SECTION 8

PLANT ELECTRICAL SYSTEMS

TABLE OF CONTENTS

TABLE OF CONTENTS [Continued]

LIST OF TABLES

TABLE OF CONTENTS [Continued]

LIST OF FIGURES

SECTION 8 PLANT ELECTRICAL SYSTEMS

8.1 SUMMARY

Each main generator feeds electrical power at 20 KV through its isolated phase bus to the associated Generator Step Up Transformer. The power requirements for station and unit auxiliaries are supplied by a Main Auxiliary Transformer connected to the isolated phase bus, following practices that have been highly satisfactory for fossil-fueled and other nuclear units. Auxiliary power for startup, shutdown and normal backup is supplied from Reserve Auxiliary Transformers designated 1R and 2RS. Transformer 1R is the normal backup source for Unit 1 and is connected to the 161kV external power system. Transformer 2RS is the normal backup source for Unit 2 and is connected to the 345kV external power system. Bus ties are provided to allow crossfeeding should one transformer be out of service. Redundant offsite power sources are provided of sufficient capacity to supply all critical loads for either or both units. Each Safeguards bus has a preferred and alternate offsite source consisting of a Reserve Auxiliary Transformer and a Cooling Tower Substation Transformer, respectively. The Cooling Tower Substation sources are not large enough to also serve as a redundant startup source. Emergency backup power, to ensure continuity of supply for critical loads, is supplied from four onsite, quick-start Emergency Diesel Generators.

The function of the Auxiliary Electrical System is to provide reliable power to those auxiliaries required during any normal or emergency mode of plant operation.

The design of the system is such that sufficient independence or isolation between the various sources of electrical power is provided in order to guard against concurrent loss of all auxiliary power.

<u>GDC 2 - Performance Standards</u>

Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design.

To satisfy GDC 2, all electrical systems and components vital to plant safety, including the Emergency Diesel Generators, are designed as Class I systems so that their integrity is not impaired by the Design Basis Earthquake, wind, storms, floods, or disturbances to the external electrical system. Power, control and instrument cabling, motors and other electrical equipment required for operation of the engineered safety features are suitably protected against the effects of either a Design Basis Accident, or of severe external environmental phenomena in order to assure a high degree of confidence in the operability of such components in the event their use is required.

GDC 39 - Emergency Power for Engineered Safety Features

An emergency power source shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning of the engineered safety features and protection systems required to avoid undue risk to the health and safety of the public. This power source shall provide this capacity assuming a failure of a single active component.

To satisfy GDC 39, independent alternate power systems are provided with adequate capacity and testability to supply the required engineered safety features and protection systems.

The plant is supplied with normal, standby, and emergency power sources as follows:

a. The main source of auxiliary power during operation of either Unit is the Unit’s generator. Power is supplied via the Main Auxiliary Transformer that is connected to the main leads of the generator.

b. Standby power required during startup, shutdown, and after reactor trip of either Unit is supplied from the Northern States Power Company’s 161 KV and 345 KV transmission systems, via the plant substation through two independent connections from the substation to the plant.

c. Two emergency diesel generator sets dedicated to each Unit are connected to the engineered safety features (safeguards) buses to supply shutdown power in the event of loss of all other AC auxiliary power.

d. Emergency power for vital instruments and controls for each Unit is supplied from two 125 VDC systems for each unit. 01471873

The Emergency Diesel Generators are connected to the separate 4160 volt auxiliary system buses in each Unit. Each set is started automatically on a safety injection signal from its Unit or upon the occurrence of undervoltage on its corresponding 4160 volt bus. The Emergency Diesel Generator arrangement provides adequate capacity to supply the engineered safety features for the Design Basis Accident in one Unit, assuming the failure of a single active component in the system.

GDC 24 - Emergency Power for Protection Systems

In the event of loss of all offsite power, sufficient alternate sources of power shall be provided to permit the required functioning of the protection systems.

To satisfy GDC 24, the facility is supplied with normal, reserve, and emergency power to provide for the required functioning of the protection systems.

In the event of a Loss of Coolant Accident (LOCA) coincident with the Loss of Offsite Power (LOOP) event, emergency power is available from two Emergency Diesel Generators dedicated to each unit.

The instrumentation and controls portions of the protection systems will be supplied from the 125 VDC systems during the diesel startup period.

THIS PAGE IS LEFT INTENTIONALLY BLANK

8.2 TRANSMISSION SYSTEM

8.2.1 Offsite Transmission Grid Configuration

The output of the Prairie Island Generating Plant is delivered to a 345/161 KV Substation located at the plant site. Electrical energy generated at 20 KV is transformed to 345 KV by the Generator Step Up Transformers. A one-line diagram of the 345 KV connections for Units No. 1 and 2 is shown in Figure 8.2-2.

There are five transmission lines that connect the Prairie Island Plant to the transmission system. Two of the 345 KV transmission lines are connected directly to the Red Rock Substation and a third 345 KV transmission line is connected to the Hampton Substation. The Red Rock and Hampton Substations are connected to the Minneapolis, St Paul area high voltage grid. A fourth 345 KV transmission line is connected to the North Rochester Substation in southern Minnesota and from there, the line proceeds to the Bryon and Adams Substations and then through Iowa to Missouri where it is tapped several times to major Substations.

The basic scheme used in the 345 KV portion of the Substation is the breaker-and-one-half system.

The 161 KV portion of the Substation is a single bus arrangement. The 161 KV Substation is connected to 345 KV Bus 2 by 345/161/13.8KV No. 10 Transformer. The fifth transmission line is a 161 KV line which connects to the Spring Creek Substation and then supplies power to the Red Wing, Minnesota area.

Figure 8.2-3 shows the site arrangement of transmission lines and underground power cables. A single line diagram for the Cooling Tower and Plant (345/161KV) Substation is included on Figure 8.2-2. The criteria for spacing between lines are based on national standards for such lines.

8.2.2 Offsite Grid Reliability

Reliability considerations to minimize the probability of power failure due to faults in the network interconnections and the associated switching are as follows:

a. Redundancy is designed into the network interconnections for the units by having four transmission circuits into the 345 KV system and one transmission circuit into the 161 KV system. These systems are interconnected at the site and any one 345 KV circuit is capable of providing the full power requirements for the startup or shutdown of either Unit.

b. Physical separation of transmission lines is maintained on site as much as possible to provide isolation. The transmission line spacing in the vicinity of the site is greater than the height of the towers.

c. Transmission line design for lightning performance is based on less than one outage per 100 miles per year.

d. The substation switching arrangement provides nine 345 KV circuit breakers for six transmission line/generator outlets. This type of design is referred to as a breaker-and-one-half design, and includes two full capacity main buses. Dual simultaneous relay protection is provided for each bus and line/outlet. Breaker failure relaying protects for scenarios where the interrupting device fails to clear a fault.

   Operating characteristics of this design include:

   1. Any transmission line/outlet may be switched open under normal or fault conditions without interrupting another line/outlet.

   2. Any single circuit breaker or bus may be isolated for maintenance without interrupting power or protection to any line/outlet.

   3. Short circuits on a single main bus are isolated without interrupting service to any line/outlet.

   4. Failure of a bus side breaker will result in the loss of only one line/outlet until the failed component is isolated.

   5. Dual simultaneous relay protection provides coverage for failure of one set of protective relaying.

e. Design and construction of the 345 KV and 161 KV transmission lines exceed the requirements of the National Electrical Safety Code for heavy loading districts, Grade B construction.

With the above features, the probability of loss of more than one source of auxiliary power from credible faults is low, however, in the event of an occurrence causing loss of all the 345-KV and 161-KV connections, power for essential service is supplied from four onsite emergency diesel generators.

In the event that both Prairie Island Units trip simultaneously, the offsite supply to the safety features system would not be interrupted. The breaker-and-one-half design is such that the two unit trip event does not isolate auxiliary power supply points from the transmission lines serving the substation.

The adequacy of offsite power supply to the auxiliary safety sources in the event of a two unit trip is discussed below.

Voltage supplied to auxiliary systems from offsite sources after a two unit trip depends on many variables. The direction and magnitude of power flows due to system load, power transactions and pattern of on-line generation play a large role in post-trip voltage.

Studies using normal peak-load system steady state load-flow simulation show that loss of the maximum generation from Prairie Island (a 2-unit trip) can be sustained with adequate voltage. Offsite sources to auxiliary systems are not interrupted, and provide proper voltage to the safety equipment.

Key to this contingent performance ability are the spinning and standby reserves maintained by NSP and other MidContinent Area Power Pool (MAPP) member utilities.

These reserves total in excess of 15% of the MAPP peak load. (For example 1990 MAPP operating reserves totaled 3529 MW).

Contingent support immediately after loss of the Prairie Island Units is supplied by rotor inertia and governor action of other generating units throughout the interconnected eastern two-thirds of the United States and the eastern half of southern Canada. NSP derives this support over transmission tie-lines with capacity exceeding 3000 MW. After several minutes the MAPP spinning and standby reserve capability replaces the import from the interconnected systems.

No customer load interruption or break-up of NSP's transmission system is anticipated as a result of a Prairie Island two unit trip. The offsite supplies to the plant safety features therefore continue to operate without interruption.

Backup systems are in place to cover contingent system conditions which may exist prior to a two unit trip. An underfrequency load shed system is in use by all MAPP member utilities which would shed approximately 10% of the system load at each of three frequencies: 59.3 Hz, 59.0 Hz and 58.7 Hz. This shed of 30% of load is intended to restore a balance between load and generation and return system frequency to a proper level.

NSP has also installed an under-voltage tripping system to cover the multiple contingency events which could pose the threat of system voltage collapse. In the scenario of several prior contingencies, and a subsequent Prairie Island two unit trip, the adequacy of 345-KV offsite voltage source to plant auxiliary system is protected by automatic load shedding. This is intended to restore system voltage to a proper level.

Simulation of Prairie Island two unit trip event is performed using computer load flow models. NSP uses two types of load flow programs, one for modeled studies, and a second for analysis of real-time system conditions using telemetered voltage and power flow data. The computer models are representations of the transmission system electrical characteristics and components. Accuracy of the models are periodically verified by comparison with actual historical data. Further studies are performed to examine details of the dynamic conditions after the assumed loss of the Prairie Island Units.

8.2.3 Protection and Control for Interconnections

Each of the 161, 34.5 and 13.8 KV sources has both overcurrent and breaker failure protective relaying.

All 345, 161, 34.5 and 13.8 KV breakers are equipped with dual trip coils.

Each of the 345 and 161 KV feeders transmission line feeder breakers has primary, secondary and breaker failure protective relaying.

The DC control system in the substation consists of two completely independent 125 volt systems. Each system has its own battery, charger and fused distribution cabinet. One 125 volt system is used for primary relaying requirements, operation of breaker trip coil #2, backup supply to breaker charging motors and MOD control. The second 125 volt system is used for secondary relaying requirements, breaker controls, operation of breaker trip coil #1 and breaker failure relaying.

Controls for 1H2 and 1H4 13.8 KV Medium Voltage Switchgear Breakers (MVSB's) are in the Substation control house. DC control power for the cooling tower area 4.16 KV breakers is supplied by a single 48 volt battery located with the 4160 volt switchgear in the Cooling Tower Equipment House.

