Table of Contents

List of Tables

List of Figures

10.0 Steam and Power Conversion System

This chapter provides information concerning the plant Steam and Power Conversion System, which includes the Main Steam Supply System, turbine generator, main condenser, and other associated subsystems.

Description is provided to allow an understanding of the Steam and Power Conversion System with an emphasis on those aspects of the design and operation of the system that affect the reactor, its safety features, and the control of radioactivity. Information is provided to show the capability of the system to function without compromising the nuclear safety of the units under both normal operating or transient conditions. The radiological aspects of the normal operation of the system are summarized in this chapter, and are presented in detail in Chapter 11 and Chapter 12.

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10.1 Summary Description

The Steam and Power Conversion System is designed to convert the heat produced in the reactor to electrical energy. Reactor heat absorbed by the Reactor Coolant System produces steam in four steam generators sufficient to drive a turbine generator unit having a nameplate rating of 1450 MVA.

The Steam and Power Conversion System is designed to operate on a closed condensing cycle, with seven stages of regenerative feedwater heating. Turbine exhaust steam is condensed in a conventional, surface type condenser; and condensate is returned to the steam generators through three stages of condensate feedwater pumping.

Extraction steam from various turbine/cycle points is used for reheating the steam in the moisture-separator reheater, regenerative feedwater heating, feedwater pump turbines and other auxiliary purposes. Condensate is normally pumped from the condenser hotwell by two of three half-capacity hotwell pumps through two stages of condensate heating to the suction of the condensate booster pumps. Two of the three half-capacity motor driven condensate booster pumps deliver condensate through three further stages of condensate heating to the suction of two half-capacity turbine driven feedwater pumps. Feedwater is pumped through two successive stages of feedwater heating to the four steam generators. Heat from the primary coolant is transferred to the feedwater in the steam generators producing the main steam. The main steam leaves the steam generator through a flow restrictor that is integral with the steam outlet nozzle to one of four main steam lines. Each of the four main steam lines has in order; one power relief valve, five safety valves, and one isolation valve, before they join in a common header. From the header, four lines carry the main steam to the four turbine stop valves and four control valves and on to the high pressure turbine. Leaving the turbine, the steam passes through the moisture-separator reheater units, then the six combined reheat valves and enters the three low pressure turbines. The steam exhausts directly from the turbines into the three main condenser shells.

Turbine and motor driven auxiliary feedwater pumps are provided to assure that adequate feedwater is supplied to the steam generators for reactor decay heat removal under all circumstances, including loss of offsite power and normal heat sink. Feedwater can be maintained until offsite power is restored or reactor decay heat removal can be accomplished by other systems.

The Steam and Power Conversion System and its auxiliary systems are designed to satisfactorily withstand greater instantaneous load changes than those available from the Reactor Coolant System. Thus, the design requirements for transient conditions such as loss of electrical load are not limited by the Steam and Power Conversion system, but rather they are based on maximum rate of load change dictated by the Reactor Coolant System. The Reactor Coolant System maximum rate of load change is a ten percent step change and/or a five percent per minute ramp load change.

A turbine bypass system capable of passing 40 percent of full load steam flow to the condenser is provided. The main steam lines also have power operated relief valves set to relieve at a lower pressure than the 100 percent capacity spring loaded safety valves and sized to relieve 10 percent of full load main steam flow to atmosphere. Following a reduction in load from 100 percent to 50 percent, there is no steam vented to atmosphere if condenser availability is maintained.

Following a turbine load reduction (<50%) without turbine trip, the Turbine Bypass System to the condenser passes 40 percent of full load steam flow with excess steam flow vented to atmosphere via the power operated relief valves until the steam generator pressure is reduced to normal. This operation can be performed without safety valve operation.

The Steam and Power Conversion System safety classifications are listed in Table 3-4.

The safety related portions of the Steam and Power Conversion Systems are located in the Auxiliary Building and are as follows:

1. Auxiliary Feedwater System, including feedwater isolation valves and piping to steam generators (See Figure 10-47).
2. Main steam isolation valves, including piping from steam generators (See Figure 10-11).

The Steam and Power Conversion System heat balances that were provided by Westinghouse and included in Figures 10-1 and 10-2 are replaced with the following Siemens Energy, Inc. proprietary drawings containing heat balance information resulting from related turbine-generator upgrades and implementation of the Measurement Uncertainty Recapture (MUR) Power Uprate on Unit 2:

- MCM 1200.00-0356.001, 100% OF RATED THRM. PWR. 1.7" HGA (GUAR. HT. BAL. DIAG.)
- MCM 1200.00-0356.007, VALVES WIDE OPEN HEAT BALANCE DIAGRAM, (NOT GUAR.)

Any modifications performed to MS System structures, systems, or components (SSCs) are required to obtain these proprietary drawings and review their content against the modification scope.

Under normal operating conditions, there will be no radioactive contaminants present in the Steam and Power Conversion System. It is possible for this system to become contaminated only through steam generator tube leaks. Means are provided to monitor and prevent the discharge of radioactive material to the environment, such that the limits of 10CFR 20 are not exceeded under normal operating conditions or in the event of anticipated system malfunctions or fault conditions. (See Sections 9.2.6, 10.4.2.3, 10.4.3.2, and 10.4.8.)

The discharge from the Turbine Building sump may be routed either to the Conventional Waste Water Treatment System or to the Condenser Circulating Water System and with the option of to the Liquid Waste Monitor and Disposal System.

No radiation shielding is required for the components and piping of the Steam and Power Conversion System. Continuous access to this system located outside the Reactor Building is possible during normal operation.

The flow diagrams and design performance data of the Steam and Power Conversion System are included in the following sections of Chapter 10.

Duke response to NRC Order EA-02-026 committed to use portions of the Feedwater system and Auxiliary Feedwater System for response to beyond design basis events (B.5.b events) if available. Alternate Feedwater supply to the Steam Generators (tempering lines) and Steam Generator level instruments are relied on for these Extensive Mitigation Strategies as well as the Auxiliary Feedwater Storage Tank and associated recirculation piping. The Turbine Driven Auxiliary Feedwater Pump and Main Steam Power Operated Relief Valves are also used for response in Extensive Damage Mitigation Strategies in response to B.5.b events.

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10.2 Turbine-Generator

10.2.1 Design Bases

The turbine-generator converts the thermal energy of steam produced in the steam generator into mechanical shaft power and thence into electrical energy. The unit is operated primarily as a base loaded unit with an output of about 1185 MWe net but will be used for load following when required. The maximum rate of load change is a 10 percent step change and/or a 5 percent per minute ramp dictated by the Reactor Coolant System without steam bypass; however, with steam bypass the turbine controls can reduce load from 100 percent to 50 percent in 20 seconds.

10.2.2 System Description

Each unit's turbine-generator consists of a tandem (single shaft) arrangement of a double-flow, high-pressure turbine and three identical double-flow, low-pressure turbines driving a direct-coupled generator at 1800 rpm. The original turbine-generator was manufactured by Siemens Energy, Inc. (formally Westinghouse Electric Corporation) with upgrades performed by Siemens Energy, Inc.

The flow of main steam is from the steam generators to the high-pressure turbine through four governor stop valves and four throttle valves. After expanding through the high-pressure turbine, exhaust steam passes through external moisture separators and two stage steam-to-steam shell and tube type reheaters. Each moisture separator drains to a drain tank, which in turn discharges to the "C" heater drain tanks. The drains from these tanks are then pumped through a common header to the suction of the steam generator feedwater pumps. Extraction steam from the high-pressure turbine is supplied to the first reheater stage tube bundle in each reheater. This bundle drains to a drain tank which drains to the shell side of "B" feedwater heaters. Main steam is supplied to the second reheater stage tube bundle in each reheater which drains to a drain tank which drains to the shell side of "A" feedwater heaters. (Figure 10-3, Figure 10-4, and Figure 10-5). Reheated steam is admitted to the three low-pressure turbines and passes through the low-pressure turbines to the main condensers.

Bleed steam from the seven stages of feedwater heating (Figure 10-5, Figure 10-6, Figure 10-7, Figure 10-8, and Figure 10-9) is provided from the following sources:

Heater	Extraction Source
A	H-P turbine
B	H-P turbine
C	H-P turbine exhaust
D	L-P turbine
E	L-P turbine
F	L-P turbine
G	L-P turbine

Each generator is hydrogen and water cooled, rated at 1450 MVA at 90 percent power factor and produces power at 24kv and 60 Hz. Generator rating, temperature rise, and class of insulation are in accordance with IEEE standards. Excitation is provided by a shaft-driven alternator with its output rectified. A conventional, automatic, oil-sealed hydrogen cooling system provides rotor cooling. The hollow stator conductors are water cooled by a self-contained, automatic, stator water system. Differential relays protect the generator against internal electrical faults.

Turbine-generator bearings are lubricated by a conventional oiling system of proven components. A turbine shaft-driven lube oil pump takes suction from the lube oil tank through an oil driven ejector. For startup and until full speed is reached an a-c motor-driven oil pump provides lubricating and operating oil, with a d-c motor-driven oil pump providing back-up capacity. Heat from the bearings is removed by either of two full capacity oil coolers using water from the Conventional L.P. Service Water System.

The prime function of the Turbine Control System is to control the speed of the turbine when the generator is not synchronized with the system and to control the output of the unit when the generator is “on line”. This is accomplished by positioning the main steam control valves to regulate the flow of steam to the turbine. The Turbine Control system is of the digital electro-hydraulic (DEH) type which performs digital computation on reference and turbine feedback signals and generator output signals to the steam valve actuators.

The DEH Control System is made up of three basic subsystems. These are the Control Panels, the Electronic Controller and the Hydraulic System.

The control panels for the DEH are located in the Control Room. The panels consist of electronic indicators, push button switches, signal lights to indicate the particular apparatus in control, and two reference displays to indicate the speed/MW reference and acceleration/MVAR values. Through keyboard push buttons, the operator can change the reference input to the electronic controller to vary the speed or load at different rates. Operator settings made at the panel are used by the electronic controller to position the steam valves by comparing the turbine speed or megawatt signals to the reference settings selected by the operator.

The electronic controller portion of the DEH consists of two bays of electronic equipment containing a small digital computer, a backup analog control system, associated power supplies, input/output wiring terminations, etc. This controller performs computations on various turbine parameters and positions the steam valves in accordance with these parameters. The analog backup control system allows the operator to control the turbine manually in case the computer should malfunction.

The hydraulic portion of the DEH consists of a hydraulic fluid reservoir, associated piping and steam valve actuators. Hydraulic fluid is triphosphate ester, possessing qualities of fire resistance and fluid stability. The hydraulic fluid reservoir, is made of stainless steel and has mounted on it a duplicate system of fluid pumps, filters and heat exchangers. The system is arranged such that one set of components function while the duplicate set serves as a stand-by system. The hydraulic system receives control signals from the electronic controller and in turn positions the steam valves. The position of each steam valve is controlled by an independent actuator which consists of a hydraulic cylinder using fluid pressure to open and spring action to close the valve.

The control and stop valve servo-actuators position the steam valves in any intermediate position to proportionally regulate the steam flow as required. The actuators are provided with a servo-valve and a LVDT (Linear Variable Differential Transformer). High pressure fluid is supplied to the servo-valve which controls the actuator position in response to a position signal from the servo amplifiers. The LVDT develops an analog signal proportional to the valve position which is fed back to the controller to complete the control loop. A signal can be introduced at the operators panel to the controller to test exercise the main stop and control valves.

The reheat stop valve and interceptor valve actuators position the steam valves only in the fully open or fully closed position. These valves can also be test exercised through controls on the operators panel.

Redundant and diverse turbine overspeed protection is provided and is shown in (Figure 10-10). This protection is divided into the two basic categories of mechanical overspeed protection in the turbine and electrical overspeed protection.

