no effect on the design functions or reliability of the safety related equipment or other components. Therefore, there is no increase in the calculated release of radioactive material due to a malfunction of an SSC.	
5. Does the proposed activity create a possibility for an accident of a different type than any evaluated previously in the plant-specific DCD?	☐ YES ☒ NO
The alternate design has no effect on the operation, performance, and pressure boundary integrity of plant equipment. The electrical overspeed trip device and blade dovetail design of the alternate turbine does not introduce any additional failure modes; therefore, there is no possibility of an accident of a different type than any evaluated previously in the DCD.	
6. Does the proposed activity create a possibility for a malfunction of an SSC important to safety with a different result than any evaluated previously in the plant-specific DCD?	☐ YES ☒ NO
There are no additional failure modes or the possibility for a malfunction of an SSC important to safety with a different result than any evaluated previously.	
7. Does the proposed activity result in a design basis limit for a fission product barrier as described in the plant-specific DCD being exceeded or altered?	☐ YES ☒ NO
There is no change to the design function of the safety related equipment. The criteria to provide for pressure boundary integrity are not exceeded or altered.	
8. Does the proposed activity result in a departure from a method of evaluation described in the plant-specific DCD used in establishing the design bases or in the safety analyses?	☒ YES ☒ NO
The alternate Steam and Power Conversion design establishes a semi-annual frequency for turbine valve testing. This change has no effects on the structural analysis or turbine generated missile analysis.	
☐ The answers to the evaluation questions above are "NO" and the proposed departure from Tier 2 does not require prior NRC review to be included in plant specific FSARs as provided in 10 CFR Part 52, Appendix D, Section VIII. B.5.b ☒ One or more of the answers to the evaluation questions above are "YES" and the proposed change requires NRC review.	

D. IMPACT ON RESOLUTION OF A SEVERE ACCIDENT ISSUE

10 CFR Part 52, Appendix D, Section VIII. B.5.a. provides that an applicant for a combined licensee who references the AP1000 design certification may depart from Tier 2 information, without prior NRC approval, if it does not require a license amendment under paragraph B.5.c. The questions below address the criteria of B.5.c.

1. Does the proposed activity result in an impact features that mitigate severe accidents. If the answer is Yes answer Questions 2 and 3 below.	☐ YES ☒ NO
The systems and components identified in the DCD Subsection 1.9.5 and Appendix 19 B that mitigate severe accidents are not impacted by the alternate Steam and Power Conversion design.	
2. Is there is a substantial increase in the probability of a severe accident such that a particular severe accident previously reviewed and determined to be not credible could become credible?	☐ YES ☐ NO ☒ N/A
3. Is there is a substantial increase in the consequences to the public of a particular severe accident previously reviewed?	☐ YES ☐ NO ☒ N/A
☒ The answers to the evaluation questions above are "NO" or are not applicable and the proposed departure from Tier 2 does not require prior NRC review to be included in plant specific FSARs as provided in 10 CFR Part 52, Appendix D, Section VIII. B.5.c. ☐ One or more of the he answers to the evaluation questions above are "YES" and the proposed change requires NRC review.	

E. SECURITY ASSESSMENT

1. Does the proposed change have an adverse impact on the security assessment of the AP1000.	☐ YES ☒ NO
The alternate Steam and Power Conversion design will not alter barriers or alarms that control access to protected areas of the plant. The alternate design will not change requirements for security personnel; therefore, the alternate Steam and Power Conversion design does not have an adverse impact on the security assessment of the AP1000.	

6.0 REFERENCES

1. APP-GW-GL-700, AP1000 Design Control Document, Revision 15.

2. APP-GW-GLR-021, AP1000 As-Built COL Information Items, Revision 0, June, 2006.