Under normal operating conditions the 13.8 KV breakers 1H2, 1H4 and 4160 volt breaker CT11-1, CT11-6, CT11-8, CT12-6, CT12-7 and CT12-8 are closed and the 4160 volt bus tie CT-BT 112 is open. Bus Tie breaker CT-BT 112 is normally maintained in the open position and can be manually closed so that either cooling tower area transformer can supply both 4160 V bus sections. 60400000033

A 345 KV bus #2 Lockout, No. 10 Transformer Lockout, operation of either the 13.8 KV feeder overcurrent or ground detection relaying, Lockout of CT 12 Transformer, or Lockout of 2RS Transformer (if 8H12 is closed) will trip and lockout 1H2 - 13.8 KV MVSB and the 4160 volt source breaker CT12-7. 1H2 breaker failure relaying will also trip and lockout CT12-7.

With only CT11 Transformer feeding both 4.16 KV bus sections CT11 and CT12, breaker CT 12-7 is open and CT-BT 112 is closed. With a fault on bus section CT12, protective relays operate a lockout relay to trip and lockout breaker CT-BT 112 and to lockout breakers CT12-7 and CT11-1. 60400000033

A phase or ground fault on 4160 volt feeder from CT12 Bus to Plant Safeguards Bus 26 operates protective relays and trip 4.16 KV breaker CT12-6. A phase or ground fault on the 4160 volt feeder from CT12 Bus to Plant Safeguards Bus 25 operates protective relays and trips 4.16 KV breaker CT12-8. 60400000033

A 345 KV Bus #1 Lockout, CT1 Transformer Lockout, operation of either the 13.8 KV feeder overcurrent or ground detection relaying, Lockout of CT11 Transformer, or Lockout of 2RS Transformer (if 8H10 is closed) will trip and lockout 1H4 - 13.8 KV MVSB and the 4160 volt source breaker CT11-1. 1H4 breaker failure relaying will also trip and lockout CT11-1.

With only CT12 Transformer feeding both 4.16 KV bus sections CT11 and CT12, breaker CT11-1 is open and CT-BT 112 is closed, a fault on bus section CT11, protective relays will operate a lockout relay to trip and lockout breaker CT-BT 112 and to lockout breakers CT11-1 and CT12-7.

With a phase or ground fault on the 4160 V feeder from CT11 Bus to Plant Safeguard Bus 16, protective relays operate and trip breaker CT11-6. A phase or ground fault on the 4160 volt feeder from CT11 Bus to Plant Safeguards Bus 15 operates protective relays and trips 4.16 KV breaker CT11-8. 60400000033

The No. 1 and No. 2 Generator Step Up Transformers are each provided with an over-undervoltage relay to protect the transformer against grounds or an overvoltage condition occurring on the transformer while it is energized from the 345 KV Substation and delivering station auxiliary load.

8.2.4 Onsite Interconnections

Three separate power systems are provided by the Substation to the Plant 4160 volt safeguards buses. An overhead 161KV transmission line from the Substation to the Plant's 161/4.16KV 1R Transformer provides power to the Unit 1 4160 volt safeguards buses 15 and 16. An underground 35KV line from 345/35KV 2RS transformer in the substation to the Plant's 35/4.16KV 2RY Transformer provides power to the Unit 2 4160 volt safeguards buses 25 and 26. Two underground 13.8 KV feeders from the 345/13.8 KV Cooling Tower Transformer (CT1) and the tertiary of the 345/161/13.8 KV No. 10 Transformer provides the power to the Cooling Tower Substation 13.8/4.16 KV transformers CT11 and CT12.

These transformers supply separate buses in the Cooling Tower 4160 volt switchgear that may be connected together by a bus tie breaker. Underground feeders from Cooling Tower Bus CT11 feed Unit 1 safeguards buses 15 and 16. Underground feeders from Cooling Tower Bus CT12 feed Unit 2 safeguards buses 25 and 26.

1R Transformer, 2RS Transformer, CT1 Transformer and No. 10 Transformer can be supplied power from any of the four 345kV transmission lines.

The 13.8 KV tertiary of 345/161/13.8 KV No. 10 Transformer is the source to 1H2 13.8 KV MVSB in the Substation. 1H2 13.8KV ACB is the source breaker for the underground feeder to the cooling tower area 13.8/4.16 KV CT12 Transformer. CT12 Transformer supplies 4.16 KV Bus Section CT12 through CT12-7, which is a 4.16 KV MVSB in the Cooling Tower Equipment house. 4.16 KV Bus Section CT12 feeds the Unit 2 Safeguards 4.16 KV Bus 25 through 4.16 KV MVSB CT12-8, and 25-5, and Bus 26 through 4.16 KV MVSB CT12-6, and 26-13. 60400000033

345/13.8 KV CT1 Transformer is the source to 1H4 13.8 KV MVSB in the Substation. 1H4 13.8 KV MVSB is the source breaker for the underground feeder to the cooling tower area 13.8/4.16KV CT11 Transformer. CT11 Transformer supplies 4.16 KV Bus Section CT11 through CT11-1, which is a 4.16 KV MVSB in the Cooling Tower Equipment house. 4.16 KV Bus section CT11 feeds Unit 1 Safeguards 4.16 KV Bus 15 through 4.16 KV MVSB CT11-8, and 15-7, and Bus 16 through 4.16 KV MVSB CT11-6, and 16-8. 60400000033

8.2.4.1 Paths for Unit 1 Safeguards Trains

For Unit 1 there are four possible paths between the offsite transmission system and the safeguard 4160V buses. Each path is capable of providing the required power to shutdown the reactor and maintain it in a shutdown condition. These four paths are as follows:

- The first path is fed from the 161kv switchyard bus. This feeds the 1R transformer which in turn supplies power to buses 15 and 16.

- The second path is fed from the 345KV switchyard Bus 1. This feeds the 345/13.8KV Cooling Tower Transformer No. 1 which is connected via an underground cable run to the 13.8/4.16KV cooling tower transformer CT11. The secondary of this transformer feeds buses 15 and 16 through breakers CT11-1 and CT11-6.

- The third path is fed from the 345kv switchyard to transformer 2RS, transformer 2RY, breaker 2RYBT, breaker 12RYBT, breaker 1RYBT and then to buses 15 and 16.

- The fourth path is fed from the 13.8kv tertiary winding of the 345/161/13.8KV No. 10 Transformer. This 13.8kv feed supplies underground cable to 13.8/4.16KV cooling tower transformer CT12. From here is it fed through bus tie breaker CT-BT 112 to breakers CT11-8 and CT11-6 and finally to buses 15 and 16, respectively. 60400000033

8.2.4.2 Paths for Unit 2 Safeguards Trains

For Unit 2 there are four possible paths between the offsite transmission system and the safeguard 4160V buses. Each path is capable of providing the required power to shutdown the reactor and maintain it in a shutdown condition. These four paths are as follows:

- The first path is fed from the 345kv switchyard to transformer 2RS, breaker 2RSY, transformer 2RY and then to buses 25 and 26.

- The second path is fed from the 13.8kv tertiary winding of the 345/161/13.8KV No. 10 Transformer. This 13.8kv feed supplies underground cable to 13.8/4.16KV cooling tower transformer CT12. From here it is fed through breaker CT12-6 to buses 25 and 26.

- The third path is fed from the 161kv switchyard bus. This feeds the 1R transformer, breaker 1RYBT, breaker 12RYBT, breaker 2RYBT and then to buses 25 and 26.

- The fourth path is fed from the 345KV switchyard Bus 1. This feeds the 345/13.8KV Cooling Tower Transformer No. 1 which is connected via an underground cable run to the 13.8/4.16KV cooling tower transformer CT11. The secondary of this transformer feeds breaker CT-BT 112 to breakers CT12-8 and CT12-6 and then to buses 25 and 26, respectively. 604000000033

THIS PAGE IS LEFT INTENTIONALLY BLANK

8.3 AUXILIARY POWER SYSTEM

8.3.1 Design Basis

The auxiliary electrical system is designed to provide redundant electrically and physically separated buses for the safety feature loads for each unit. As shown in Figure 8.3-1, the redundant safety features loads (per Unit) are divided between these buses, with each bus fed (in emergency) from a different Emergency Diesel Generator. No paralleling or synchronizing of Emergency Diesel Generators is required.

Two normally open bus tie breakers are provided between each 4160V bus section of one Unit and the companion bus section of the second Unit. These tie breakers would be closed only during a station blackout as discussed under 8.4.4, or during maintenance, testing, or other manually supervised operations.

8.3.2 Description

The basic components of the plant electrical system are shown in Figure 8.3-1.

The plant's main generators serve as the main source of auxiliary electrical power to the non-safeguards buses during "on-the-line" operation of the plant. Power is supplied by a 20/4.16 KV three winding Main Auxiliary Transformer that is connected to the main leads from the generator via isolated phase bus connections having the same reliability as the main generator leads. Each safeguards bus is normally supplied from one of two possible offsite sources.

8.3.2.1 Load Transferring

During controlled startup, the non-safeguards 4160 volt auxiliary power buses are manually transferred without interruption from the Reserve Auxiliary Transformer to the Main Auxiliary Transformer (and in the reverse direction on shutdown), under supervision of synchronism check interlock relays.

Trouble in the reactor, turbine, main generator, Generator Step Up, or Main Auxiliary Transformer, calling for isolation of the Unit from the system, would automatically initiate a supervised fast transfer of station auxiliaries from the Main Auxiliary Transformer to the Reserve Auxiliary Transformer. In the event that the safeguards buses are subjected to an undervoltage condition, the logic attempts to transfer the safeguards buses to their respective alternate offsite sources, if available, either the Reserve Auxiliary Transformers or the Cooling Tower Transformers.

Assuming a normal successful transfer, the Emergency Diesel Generators would not start and their connecting circuit breakers would not close because the buses would be re-energized from the alternate offsite sources. In case of an unsuccessful transfer to the alternate offsite source, the associated Emergency Diesel Generators would automatically start, come up to speed and voltage, and close on to the safeguards buses.

All electrically operated circuit breakers used in the 4160 volt and 480 volt Auxiliary Electrical System are of the stored energy type to ensure reliable operation.

8.3.2.2 Load Sequencing

Starting of safety features loads is sequenced in five second steps to avoid momentarily overloading a power source by sudden application of too great a load. The control or logic equipment to accomplish this sequential loading consists essentially of programmable logic controllers (PLC) which have undergone extensive verification testing as outlined in NSP's letter to the NRC, (Reference 1). Control and logic systems are designed to ensure maximum reliability of the system within the safety requirements that the control scheme must provide.

8.3.2.3 4160 Volt Auxiliary System

The 4160 volt auxiliary system for each unit is divided into safety related and non-safety related buses. The non-safety related buses are arranged so that each bus can be supplied from its associated main generator through its Main Auxiliary Transformer or from the 345kV/161kV system through the Reserve Auxiliary Transformers. All 4160 volt auxiliaries are distributed between the 4160 volt buses in accordance with reliability requirements and diversity. For Unit 1, buses 11 and 12 serve large reactor auxiliaries (Reactor Coolant Pumps, Feedwater Pumps). Buses 13 and 14 serve general plant auxiliaries. Buses 21, 22, 23 and 24 serve similar functions for Unit 2.

The safety related (safeguards) 4160 volt buses 15, 16, 25 and 26, can be supplied from the 345 KV/161KV system through the Reserve Auxiliary Transformers and the Cooling Tower Substation Transformers, or from one each of the four Emergency Diesel Generators. Buses 15 and 16 serve engineered safety feature auxiliaries on Unit 1, and buses 25 and 26 serve similar functions on Unit 2.