Mechanical overspeed protection, which is independent of the DEH controller, is provided by the mechanical overspeed trip mechanism. This mechanism consists of an eccentric weight mounted in a transverse hole in the turbine rotor extension shaft. The weight is offset from the center so that centrifugal force tends to move it outward. Normally the weight is held in position by the compression of a spring. When the turbine overspeeds to approximately 110% of rated speed, the spring compression is overcome by the centrifugal force of the rotor speed, and the weight moves to strike a trigger which trips the overspeed trip valve and releases the auto stop oil and high pressure emergency trip fluid to drain, closing all turbine valves.

The diaphragm emergency trip valve is the interface between the high pressure fluid emergency trip header and the auto-stop trip oil supplied from the lubrication system. Auto-stop trip oil is supplied to a chamber above the diaphragm in the valve bonnet. This pressure acts to overcome a compression spring and holds the valve closed. A decay in autostop trip oil pressure allows the compression spring to open the valve, thus opening the emergency trip header fluid to drain causing all turbine valves to close.

Electrical overspeed protection is provided to both correct an overspeed condition and to trip the turbine on excessive overspeed.

At 103% rated speed the DEH will output a signal to the redundant overspeed protection controller solenoid valves opening these valves momentarily to dump EH fluid from the governor and intercept valves thus closing the valves to limit overspeed. The DEH will continue to pulse the solenoids until speed is reduced. If overspeed continues to approximately 111% of rated speed the DEH will send a signal to the autostop trip relay which in turn picks up the autostop trip solenoid valves dumping the autostop oil to close the turbine valves and trip the turbine. In addition to the overspeed protection control and trip functions provided by the DEH a diverse method of tripping is provided by an independent overfrequency relay which is used to trip the turbine if the generator frequency reaches approximately 111% of its rated value by energizing the autostop trip solenoid valve. A potential transformer, on the isolated phase bus, is used to trip the generator power circuit breaker. The circuit breaker lockout then trips the autostop trip solenoid to drain the autostop oil thus tripping the turbine.

The multiple redundant and independent measures as detailed above prevent failures in the hydraulic control system from precluding loss of the turbine overspeed protection function. The mechanical and electrical trips dump autostop oil by independent means through separate drains. The electrical and overfrequency overspeed trips dump autostop oil by energizing the autostop trip solenoid whereas the mechanical overspeed trip mechanism acts via mechanical linkage to trip open the overspeed trip valve dumping the autostop oil to drain. When autostop oil is dumped (through two separate drains) the emergency trip fluid will also be dumped to drain through two separated drains. Dump of the autostop oil allows the diaphragm emergency trip valve to open dumping the emergency trip fluid to drain. Decay of autostop oil pressure will also result in a dump of the emergency trip fluid. This is accomplished by 2/2 logic via pressure switches sensing autostop oil pressure which opens redundant solenoids to dump the emergency trip fluid to drain when a trip setpoint is reached on both pressure switches.

The turbine mechanical overspeed protection device is tested periodically by actually overspeeding the turbine to cause a trip and check the trip speed. The overspeed protection controller can be tested on-line provided that the unit is in speed control via a three position key switch on the DEH operators panel. This test is inhibited when the generator is synchronized to the system. The mechanical overspeed trip can also be tested while the unit is on-line by the following method. With the overspeed trip mechanism "test" handle in the "test" position, high pressure oil is admitted to the inside of the trip weight by opening a hand valve at the trip device. A pressure gage is provided to monitor the pressure at which the weight moves outward to the trip position. This value is then compared to a previously recorded setpoint value to check proper operation.

In addition to the turbine overspeed trips described above, the following conditions also trip the turbine.

1. Low condenser vacuum
2. Thrust bearing failure
3. Low bearing oil pressure
4. Internal fault in generator
5. Generator breaker failure
6. Reactor trip
7. Loss of generator stator coolant
8. DEH d-c power failure
9. Steam generator hi-hi level
10. Safety injection
11. Both main feedwater pumps tripped
12. Manual turbine trip
13. Turbine oil fire
14. Load rejection > 50%

In the event of a trip of the generator output circuit breakers, which isolates the unit from the external electrical load (< 50%), a signal is initiated to operate the Turbine Bypass System, described in Section 10.4.4, thereby allowing the unit to continue to supply the plant auxiliary electric load.

The turbine-generator and its auxiliary systems are designed to satisfactorily withstand greater instantaneous load changes than those available from the Reactor Coolant System. Because of this, the design requirements for transient conditions such as loss of electrical load are not limited by the Turbine-Generator System but rather they are based upon the maximum rate of load change dictated by the Reactor Coolant System.

10.2.3 Turbine Generator Missiles

There is an extremely low probability that turbine generator missiles will be generated. There is an even lower probability that a missile penetrating the turbine casing would strike a safety-related structure or component. The report “Probability of Damage to Nuclear Components Due to Turbine Failure”; Bush, S. H.; Battelle Memorial Institute - Pacific Northwest Laboratories, analyzes all turbine generator failures since 1951 and predicts reasonable values for turbine generator missile probabilities based on actual data during this period. There were no missiles attributed to Westinghouse turbine generators during the period covered by this report.

Through the actions of the turbine overspeed protection systems described in Section 10.2.2, the maximum turbine speed following a turbine trip by either control system should be less than 120 percent of rated speed. Studies indicate probable turbine wheel failures at 170 to 180 percent of rated speed. Therefore, the turbine speed range in which reliable, redundant overspeed controls are initiated is conservative compared to the speed at which probable wheel failures occur.

The orientation of the turbine and the fact that Category 1 structures, as described in Section 3.5 are designed to withstand low-trajectory turbine missiles in accordance with Regulatory Guide 1.115 (Rev. 1) provide additional assurance that safety-related structures and components will not be affected in the extremely unlikely event a turbine missile is generated.

Assuming the highly unlikely event of a disc failure at design overspeed, there are credible missiles for the low pressure turbines. See Westinghouse “Report Covering the Effects of a High Pressure Turbine Rotor Fracture and Low Pressure Turbine Disc Fractures at Design Overspeed, 1970.” The low pressure turbine missile analysis is presented in Section 3.5.2.7 and missile data is presented in Table 3-15 and Figure 3-4. In addition, the low pressure turbine rotors have been replaced with FI (Fully Integral) rotors which further reduce the probability of turbine missile generation.

The peninsular turbine orientation with respect to station layout is shown on Figure 1-7.

10.2.4 Safety Evaluation

The turbine-generator and all related steam handling equipment is of conventional proven design. This unit will automatically follow the electrical load requirements above 15 percent power.

Under normal operating conditions, there are no radioactive contaminants present. It is possible for this system to become contaminated only through steam generator tube leaks. In this event, radioactivity in the Main Steam System is detected and measured by monitoring condenser air ejector off-gas which is released through the unit vent, Section 10.4.2 and by monitoring the steam generator blow-down samples, Section 10.4.8.

No radiation shielding is required for the components of the turbine-generator and related steam handling equipment. Continuous access to the components of this system is possible during normal conditions.

The original turbine-generator was designed and manufactured in accordance with Siemens Energy, Inc. (formally Westinghouse Electric Corporation) design criteria and manufacturing practices, procedures, and processes, as well as its Quality Assurance Program. Subsequently, turbine-generator upgrades were performed by Siemens Energy, Inc.

The moisture separator reheaters and drain tanks are designed and constructed to ASME Section VIII. The generator rating, temperature rises and insulation class are in accordance with IEEE Standards.

10.2.5 Tests and Inspections

During the initial startup operation, Turbine Generator and Auxiliary Systems were initially operated and tested in accordance with the manufacturer's recommendations with guidance from an on-site representative. This includes the following Systems:

1. Generator Hydrogen System
2. Generator Stator Cooling Water System
3. Generator Seal Oil System
4. Turbine Hydraulic Oil System
5. Turbine Lube Oil and Purification System
6. Turbine Lube Oil Cooler System
7. Turbine Leakoff and Steam Seal System
8. Turbine Exhaust Hood Spray System

In addition, the Turbine Generator trip devices listed in Section 10.2.2 of the FSAR are initially set and checked. The following equipment is checked periodically:

1. Throttle valve stem freedom
2. Reheat stop and interceptor valve stem freedom
3. Motor-driven oil pumps and controls
4. Oil trip test devices
    a. Overspeed trip oil test device
    b. Low vacuum trip
    c. Low bearing oil pressure trip
    d. Thrust bearing oil trip
5. Overspeed trip

Further, a turbine performance/acceptance test may be periodically performed. The test method employed is based on the test procedures described in ASME PTC6-1996, “Performance Test Code 6 on Steam Turbines”. In general, the test method involves isolation of systems, equipment and flow associated with the turbine cycle. Following isolation, data is collected under various operating conditions.

The Duke Energy in-service inspection program for the turbine normally includes, but is not limited, to the following points:

1. Disassembly of the turbine at approximately 10-year intervals adheres to both the vendor design basis and NEIL (Nuclear Electric Insurance Limited) insurance requirements for forged turbine rotor inspection intervals. A complete inspection of all normally inaccessible parts, such as; couplings, coupling bolts, bearings, casings, blades, low pressure and high pressure rotors is performed during plant shutdown. This inspection consists of visual, surface, and volumetric examinations, as required. The disassembly does not include removal of blades and wheels from the turbine rotor, unless some specific reason exists for doing so. Duke Energy is well abreast of current volumetric inspection technology and incorporates improved methods of turbine rotor inspection into the in-service inspection program as these techniques are developed and improved.

2. An in-place visual examination of the turbine assembly at intervals recommended by turbine manufacturer.
3. Dismantling of all main steam throttle valves, main steam governor valves, reheat stop valves, and reheat interceptor valves, for inspection and component repair or replacement as necessary. The frequency and scope of these inspections is as specified by the McGuire Turbine Overspeed Reliability Program.

10.2.6 Instrumentation Application

Instrumentation on the turbine-generator continuously monitors and/or alarms the following conditions:

1. Generator megawatts and vars
2. Internal fault in generator
3. Generator stator winding temperature
4. Generator stator water temperature and conductivity
5. Generator hydrogen gas temperature, purity and pressure
6. Generator seal oil pressure and level
7. Electro-hydraulic fluid low-high level and pressure
8. Turbine speed
9. Each main bearing oil and metal temperature
10. Turbine metal temperature
11. Shaft eccentricity
12. Shaft vibration of main bearings
13. Shell expansion
14. Differential expansion between shell and rotor
15. Condenser vacuum, each shell
16. Exhaust hood temperature
17. Gland seal steam pressure
18. Electrical malfunctions in the electro-hydraulic control unit.

The Main Turbine Hydraulic Oil System is provided with the following instrumentation and controls:

1. One (1) level control to actuate the fluid low level alarm switch and the fluid emergency low level alarm switch.
2. One (1) level control to actuate the fluid high level alarm switch and the fluid low-low alarm switch.
3. One (1) temperature modulated control valve, KR196 (Figure 9-28), is installed in the cooling water discharge line from the two coolers. This valve is connected to a thermostat bulb emersed in the fluid reservoir and provides a modulating control on the water flow through the coolers.

4. One (1) thermostat switch arranged to sense the reservoir temperature and alarm at 140°F as shown.
5. Two (2) differential switches on the inlet and outlet sides of the 10 micron cartridge filters mounted in the pump discharges of both pumps 1A and 1B.
6. One (1) pressure switch in the fluid drain line to the reservoir. This switch is set to close contact and sound an alarm on increasing pressure at 30 psig.
7. One (1) pressure switch in the H.P. fluid header to indicate low pressure. This switch is set to close contact and start the fluid auxiliary pump on decreasing pressure at 1350 psig.
8. One (1) pressure switch in the H.P. fluid header to indicate low pressure. This switch is set to close contact and sound an alarm on decreasing pressure at 1400 psig.
9. One (1) pressure switch in the H.P. fluid header to indicate high pressure. This switch is set to close contact and sound an alarm on increasing pressure at 2200 psig.
10. Solenoid valve LH17 open/close control is provided to allow the idle fluid pump start-up switch to be tested from some remote point.
11. Solenoid valves LH19 and LH20 are operated by the overspeed protection control.
12. Solenoid valve LH21 is controlled by the emergency trip circuit.