8.3.2.4 480 Volt Auxiliary System

The 480 volt auxiliary system for Unit 1 consists of ten power centers, six of which serve non-safety related equipment. Five of the non-safety related centers are double-ended, consisting of a split bus, a bus tie break, and two 4160/480 volt transformers. The sixth center is single-ended, consisting of a single bus and transformer. For Unit 1, 480 volt power for engineered safety features and other essential plant loads is fed from load centers 111, 112, 121 and 122. These load centers are fed from step-down transformers connected to 4160 volt buses 15 and 16. Normal operation is with the normal feed transformer of a load center energized, and carrying the single bus normally associated with it.

For Unit 2 there are ten power centers, six of which serve non-safety related equipment. Five of the non-safety related centers are double-ended, consisting of a split bus, a bus tie break, and two 4160/480 volt transformers. 480 volt power for engineered safety features and other essential plant loads is fed from load centers 211, 212, 221, and 222. These load centers, are fed from 4160 volt buses 25 and 26. Normal operation is with the normal feed transformer of a load center energized, and carrying the single bus normally associated with it.

Alternate power sources for the 480V safeguards buses, from the same train of the opposite unit, are included in the design. These are used primarily for ease of maintenance during outages on the 4.16 KV buses, and are not required for operation. Each alternate source line-up consists of an incoming line compartment, and a 4160-480 volt transformer section. One alternate souce line-up per train is provided for use by either or both 480V safeguards buses.

NRC Bulletin 88-10, “Nonconforming Molded-case Circuit Breakers” and Supplement 1 to Bulletin 88-10 requested licensees to provide reasonable assurance that molded-case circuit breakers purchased for use in safety-related application without verifiable traceability to the manufacturer can perform their intended safety functions. Northern States Power responded to NRC Bulletin 88-10 as it applied to Prairie Island in References 2 and 3. In response to Supplement 1 to NRC Bulletin 88-10, as documented by Reference 3, Northern States Power reviewed and verified that the provisions of the bulletin were met and provided additional clarification on actions taken with respect to six nontraceable molded-case circuit breakers. The NRC Staff found the Northern States Power response to NRC Bulletin 88-10 and Supplement 1 acceptable in Reference 4.

8.3.3 Performance Analysis

The physical locations of electrical distribution system equipment are such as to minimize vulnerability of vital circuits to physical damage as a result of accidents.

Main and Reserve Auxiliary Transformers are located outside and are physically separated from each other.

Lightning arresters are used where applicable for lightning protection. All oil transformers located close to the plant are covered by water-spray systems to extinguish oil fires quickly and prevent the spread of fire. The transformers have oil catch basins and drains to remove oil from the transformer area in case of an oil spill or leak. Transformers are spaced to minimize their exposure to fire, water, and mechanical damage.

The design of the Auxiliary Electrical System capacity is based on computerized studies of loading under normal running, normal sequential starting, and emergency transfer of the system from normal to reserve source conditions.

System capacity is adequate to operate the plant in a safe manner under all normal conditions. Under emergency conditions, automatic load shedding and tripping of non-essential loads are provided in the transfer control system, prior to connecting safety features loads to the emergency diesel generators.

The adequacy of station electric distribution voltages was analyzed in accordance with Plant System Branch position PSB-1. The analysis demonstrated:

a. Station distribution system voltages remain acceptable under minimum and maximum expected values of grid voltage for motor starting and running

b. Undervoltage protection circuitry is not challenged with minimum expected values of grid voltage and component drift

The analysis results were used to establish operating guidelines which guarantee a minimum 4160V safeguards bus voltage of 94.8% to allow long term operation on offsite power without actuating degraded voltage protection relays (set at 95.5 $\pm$ .7%). Testing and analysis (Reference 19) have shown that all safeguards loads will operate properly at or above the minimum degraded voltage setpoint.

Sufficient protective devices, circuit breakers, and fuses, are provided and coordinated to assure isolation of faulted equipment with a minimum of disturbance to the rest of the system. Electrical coordination is also credited in the post-fire safe shutdown analysis described in 10.3.1.

60400000193

The design of the system is such that sufficient independence or isolation between the various sources of electrical power is provided in order to guard against concurrent loss of all auxiliary power.

Independence or isolation of supply to the various duplicated auxiliaries provided as engineered safety features is maintained so that a single failure does not result in a loss of more than one group of the plant's redundant engineered safety features systems. Arrangements and location of the components of the auxiliary power system, transformers, switchgear, cable runs containment vessel penetrations, etc., provides this isolation. A simple arrangement of buses is provided, requiring a minimum of switching to restore power to the bus in the event that the normal supply to that bus is lost.

Special attention has been given to the separation of cable trays, troughs, and channels, and the routing of cable trays to avoid fire hazards areas. Power cables are separated from control or instrumentation cables. Control and power cables for the engineered safety features system have a minimum separation between redundant circuits of 36 inches. Where closer spacing cannot be avoided, an approved barrier is placed between the circuits. Cable entrances into the control room, relay room, and Class I areas are sealed to prevent the entrance of smoke and fire from outside sources. In the D5/D6 Building cable and trays are routed in accordance with IEEE-384-1981. Refer to Section 8.7 for more detailed information on all separation requirements.

Two separated control trains are provided for redundancy in the engineered safety features system. This separation is maintained to preclude the possibility of any single incident causing both systems to become inoperative.

The supervised fast transfer of the auxiliary system or its components from the Main Auxiliary Transformer to Reserve Auxiliary Transformer is automatically controlled to assure a minimum interrupted time for power and a minimum effect on the system.

The 4160 volt switchgear and 480 volt load centers are located in areas which minimize their exposure to mechanical, fire, and water damage. This equipment is properly coordinated electrically to permit safe operation of the equipment under normal and short-circuit conditions.

The 480 volt motor control centers are located in the areas of electrical load concentration. Those associated with the turbine-generator auxiliary system in general are located in the turbine building. Those associated with the nuclear steam supply system are located in the Auxiliary Building.

The application and routing of control, instrumentation and power cables are such as to minimize their vulnerability to damage from any source. All cables are designed using conservative margins with respect to their current carrying capacities, insulation properties, and mechanical construction.

All engineered safety features power cable insulation and all power cables in the containment have fire-resistant sheathing selected to minimize the harmful effects of radiation, heat and humidity. Appropriate instrumentation cables are shielded to minimize induced voltage interference. Wire and cables related to engineered safety features and reactor protection systems are routed and installed to maintain the integrity of their respective redundant channels and protect them from physical damage. This wire is color-coded and routed in color-coded cable trays.

Supports for cable trays are designed in accordance with the tray manufacturer’s recommendation, based upon 100% tray load (corresponding to 40% cross-sectional fill) and calculated seismic loads. The number of conductors in a tray is limited according to factors recommended by the 1990 National Electric Code (NEC) or the cable manufacturer. Trays filled beyond 40% cross-sectional fill or the NEC recommendations are evaluated.

Cables in trays are derated for ambient temperatures.

8.4 PLANT STANDBY DIESEL GENERATOR SYSTEMS

8.4.1 Design Basis

The normal power sources for the safeguards buses are the 161-4.16/4.16 KV Reserve Auxiliary Transformer (Unit 1 1R), the 34.5/4.16 KV Reserve Auxiliary Transformer (Unit 2 2RY), and the redundant 13.8-4.16 KV Cooling Tower Substation buses (Unit 1 CT11 and Unit 2 CT12), as discussed in Section 8.2.1.

If the Reserve Auxiliary Transformers and the Cooling Tower Substation buses should fail, backup power is provided by two Emergency Diesel Generators in each unit sized and connected to serve the engineered safety features equipment of the unit. Each Emergency Diesel Generator is sized to start and carry the engineered safety features load required for the Design Basis Accident and concurrent loss of offsite power (LOOP).

In the event that an Emergency Diesel Generator fails to start, only one set of redundant safety features components would be lost in that unit. By means of later manual switching, safety features components on the bus associated with a failed Emergency Diesel Generator could be fed from the other Unit's Emergency Diesel Generator up to the capacity of the running engine, as discussed under 8.4.4. There is no single known component whose failure prevents both Emergency Diesel Generators in a Unit from starting.

Emergency Diesel Generator starting control is independent of the AC system except for the associated 4.16 KV bus voltage-detecting relay which is connected in a "fail-safe" manner to start the Emergency Diesel Generator on loss of AC power.

Unit 1 Emergency Diesel Generator equipment is located in separate heated rooms, protected from atmospheric conditions, in a Class I portion of the Turbine Building, permitting nearly ideal rapid-start conditions. The rooms are connected by a single access opening which is provided with a Class "A" fire rated door. The door, which is normally closed, is furnished with an extra-strong door closer equipped with a fusible link arm. Since the wall separating the two emergency diesel generators is parallel with the rotation of the diesel generator, it is incredible that a missile generated by the failure of one diesel generator will breach the wall opening.

Unit 2 Emergency Diesel Generator equipment is also located in separate rooms, protected from atmospheric conditions, in the Class I D5/D6 Building. These rooms are separated by a twelve inch thick reinforced concrete barrier. There are no wall openings directly between the two rooms.

8.4.2 Description

Each Emergency Diesel Generator, as a backup to the normal standby AC power supply, is capable of sequentially starting and supplying the power requirements of one of the redundant sets of engineered safety features for its reactor Unit. In addition, in the event of a station blackout (SBO) condition, each Emergency Diesel Generator is capable of sequentially starting and supplying the power requirements of the hot shutdown (Mode 3, Hot Standby in ITS) loads for its unit, as well as the essential loads of the blacked out unit, through the use of manual bus tie breakers interconnecting the 4160V buses as discussed in 8.4.4.

Unit 1 Emergency Diesel Generators (D1 and D2)

The Unit 1 Emergency Diesel Generators consist of two Fairbanks Morse units each rated at 2750 KW continuous (8760 hr basis), 0.8 power factor, 900 rpm, 4160 Volt, 3-phase, 60 Hertz. The 1,000 hour rating of each Emergency Diesel Generator is 3000 kilowatts. The 30 minute rating of each unit is 3250 kilowatts maximum. This figure is based on cooling water at a maximum temperature of 95°F and ambient air at a temperature of 90°F. The limitations imposed by the generator and the heat removal equipment limits the overall 30 minute rating of the system to 3250 kilowatts.

Each diesel engine is automatically started by compressed air stored at a pressure of approximately 250 psia. Two parallel solenoid admission valves deliver air simultaneously to a timed pilot air-distributor valve and an individual air-start valve located in each of the twelve cylinders. Starting air is thus admitted directly into the cylinder liners for fast, reliable cranking and starting. Adequate cranking effort is obtained with only six air valves. The additional six valves give increased starting reliability.

Each Unit 1 Emergency Diesel Generator has its own independent air starting system including a motor-driven air compressor, (powered from a 480 Volt emergency bus) and two accumulators each of sufficient capacity to crank the engine for 20 seconds. An interconnecting header with manual valving is provided between the starting system of the two engines, to allow the air accumulators of the opposite engine to be replenished. Cranking continues until the engine starts (speed over 250 rpm) or until a predetermined time limit (10-15 seconds) has elapsed, whichever occurs first. If an engine fails to start within the predetermined time limit, a “start failure” alarm is initiated and the engine control locks out, requiring manual reset.