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10.3 Main Steam Supply System

10.3.1 Design Bases

The Main Steam Supply System is designed to achieve the following:

1. Provide steam flow requirements at turbine inlet design conditions.
2. Dissipate heat from the Reactor Coolant System following a turbine and/or reactor trip.
3. Provide steam for:
    a. Main and auxiliary feedwater pump turbines.
    b. Condenser steam air ejectors. (CSAE)
    c. Main and feedwater pump turbine seals.
    d. Miscellaneous auxiliary equipment.
4. Conform to applicable design codes presented in Table 3-4.
5. Allow fulfillment of visual in-service inspection requirements.

10.3.2 System Description

The Main Steam Supply System is shown on Figure 10-11 and Figure 10-13. Main steam is generated in the four steam generators from feedwater which absorbs heat generated by the Reactor Coolant System. Main steam is conveyed by four, one per steam generator, steam lines to a steam pressure equalization and distribution header then to the turbine inlet valves. A flow restrictor is provided in each main steam line steam generator outlet nozzle to limit maximum flow and the resulting steam generator nozzle thrust loading caused by a steam line rupture. The steam generators and all piping and valves down to and including the main steam isolation valves are Duke Safety Class B. Piping downstream of the main steam isolation valves including the forty-eight inch main steam header and the twenty-eight inch turbine inlet piping is Duke Safety Class F. A Duke Safety Class B flow restrictor is provided in each main steam drain line, downstream of the doghouse drain line isolation valve, to limit flow and the resulting dose during postulated RSG DNB transients. Portions of the main steam system piping, exiting the doghouses (in the roof area of the diesel generator rooms), were upgraded from class G to class F to preclude seismic interactions with the diesel generators.

Self-actuated safety valves are located immediately outside the containment to assure the integrity of the Main Steam System under all conditions. These ASME Code valves are designed to relieve at a predetermined pressure with a combined capacity equal to maximum calculated heat balance steam flow conditions. The design capacities of the safety valves are shown in Table 10-2.

Main steam isolation valves are provided in each steam generator steam line immediately downstream of the safety valves to isolate each individual steam generator and prevent reverse flow in the event of a steam line rupture. The main steam isolation valves close on high-high Containment pressure signal and/or on high steam line pressure rate of change or low steam line pressure as the result of a main steam line rupture between the steam generator and the turbine steam stop valves.

These air-operated valves close, under actuator spring force and air assist, within 8 seconds. The MSIVs close with spring force along with motive force provided by Instrument Air (VI). A safety-related VI accumulator for each MSIV will provide motive force and maintain valve control for approximately four hours following a loss of the non-safety instrument air system. The accumulator pressure must be equal to or greater than 60 psig to maintain valve operability.

Closure of the main steam isolation valve in-service against reverse flow will yield a maximum leakage of 2% flow. This volume of leakage into the containment is within limits set by Westinghouse criteria.

The main steam isolation valves are located as close to the Containment as possible and protected in service by reinforced concrete doghouses. The valves and piping within the doghouse are restrained to prevent pipe whip damage if pipe break occurs within the doghouse.

Bypass valves are provided around each main steam isolation valve for pressure equalization and to supply auxiliary steam for start-up, if required.

Main steam isolation valves and bypass valves close upon receipt of a MSIV isolation signal. These valves remain in emergency mode and require deliberate manual operator action for resetting (Reference 1).

Steam supply for the turbine driven auxiliary feedwater pump is taken from two main steam lines upstream of the main steam isolation valves. Power relief valves are provided upstream of the main steam isolation valves to provide atmospheric steam relief capacity as a means of heat dissipation in the event of loss of normal heat sink capabilities. Minimum total capacity of the main steam power relief valves is ten percent of full load steam flow. The forty percent turbine bypass to the condenser, allows a turbine 50% load rejection without a reactor trip. Turbine full load rejection is estimated to occur an average of four times per year. Section 10.4.4 discusses the Turbine Bypass System. Section 15.2.7 discusses releases to the atmosphere on loss of turbine load.

The steam equalization header provides a main steam pressure and temperature equalization chamber and a steam distribution manifold to the following systems:

1. Turbine Bypass to Condenser System
2. Condenser Steam Air Ejectors
3. Main Feedwater Pump Turbines (See Figure 10-16)
4. Auxiliary Steam System
5. Deleted per 2003 update.
6. Turbine Gland Sealing System

A total of four turbine stop and four turbine control valves are provided for turbine control and protection.

10.3.3 Safety Evaluation

A failure of any main steam line or malfunction of a valve in the system does not:

1. Reduce flow capability of Auxiliary Feedwater System below the minimum required.
2. Prohibit function of any Engineered Safety Feature.
3. Initiate a loss-of-coolant accident.
4. Cause uncontrolled flow from more than one steam generator.
5. Jeopardize Containment integrity.

The Main Steam System delivers the generated steam from the outlet of the steam generators to the various system components throughout the Turbine Building without incurring excessive pressure losses. Steam is generated at essentially dry and saturated conditions. Functional requirements of the system are as follows:

1. Achieve optimum pressure drop between the steam generators and the turbine steam stop valves.
2. Assure similar steam conditions between each steam stop valve and between each steam generator.
3. Achieve adequate piping flexibility for acceptable forces and moments at equipment interfaces.
4. Assure adequate draining provisions for startup and for operation with saturated steam.

Safety class requirements of the Main Steam Supply System are presented in Table 3-4. The steam generated in the four steam generators is normally not radioactive; however, in the event of primary-to-secondary leakage due to a steam generator tube leak, it is possible for the main steam to become radioactively contaminated. A discussion of the radiological aspects of primary-to-secondary leakage, including anticipated releases to the environment as a result of the opening of the power-operated relief valves and the safety valves, is contained in Section 15.6.3.

10.3.4 Tests and Inspection

The Main Steam Supply System was fully tested and inspected before unit startup. Visual inservice inspection of the system is performed periodically by station operating personnel.

Prior to unit commercial operation, each main steam isolation valve was tested to demonstrate proper operation and to verify closure within the required time. During pre-operational hot functional testing, the operability of each valve was verified by part stroke exercising the valve and by verifying valve closure times at hot and cold conditions.

Post unit commercial operation, each main steam isolation valve is tested in accordance with the McGuire Pump and Valve In-Service Testing Program. Testing is performed at cold shutdown and while the main steam supply system temperature is greater than or equal to 500°F and system pressure is greater than or equal to 900 psig.

The main steam isolation valves seat and back seat leakage are tested during manufacture in accordance with the Manufacturer's Standardization Society, Standard Practice 61. The duration of seat and back leakage tests is four times that required by the Manufacturer's Standardization Society Standard Practice 61. In addition, Duke requires on the main steam isolation valves, an ultrasonic test of the valve stems and a dye penetrant check of the valve seats. Procedure and acceptance standards are in accordance with Paragraphs NB-2542 and NB-2546 of the ASME Code, Section III.

Seat leakage in the forward direction and back seat leakage is less than 3cc per hour per inch of seat diameter. Seat leakage in the reverse direction is approximately two percent of rated flow.

Valve gland leakage is less than 1cc per hour per inch of stem diameter under hydrostatic pressure.

Each main steam isolation valve is factory tested to prove their ability to close against full line pressure. This will be done prior to valve shipment, using air pressurization of the body.

The MSIV's were tested in a joint project by GE and Commonwealth Edison Co. at accident downstream blowdown flow rates (APED-5750, Design and Performance of General Electric Boiling Water Reactor Main Steam Line Isolation Valves, March 1969 by: D. A. Rockwell and E. H. Van Zylstra). Analysis of closing performance on a wide variety of conditions demonstrated that the valve closure is not critically sensitive to temperature, pressure, fluid or fluid flow in the valve.

10.3.5 Instrument Application

Main steam flow is measured between the steam generator and a point located in the downstream steam piping.

Flow transmitters and pressure transmitters are installed in the main steam line from each steam generator. The steam pressure signals are fed into reactor protection cabinets and steam flow signals are input to the Ovation PCS to control the feedwater flow to each steam generator. The reactor protection cabinets provide input to the SSPS. The SSPS performs the logic required to close the main steam isolation valves in case of rupture in main steam lines, and to open the power-operated relief valves in case of overpressure.

Three turbine inlet pressure transmitters provide signals to the Ovation PCS that are directly proportional to turbine-generator power.

Condenser steam dump control and reactor control inputs are obtained from the T_{AVG} - T_{REF} deviation signal generated in separate Ovation PCS controllers. Refer to Section 7.7.1.1 for a description of the reactor controls, and to Section 7.7.1.8 for a description of the steam dump controls.

One main steam header pressure transmitter is located in the common header before the turbine, and is selected by the Ovation PCS for control.

10.3.6 Water Chemistry

A discussion of the secondary side water chemistry is presented in Section 10.4.7. The radioactive iodine partition coefficients in the steam generators and air ejectors are discussed in Section 11.3.6.

10.3.7 References

1. Letter from Westinghouse to T. C. McMeekin (Duke), “Steamline Isolation SSPS Modification,” *DAP-86-672*, November 24, 1986.

THIS IS THE LAST PAGE OF THE TEXT SECTION 10.3.

10.4 Other Features of the Steam and Power Conversion System

This section provides information on the principal design features and subsystems of the Steam and Power Conversion System.

Each of the following subsections provides information on

1. design bases,
2. system description,
3. safety evaluation,
4. tests and inspections, and
5. instrumentation applications for each subsystem or feature.

10.4.1 Main Condensers

10.4.1.1 Design Bases

The main condensers (See Figures 10-18, 10-19, 10-20) are designed to condense the low pressure turbine exhaust steam so it can be efficiently pumped through the steam cycle. The main condensers also serve as a collection point for the following:

1. Feedwater heater drains and vents.
2. Condensate and Feedwater System makeup.
3. Condenser steam air ejector inter-condenser.
4. Gland steam condenser drains.
5. Miscellaneous equipment drains and vents.

The main condensers are also designed to condense up to 40 percent of the full-load main steam flow bypassed directly to the condenser by the Turbine Bypass System. The steam is bypassed to the main condensers in case of a sudden load rejection by the turbine generator or a turbine trip, and at unit startup and shutdown as described in Section 10.4.4. The main condenser hotwells serve as a storage reservoir for the Condensate and Feedwater Systems with sufficient volume to supply maximum condensate flow for approximately 8 minutes. The main condensers are also designed to provide for removal of noncondensable gases from the condensing steam by the Main Condenser Evacuation System described in Section 10.4.2. Heat is removed from the main condensers by the Condenser Circulating Water System. The main condensers are designed in accordance with the Heat Exchanger Institute Standards for Steam Surface Condensers. Table 10-3 gives additional data on the design and performance of the main condensers.

10.4.1.2 System Description

The main condenser for each unit is a single pass, three shell, surface type deaerating condenser. Each condenser shell is located below its respective low pressure turbine and is joined to the turbine by a rubber belt type expansion joint. The main condensers are of conventional shell and tube design with steam on the shell side and circulating water on the tube side. The tubes in each shell are oriented transverse to the turbine generator longitudinal axis. Each shell has two pairs of tube bundles, each pair connected to a separate circulating water line. Each circulating water circuit can be isolated for in-service repair of leaking tubes by closing motor operated butterfly valves on the condenser inlet and outlet connections. Non-condensable gases removed from the condensers are vented to atmosphere through the Main Condenser Evacuation System and are continuously monitored for radiation.

10.4.1.3 Safety Evaluation

The main condensers are normally used to remove residual heat from the Reactor Coolant System during the initial cooling period after unit shutdown when the main steam is bypassed to the condensers by the Turbine Bypass System. The condensers are also used to condense the main steam bypassed to the condenser in the event of sudden load rejection by the turbine-generator or a turbine trip. In the event of generator load rejection, the condensers condense 40 percent of full load main steam flow from the Turbine Bypass System, and the power-operated relief valves will discharge the remaining main steam flow to atmosphere to effect safe reactor shutdown and to protect the Main Steam System from overpressure. If the main condensers are not available during normal unit shutdown, or sudden load rejection on turbine trip, the power-operated relief valves and the spring-loaded safety valves can discharge full main steam flow to the atmosphere and effect safe reactor shutdown. Non-availability of the main condensers considered here includes failure of the circulating water pumps to supply cooling water, or loss of condenser vacuum for any reason.