Unit 2 Emergency Diesel Generators (D5 and D6)

The Unit 2 Emergency Diesel Generators consist of two tandem-drive units (gensets) manufactured by Societe Alsacienne de Constructions Mecaniques de Mulhouse (SACM), each rated at 5400 KW continuous (8760 hr basis), 0.8 power factor, 1200 rpm, 4160V, 3-phase, 60 Hertz. The gensets are radiator cooled independent of the plant cooling water system.

Each Unit 2 genset, has its own air starting system consisting of four independent subsystems, composed of a dryer, compressor (powered from a 480 volt nonsafeguards bus), and air receiver. Any two of the four air receivers will start the genset within ten seconds. This capability allows each Unit 2 genset to remain “available” to start and accept load within 10 seconds when only two of the four starting air receivers are charged to a pressure of ≥480 psig. (Reference 39 and Reference 44)

For each Unit 2 genset to be considered “operable”, any three of the four air receivers charged to a pressure of ≥480 psig are required. This ensures that the genset will start and accept load within 10 seconds and ensures the capability of the air receivers to provide a minimum of five cranking cycles without recharging. This is an air receiver sizing requirement. (Reference 38 and Reference 44)

Cranking continues until the genset starts (based on lube oil pressure) or until five seconds has elapsed, whichever occurs first. If the genset fails to start within the five seconds, a “start failure” alarm is initiated and the genset control locks out, requiring manual reset.

The two air-start subsystems for each engine of the genset have interconnecting piping to the fuel injection stop jacks on the other engine. This piping is pressurized only on an overspeed trip by a valve device which opens at the overspeed setpoint. The piping to the opposite engine stop jack is to assure that both engines shutdown on an overspeed trip without depending on the governor shutdown solenoid valves. Each engine has two separate overspeed trip devices.

The Unit 2 gensets are provided with various surveillance instrumentation as defined in IEEE 387-1977. This instrumentation permits remote and local monitoring to indicate the occurrence of abnormal, pre-trip and trip conditions. Except for overspeed, generator differential current and manual emergency stop, the trip functions of the EDG system are bypassed in the event of Safety Injection or Undervoltage Start signal. 60400000174

Units 1 and 2 Emergency Diesel Generators (D1, D2, D5, D6)

Control voltage for the diesel starting/control system is obtained from 125 volt DC System 11 for D1, and DC System 12 for D2. Similarly, control voltage is obtained from DC System 21 for D5, and DC System 22 for D6. Figures 8.5-1a, 8.5-1b, 8.5-2a and 8.5-2b show the 125V DC distribution for Unit 1 and Unit 2. For D1 and D2, loss of DC control power after the engine starts will not stop the engine or interfere with its operation. Direct current power must be restored to stop the engine electrically. For D5 and D6, engine speed control will fail to the hydraulic droop governor so that the speed/frequency depends on busload per the hydraulic governor droop curve. If only the control circuit for the genset control is lost, it will keep on running; however, if the entire DC source to the Vertical Panel for all circuits is lost, the diesel will keep running and cooling fans and fuel booster pumps will be lost. The operator would have to manually stop the genset.

To ensure rapid start, each diesel generator is equipped with electric heaters which furnish heat to the engine cooling water and engine lubricating oil when the engine is shut down. Motor driven circulating pumps for cooling water and lube oil operate continuously when the engines are shut down.

For each EDG, an audible and visual alarm system is mounted on the control panel located adjacent to the associated engine. An “engine trouble” alarm is sounded in the main control room whenever an alarm is sounded on the local engine generator control panel. A main control room alarm also sounds if the controls at the engine are not set on “automatic”, or DC control power is lost.

Sufficient fuel is stored in the day tank for each Unit 1 Emergency Diesel Generator for up to two hours operation at full load. Sufficient fuel is stored in the day tank for each Unit 2 EDG for at least 60 minutes of operation at the level where oil is automatically added to the day tank based on the fuel consumption at a load of 100% of the continuous rating of the EDG plus a minimum margin of 10% per ANSI N195-1976. Fuel from interconnected storage tanks can be transferred to the day tanks by electric pumps for operation of any single Emergency Diesel Generator up to two weeks. See Section 10.3.13 for further information.

Redundancy and flexibility are provided by two engineered safeguards buses, serving safety related equipment, associated with each of the two Units, connected so that each safeguards bus is served from a different Emergency Diesel Generator (four total). The sequence in which the safeguards loads are picked up by the Emergency Diesel Generators, and the delay times required, are discussed in the following loading description:

Each Emergency Diesel Generator is automatically started by either of the following events:

a. Undervoltage, which envelopes loss of voltage (including LOOP), or degraded voltage on the associated 4160 Volt buses (buses 15 and 16 for D1 and D2, and buses 25 and 26 for D5 and D6 respectively. Automatic starting of the Emergency Diesel Generators is initiated by a modified 2-out-of-4 voltage relay scheme on each 4160 Volt bus to which the Emergency Diesel Generator is to be connected.

b. Initiation of a Safety Injection Signal (both of the affected Unit's Emergency Diesel Generators start on this signal).

<u>Undervoltage Logic</u>

Relays are provided on buses 15, 16, 25 and 26 to detect undervoltage and degraded voltage conditions. The undervoltage setpoint is 75 ± 2.5% with a time delay of 4 ± 1.5 seconds. When an undervoltage condition exists on any of these buses, the associated PLC based Load Sequencer automatically initiates the following steps for the affected bus.

a. Trip source breakers to the bus.

b. Load rejection of designated loads on bus.

c. If the alternate offsite source is available, attempt to restore power from the alternate source.

d. If the alternate offsite source is not available, or does not successfully restore the bus, the associated Emergency Diesel Generator auto starts.

e. The EDG breaker closes onto the bus after the EDG has met established frequency and voltage criteria (within 10 seconds of receiving start signal).

f. Load restoration by sequenced steps at 5 second intervals.

If an SI signal is received during an undervoltage condition, the EDG is started and steps c and d above are not performed.

If an SI signal is present and the Emergency Diesel Generator is supplying power to the bus when an undervoltage occurs, its breaker is not tripped in item a. above. The bus remains powered from the Emergency Diesel Generator, and there is no load rejection or load restoration.

Degraded Voltage Logic

The degraded voltage setpoint is 95.5 ± 0.7% with time delays of 8 ± 0.5 seconds and 60 ± 3 seconds. The upper limit to the setpoint has been established to preclude unnecessary actuations of the voltage restoration scheme at the minimum expected grid voltage. Analysis has shown that the 8 second delay is adequate to account for normal transients, such as voltage dips from the starting of large loads, and is longer than the time required to start the Safety Injection pump at minimum voltage. This first delay annunciates that a degraded voltage condition exists. The second delay of 60 seconds allows the degraded condition to be corrected by external actions within a time period that will not cause damage to the operating equipment. With degraded voltage on any of the four safeguards 4160V buses, the associated PLC based Load Sequencer automatically initiates the following steps after the 60 second delay.

a. Auto start the Emergency Diesel Generator and trip the offsite source breakers to the bus.

b. Load rejection of the designated loads on the bus.

c. Close the breaker to the Emergency Diesel Generator once it has met established voltage and frequency criteria (within 10 seconds of receiving start signal).

d. Load restoration by sequencing loads at 5 second intervals.

If a SI signal is received during the 60 second degraded voltage time delay, the above logic is immediately actuated by the Load Sequencer with SI loads added during the last step, item d. Except for auto starting the Emergency Diesel Generator, that is a function of the SI signal.

In both the undervoltage and degraded voltage scenarios described above, after voltage is re-established on the subject 4160 Volt bus, either from an offsite source or from an Emergency Diesel Generator, the Emergency Diesel Generator, if started (see discussion under 8.4.2), continues to run (loaded or unloaded) until manually shut down. The 480 Volt buses are immediately energized at the same time as the 4160 Volt bus from which it is fed.

Motors and loads which are operating or connected prior to the loss of voltage condition, that were not shed either automatically or manually during the time of voltage loss, and whose start signals are sealed-in would automatically restart or be re-energized upon return of bus voltage.

Motors not running prior to the loss of voltage condition would not start upon restoration of voltage, until subsequent manual or automatic action is initiated.

Load Sequencer Out of Service

With properly aligned 480V loads, the offsite sources have been analyzed to verify that a load sequencer failure will only affect the ability of the associated EDG to automatically power its respective safeguards loads following a LOOP independent of, or coincident with, a Design Basis Event.

Emergency Diesel Generator Loading

Three 25 HP Waste Gas Compressors are supplied, two fed from Emergency Diesel Generator D1 and one fed from Emergency Diesel Generator D2. One waste gas compressor is included in Step 1 of the load sequence for Emergency Diesel Generator D1 and one waste gas compressor is included in Step 1 of the load sequence for Emergency Diesel Generator D2. (Reference 43)

Three air compressors (121, 122, 123) feed into a common Instrument Air header which, in turn, supplies Instrument Air for both Unit 1 and Unit 2. Compressor 121 is fed from Emergency Diesel Generator D1, via Unit 1 480 Volt Bus 111. Compressor 122 is fed via Unit 1 480 Volt Bus 121 from Emergency Diesel Generator D2. Compressor 123 is fed via Unit 2 480 Volt Bus 211 from Emergency Diesel Generator D5.

Instrument Air is not essential for plant safety during a DBA, however, for nonsafeguards reasons, it is desirable to maintain Instrument Air if possible under this condition, one compressor is adequate for both units. Assuming either Unit 1 Emergency Diesel Generator (D1 or D2) is operating, either Air Compressor 121 or 122 can be assumed to be operating. Similarly, if Emergency Diesel Generator D5 is operating, Air Compressor 123 can be assumed to be operating.

Safeguards MCC's and their associated motor operated valves are energized simultaneously with the 480V safeguards busses except for the pressurizer heaters MCC's which are energized on Step 6 of the Load Restoration Sequence.

Loading on Emergency Diesel Generators is analyzed for a "worst case" condition as represented by a Safety Injection signal coincident with a complete loss of offsite power. (References 41 and 43) A "small break" LOCA that was sufficient to initiate automatic Safety Injection (SI) action would represent the same inrush KVA load on the Emergency Diesel Generator. If the break is so small that automatic SI is not initiated, manual action would be required as soon as the operator is aware of the break. Manual action would represent loads less than or equal to that analyzed in the calculations.

A small break would represent considerably less running load on the RHR Pump and possibly less on the SI Pump, but a longer running time for the SI Pump.

Emergency Diesel Generator Design and Qualification

The redundant onsite standby power sources and their corresponding distribution systems are arranged in the Prairie Island plant to meet all the requirements of Safety Guide 6.

Emergency Diesel Generators D1 and D2 were sized per AEC Safety Guide 9, Paragraph C-2, which requires the predicted load seen by an EDG not to exceed the smaller of either the 2000 hour rating or 90% of the 30 minute rating. The D1/D2 2000 hour rating is unknown. The continuous rating, which bounds the 2000 hour rating conservatively, is 2750 KW. The D1/D2 30 minute rating is 3250 KW, and 90% of the 30 minute rating is 2925 KW. Therefore, the conservative limit of 2750 KW is placed on D1/D2 predicted loads.

Analyses of maximum predicted loading for transient (Reference 43) and steady state conditions (References 36 and 42) show predicted loads are less than the conservative limit of 2750 KW. Therefore, D1 and D2 continue to meet the loading guidelines of paragraph C-2 of Safety Guide 9. Preoperational testing was performed on D1 and D2 in accordance with paragraph C-3 of Safety Guide 9.