A leak in a condenser shell could allow condensate to drain out, but the pits located below the condenser are designed to hold more water than the condenser hotwell volume. During normal operation, a leak in a condenser shell permits air to enter the condenser until the pressure increases to approximately twenty inches Hg vacuum at which time the turbine trips. The prevention of flooding due to failure of water boxes or circulating water piping is discussed in Section 10.4.5 and Section 3.6.

During normal operation and shutdown, the main condensers will have no radioactive contaminants inventory. Radioactive contaminants can only be obtained through primary to secondary system leakage due to a steam generator tube leak. A discussion of the radiological aspects of primary to secondary leakage, including operating concentrations of radioactive contaminants is included in Chapter 11. There is no hydrogen buildup in the main condensers.

10.4.1.4 Tests and Inspections

The main condensers are tested in accordance with the Heat Exchanger Institute Standards for Steam Surface Condensers. Proper operation of the system after startup assures system integrity and further testing of components in continuous use is not necessary. Periodic visual inspections and preventative maintenance are conducted following normal industrial practice.

10.4.1.5 Instrumentation Application

The main condenser hotwells are equipped with level control devices for automatic control of system water makeup and rejection. On low water level in the hotwell, a control valve opens and condensate flows from the upper surge tank into the hotwell by gravity. On high water level in the hotwell, another control valve opens to pump condensate from the hotwell pump discharge to the upper surge tank. A low level hotwell water level alarm is provided in the Control Room. Local and remote indicating devices are provided for monitoring pressures and water levels in the condenser shells. All of the instrumentation for this system is operating instrumentation, and none is required for safe shutdown of the reactor.

10.4.2 Main Condenser Evacuation System

10.4.2.1 Design Bases

The Main Condenser Evacuation System is designed to remove noncondensable gases and inleaking air from the main and feedwater pump turbine condenser shells during plant startup, cooldown and normal operation. The system serves no safety related functions (Refer to Figure 10-22 through Figure 10-25, Main Vacuum and Condenser Steam Air Ejector System). The system is composed of two main vacuum pumps and six (three per unit) condenser steam air ejectors (CSAE's).

The two main vacuum pumps are designed to rapidly evacuate the shell side of the main and feedwater pump turbine condensers, the main and feedwater pump turbine casings, and the upper surge tanks during startup. Each vacuum pump is designed to remove 3125 SCFM of air with suction conditions of 20 in. Hg vacuum and 80°F. These two pumps serve both units.

There are three CSAE's per unit, each one normally handling one of the three condenser shells. However, flow from a condenser shell can be transferred to a spare jet on one of the two remaining ejectors if a CSAE must be isolated for maintenance. Each CSAE is designed to remove 288 lb/hr (total air-vapor mixture) at 1.0 in. Hg absolute when supplied with 1300 lb/hr of steam at 110 psig, 345°F.

10.4.2.2 System Description

The Main Condenser Evacuation System consists of two full capacity main vacuum pumps and six (three per unit) condenser steam air ejectors and associated piping and valves. During startup operations, the main vacuum pumps are started first, bringing the condenser pressure down to approximately 20 in. Hg vacuum, at which time the condenser steam air ejectors lower the pressure to the design point. Normal operation requires the use of the CSAE's only.

Each CSAE draws the noncondensable gases and water vapor mixture from a condenser shell to the first air ejector stage. The mixture then flows to the intercondenser where it is cooled to condense and remove the water vapor and motive steam. The second air ejector stage draws the uncondensed portion of the cooled mixture from the intercondenser and compresses it further. The compressed mixture then passes through the aftercondenser where it is cooled and more water vapor and motive steam are condensed. The condensed water vapor and motive steam from the intercondenser and aftercondenser drain to the main condenser and condensate storage tank, respectively, while the remaining noncondensable gases and water vapor are released to the atmosphere through the unit vent.

10.4.2.3 Safety Evaluation

The Main Condenser Evacuation System is not assigned a safety class as it serves no plant safety function. It can be used during reactor cooldown or following a turbine-generator or reactor trip when main steam is bypassed to the condenser; but it is not necessary to have the condenser available, as discussed in Section 10.4.1, to have a safe reactor shutdown under these conditions.

The non-condensable gases and vapor mixture discharged to the atmosphere from the Main Condenser Evacuation System are not normally radioactive; however, in the event of primary to secondary system leakage due to a steam generator tube leak, it is possible for the mixture discharged to become radioactive. A full discussion of the radiological aspects of a primary to secondary leakage including radioactive discharge rates under postulated design conditions is discussed in Chapter 11 and Chapter 15. A radiation monitor on the CSAE discharge and another radiation monitor on the unit vent monitors the CSAE discharge for possible radioactivity.

10.4.2.4 Tests and Inspections

Proper operation of the Main Condenser Evacuation System is verified during unit startup, and is subject to periodic inspections after startup by plant operating personnel. System performance indicates proper functioning of the system and any system malfunction is corrected by appropriate means when necessary.

10.4.2.5 Instrumentation Applications

A radiation monitor (1EMF 33) is provided in the exhaust line from the CSAE's with OAC indication recorder, and alarm located in the Control Room. Local indicating devices for pressure, temperature, and flow are provided as required for monitoring system operation. All the instrumentation for this system is operating instrumentation and none is required for safe shutdown of the reactor.

10.4.3 Turbine Gland Sealing System

10.4.3.1 Design Basis

The Turbine Gland Sealing System (TGSS) is designed to seal the annular openings around the rotor shafts of the H.P. and L.P. main turbines and the main feedwater pump turbines where they emerge from the shell casings. (Refer to Main Turbine Leakoff and Steam Seal System, Figure 10-26, and FDW Pump Turbine Steam Seal System, Figure 10-27.) All seals for the L.P. main turbines and the exhaust end seals for the main feedwater pump turbines are designed to prevent the leakage of atmospheric air into the turbines since these turbine exhausts are subatmospheric at all loads. All seals for the H.P. main turbine and the steam inlet end seals for the main feedwater pump turbine are designed to prevent the leakage of steam from the turbines to atmosphere as well as to prevent atmospheric air in leakage since the H.P. turbine exhaust pressure and the main feedwater pump turbine steam inlet end pressure vary from below atmospheric to above atmospheric as these turbines progress from startup to normal operation. The TGSS is designed to supply the steam required to seal the turbines with 1.5 times the normal seal clearances.

10.4.3.2 System Description

Sealing steam is supplied from the auxiliary steam system during normal operation and for initial startup (see Figure 10-26). An option to supply steam from main steam is also available. Steam from either source is throttled by a fail open control valve which supplies steam to the low pressure turbine glands, the high pressure turbine glands, and the main feedwater pump turbine glands.

The steam to the low pressure turbine glands is further throttled by individual fail open valves at all loads. During low load operation only, the steam to the high pressure turbine glands is further throttled by a fail open regulating valve. In addition, the low pressure turbine glands receive steam from the governor valve leakoffs and the high pressure turbine glands receive steam from the throttle valve leakoffs. At higher loads, the backseating feature of the throttle valves terminates steam flow to the high pressure turbine glands. Also at higher loads, the high pressure turbine glands no longer require a supply of sealing steam and gland pressure is maintained by a fail closed spillover control valve which discharges excess steam to the main condenser.

The steam to both feedwater pump turbine glands is further throttled by a fail open regulating valve.

Steam and air leakoff from the high and low pressure turbines and both feedwater pump turbines drains to the gland seal condenser where the air is exhausted to the unit vent and the steam is condensed and returned to the condensate storage tank. Separate radiation monitoring of the discharge air is not provided since the condenser air ejector discharge is continuously monitored to detect any activity.

The TGSS is capable of sealing the turbine using auxiliary and main steam pressure from 125 psia to 1107 psia. The TGSS can be used during reactor cooldown following a turbine generator or reactor trip as well as during a normal start-up or shutdown.

10.4.3.3 Safety Evaluation

The Turbine Gland Sealing System serves no safety function and separate radiation monitoring is not provided since the discharge is continuously monitored to detect any activity. The TGSS valves are arranged for fail safe operation to protect the turbine. The steam seal header pressure, displayed in the Control Room, indicates any steam malfunction. Should the main supply regulating valve fail open, a relief valve and a rupture disc are provided to limit the header pressure to a safe level. A motor operated bypass valve is provided to correct this situation. Should the individual regulating valves to the low pressure and high pressure glands fail open, the pressure increases to a safe level which does not cause steam leakage to the atmosphere. Manual bypass valves are provided to correct this situation. Should the high pressure gland spillover valve fail close, a relief valve is provided to limit the pressure to a safe level. A motor operated bypass valve is provided to correct this situation. The TGSS continues to operate with the gland seal condenser inoperative because vacuum on the steam side is maintained by the centrifugal blower.

10.4.3.4 Tests and Inspections

Proper operation of the Turbine Gland Sealing System is verified during unit startup. Normal operating system performance monitoring will detect any deterioration in the performance of system components and will be corrected by appropriate means as necessary.

10.4.3.5 Instrumentation Application

The steam seal header pressure and pressure alarm are displayed in the Control Room. All of the instrumentation for this system is operating instrumentation, and none is required for safe shutdown of the reactor.

10.4.4 Turbine Bypass System

10.4.4.1 Design Bases

The Turbine Bypass System is designed to provide an artificial Reactor Coolant System load by providing the following steam dump capabilities:

1. 100 percent full load steam dump to atmosphere via main steam safety valves.
2. 40 percent full load steam dump to condenser via pressure reducing control valves.

3. Deleted per 2003 update.
4. 10 percent full load steam dump atmosphere via four (one per main steam line) power operated relief valve.

10.4.4.2 System Description

The main steam safety valves are designed in accordance with ASME Boiler and Pressure Vessel Code, Section III, Class 2, to relieve 100 percent full load steam flow to assure the integrity of the Steam and Power Conversion System under all conditions. These Safety Class 2 valves are located upstream of the main steam isolation valves. (See Figure 10-11 and Table 10-2. Refer to Table 10-4 for proper valve identification numbers.)

The power operated relief valves located upstream of the main steam isolation valves are set at a lower pressure than the spring loaded safety valves and are designed to vent a minimum of ten percent full load steam flow to the atmosphere for controlled cooldown during blackout conditions.

The bypass system to the condenser is designed to bypass 40 percent of full load steam flow from the main steam header directly to the condenser using a total of nine pressure reducing valves, three per condenser shell. Steam traps and local strainers are provided in each bypass line. (See Figure 10-17.) This bypass to the condenser is used during normal plant startup and shutdown operation. The 40 percent condenser system is not required to serve any safety function.

Deleted paragraph(s) per 2003 update.

10.4.4.3 Safety Evaluation

Full load steam flow turbine bypass to atmosphere is assured by the steam generator safety valves in the event of the loss of all normal heat sinks. Adequate condensate storage facilities provide steam generator feedwater flow under this condition. (Refer to Section 10.4.7,) The 40 percent steam flow bypass to the condenser permits a 50 percent turbine generator load rejection without a reactor trip or venting steam to atmosphere. The 40 percent bypass capability to the condenser permits a 50% load rejection without lifting the steam generator safety valves or tripping the reactor. See Table 10-4 for failure mode and effects analysis of the control system and valves of the Turbine Bypass System.

10.4.4.4 Tests and Inspections

Proper operation of the power operated atmospheric relief valves, and steam bypass to condenser valves is verified prior to and/or during startup. A dynamic test of the steam dump control system is performed during the startup sequence. Main steam line safety valve setpoints are established using a hydrostatic test set during hot functional testing, in accordance with manufacturer's instructions.

Deleted paragraph(s) per 2003 update.