With reference to Paragraph C-4 of Safety Guide 9, tests performed on a prototype of the Unit 1 Emergency Diesel Generator and subsequent calculations indicated that the speed limitations listed in Safety Guide 9 are met by Prairie Island Unit 1 Emergency Diesel Generators D1 and D2.

With reference to voltage variations, the prototype tests and subsequent calculations and surveillance testing indicate that the first inrush seen by the diesel when starting both the safety injection pump and the nonrejected loads that are connected to the EDG supplied bus can cause the voltage to decrease in excess of the 75% of nominal as stated in Safety Guide 9, and not be restored to normal within a maximum of 40% of the step duration (2 seconds). This voltage dip occurs on the first step of load application to the Emergency Diesel Generator and this exception to Safety Guide 9 does not degrade the reliability of the safety features in the plant for the following reasons:

1. Integrated SI testing history shows that < 3 seconds (60% of 5 seconds) is achieved. This is within the guidelines of Reg. Guide 1.9, Revision 2 utilized for D5/D6.

2. The Load Sequencer time interval is controlled by an internal digital clock in the Programmable Logic Controller driven Load Sequencer. This provides a very high degree of accuracy and repeatability in sequence timing. This lessens the needed margin between recovery from the dip and the end of the load step.

3. Historical data shows that the voltage returns to 100% well within five seconds as discussed below, assuring that excitation returns to normal, and full voltage is available for starting equipment at the beginning of the second load sequence step.

Engine speed under loading condition is difficult to predict accurately, but momentary speed drop during predicted inrush conditions will reach 90% with recovery in 2 to 4 seconds. Actual performance verification data is available from the Pre-Operational Surveillance Test results. Surveillance tests (SP1083) have shown 100% voltage recovery within three seconds.

The Unit 2 Emergency Diesel Generators (D5 and D6) meet the requirements of Reg. Guide 1.9, Revision 2, except portions of the 1984 Edition of IEEE 387 were implemented in the factory testing instead of the 1977 revision (NSP letter to NRC, September 9, 1989, Reference 5). These two diesel generators are rated at 5400 KW continuous. Analyses of maximum predicted loading for transient (Reference 41) and steady state conditions (References 36 and 42) show predicted loads are less than the conservative limit of 5400 KW. Thus the guidance of Reg Guide 1.9 paragraph C2 is satisfied. Testing has proven that the loading capabilities required by Reg Guide 1.9 paragraph C4 are also satisfied.

8.4.3 Performance Analysis: Loss-of-Coolant Accident and Loss of Offsite Power

Situations in which the high head safety injection pumps and the Emergency Diesel Generators would be simultaneously required are limited to the loss of either primary or secondary coolant from one Unit, concurrent with the loss of offsite a-c power. In the event of an accident requiring safety injection in one Unit, accompanied by loss of offsite power, the sequence of automatic operations is as follows:

a. A safety injection signal is derived from SI actuation circuits;

b. Reactor and turbine both trip;

c. When the reactor coolant pressure has fallen below 700 psi, the accumulators attached to the cold legs of loops A and B discharge their contents of borated water into the Reactor Coolant System;

d. The Emergency Diesel Generators start and upon loss of offsite power, as sensed by voltage relays, the load sequencers connect each Emergency Diesel Generator to its safeguards bus;

Upon receipt of a command signal, the Emergency Diesel Generators start. Within ten seconds, the EDG is up to speed and ready to accept load. As a result of continuing undervoltage on the buses, designated breakers then close, placing the EDG on the buses which feed the engineered safety features equipment (see discussion under 8.4.2). The load sequence on each Emergency Diesel Generator would be:

Step 1:	Safety Injection Pump and 480 V buses
Step 2:	Residual Heat Removal Pump Containment Spray Pump
Step 3:	121 Cooling Water Pump (Unit 2 only)
Step 4:	Component Cooling Water Pump 2 Fan Coil Units
Step 5:	Auxiliary Feedwater Pump (Unit 1 Train B, Unit 2 Train A) 1 Air Compressor (except Unit 2 Train B)
Step 6:	Pressurizer Heaters EDG Auxiliaries (Unit 2 only)
Step 7:	Control Room Chiller Chiller Water Pump

The time delay between starting the various components is long enough to allow the drive motors to approach synchronous speed (5 seconds or until voltage recovers, whichever is longer) as described in Section 8.4.2. The engines for the emergency diesel driven cooling water pumps are direct-connected to the pumps and operate independently of the Emergency Diesel Generators. Charging pumps are not necessary, and have not been included in the automatic starting sequence.

The instrument Air Compressors have a built-in 10 second restart time delay that will cause them to start after Step 5.

60400000327

The configuration and operation of the Safety Injection System during the injection and recirculation phases of mitigation of a loss of coolant accident are described in Section 6.2.

In addition to the double ended break of a main reactor coolant pipe, all other less severe ruptures of the Reactor Coolant System require the operation of the engineered safety features system to an extent which depends upon the size of the rupture. Very small breaks cause expulsion of the reactor coolant at a rate which may be accommodated by operation of the charging pumps alone.

The double ended rupture of a main reactor coolant pipe remains the most severe of all of these accidents in terms of required operation of the engineered safety features system, and thus it is used together with a loss of auxiliary AC power as the basis for determining the requirements of the Emergency Diesel Generator capacity and, with a shutdown on the second unit, for determining the cooling water requirements, as described in Section 10.

8.4.4 Station Blackout

A Station Blackout (SBO) exists when there is a Loss of Offsite Power (LOOP) and concurrent loss of both of a unit’s Emergency Diesel Generator sources. An SBO is assumed to occur on only one Unit of a two unit site, in accordance with Reg. Guide 1.155. Prairie Island meets the SBO rule of 10CFR50.63 (June 21, 1988) and the related guidance of Reg. Guide 1.155 (August, 1988). Prairie Island is classified as a four hour plant (four hour SBO duration) based on criteria contained in Reg. Guide 1.155 and NUMARC-8700 (References 32 and 33). In accordance with Reg. Guide 1.155 and NUMARC-8700, it has been demonstrated by testing that alternate AC (AAC) from the non-SBO unit’s Emergency Diesel Generator is available and the interconnecting bus ties can be manually closed within ten minutes of the realization that an SBO condition exists to provide power to the required loads on the SBO unit (References 34 and 35). Analysis has shown that the AAC has sufficient capacity to supply the required loads for the non-SBO unit plus the required loads of the SBO unit for the required four hour SBO duration (References 32, 33, and 36) and that adequate condensate inventory is available to provide decay heat removal for the four hour SBO duration (References 32, 33, and 37). Additional coping analyses for other plant systems are not required for the SBO unit per Reg. Guide 1.155 and NUMARC-8700 due to the alignment of AAC to the SBO unit within ten minutes of the realization that an SBO condition exists (References 32 and 33).

EDG Loading criteria:

Because of the low probability of either an SBO or DBA occurring, the simultaneous occurrence of a DBA and SBO is not credible. NUMARC 87-00 provides the loading criteria for an EDG in the non-SBO unit cross-tied to the SBO unit and requires the EDG to carry: (1) the loss of off-site power safe shutdown loads on the non-SBO unit, and (2) the SBO loads on the SBO unit for the required coping duration. Reference NUMARC 87-00 Appendix J Question and Answer B.3.

These loading conditions are analyzed in Reference 36 for each EDG and each EDG is found to be loaded within its continuous rating.

SBO Loads:

Typically during an SBO, once the power is available to the SBO unit through the bus ties, equivalent equipment would be operated in the SBO unit as under a LOOP. Notable exceptions are that the SBO unit’s EDG auxiliaries would not be operated, nor would the 121 Cooling Water Pump for a Unit 2 SBO. This condition is more conservative for the SBO unit than operating the “essential” SBO equipment as required by NUMARC because it includes more load than the essential SBO load.

8.4.5 Non-Safeguards Standby Diesel Generators

Non-safeguards 4.16 KV Buses 31, 41, 32 and 42 are normally supplied from Normal Buses 13, 23, 14 and 24 and their offsite sources, respectively. Buses 31 and 41 serve 480V Buses 310 and 410 respectively which have bus ties to form a double ended load center. Similarly, 480V Buses 320 and 420 are supplied by 4.16KV Buses 32 and 42. These 480V buses serve a variety of non-safeguards loads including plant process computers Uninterruptable Power Supplies, Non-safeguards station battery chargers, turbine generator AC auxiliaries, and miscellaneous Normal motor control center loads. The Bus 31/41 Load Centers are backed up by diesel generator D3, and Bus 32/42 Load Centers are backed up by diesel generator D4.

Diesel generators D3 and D4 consist of General Motors Electromotive Division units which were converted from MP-45 peaking units to emergency standby service. They are rated 2500 KW continuous (2750 KW peak), 0.8 power factor, 900 RPM, 4.16KV, 3-phase, 60Hz. They are radiator cooled with closed cooling,and utilize DC electric starting motors. DC power for engine starting, field flashing, and control is supplied from 125V DC Non-safeguards Systems 31 and 42. The diesel generators are capable of being manually run and synchronized onto the Normal 4.16KV plant buses from their respective control panels in the 31/41 and 32/42 Bus rooms. They are normally left in auto standby with the coolant and lube oil partially heated with a keep-warm system.

Both the 31/41 and 32/42 Load Centers have a load shedding and restoration scheme which will operate in the case that voltage is lost on a 480V bus. If both 480V buses in a load center lose power, then the diesel generator is given a fast start signal, source breakers are tripped, and the diesel comes up to speed and voltage after which the loads are sequenced back on the buses. Each diesel generator also has the capability to test the associated load-shedding and restoration scheme without actually tripping any loads.

THIS PAGE IS LEFT INTENTIONALLY BLANK

8.5 DC POWER SUPPLY SYSTEMS

8.5.1 Safeguards 125 Volt DC System

The safeguards 125 VDC Electrical Power System for each unit consists of two independent and redundant safety related DC electrical power subsystems (Train A and Train B). 125 VDC Subsystems 11 and 12 serve Unit 1 and 125 VDC Subsystems 21 and 22 serve Unit 2. Each subsystem consists of one 125 VDC battery, battery charger, and associated distribution equipment. The configurations of the safeguards 125 Volt DC Systems for both Units are shown in Figures 8.5-1a, 1b, 2a, and 2b.

The 125 VDC Systems supply instrumentation, control, and motive power to safety related equipment. Redundant safety related equipment is divided between the two DC subsystems associated with each Unit such that loss of one DC subsystem does not affect redundant circuits.

The 125 VDC Systems and their components have a Safety Related quality assurance classification. The 125 VDC Systems are qualified to allow operation during and following a Safe Shutdown Earthquake. Specific components were tested or qualified for seismic events as described in Section 7.9.

The battery, battery charger, transfer switches and main panels for each of the 125 VDC Subsystems are located in their associated subsystem's battery room. The four battery rooms are located in a Design Class I area of the Turbine Building on the 695′ elevation as depicted on Figure 1.1-4. Two access routes per room are provided for personnel safety. The access between adjoining battery rooms is through openings in the reinforced concrete block walls. Each of these openings is furnished with a counterweighted gravity sliding Class "A" fire door provided with dual fusible links, one located on each side of the common concrete block wall. Fire dampers are provided in the ventilation ducts.

A detailed description of the safeguards 125 VDC Systems, including associated alarms, indications, procedures, maintenance, surveillance, and test procedures was provided to the NRC in Reference 20 in response to Generic Letter 91-06, Resolution of Generic Issue A-30, "Adequacy of Safety Related DC Power Supplies."