10.4.4.5 Instrumentation Application

The Turbine Bypass System, during normal operating transients, is automatically regulated by the Ovation PCS to maintain the desired reactor coolant temperature. The controls are subdivided into a load rejection controller and a turbine trip controller, each of which sequentially modulates nine individual steam dump valves to gradually admit steam into the condenser. Following a reactor trip, the operator places the turbine bypass to the condenser system in the main steam pressure control mode for a more precise control capability during the plant shutdown. The steam pressure mode is also used for start-up operation before turbine connection to the grid to provide for Reactor Coolant System (RCS) average temperature control. The control sequence for the Turbine Bypass System is arranged for preferential operation of the bypass to the condenser to conserve condensate. Interlocks are provided in the condenser steam dump control logic to prevent operation when the condenser is not functional due to C9 interlock (a loss of circulating water pumps, or a loss of condenser vacuum (setpoint 10 in. Hg Abs)). RCS average temperature below the low-low T_{AVG} setpoint (P-12), also blocks the operation of the steam bypass valves to the condenser. For each train, a three-position switch is provided on the control board near the steam dump mode control for manual bypass of the low-low T_{AVG} temperature interlock. The bypass applies only to the condenser dump valves designated as cooldown condenser dump valves. The steam dump valves to the condenser are spring loaded to fail closed on loss of signal. All of the controls for this system are considered operating instrumentation and none is required for safe shutdown of the reactor.

10.4.5 Condenser Circulating Water System

10.4.5.1 Design Bases

The Condenser Circulating Water System is designed to use water from Lake Norman to remove rejected heat from the main and feedwater pump turbine condensers and other selected plant heat exchangers. It also serves as the normal supply for the Conventional Low Pressure Service Water System and the Fire Protection System jockey pumps and a secondary supply for the Nuclear Service Water System. Each of the eight condenser circulating water pumps (four per unit) is designed to supply 254,000 GPM at 23 feet TDH. The Condenser Circulating Water System is shown schematically in Figure 10-28.

The Low Level Intake Cooling Water System is designed to take cool water from the lower levels of Lake Norman and mix it with the warmer water at the condenser circulating water intake structure during times of high lake water temperature. The Containment Ventilation Cooling Water System and the Nuclear Service Water System can also be supplied with water from the Low Level Intake Cooling Water System. The low level intake pumps are each designed to supply 150,000 GPM at 10 feet TDH. Originally, the Low Level Intake Cooling Water System consisted of three low level intake pumps per unit. However, Unit 2 low level intake pumps have been abandoned in place. See Figure 10-36 for the plan and elevation sections of the low level pump structure.

As part of the FLEX mitigation strategy in response to NRC Order EA-12-049, the RC system is credited as a suction source for the Turbine Driven Auxiliary Feedwater Pump in the event that the condensate grade suction source is lost as a result of a postulated beyond design basis event.

10.4.5.2 System Description

Four (per unit) main condenser circulating water pumps, mounted on the intake structure, discharge into four pipes. These pipes then combine into two pipes and finally into one before splitting into three pipes and entering the Turbine Building. Each of these three divides into two smaller pipes before entering the condenser water boxes. On the outlet side of each condenser water box these two pipes combine to form one larger pipe, and discharge CCW into the discharge canal. See Figure 10-28. A crossover supply header placed before the condenser waterbox inlet supplies water to the following:

1. Feedwater pump turbine condenser (See Figure 10-21).

2. Condensate coolers.
3. Recirculated cooling water coolers.
4. Conventional low pressure service water pumps.
5. Fire Protection System jockey pumps.
6. Nuclear Service Water System pumps.

A crossover return, located on the outlet of the condenser returns water to the CCW discharge piping. The condensers are equipped with a mechanical system for cleaning the interior of condenser tubes to prevent the fouling of condenser heat transfer surfaces. Cleaning of these tubes is necessary to avoid a reduction of thermal efficiency and a corresponding increase in waste heat rejection to the cooling water. The mechanical cleaning system injects sponge rubber balls into the condenser inlet water boxes where they disperse and flow with the water through the condenser tubes to achieve a scrubbing of the tube inner surfaces. The sponge balls are collected by a strainer in the condenser discharge water pipe and pumped back for reinjection into the inlet water boxes. This method of cleaning condenser tubes does not use any chemical treatment of the lake water.

The Level Intake (LLI) structure is part of Cowans Ford Dam with the inlet approximately 100 feet beneath Lake Norman full pond elevation. Covering the inlet is a macrofouling barrier comprised of 3/4" x 3/4" stainless steel mesh panels which are inspected periodically. The LLI structure feeds three CCW LLI pipes which supply water to the following:

Pipe from Cowans Ford Dam intake gate A - Unit 1 A and B LLI pumps.

Pipe from Cowans Ford Dam intake gate B - Unit 1 C LLI pump.

Pipe from Cowans Ford Dam intake gate C - Normal source of water for the Nuclear Service Water System and the Containment Ventilation Cooling Water System.

Pipes from Cowans Ford Dam intake gates B and C are also aligned to the Unit 2 LLI pumps which have been abandoned in place. The LLI pumps receive cool water from the lower levels of Lake Norman. The pump discharge enters the Unit 1 side of the condenser circulating water pump structure, and supplies cool water to mix with the warmer water through a pipe ahead of each condenser circulating water pump. The LLI pumps are operated during specific periods during late summer and typically are not operated when fish are concentrated in the vicinity of the LLI. Fish population behavior in the vicinity of the LLI is monitored periodically each summer.

Lake Norman water is monitored periodically for consistency of water chemistry and it is the normal common source for the Condenser Circulating Water (RC) and Nuclear Service Water (RN) systems. Therefore, the RC system water chemistry is the same as that listed in Table 9-13.

10.4.5.3 Safety Evaluation

The Condenser Circulating Water System is designed to operate under full pond and maximum drawdown conditions of Lake Norman. The effects of low water level are addressed in Section 2.4.11.5, and dependability requirements are addressed in Section 2.4.11.6. It is adequately sized to remove the predetermined amount of latent and sensible heat from the steam in the condenser plus the heat from other loads. The condenser is designed to operate with one water box out of service thus enabling maintenance personnel access to the water box while the unit remains operational. The CCW System serves no safety function, and therefore, is not assigned any safety class.

The Condenser Circulating Water System is normally used to supply cooling water to the main condenser to remove residual heat from the Reactor Coolant System during the initial cooling period of unit shutdown when main steam is bypassed to the condenser. However, if the Condenser Circulating Water System fails to supply cooling water due to a failure of the condenser circulating water pumps or piping, the main steam cannot be condensed in the main condenser. This is considered a condenser failure, and safe shutdown of the reactor in such an event is discussed in Section 10.4.1.

A failure in the Condenser Circulating Water System or the Condensate System large enough to cause flooding will be detected by high level alarms in the turbine room sumps and the condenser pits. These high level alarms will alert the operator to check other Control Room instrumentation such as condensate flow and condenser differential pressure to see which system has failed. The control room instrumentation allows the operator to take action immediately on a major failure to isolate the faulty piece of equipment or shut the system down completely.

Flooding of the Turbine Building from failure of the condenser expansion joint or a failure of the Circulating Water System is, at best, a remote possibility. Even though these failures are considered unlikely, a failure of the expansion joint at the condenser connection to the cooling water pipe is considered the more probable and is therefore considered in design. A complete rupture of this joint would result in a 61 cfs leak into the Turbine Building basement. The previous volume calculation was based on an expansion joint with a four inch gap between pipe ends when a complete rupture occurs. The expansion joint was purchased with less clearance (1 1/8 in. gap) to minimize the rubber expansion joint failure and the leak volume was recomputed to reflect service conditions. The volume of sumps and pits below the Turbine Building basement level (El. 739) is 79,253 cubic feet for Unit 1 and 83,812 cubic feet for Unit 2, and the total volume above basement level is 133,211 cubic feet per vertical foot for both units and the Service Building combined. Unit 1 Turbine Building basement (54,139 cubic feet per vertical foot) is isolated from the Service Building and Unit 2 Turbine Building basements (24,882 cubic feet per vertical foot for the Service Building and 54,190 cubic feet per vertical foot for Unit 2) by a fire wall. Flooding calculations are therefore based on the Unit 1 Turbine Building basement. A rupture in the expansion joint would fill the pits below the basement level to El. 739 in 21.7 minutes and at a rate of 0.068 feet per minute above El. 739. To contain this flood water in the Turbine Building basement, either water tight doors or curbs 1.25 feet high are provided at all openings to the Auxiliary Building. This curbing provides 40.2 minutes of storage in the Unit 1 Turbine Building basement and allows time for action to be taken to control the flooding. The maximum flood elevation in the Turbine Building basement will be less than El. 740.25 and no penetrations or openings are located below this level. Therefore, no safety related equipment in the Auxiliary Building will be affected by this potential flood level.

Flooding of the Turbine Building from a failure of the Auxiliary Feedwater Storage Tank or associated piping is a remote possibility. A complete failure of the tank or piping could release 300,000 gallons (40,000 cubic feet) of water into the Turbine Building. The water would flow through penetrations in the mezzanine floor or stairwells and migrate to the Turbine Buildings sumps. The smallest volume of the sumps and pits below the Turbine Building basement level (El. 739) is 79,253 cubic feet. Since the volume of water in the tank is less than the sump volume below El. 739, the sumps would contain this volume.

A condenser hot well failure results in the release of 170,000 gallons (22,727 c. ft.) of water into the Turbine Building. The sump capacity below El. 739 greatly exceeds this volume and would easily contain this water.

Flooding due to other pressurized components can be prevented by closing the Condenser Circulating Water System crossover valves between the two Units and by closing the Nuclear Service Water System valves which isolate the containment ventilation cooling water pumps from the low level intake pipe.

All major isolation valves in the Condenser Circulating Water System are electric motor operated and are capable of closing in approximately 60 seconds. The Condenser Circulating Water System is designed to withstand any pressure peaks due to a valve closure or maximum allowable pump head.

10.4.5.4 Tests and Inspections

A shop test was performed on a model of the Condenser Circulating Water Pumps and the performance was found to be satisfactory. The Condenser Circulating Water System and Low Level Intake Cooling Water System are preoperationally tested to demonstrate proper operation of the system pumps, valves, interlocks, and controls. The capability of each system to adequately supply cooling water to the required components and systems is also verified. Level sensors and associated alarms intended to detect internal flooding are calibrated and checked.

Both systems are subject to periodic inspection by station operating personnel. Normal operating system performance monitoring will detect deterioration in the performance of system components and will be corrected by appropriate means as necessary.

10.4.5.5 Instrumentation Application

Condenser Circulating Water System valve interlocks are as follows:

1. Respective pump discharge valves must be closed before the individual pumps can be started. This is to prevent the pump motors from being energized during reverse flow. Pump discharge valves are also interlocked with their respective pumps so that the valve opening and the pump starting can be initiated simultaneously. The discharge valve should be fully open within 30 seconds after starting a pump.
2. The respective valves on the inlet to the condenser water box sections are interlocked with the corresponding valve on the outlet section so that the inlet valve is always closed before and opened after the corresponding valve on the outlet. This is to prevent over-pressurizing the condenser water boxes.

Low Level Intake Cooling Water System valve interlocks are as follows:

1. A low level pump cannot be started if its suction valve is closed.
2. Pump discharge valves are interlocked with their respective pumps so that, the pump starts 10 seconds after the valve begins to open, and, the pump cannot be started unless the valve is closed. The valve should be fully open within 30 seconds after starting a pump.

Local indicating devices for pressure, temperature and flow are provided as required for monitoring system operation. All of the instrumentation for this system is operating instrumentation, and none is required for safe shut-down of the reactor.

10.4.6 Condensate Cleanup System

See Sections 10.4.7 and 10.4.8.

10.4.7 Condensate and Feedwater System

10.4.7.1 Design Bases

The Condensate and Feedwater System is designed to return condensate from the condenser hotwells through the condensate polishing demineralizer and drains from the regenerative feedwater heating cycle (See Section 10.2) to the steam generators while maintaining water inventories throughout the cycle. The Condensate and Feedwater System is made up of the following subsystems:

1. Condensate System (See Figure 10-37, Figure 10-38, Figure 10-39, Figure 10-40, Figure 10-41, Figure 10-42, Figure 10-43, and Figure 10-44)
2. Feedwater System (See Figures 10-45 and 10-49)

Safety classifications of the Condensate and Feedwater Systems are shown in Table 3-4.

10.4.7.2 System Description

Three 50 percent capacity motor-driven hotwell pumps deliver condensate from the hotwell through the condensate polishing demineralizers, the condensate coolers, (if required to reduce the condensate temperature to meet the design temperature required by the generator stator water coolers and hydrogen coolers), the generator stator water cooler and hydrogen coolers, the condenser steam air ejectors and the gland steam condenser, SG Blowdown Regenerative Heat Exchangers, and two stages of low pressure feedwater heaters (“G” and “F”) to the suction of the condensate booster pumps. Each stage of regenerative feedwater heating consists of three parallel heater trains. The “G” and “F” heaters are located one each in each condenser shell. The “G” heater drain tank pumps discharge re-enters the condensate between “G” and “F” heater trains.

Three 50 percent motor-driven condensate booster pumps deliver condensate through three stages of feedwater heating to the suction of the main feedwater pumps. Adequate condensate makeup and storage facilities are provided (see Table 10-1). The condenser hotwells with normal operating water level have a condensate storage approximately equal to eight minutes full load hotwell pump capacity. Four minutes of additional storage is provided by the upper surge tanks. An additional capacity of up to 30,000 gallons is provided by the condensate storage tank.

Makeup for the Condensate and Feedwater System is provided from the upper surge tanks to the condenser hotwell to maintain proper hotwell operating water level.

Makeup condensate is supplied to the upper surge tanks as required by the Demineralized Water System. (Refer to Section 9.2.3).

Two 50 percent capacity dual admission type steam turbine driven main feedwater pumps are provided to deliver feedwater through two stages of high pressure feedwater heaters to a single feedwater distribution header where feedwater flow is divided into four single lines to the steam generators. Individual steam generator feedwater line check valves close with flow reversal.

Individual steam generator water level is controlled by a three element feedwater control system using feedwater flow, steam generator water level, and steam flow as control parameters using control valves CF17AB, CF20AB, CF23AB, and CF32AB. These valves and the feedwater control valve bypass valves CF104AB, CF105AB, CF106AB and CF107AB fail closed on a loss of control air pressure. These control valves, feedwater containment isolation valves CF26AB, CF28AB, CF30AB, and CF35AB, feedwater to auxiliary feedwater nozzle isolation valves CF126B, CF127B, CF128B and CF129B close on a feedwater isolation signal. The feedwater to auxiliary feedwater isolation valves are normally open only during maintenance of the CF System on the feedwater valves or the piping downstream of the feedwater isolation valves. CF26AB, CF28AB, CF30AB, CF35AB, are supplied with an assured Nitrogen supply for pneumatic operation (motive force). The Unit 1 valve control panels are supplied with an assured Instrument Air supply for pilot control, whereas the Unit 2 valve control panels use the assured Nitrogen supply for pilot control.

As part of the FLEX mitigation strategy in response to NRC Order EA-12-049, the ability to maintain core cooling is required following a postulated beyond design basis event. Feedwater piping connections are provided for this capability in the Exterior and Interior Doghouses.

Corrosion protection for the Condensate and Feedwater Systems is provided through chemical addition. Hydrazine or other approved reducing agents are used to scavenge oxygen and maintain desirable reducing conditions. During operation, thermal decomposition also provides ammonia which helps to elevate the pH into the desirable alkaline range. Additional ammonia may be added through direct injection, if necessary. pH control from ammonia alone is inadequate for overall system protection since its high relative volatility results in preferential partitioning to the steam phase. Areas of particular concern include moisture separators and high pressure steam extractions. In order to provide complete system protection, additional approved akaline amines are added which partition such that the desired elevated pH is maintained in both the steam and water phases

Precautions are taken to protect plant personnel from possible adverse effects of contact with the chemical additives. Appropriate personal protective equipment is used, and emergency showers and eyewash facilities are located in the vicinity of all storage locations for these chemicals.

The maximum inventory for ammonium hydroxide and hydrazine is the equivalent weight of functional product contained within 275 gallons of a 30% by weight solution of ammonium hydroxide and 1300 gallons of a 54.4% by weight solution of hydrazine.

Critical secondary water chemistry parameters are monitored and controlled to inhibit secondary side steam generator corrosion and associated tube degradation. This monitoring program is described in detail in the Station Chemistry Manual and includes the following:

1. Identification of a sampling schedule for the critical parameters and control points for these parameters;
2. Identification of methods used to measure the value of the critical parameters;
3. Identification of process sampling points;
4. Methods for recording and management of data;
5. Methods for defining corrective actions for off-control chemistry conditions;
6. Identification of (a) the authority responsible for the interpretation of the data and (b) the sequence and timing of administrative events required to initiate corrective action.

The secondary chemistry program is primarily derived from vendor recommendations and the current revision of the Electric Power Research Institute (EPRI) PWR Secondary Water Chemistry Guidelines. Other EPRI documents are utilized as appropriate. The applicable EPRI documents represent a compilation of industry-wide experience on issues regarding the protection of secondary side components, including steam generators. Guidelines and recommendations are evaluated and optimized for specific plant design to ensure a comprehensive program is maintained. Changes to the secondary chemistry program are evaluated for safety-related issues where appropriate and along with any exceptions to vendor and industry recommendations, are technically justified and approved by station management prior to implementation.

To assist in maintaining optimum water chemistry, condensate and steam generator purification equipment is provided. The condensate polishing system consists of four (4) filter/demineralizers arranged in a parallel flowpath. The cells may be pre-coated with powdered ion exchange resin which serves the dual purpose of providing filtration as well as short-termed demineralization. The vessels require replenishment on a frequency determined by pressure drop and/or system chemistry. A complete backwash cycle generates approximately 5000 gallons (or 668 cubic feet) of waste containing no more than 20 cubic feet of spent resin. The spent coats are backwashed to the backwash tank which has a holding capacity of three cell backwashes. As a result of primary to secondary leakage, waste resin can become contaminated. Spent resins are sampled and analyzed prior to disposal. Non-contaminated waste may be pumped to the Conventional Waste Water Treatment System. Contaminated resin (as described by 10CFR 20 limits) are decanted using the backwash decant system and the solids are held for eventual disposal as a radioactive waste.

Due to the concentrating effects within a recirculating steam generator it is desirable to allow direct cleanup of blowdown water from the steam generators, without prior mixing with the higher quality condensate. The Steam Generator Blowdown System described in Section 10.4.8 was provided to perform some chemistry and activity cleanup with a design basis limit of 45000 #/hr blowdown flowrate. Because this original system provided much less than desired cleanup, a second blowdown system was installed later and is described in more detail in Section 10.4.8.

Design data for all feedwater heaters, hotwell pumps, condensate booster pumps, steam generator feedwater pumps and the condensate polishing demineralizer is provided in Table 10-5, Table 10-6, Table 10-7, Table 10-8 and Table 10-14 respectively.

10.4.7.3 Safety Evaluation

The Condensate and Feedwater System is designed to automatically maintain the steam generator water level during steady state and transient operating conditions. Uniform feedwater temperature, pressure and flow are maintained to all steam generators at all loads. Sufficient condensate storage capacity is provided to accommodate the mass transfer of fluid due to the expansion and contractions arising from thermal and pressure transients in the steam generator, and Condensate and Feedwater System. The condensate storage capacity compensates for loss of fluid during unit cooldown under atmospheric steam turbine bypass conditions.

A Condensate and Feedwater System component failure analysis is presented in Table 10-11.

An evaluation of the effects of a feedwater system line break on the reactor coolant system is provided in Section 15.2.8.

Secondary system flow instability such as steam water slugging is not expected to occur in the main feedwater lines during anticipated operational occurrences. One of the conditions necessary to produce a water hammer event is for the inlet nozzle to the steam generator to become uncovered thus allowing steam to enter the feedwater line. McGuire Nuclear Station utilizes the following provisions to minimize the potential for this type of condensation induced water-hammer, in the Feedwater System:

1. Steam Generator feedring and gooseneck design for internal piping.
2. An all welded internal piping design.
3. Schedule 80 feedwater piping system.
4. The Feedwater isolation valve opening time is very slow.

5. Top discharing hairpin bend J-tubes coming off of the feedring on the Steam Generator.
6. Piping around the feedwater nozzle is routed to prevent steam voids.

These design features preclude the possibility of a destructive water-hammer event; however a structural analysis for water-hammer forces has been included in the ASME code compliance piping qualifications.

A minimum stroke time of 4.5 seconds is needed to insure a water-hammer event does not occur when closing the main feedwater isolation valves. A water-hammer analysis was performed in a calculation for the main feedwater system between the main feedwater header and the main feedwater isolation valves. The fast closing time of 4.5 seconds was supplied from the vendor as input to the calculation. A conservative value of 4.0 seconds was used in this calculation to determine the water-hammer forces on the system. The conclusions from the water-hammer force calculation were used as input into the general Feedwater Piping Analysis calculation on both units. Water-hammer analysis forces with a 4.0 second closing time of the main feedwater isolation valves were analyzed in the Feedwater Piping Analysis General calculation. All loads and stresses are acceptable in these calculations based on the assumed inputs.

10.4.7.4 Tests and Inspections

The Feedwater and Condensate System is initially tested to verify proper operation of system pumps, valves and associated interlocks. The capability of the system to provide water to the steam generators is also verified. A dynamic test of the feedwater control system is performed during the startup sequence.

System performance monitoring detects any deterioration of system components and appropriate corrective action is taken as required.

10.4.7.5 Instrumentation Application

Sufficient instrumentation is provided to monitor and control automatically or manually the Condensate and Feedwater System under all operating conditions. Minimum flow protection systems are provided for the hotwell, condensate booster, and main feedwater pumps. The steam generator water level is maintained by a three element feedwater control system using feedwater and main steam flow and steam generator water level as control parameters. (See Figure 10-37, Figure 10-38, Figure 10-39, Figure 10-40, Figure 10-41, Figure 10-42, Figure 10-43, Figure 10-44, and Figure 10-45.)

Controls and indicators are provided in the control room for the hotwell, condensate booster, heater drain and main feedwater pumps, generator full load rejection bypass control valve, hotwell makeup and overflow valves and the feedwater control valve in each steam generator feedwater line.

The condensate polishing demineralizer has a bypass arrangement which consists of two split range control valves in parallel. The first valve starts opening when the total pressure drop across the condensate polisher and the inlet and outlet piping exceeds 40 psid. The bypass is capable of handling full hotwell pump flow.

The feedwater pump seal injection system automatically supplies the main feedwater pump seals at a pressure higher than feedwater suction pressure. Flow elements monitor the seal water flow for abnormal conditions.

The main feedwater pump turbine speed control system receives input from the feedwater and steam header pressure transmitters as well as the control room feed pump manual - auto stations.

Feedwater pressure, temperature and flow to each steam generator is used by the computer to calculate the thermal output of the plant. Feedwater flow measurement in each steam generator feed line is supplied to the reactor protection system. In addition to the ASME flow nozzle instruments, ultrasonic flow meters are installed to provide more precise feedwater measurement. These ultrasonic flowmeters measure both feedwater flow and temperature, and provide input to the core power calorimetric calculation.

10.4.8 Steam Generator Blowdown System

Note: The steam generator blowdown recycle heat exchanger and demineralizer flow path is no longer utilized to remove radioactive contaminants and other dissolved solids. This flow path has been permanently isolated and abandoned in-place per NSM MG-12430 and MG-22430.

10.4.8.1 Design Bases

The Steam Generator Blowdown System is designed to:

1. Provide about 38,000 lbm/hr of continuous blowdown of the secondary side of the drum-type steam generators under controlled, stabilized operating conditions.
2. Process steam generator blowdown for reuse as condensate/feedwater makeup.
3. Provide a normal path for the steam generator blowdown fluid to the inlet of the condensate polishing demineralizers or regenerative heat exchanger/demineralizer for purification and reuse in the condensate cycle.
4. Provide a continuous sample for measurement of the radioactivity of the steam generator blowdown.
5. Isolate the blowdown lines leaving the Containment on a Containment isolation signal.