8.5.2 Safeguards Batteries

There are four safeguards batteries, one per 125 VDC Subsystem. The batteries temporarily assure a continuous source of DC electrical power to the DC System in the event of the loss of AC charging power until the AC power to the chargers is restored. The batteries also assist with supplying DC loads when the associated charger cannot supply the total DC load.

The batteries are flooded vented lead acid storage batteries. Each battery consists of 58 cells nominally. The batteries have a nominal rated capacity (to 1.75 volts per cell) of 1800 amp-hours at an 8 hour discharge rate.

One battery charger is in service on each battery so that the batteries are always at full charge in anticipation of a loss of AC power. This ensures that adequate DC power is available for starting the Emergency Diesel Generators and for other emergency uses. Once AC power is restored to the battery charger, it will resume powering the DC system loads and charge the battery.

Each battery has been sized to carry expected shutdown loads following a plant trip, and a loss of AC battery charging power for a period of 1 hour without battery terminal voltage falling below the required minimum. For each battery system, the minimum terminal voltage is that required to maintain the operability of all components required to operate during a design basis event (Reference 21). Battery sizing determination was also done using the methodology of IEEE-485 as guidance and takes into account minimum expected electrolyte temperature and margin for battery aging (Ref. 21). Major loads with their approximate operating times on each battery as well as minimum terminal voltage for each battery are provided in the referenced calculations (Ref. 21).

For Station Blackout, as discussed in section 8.4.4, Prairie Island is categorized as a four hour plant. However, Prairie Island has demonstrated that Alternate AC can be aligned within 10 minutes. Therefore, no coping assessment is required per NUMARC 87-00 Section 7.1.2. The safeguards 125 VDC battery on the SBO unit will provide DC power to support actions on the SBO unit for aligning the Alternate AC source to the SBO unit during the 10 minute timeframe and will power the one division of safeguards battery chargers. The battery sizing load profile stated in the previous paragraph bounds the battery performance load profile for Station Blackout.

8.5.3 Safeguards Battery Chargers

There are five safeguards battery chargers, one per 125 VDC Subsystem plus one portable battery charger. The battery chargers are supplied from the associated safeguards 480 Volt AC System MCC. The battery chargers supply DC electrical power to the connected loads while maintaining safeguards batteries fully charged during normal operation when the AC charging power is available except as allowed by Tech Specs. During transient or accident conditions, the battery chargers are the primary source of DC power when AC charging power is available.

Each of the four stationary battery chargers has been sized to recharge its associated partially discharged battery from a voltage of 105 VDC within 24 hours, while carrying its normal load.

Each battery charger has a nominal rated DC output of 400 amps with an adjustable current limit set under 315 amps at 130 VDC. Both float and equalize voltage are adjustable. The charger supply rating is 90 amps at 480 VAC while supplying 300 amps.

The battery chargers normally operate in float condition supplying power to the connected loads and charging power to their associated battery. Each battery charger has a three phase AC input circuit breaker and a two pole DC output circuit breaker. The battery chargers function to give desired output regardless of whether the battery is connected. The rectifier section of the battery charger ensures that the AC supply system does not become a load on the battery.

One portable battery charger can provide backup service in the event that one of the four stationary battery chargers is out of service. If the portable battery charger is substituted for one of the stationary battery chargers, then the requirements of independence and redundancy between subsystems are maintained.

The battery charger AC input transfer switches and DC output isolation switches allow switching of the normal DC power source from the stationary battery charger to the portable battery charger. These AC input transfer break-before-make switches prevent paralleling the portable and the stationary battery chargers.

8.5.4 Safeguards Distribution Equipment

The DC fused disconnect switches connect the battery to the Safeguards DC panels while protecting downstream loads from the potential fault current of the battery.

The DC load transfer switches allow switching the power sources to selected loads from the 125 VDC Subsystem of one Unit to the same train subsystem on the other Unit. These are break-before-make switches so that it is not possible to parallel the DC subsystems of both units during switching operations.

The main distribution panel for each DC subsystem provides power to loads throughout the plant.

8.5.5 Instrumentation, Controls, and Alarms

Control room alarms are provided for 125 VDC System grounds, undervoltage, fire doors, special exhaust fans, and general trouble. In addition, control room alarms and status indication are provided for several 125 VDC System parameters on the Plant ERCS.

Local indications for battery amps and panel volts are provided in each battery room.

The system operates ungrounded with ground fault detectors provided. With this type of arrangement, two grounds are required (one in the positive line and one in the negative line) before any of the system protective devices would operate. Occurrence of a ground of either polarity of sufficient magnitude, will cause control room alarm. This provides an opportunity for trouble-shooting.

8.5.6 Battery Room Special Exhaust Fans

The Battery Room Special Exhaust Fans (Unit 1: 11 and 12; Unit 2: 21 and 22) provide exhaust flow from the Battery Rooms to prevent the buildup of a combustible concentration of hydrogen gas in the battery rooms. The two fans for each Unit operate in parallel drawing exhaust through a common duct from the Unit's two battery rooms and discharging into a common duct which exhausts to the atmosphere. The battery room special exhaust fans are not required for accident mitigation.

8.5.7 Inspection and Testing

The station batteries and other equipment associated with the battery systems are accessible for inspection and testing. Battery and Battery charger maintenance, surveillance testing, and discharge testing is performed in accordance with Battery Monitoring and Maintenance Program and the plant Tech Specs. 60400000210

8.6 INSTRUMENTATION AND CONTROL AC POWER SUPPLY SYSTEMS

The configurations of the Instrumentation and Control AC Power Supply Systems for both Units are shown in Figures 8.5-1a, 1b, 2a, and 2b. Each Unit has four inverters that each supply one Panel that is dedicated to one Reactor Protection and NIS Channel. These Panels are also referred to as Instrument Buses. Each Unit also has two inverters that each supply one Panel that is dedicated to one train of Event Monitoring and other critical loads.

Each inverter contains an associated rectifier permitting the inverter to be normally fed from an AC source with instantaneous non-interrupted transfer to the DC system on loss of rectifier or AC supply. 01316490

Power supplied to the Instrument Buses is provided by the uninterruptable power supply (ups) which includes an automatic static transfer switch and a manual bypass switch in addition to the inverter. The automatic static transfer switch is designed to transfer the Instrument bus load from the inverter, if it fails, to the AC source through a bypass breaker.

The availability of control power to the engineered safety features trip signals is continuously indicated by means of indicating lights on the engineered safety feature panels and loss of control power for the engineered safety features actuation signals is annunciated in the control room.

A 3-phase 208/120 Volt AC “minimum interruptible bus” is provided on each unit. This bus is identified as Panel 117 on Unit 1 and Panel 217 on Unit 2. These panels are fed from a 480 Volt safeguard bus via a safeguard MCC. Various important AC instrument and control loads that can tolerate an infrequent short interruption (approximately 10 seconds) are fed from these Panels. Inverter loads are transferred to these panels when the inverter fails or must be removed from service for maintenance.

THIS PAGE IS LEFT INTENTIONALLY BLANK

8.7 CABLES AND RACEWAYS

8.7.1 Cable Derating

Current ratings of all the cables used in this plant are based on the values specified for the type of cable used, by IPCEA, NEC, or by the individual cable manufacturer. Power cables are installed in ladder type cable trays. They are installed with only a single layer of cables per tray and clamped in the ladder to ensure that a specified spacing exists between these cables to ensure that air cooling is available. Alternatively, the manufacturer's cable derating based upon random fill is utilized, and the cable installation maintains spacing which provides margin from the assumed random fill.

Control cables are grouped in the trays with random lay, and the ampacity rating for these cables is based on the load of the control circuits involved. NEC derating factors are appropriately applied for multiple conductors in conduit, or multi-conductor cables in tray.

All original construction Power Control and Instrument Wire and Cable used on safeguards related circuits in the plant was purchased and qualification tested from manufacturers certifying that the insulation used on these conductors, including splicing material, would perform satisfactorily and not be appreciably degraded when exposed to the following environmental conditions:

Normal Temperature (40 years)	90°C (194°F) conductor temperature
Emergency Temperature (48 hours)	138°C (280°F)
Pressure	46 psig
Relative Humidity - Normal	70%
Relative Humidity - Emergency	100%
Radiation	5×10^7 Rads
Containment Spray	Dilute solution of Boric (Acid 2000 - 3000 ppm of Boron) adjusted to pH of 9.0 to 9.5 with Sodium Hydroxide
Fire	Successfully pass the so-called "Philadelphia Electric Flame Test" or its equal.

Cables, relays, and control devices supplied by P.S.&E were temperature qualified as follows:

a. Cable and wire - 280°F (138°C) - tested for a minimum of two hours at this figure.

b. Relays and control devices - 178°F (70°C).

All new cable installed after original construction is qualified for the environment it is used in.

8.7.2 Cable Routing

The following categories are those to which the term “Power Cable” shall apply:

4160 volt feeders
480 volt feeders
120/208 volt main feeders and motor feeders
125 volt DC main feeders and motor feeders
125 volt DC subfeeders that are rated 30 ampere or higher

The following categories are those to which the term “Control Cable” shall apply:

120 volt AC and 125 volt DC metering
120 volt AC and 125 volt DC relaying
120 volt AC and 125 volt DC interlocking, indication and controls
120 volt AC and 125 volt DC annunciation
125 volt DC subfeeders with a continuous rating of 25 amperes or less

The term “Instrumentation Cable” shall apply to all cables that are used for low level circuits. The following categories are some of the areas to which this will apply:

Computer input and output signals
Thermocouples
RTD’s
Nuclear instrumentation and monitoring
Electronic control and recording devices
Transducer output signals

Mixing of power cables with control or instrument cables in the same tray is not permitted. Whenever a control and/or instrument cable tray and a power tray are in the same stack, the power tray is located in the top tier. Non-safeguard trays installed in stacks are spaced vertically with a minimum of 12″ bottom to bottom in all areas. However, Class IE trays have a minimum bottom to bottom dimension between trays of 15″ or 36″, depending on adjacent groupings. Class IE trays containing instrument, control, or power cables have a minimum horizontal separation between redundant circuits of 36″. Redundant circuits are not permitted in the same tray or conduit. If closer spacing than 36″ cannot be avoided an approved barrier must be placed between the circuits. Cable trays are routed to avoid a fire hazard area, such as oil storage rooms, oil tanks, etc., whenever possible. When this cannot be done, the cable tray system is protected by fire resisting barriers. Whenever possible, a wall or floor has been introduced between trays carrying redundant safeguard circuits.

Class IE cables for each of the two units in the plant are divided into six(6) basic groups consisting of the four Reactor Protection/NIS (colored) Channels and “A” and “B” redundant trains. Minimum spacing between these groups are maintained as follows:

1.	Redundant A & B Trains	-36″ Horizontally (tray rail to tray rail) and Vertically (tray bottom to tray bottom)
2.	Reactor Protection/NIS Channels	-36″ Horizontally (tray rail to tray rail) and Vertically (tray bottom to tray bottom)
3.	Spacing Between any Reactor Protection/NIS Channel and any redundant A or B Train	-36″ Horizontally (tray rail to tray rail) and 15″ Vertically (tray bottom to tray bottom)

In items 1, 2, and 3, horizontal dimensions indicate clear air space between adjacent side rails. Vertical dimensions are tray bottom to tray bottom.