10.4.8.2 System Description

10.4.8.2.1 General Description

A Steam Generator Blowdown System, as shown on Figure 10-51, is provided for each unit. Steam generator blowdown is continuously performed to maintain acceptable steam generator water chemistry. This flow is then recycled through the condensate polishing demineralizer or the regenerative demineralizer to be returned to the Condensate System.

The blowdown flow is recycled through the condensate polishing demineralizers or the regenerative demineralizer by first allowing the blowdown to flash in a blowoff tank. The blowoff tank is vented to "D" heater extraction allowing that portion of the blowdown which flashes to steam to be recovered thus conserving 25 to 30 percent of the heat which is being lost with blowdown. At < 20 percent Unit load the vent path is to the condenser. The condensate which collects in the blowoff tank may be pumped into one of two different flow paths, the condensate polishing demineralizers or the regenerative demineralizer. The BB water is pumped into the condensate system prior to entering the condensate polishing demineralizers. This allows any dissolved or suspended solids to be removed. The BB water pumped to the regenerative demineralizer path enters the regenerative heat exchanger where it is cooled to a temperature less than 145°F. Condensate then passes through the prefilter and demineralizer, it then exits the demineralizer and enters the condenser. The blowoff tank condensate can be dumped to the condenser if the blowoff tank pumps are unavailable. If the blowoff tank water quality is unacceptable, the condensate can be manually dumped to the Conventional Waste Water Treatment System. The blowdown water is continuously monitored for activity by radiation monitor EMF34 in the Nuclear Sampling System. Detection of activity by this monitor will cause air operated valves BB123, 124, 125, and 126 to isolate, thus ceasing blowdown to the blowoff tank. The Nuclear Sampling System is then used to determine which steam generator or generators have a primary to secondary coolant leak. The blowdown for the steam generators which have no leak is then returned to the normal path discussed above.

Table 10-21 presents the Steam Generator Blowdown System component design data. The portion of the system inside the Containment utilized as Containment isolation is designed to Safety Class 2 criteria.

The remainder of the system in the Auxiliary and Turbine Building serve no safety function and is not assigned a safety class. System safety class requirements are presented in Table 3-4.

All steam generator blowdown system equipment is located in the Auxiliary Building or Turbine Buildings, hence it is designed to operate with the ambient temperatures incurred during normal operation and relative humidity up to 100 percent.

10.4.8.2.2 System Operation

10.4.8.2.2.1 Normal Operation

The blowdown path from steam generator “A” is selected for descriptive purposes. During normal operation, blowdown flow is discharged from each steam generator's two (2) blowdown nozzles and the connected drilled holes which are located along the tube free lane in the tube sheet. Both blowdown nozzles are 3 inch pipes which combine into a common 2 inch line to transport the flow from the steam generator.

A continuous sample of the blowdown is taken from the common 2 inch pipe and transported to the Nuclear Sampling System (See Figure 9-91) through valve BB17. Also, a steam generator upper shell sample is directed to the Nuclear Sampling System through valve 1NM495.

Downstream of the outside Containment isolation valve BB1B, the blowdown enters a 4 inch line to the blowdown blowoff tank located in the Turbine Building. This 4 inch path passes the manual flow control valve BB123 which also isolates flow upon signal from EMF34. This manual flow control valve is provided for each blowdown line so the blowdown rate for each steam generator may be selected as required by individual steam generator water chemistry. Upon crossing the manual control valve, the fluid flashes into the blowoff tank.

That portion which flashes to steam (approximately 25 percent) is vented to “D” feedwater heater extraction, thus the heat is recovered by heating condensate in “D” heaters and the water is recovered by the “D” heater drains. That portion which condenses in the blowoff tank (approximately 75 percent) is pumped to the condensate polishing demineralizer inlet header where dissolved and suspended solids are removed or the regenerative demineralizer. Each regenerative heat exchanger, prefilter and demineralizer is 100% capacity. The heat exchanger outlet temperatures are monitored and will alarm at 145°F and will initiate a BB pump trip at 160°F. Demineralizer D/P is also monitored and will provide an alarm on high D/P of 25 psid and on high-high will provide an alarm, pump trip signal and close valve BB 227. If the unit is not above 20 percent load, the blowoff tank may be vented to the condenser by opening the vent to condenser isolation BB100 and closing the vent to “D” heater extraction isolation, BB98. Also, if the blowoff tank reaches high level, BB100 opens and BB98 closes automatically to assure that water does not enter “D” heater extraction. During periods when the blowoff tank pumps are unavailable, the blowoff tank condensate level is maintained by dumping to the condenser through control valve BB89.

Detection of high radioactivity in the combined blowdown sample by EMF34 (See Section 9.3.2) causes the S/G BB control valves BB123, BB124, BB125 and BB126 to close thus terminating blowdown to the blowoff tank.

10.4.8.2.2.2 Operation with Steam Generator Tube Leakage Resulting in Blowdown High Radiation Levels

High radiation as detected by EMF34 causes blowdown to the blowoff tank to be terminated. After this has occurred the operator may determine the origin of the high radiation by monitoring each blowdown sample individually on the nuclear sample panel. Once the affected Steam Generator is identified, the blowdown from the unaffected Steam Generators can be re-established.

If the magnitude of the leak is below Technical Specification and Administrative limits, blowdown from the affected Steam Generator may be re-established. The BB System demineralizers would remove radioactive ions and maintain secondary water quality. Discharge from the BB demineralizers is monitored for compatibility with Secondary Side Water Chemistry.

If the magnitude of the leak exceeds Technical Specification or Administrative limits, Operators would follow the appropriate AP or EP procedures.

10.4.8.2.2.3 Deleted Per 2011 Update

10.4.8.3 Safety Evaluation

The Steam Generator Blowdown System is designed to operate manually and on a continuous basis as required to maintain acceptable steam generator secondary side water chemistry. The System serves no safety function. All blowdown lines which penetrate the Containment are isolated automatically upon Containment isolation signal. The portion of the system inside the Containment and the portion utilized as Containment isolation are designed in accordance with applicable safety class requirements.

The Steam Generator Blowdown System is designed to prohibit radioactive discharge to the environment from the blowdown liquid. During times of abnormally high primary-to-secondary leakage, blowdown is terminated by the radiation monitor. At this point the operator analyzes the situation and aligns the Steam Generator Blowdown System in the proper mode of operation.

10.4.8.4 Tests and Inspections

The Containment Isolation System was functionally tested under conditions of normal operation in accordance with the procedure outlined in Chapter 14 to ensure that all valves closed properly and that design leakage requirements were met.

The ability of the Steam Generator Blowdown System to maintain water chemistry within specifications is verified by the following design functions.

1. Specified flow paths and flow rates can be established.
2. The blowdown is reduced in temperature and pressure to an acceptable level.
3. System controls and interlocks function as designed.

10.4.8.5 Instrumentation Applications

The following controls and monitors are provided in the Steam Generator Blowdown System:

	Manual	Automatic	Controlled by:
Steam Generator Blowdown Flow Rate	X	X	Flow element
Steam Generator Blowdown Radiation Monitoring		X	High signal from monitor terminates pump operation and isolates system.
Steam Generator Blowdown Blowoff Tank Level		X	Level Control operating dump to condenser, pump discharge and pump min flow recirculation control valves.

10.4.9 Reheater, Moisture Separator and Feedwater Heater Drain Systems

10.4.9.1 Design Bases

The Reheater, Moisture Separator and Feedwater Heater Drain Systems are designed to return to the Condensate and Feedwater System all condensate drains from the following equipment:

1. Seven stages of high and low pressure feedwater heaters with three parallel heater trains per stage
2. Six moisture separators
3. Six first stage reheaters
4. Six second stage reheaters

10.4.9.2 System Description

The Reheater, Moisture Separator and Feedwater Heater Drain Systems are shown on Figures 10-54, through Figure 10-63. Condensate drains from the first stage reheaters into the first stage reheater drain tanks where the water level is maintained by regulating drain flow to the “B” feedwater heaters. Drains from the second stage reheaters drain into the second stage reheater drain tanks and then to the “A” feedwater heaters. The “A” feedwater heater drains cascade into the “B” feedwater heaters which drain into the “C” feedwater heater drain tanks. The moisture separators drain into the moisture separator drain tanks and then flow into the “C” feedwater drain tanks. The “C” feedwater heater shell condensate is also drained to the “C” feedwater heater drain tanks. Condensate drains collected in the “C” heater drain tanks are returned to the Condensate System between the “C” feedwater heaters and the main feedwater pump by the “C” heater drain pumps, (See Figure 10-43 page 1 of 2). The “C” heater drain pump design data is presented in Table 10-24.

Drains from the “D” feedwater heaters cascade into the “E” heaters which in turn cascade into the “F” heaters. Drains from the “F” and “G” feedwater heaters are collected in the “G” heater drain tanks and then returned to the Condensate System between the “G” and “F” heaters by the “G” heater drain tank pumps. The “G” heater drain pump design data is provided in Table 10-25.

Emergency drains to the condensers are provided on all moisture separators, reheater and heater drain tanks, and feedwater heaters to maintain proper water levels under all operating conditions.

10.4.9.3 Safety Evaluation

The Moisture Separator, Reheater, and Feedwater Heater Drain Systems are conservatively designed to maintain required equipment drain flow and return drains to the Condensate System under all normal and transient operating conditions. The Moisture Separator, Reheater and Feedwater Heater Drains System perform no Safety function.

10.4.9.4 Tests and Inspections

Moisture Separator, Reheater and Feedwater Heater Drain Systems components are initially placed in operation during unit startup as required for power operation. Operating performance monitoring determines any component performance deterioration and appropriate corrective action is taken as required.

10.4.9.5 Instrument Application

Proper drain tank and heater water levels are automatically maintained by normal and emergency drain regulating valves. Sufficient instrumentation is provided to monitor the state of the drains system and alarm any malfunction. The heater drain tank pumps are protected by automatic flow recirculation control systems.

All of the instrumentation for this system is operating instrumentation and none is required for safe shutdown of the reactor.

10.4.10 Auxiliary Feedwater System

10.4.10.1 Design Bases

The Auxiliary Feedwater System assures a feedwater supply to the steam generators for decay heat removal if the Condensate and Feedwater System is not available through loss of power or other malfunctions. Safety classifications of the Auxiliary Feedwater System shown in Table 3-4.

See Figure 10-47 for a summary flow diagram of the Auxiliary Feedwater System. Auxiliary Feedwater piping layout is depicted in Figure 10-50.

10.4.10.2 System Description

The AFS is provided with two motor driven pumps and one turbine driven pump. Each of the motor driven pumps supply two steam generators. The turbine driven pump supplies water to all four steam generators. The minimum system capability during normal operation of the AFW system required to bring the unit to and maintain it at safe shutdown is one AFW pump feeding two steam generators.

The motor driven pumps and the turbine driven pump suction supply is from the following sources in the order of their priority based on water quality:

Source	Alignment	Maximum Capacity
1. Auxiliary Feedwater Storage Tank	Normal Supply	300,000 gallons
2. Auxiliary Feedwater Condensate Storage Tanks	Normal Supply	85,000 gallons
3. Nuclear Service Water	Automatic Switchover on Low Suction Pressure	1.8 x 10^8 gallons

Each auxiliary feedwater pump discharge line is provided with an air operated control valve and a check valve downstream. The turbine and motor driven pump discharge lines to each individual steam generator join into a single line outside containment. These individual lines penetrate the Containment and enter each steam generator through the auxiliary feedwater nozzle. The auxiliary feedwater pump discharge lines to the auxiliary feedwater storage tank are provided for minimum flow and testing purposes. A separate discharge line for each pump through the Auxiliary Building AA wall into the Turbine Building basement provides an assured minimum recirculation flow path, in the event that the recirculation discharge line to the Auxiliary Feedwater Storage Tank is crimped during a tornado/seismic event. The Automatic Recirculation Valve (ARV) on the discharge of each pump modulates to ensure minimum flow requirements are satisfied. During pump testing, control valves CA20, CA27 and CA32 can be opened for full flow testing.

The diversity and redundancy provided in the present system design precludes the possibility that any single credible failure would prohibit the Auxiliary Feedwater System from performing its intended safety function. The system is normally aligned to receive water from the AFW storage tank and the AFW condensate storage tank. However, the Nuclear Service Water System is automatically aligned to provide a source of water if the normal source becomes unavailable. The failure of AC power or air supply does not cause loss of function for the AFS for the following reasons:

1. The turbine driven pump steam supply valve is designed to fail open for either loss of AC power or loss of air supply.
2. The auxiliary feedwater supply to the steam generators via the turbine driven pump is normally aligned such that no action is required under loss of AC power or loss of air conditions to assure feedwater supply.

10.4.10.2.1 Auxiliary Feedwater System Motor Driven Pumps

Power for the AFS motor driven pumps is normally provided by the station auxiliary power system. Each AFS motor driven pump is provided emergency power from one of the two unit emergency diesel generators. Motor driven pump A is supplied from diesel generator A and motor driven pump B is supplied from diesel generator B. The power supply train for each pump is physically separated from the other pump. This complete physical separation is followed throughout on the control and instrumentation systems for each AFS motor driven pump. Each AFS motor driven pump start circuit provides an automatic start signal to its respective Nuclear Service Water pump.

Auxiliary Feedwater System motor driven pump design data is presented in Table 10-9.

10.4.10.2.2 Auxiliary Feedwater System Turbine Driven Pump

Driving steam for the AFS turbine driven pump is provided from either of two steam generator main steam lines upstream of the main steam isolation valves and is discharged to the atmosphere. (See Figure 10-11). Each steam supply is provided with a piston operated valve that opens on a signal to start the turbine driven pump. Redundant control systems are provided to assure opening of each valve on a turbine driven pump start signal. A check valve is provided in each steam supply line to prevent flow reversal.

Auxiliary Feedwater System turbine driven pump design data is presented in Table 10-10.

10.4.10.2.3 Normal Unit Operation

The AFS is not required for normal unit operation and is normally aligned in standby readiness.

10.4.10.2.4 Unit Start-Up

During unit start-up, the AFS can be used under manual control to provide water flow to the steam generators until the steam generator feedwater flow requirements reach the design capability of the AFS. At this point the Main Feedwater System is used to provide the steam generator feedwater requirements. The AFS is taken out of service and placed in standby readiness.

10.4.10.2.5 Unit Shutdown

During unit shutdown, the AFS can be used under manual control to provide steam generator feedwater requirements when these cooldown requirements diminish to within the capability of the AFS. The AFS is removed from service when the reactor cooldown requirements are within the capability of the Residual Heat Removal System (See Section 5.5.7).

10.4.10.2.6 Unit Emergency Operation

The motor driven auxiliary feedwater pumps will start automatically and provide flow from the normal suction source within one minute on any one of the following conditions:

1. Two out of four low-low level alarms in any steam generator.
2. Loss of all main feedwater pumps.
3. Initiation of the safety injection signal.
4. Loss of off-site and station normal auxiliary power (blackout).

The turbine driven auxiliary feedwater pump will start automatically and provide flow from the normal suction source within one minute on any one of the following conditions:

1. Two out of four low-low level alarms in any two (2) steam generators.
2. Loss of offsite and station normal auxiliary power (blackout).

Solenoid valves are provided in the instrument air lines to the flow control valves operators to dump air thus allowing the control valves to fail open to the travel stop setting on an automatic start signal. These solenoids prevent interaction with non-qualified controls and realign the system if an automatic start signal is generated during a pump test.

As an emergency initiated cooldown progresses, control of the AFS is maintained manually either from the Control Room or locally at the pumps. The AFS will continue to function during the shutdown until the steam generator pressure reduces to 124 psia with a corresponding reactor coolant temperature and pressure of 350°F and 415 psia, respectively. At this point the Residual Heat Removal System (See Section 5.5.7) is placed in operation as the AFS is removed from service.

10.4.10.3 Safety Evaluation

The Auxiliary Feedwater System assures required feedwater flow to the steam generators to remove decay heat while maintaining steam generator water levels adequately to prevent undue thermal cycling of the steam generators.

Because the Auxiliary Feedwater System is the only source of makeup water to the steam generators for decay heat removal when the main feedwater system becomes inoperable, it has been designed with special considerations. The use of redundancy and diversity has been incorporated into the design of the AFS to ensure its capability to function.

AFS pump redundancy is provided by using two motor driven pumps and one turbine driven pump. The motor driven pumps are aligned to separate diesel power sources and the turbine is powered by steam from two of the main steam lines.

To monitor conditions which could lead to steam binding of the AFS pumps, temperature instrumentation is installed upstream of the auxiliary feedwater injection line check valves. These instrument loops provide indication and alarm in the control room of increased temperatures which indicate probable check valve leakage. This leakage could result in steam binding of auxiliary feedwater pumps.

The analyzed plant configuration for a Design Basis Accident (DBA) or a Design Event (DE), assuming a worst case single failure and loss of offsite power, is two AFW pumps feeding three steam generators. This configuration establishes the minimum AFW flow available when evaluating the event for safety analysis purposes. Travel stops are set on the steam generator flow control valves to maximize flow to the intact steam generators.

AFS pump suction diversity is provided by using several water sources and adequate valving for source change. All three AFS pumps are normally supplied from a common header which is normally aligned to the AFW storage tank and the AFW condensate storage tank. These sources are provided with motor operated valves with control room operation. The assured AFW pump suction is from the Nuclear Service Water System. The A motor driven AFW pump is aligned to the A NSWS supply header and the B motor driven AFW pump is aligned to the B NSWS supply header. The turbine driven AFW pump is aligned to both the A NSWS supply and B NSWS supply channels. Each source is provided with diesel aligned motor operated valves which open automatically on low suction pressure.

In support of the Standby Shutdown System (SSS), normally closed valves CA316 and CA317 can align the Condenser Circulating Water (CCW) system with the turbine-driven AFW pump, as described in section 9.5.1.3. For Unit 1 only, vent valves associated with this suction source assist in maintaining this source water solid, as described in section 9.5.1.3. Valves CA316 and CA317 remain closed until manually aligned for SSS support, thus preventing any interaction of this source with the assured suction sources. Valve CA162B will automatically open on a low turbine-driven AFW pump suction pressure, aligning the CCW system to the turbine-driven AFS pump. However, the automatic opening feature is not credited for SSS response. CA162B automatic opening feature is credited for postulated beyond design basis events described in NRC Order EA-12-049 only. Interaction of this source with the assured suction sources is prevented by actuation logic and the higher pressures provided by the assured suction sources. Check valve CA221 will maintain this flow path isolated unless the AFW storage tank and AFW condensate storage tanks are depleted/failed and the NSWS has failed.

AFS pump discharge piping diversity is provided by using separate lines to each steam generator from the motor driven AFS pumps as well as the turbine driven AFS pump. The discharge piping from each motor driven pump feeds two of the four steam generators. A crossover line with normally closed manual valves is provided between each motor driven AFS pump discharge. The discharge piping from the turbine driven AFS pump feeds all four steam generators. Each of these lines to the steam generators is provided with a check valve, a fail open air operated control valve, a diesel aligned motor operated isolation valve, and a locked open manual isolation valve.

The AFS is designed with suitable redundancy and diversity to preclude the possibility of a complete loss of function due to a single active or passive failure on any condition requiring the AFS to function. AFS postulated pipe rupture analysis is discussed in Section 3.6.1.

An Auxiliary Feedwater System component failure analysis is presented in Table 10-12.

Transients and accidents requiring the AFS to function are discussed in Chapter 15.

Duke Energy has reviewed the safety related portions of the Auxiliary Feedwater System with reference to the applicable portions of the seismic related Bulletins 79-02, 79-04, 79-07, 79-14, 80-11 and IE Information Notice 80-21. The review concludes that Auxiliary Feedwater System is adequately designed to withstand the Safe Shutdown Earthquake and has sufficient redundancy to perform its intended function (Reference 2).

Secondary system flow instability such as steam water slugging is not expected to occur in auxiliary feedwater lines during anticipated operational occurrences. One of the conditions necessary to produce a water hammer event is for the inlet nozzle to the steam generator to become uncovered thus allowing steam to enter the auxiliary feedwater line. McGuire Nuclear Station utilizes the following provisions to minimize the potential for this type of condensation induced water-hammer in the Auxiliary Feedwater System:

1. Piping around upper steam generator nozzle is routed to prevent steam voids.
2. Steam Generator programmed water level is above auxiliary feedwater nozzles during power operation.
3. System check valves will minimize backleakage.
4. Two check valves are installed in series to prevent backleakage.

Because design features preclude the possibility of a destructive water hammer, no analyses have been performed or test programs conducted regarding this occurrence.

Auxiliary Feedwater System Reliability Analysis

An evaluation of the McGuire auxiliary feedwater system was performed by Duke and Westinghouse. This evaluation consisted of the following items:

1. A simplified auxiliary feedwater system reliability analysis that used event-tree and fault-tree logic techniques to determine the potential for AFWS failure following a main feedwater transient, with particular emphasis on potential failures resulting from human errors, common causes, single point vulnerability, and test and maintenance outage;
2. A determination of the extent to which the McGuire auxiliary feedwater system meets each requirement in Standard Review Plan 10.4.9 and Branch Technical Position ASB-10-1; and
3. A determination of the design basis for the McGuire auxiliary feedwater system flow requirements and verification that these requirements are met.

This evaluation determined that no modifications to the McGuire auxiliary feedwater system were necessary. Results of this Reliability Analysis were documented in a letter to the NRC dated 08/13/1980.

Additional analyses of the reliability of the McGuire auxiliary feedwater system were performed at the request of the NRC. These analyses show that for the four additional cases analyzed, assuming credit for operator action or using more realistic assumptions, the reliability of the McGuire auxiliary feedwater system is in the "high" category. These reanalyses in conjunction with the previous analyses provide the basis for Duke's conclusion that the current design of this system is acceptable. The current auxiliary Feedwater reliability analysis is presented in the McGuire Nuclear Station Probabilistic Risk Assessment.

10.4.10.4 Tests and Inspections

Preoperational testing of the Auxiliary Feedwater System verifies pump performance and the capacity to draw water from the Upper Surge Tank, the auxiliary feedwater condensate storage tank and the condensate hotwell.

System performance monitoring detects any deterioration of system components and appropriate corrective action is taken as required. The Auxiliary Feedwater System is capable of being tested while the unit is operating.

10.4.10.5 Instrumentation Application

Minimum flow protection systems are provided for the auxiliary feedwater pumps. (See Figure 10-47)

The Auxiliary Feedwater System is designed to start automatically as required. Sufficient instrumentation is provided to allow control of the system from the control room or locally at the auxiliary feedwater pumps.

Local indication for flow to the Steam Generators and Turbine Driven miniflow is provided for Beyond Design Basis External Events (NRC Order EA-12-049). These local indications will be operable when electrical power is not available.

In response to NRC Generic Letter 88-03, Resistance Temperature Detectors (RTD) are installed upstream of the auxiliary feedwater injection line check valves. These Resistance Temperature Detectors provide indication and alarm in the control room when increased temperatures indicate check valve leakage. This leakage could result in steam binding of auxiliary feedwater pumps Reference 4.

The controls and instrumentation for the Auxiliary Feedwater System are listed in Table 10-13.

10.4.11 References

1. Deleted Per 1999 Update
2. Letter from W. O. Parker Jr. to Harold R. Denton (NRC) dated July 15, 1981 Subject: Response to NRC Generic Letter 81-14.
3. McGuire Nuclear Station Response to TMI concerns Item II.E.1.1 Letters from W. O. Parker Jr. (Duke) to H. R. Denton (NRC) dated August 13, 1980 and September 18, 1980. Reliability Analysis of the Auxiliary Feedwater System for McGuire Nuclear Station, *WCAP-9751* July, 1980.

4. McGuire Nuclear Station and Catawba Nuclear Station Response to Generic Letter 88-03. Letter from H.B. Tucker (Duke) to Document Control Desk (NRC) dated May 26, 1988. NRC Generic Letter 88-03, Steam Binding of Auxiliary Feedwater Pumps.

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