In item 3, redundant channels and trains are as follows:

Train A and the White and Blue Instrument channels, are redundant to Train B and the Red and Yellow Instrument channels.

In item 3, minimum clear air spacing between bottom of upper tray and top of lower tray is 9″ which allows a maximum 6″ tray siderail for the 15″ vertical spacing. This minimum vertical spacing would also apply between a Class IE Tray and a Non-Safety System Tray.

Lack of separation between a single train and any one channel of Reactor Protection/NIS is allowed as long as the channel has the same power supply as the train. There must not be a lack of separation such that both trains, two channels, or one train and two channels are affected by an uncleared fault.

Where separation is not attainable, protective barriers are provided.

Barriers are required where mutually redundant trays cross. The barriers extend to each side of the protected tray by a distance equal to approximately three times the widest tray involved in either system. Barriers are provided in areas where non-safeguard trays may cause common mode involvement between two or more mutually redundant safeguard systems, and the mutually redundant trays are not separated by more than three times the sum of the widest trays involved in each interaction.

Cable and raceway separation and segregation within the D5/D6 Building and Fuel Oil Storage Area conform to the requirements of IEEE 384-1981 as modified by NRC Regulatory Guide 1.75. Deviations from the requirements contained in those documents are shown to be acceptable and meet the intent of IEEE 384/RG 1.75 through analysis. Cable and raceway interconnections between the D5/D6 Building and existing plant facilities, including direct buried cable, duct runs and other raceway systems, as well as all cables and raceways routed within existing plant facilities, are separated and segregated in accordance with the requirements contained in the balance of this section as a minimum.

Safety related Train B cables are routed from the D5/D6 Building to the plant's Class I corridor through the Turbine Building, a Class III structure. These cables are enclosed in a steel structure to afford them Class I protection. This enclosure is designed as a Class I structure and provides protection from seismic and jet impingement forces. Analysis addressed other concerns, such as cable derating (8.7.1), tornado winds, missiles and fires.

8.7.3 Cable Tray Sharing

Every effort has been made to install safety related cables in their own trays. However, there may be isolated cases where non-safety related cables may be installed in the same trays with safety related cables. Non-safety related cables are not routed with cables of one safety-related system and then routed through its mutually redundant system.

8.7.4 Fire Protection

Fire Protection is discussed in Section 10.3.1. 01484954

8.7.5 Cable and Cable Tray Markings

Each tray section of the cable tray system has an identifying code indicated on the drawings and the same identification is stenciled on the tray after it is installed. This stenciling is applied on each section of the tray whenever the code changes. Any tray that is continuous through walls or floors has the identifying code stenciled on both sides of the wall or floor. Cable trays assigned to safety related circuits are also color coded. This coding is accomplished by a strip of colored plastic tape 2″ wide by approximately 3″ long affixed to the tray near the stencilled identifying number. Conduits carrying safety related conductors are similarly color coded with a wrap of colored tape affixed to each end of the conduit and on either side of the wall or floor it passes through. Straight portions of the conduit have this tape affixed at suitable intervals. Each multi-conductor control or instrument cable has a 1″ diameter brass identifying tag at each end carrying the cable number, which is affixed on to the outer jacket of the cable.

Safety related control cables have a colored strip applied to the jacket approximately 1 foot long at intervals of approximately 10 feet.

Cable color coding consists of 6 colors, based primarily on 6 sources of electrical supply.

The first two supplies consist of Train “A” and Train “B”. This may be 4160V AC, 480V AC, 240V AC, 120V AC or 125V DC. These AC supplies are fed directly from either offsite sources or Emergency Diesel Generators D1 and D2 for Unit 1, and from D5 and D6 for Unit 2. The DC Sources are fed from 125 VDC systems 11 and 12 for Unit 1, and from 125 VDC systems 21 and 22 for Unit 2.

The remaining 4 supplies consisting of 120V AC for instrument and reactor protection channels are fed from 4 separate inverters.

All cables associated with safeguards related equipment are color coded.

a. Train “A” supplies and controls are color coded “Orange”.

b. Train “B” supplies and controls are color coded “Green”.

c. Reactor protection and nuclear instrumentation systems (supply and control) listed as Channel I are color coded “Red”.

d. Reactor Protection and N.I.S. (supply and control) listed as Channel II are color coded “White”.

e. Reactor Protection and N.I.S. (supply and control) listed as Channel III are color coded “Blue”.

f. Reactor Protection and N.I.S. (supply and control) listed as Channel IV are color coded “Yellow”.

Power Supplies to the 4 inverters must originate from either Train “A” or Train “B”, White and Blue inverters are fed from Train “A” sources (either AC or DC) and Red and Yellow inverters are fed from Train “B” sources (either AC or DC).

If an engineered safeguards circuit is either Train A or Train B it can be easily distinguished from a reactor protection channel due to color coding.

If the circuit in question is an instrument channel entering a logic matrix with 2 or 3 other similar channels to form two safeguards action trains (“A” or “B”) by means of 2 out of 3, 2 out of 4, or similar logic means, that channel bears the same color code as the instrument bus (inverter) supplying it. AMSAC AFW actuation logic takes exception to this criteria, due to its required diversity of power.

Color coding is not intended to spell out the individual usage of each cable. The metal tag at the end of each cable carries a number distinctive to that one cable and by checking drawings this number can be used to find the exact usage of each cable.

Color coding was established as an easy means of maintaining the specified separation between 6 systems or sets of control, namely Train “A”, Train “B” and 4 instrument channels.

8.7.6 Relay Room Arrangement

The Safeguards Relay Racks and Reactor Protection Relay Racks are located in the Relay Room. The Safeguards and Reactor Protection Relay Racks are separated into “A” train and “B” train groups. Each train is in a common line-up with an approximate 5′-0″ aisle between groups.

The cable routing in this room is primarily in cable trays. The separation provided is in accordance with the previously stated separation criteria, except that one train is not allowed to interact with one channel even if the channel has the same power supply as the train.

8.7.7 Panel Wiring Separation

Control board switches and associated lights are furnished in modules. Modules provide a degree of physical protection for the switches associated lights and wiring.

The control board layout is based on making it easy for the operator to relate the control board devices to the physical plant and to determine at a glance the status of related equipment. This is referred to as providing a functional layout. Within the boundaries of a functional layout, modules are arranged in columns of control functions associated with separation trains defined for the Reactor Protection and Engineered Safeguards Systems. Teflon covered wire is generally used within the module and between the module and the first termination point.

The interface between the control board wiring and field wiring is made in terminal board cabinets one level below the control board. Teflon covered cables with connectors are provided for control board to terminal board cabinet interconnection. These cables are secured to metal supports to ensure separation of the cables consistent with the separation afforded by the front panel layout.

Redundant components are located in separate racks which are shown on Figure 7.8-1, which also shows the general arrangement of the control room.

Separation between redundant relay and terminal block cabinets is accomplished by using a separate cabinet for each train of components. Where redundant cabinets are placed side by side, the solid metal side walls of each cabinet provides the separation requisite.

Redundant Local Racks, Panels, and Control Stations used with Safeguards Systems are either separated by 3 feet of air space or an appropriate barrier is placed between the redundant components.

Instruments used with Safeguards Systems are either separated by a minimum air space of 36″ between mutually redundant devices or are mounted on independent racks separated by a minimum clear air space of 36″.

Cables entering redundant Local Racks, Control Stations Instrument Stations, Relay Cabinets, and Terminal Cabinets are designed to meet “Cable Separation” Criteria discussed in Section 8.7.2 “Cable Routing”.

Control Modules on the Control Boards in the Main Control Room, have a minimum center-to-center separation of 4-1/2″. Such controls are completely enclosed in a Fire Resistant housing. Cables are connected to these modules with plug-in metal connectors and the cables are insulated and jacketed with Teflon. The criteria for minimum separation between redundant cable is 4-1/2″ except in cases where redundant cables enter the same Control Module where center-to- center separation is 3-1/4″ and except for cases of reduced separation that have undergone technical evaluation (Reference 13).

Panels containing safety related components have redundant counterparts located in separate cabinets or isolated areas within cabinets. This includes such devices as 4160 V undervoltage transfer relays and automatic permissive starting sequence relays; emergency diesel generator protection and control relays; D.C. Distribution Panels; and Terminal Block Panels for redundant safety related wiring to main control board.

8.7.8 Electrical Penetrations

Electrical penetrations entering the Reactor Building are subdivided into 6 basic groups:

Approx. Dimensions:

|← 9′ →|← 9′ →|← 54′ →|← 9′ →|← 9′ →|

A	B	C	D	E	F

Each of the six groups has provision for 12 penetrations. The configuration in each group is three wide by four high. Each penetration in each group is spaced 2′-0″ center to center from any penetration in its group.

Groups A, B and C are located in one quadrant of the containment vessel with groups D, E, and F located in another quadrant approximately 54′-0″ apart.

Each group of penetrations in each quadrant is separated by a distance of approximately 4′-0″ to any adjacent penetration in any other group.

Each penetration in a group has a specific circuit function, e.g., Nuclear Instrumentation, Instrumentation and Control, Low Voltage Power, and Medium Voltage Power. In addition, each group of penetrations is assigned an Engineered Safeguards Train and Reactor Protection Channels as follows:

Group A - Normal circuits

Group B - Normal and Channel II circuits

Group C - Normal, Train “A” and Channel III circuits

Group D - Normal, and Train “B” circuits

Group E - Normal, Train “B” and Channel I circuits

Group F - Normal, Train “B” and Channel IV circuits

Cables passing through the air annulus between the reactor building and the containment building are segregated into the six basic groups as shown above and the same relative spacing between the six groups is maintained, as the cables pass through this air annulus.

When control and instrumentation connections between cables within the containment and the penetration connections are made at terminal blocks, exposed connections are covered with environmentally qualified materials suitable for the LOCA environmental conditions.

8.7.9 Annulus Cable Supports

All electrical cables in the annulus are provided with support systems of various methods.

Generally, the cables are supported by tiers of cable trays that are supported by structural members bearing on the external support concrete and tied back to the shield building. Power cables are clamped to the cable tray system with enough slack allowed at both ends so as to accommodate differential movements between the two buildings without interaction. Control cables are not clamped to the cable tray system and slack has been allowed at both ends.

The large 5000 volt cables used for the reactor coolant pump are supported somewhat differently. A supporting framework is clamped to the penetration nozzle (part of the containment vessel) to provide a rigid support for the cables at the outboard end of the porcelain bushings. The cables have approximately 18″ of slack prior to entering the embedded conduit in the shield building.

Annulus lighting system cables are all fully supported in conduit, which is fastened only to the shield building by clamps.

THIS PAGE IS LEFT INTENTIONALLY BLANK

8.8 INSPECTION AND TESTING

Historic Background for Class I Electric Equipment:

Inspection and testing at vendor factories and/or during construction were conducted to demonstrate the following on all Class I electrical equipment:

a. All electrical assemblies operate within their design ratings;

b. All components are properly mounted;

c. All metering and protective devices are properly calibrated and function correctly;

d. All connections are properly made and the circuits are continuous. Operational testing of the normal and standby power systems were conducted under conditions which simulate the loss of offsite power conditions. This testing demonstrated the following:

   1. All essential loads can be operated in the proper sequence for each Design Basis Accident condition with normal power for essential loads available;

   2. The relaying and control system can detect a loss of external power and, with the buses dead, start and load the standby power sources;

   3. The standby power sources can provide sufficient power for an adequate time interval.

Historic Background for D1/D2 Qualification and Testing:

The essential requirements of generator sets for nuclear power plant protection include positive start, rapid acceleration and load acceptance with acceptable voltage drop and fast recovery to rated voltage. To obtain more information related to these requirements with the 3000 KW Unit 1 emergency diesel generator sets (D1 and D2), the following tests were conducted:

a. Start, Parallel and Load Acceptance

   Arrangements were made to isolate a block of power house engines and suitable resistive load from factory operations for these demonstrations.

   Automatic equipment was set up to synchronize the test generator set with the power house engines. The synchronizer signal simultaneously opens the power house engine breakers, and closes the test generator set breaker connecting 3000 KW resistive load.

b. Motor Starting

Motor starting tests included:

1. Across line starting 2000 HP motor

2. Across line starting 1250 HP motor

3. Across line starting 2000 HP and 1250 HP motors simultaneously

4. Across line starting 2000 HP and 1250 HP motors with 1000 KW initial resistive load.

5. Simultaneous start of 3000 KW generator set and 2000 HP motor

6. Simultaneous start of 3000 KW generator set and 1250 HP motor

7. Simultaneous start of 3000 KW generator set, 1250 HP motor and 2000 HP motor

8. Locked rotor tests of 2000 HP and 1250 HP motors.

Demonstrations of motor start capabilities were conducted with unloaded motors. However, it is believed that the data obtained permits accurate prediction of starting similar motors with specified loads.

c. Instantaneous Overload Capability

With the engine producing 3000 KW on a resistive load bank, an additional 1000 KW resistive load was added for 7-1/2 seconds duration. These demonstrations showed that the system would accept the additional load and recover to rated frequency and voltage during the overload condition. The purpose of this demonstration was to show capability of accepting overload surges which may occur when a large motor “locks in” during the starting cycle.

d. Reliability Test

Test information for the Prairie Island Unit 1 Emergency Diesel Generators consists of the information obtained from the prototype tests performed in the manufacturer's plant on September 13 and 14, 1968. The various tests performed are the same as those listed in b. above. The first test consists of cross-the-line starting of a 2,000 horsepower motor. Test figures indicated that at initial inrush the voltage dipped to a figure approximately 55% of normal. The locked rotor KVA of this 2,000 horsepower motor was approximately 11,000 KVA. The manufacturer's curves supplied with the Prairie Island generator indicates that for a starting KVA of 11,000 the voltage dip can be expected to reach 50% of rated. Calculations for the Prairie Island diesel generators indicate that the initial in-rush seen on either generator is approximately 6,800 KVA and is the worst condition.

Curves for the D1/D2 generators indicate that for an inrush of 6,800 KVA the initial voltage dip will be to approximately 62% of normal and will recover to 100% of normal within 1-1/2 seconds. The inrush KVA imposed on the factory engine during the prototype test was approximately 1-1/2 times that calculated for the Prairie Island engines. Because the prototype tests indicated that a larger load than anticipated at Prairie Island could be safely started and brought up to speed, and no difficulties were expected with the Prairie Island engines.

Another of the tests performed on the prototype consists of cross-the-line starting of both a 2,000 and a 1,250 horsepower motor. This represents an in-rush of approximately 18,000 KVA. Voltage dip at this point was approximately 40% of rated and full recovery to normal voltage was delayed until the in-rush reduced to approximately 8,000 or 9,000 KVA. The test indicated the motors could be started and accelerated to speed. Testing as indicated was more severe than anything that can be predicted for the Prairie Island units.

In addition to the performance requirements of a satisfactory nuclear power plant protection system, reliability is an extremely important aspect. To prove the generator set, arrangements were made to demonstrate its reliability.

The generator set was direct connected to a water rheostat. The system was adjusted to 3000 KW load and suitable controls attached to effect the following sequence:

1. Start unit and accelerate it to rated speed and load.

2. Maintain 3000 KW load for five minutes.

3. Stop generator set without an idling or cooling off period.

4. Allow to stand for 1 hour, 55 minutes permitting temperatures to drop to the keep warm level.

5. Repeat 1, 2, 3, and 4 above through 100 consecutive cycles.

The prototype unit started each time with no failures. Each start was accomplished in 10 seconds or less. At end of the test, the unit was disassembled for inspection and was found to be in excellent condition.

Based on these 100 successful starts the probability of success (reliability) in starting the Emergency diesel generator within 10 seconds after initiation of the Start Signal is calculated to be 0.977 at a 90% confidence level. See Figure 8.8-1.

The Confidence Level is the probability that the calculated reliability is no less than the actual reliability. In other words, an increase in confidence level will add conservatism to the calculated reliability. This is necessary since the failure data sample is small (no failures in 100 starts). Also, the Calculation ($r=e^{-\lambda t}$, λ=Failure Rate, t=Mission Period or Cycle, λt=Failures/Test) was based on the exponential distribution of failures. This was an acceptable assumption until sufficient failure data is obtained which proves that the failures fit a distribution other than the exponential distribution.

Additional failures per start data were accumulated during the weekly emergency diesel generator tests. Starting each of the two diesel generators once a week accumulated an additional 200 starts in 23 months. This added to the 100 prototype engine starts represents data accumulated on 300 starts.

The acceptance test consisted of a 100 hour run at full (3000 KW) load. Subsequent plant tests were run to establish that the total and incremental blocks of load could be adequately started and maintained.

These tests have established the reliability and capability of the emergency diesel generators to provide their design function.

The Auxiliary Electrical System is tested at regular intervals during the life of the plant to demonstrate the capability of the system to provide sufficient power to the essential loads.

Since the emergency diesel generators are utilized as standby units, readiness is of prime importance. Readiness can best be demonstrated by periodic testing which, insofar as practical, simulates actual emergency conditions. The testing program is designed to test the ability to start the system as well as to run it under load for a period of time long enough to bring all components of the system into equilibrium conditions, to assure that cooling and lubrication are adequate for extended periods of operation. Full functional tests of the automatic circuitry are conducted on a periodic basis to demonstrate proper operation.

If the number of tests were increased to possibly 300, it was felt that the calculated reliability could be raised to 99% based on an anticipated failure rate of two or three in 300 starts.

Northern States Power Company accumulated this additional failures per start data on D1/D2 during the initial preoperational and startup test phase of Prairie Island Unit #1 startup. This data when added to the 100 prototype engine starts represents data accumulated on 300 starts.

The Unit 1 emergency diesel generator preoperational testing program included tests that:

1. Verified that the diesel generator's control, power and auxiliary systems can be normally maintained at a ready operating condition.

2. Verified that the various control switches in the diesel generator rooms activate the engine stopping relay.

3. Verified that the diesel operators can be started and controlled from the diesel generator rooms.

4. Verified that the diesel generators can be started and controlled manually from the control room G-1 panel.

5. Verified that the diesel generators automatically trip from the various engine trip signals and the alarms do occur, but does not trip from these signals if the MCA relay is closed.

6. Verified that the diesel generators can be paralleled with the NSP interconnected system and operated at various loads for a two week period. This test also included fuel consumption tests.

7. Verified that the diesel generators can carry a load of 3250 kilowatts for 30 minutes.

8. Verified that the diesel generators start when initiated by the undervoltage relay scheme on each 4160 volt bus to which the diesel generator is connected.

9. Verified that the diesel generator performance upon loss of the largest single load during emergency operation, does not adversely affect either of the diesel generators. These tests involved loading the diesel generators as outlined in Table 8.4-1 of FSAR Amendment 19, tripping of the largest single load, and measuring the voltage and frequency disturbance. This test also verified the proper loading sequence and include pumping of water to the vessel with the RHR pumps and the safety injection pumps.

The above tests were part of the Preoperational (Preop) Test Program for D1/D2 and the results are available in the Prairie Island Plant Preop Test File. All subsequent starting and testing is documented and becomes part of the plant surveillance file.

Historic Background for D5/D6 Qualification and Testing:

The Unit 2 Emergency Diesel Generators (D5/D6) underwent the following factory tests conducted by the manufacturer, SACM. This testing fulfilled the requirements for qualification testing delineated in Reg Guide 1.9, December 1979, and IEEE-387 with two principle exceptions, discussed in NSP's letter of September 29, 1989 (Reference 5) to the NRC, and accepted by their letter of January 31, 1990 (Reference 7). The first exception is utilizing portions of the 1984 edition of IEEE-387 instead of the 1977 edition invoked by Reg Guide 1.9. The second was 70 start and load acceptance tests, (item b. below) in place of the prescribed 300. The basis of this lesser number of start tests is summarized in item d. below.

a. Load Capability Test

   The genset was started and run until system temperatures were at equilibrium. The generator set was then loaded to 110% of nameplate load for a continuous period of two hours. The generator set was then loaded to 100% of nameplate load (5400KW) for a continuous period of twenty two hours. Finally, the generator set was tested for loss of load transient response, which verified that engine overspeed values remained within acceptable parameters.

b. Start and Load Acceptance Test

   The genset was started thirty times at standby temperatures and five times at normal operating temperatures. The diesel generator set was required to start and reach operating speed within ten seconds for this test and was step loaded to 50% of the continuous rating.

   Each diesel generator set was subjected to one simulated loading sequence, using appropriate combinations of motor and resistive loads. Motors with horsepower ratings of 250, 750, and 1000 HP were used in combination to closely match the values for each sequence step load. Loading was continued until the 5400 KW generator load rating was reached. The generator set then underwent a loss of 100% load test with voltage and frequency monitored during the transient.

c. Margin Test

   The diesel generator set underwent two margin tests, each consisting of start, acceleration, and step loading to a value at least 10% larger than the largest step load. A step loss of this load was then initiated, with voltage and frequency monitored during the transient.

d. Reliability Test

For the type of diesel generator set utilized for Prairie Island Unit 2, SACM applied extensive qualification testing for other nuclear sites. The results of this type testing included:

1. over 600 successful test cycles (start and load) without a failure,

2. over 1500 successful starts without a failure, and

3. over 100 starts with various subsequent loading profiles successfully applied.

This extensive testing, in conjunction with the factory testing described above, demonstrated the ability of the diesel generator sets to reliably start and carry load under required conditions. The high operational reliability of these generator sets and low failure rate (1.25 x 10 -3/hour) support the qualification of this design for emergency use at Prairie Island.

Site testing implemented the guidance of Reg Guide 1.108, August 1977, as outlined in NSP's letter of September 29, 1989 (Reference 5), including repeat of the factory 24-hour load run. The Unit 2 diesel generator preoperational testing program included tests that:

1. Demonstrated proper startup operation by simulating loss of all AC voltage and demonstrating that the diesel generator set could start automatically and attain the required voltage and frequency within acceptable limits.

2. Demonstrated proper operation under design accident loading sequence with voltage and frequency maintained within acceptable limits.

3. Demonstrated full load carrying capability for 24 hours of which 22 hours was at a load equivalent to the continuous (100% nameplate) rating of the diesel generator, and two hours was at a load equivalent to 110% of nameplate rating. This test, in conjunction with others, also verified proper operation of the cooling system.

4. Demonstrated proper operation during load shedding, including loss of the largest single load, and a complete loss of load, without exceeding voltage transient requirements and overspeed limits.

5. Demonstrated functional capability at full load temperature conditions by rerunning test one and two immediately following test three above.

6. Demonstrated the ability to synchronize with offsite power while connected to the emergency load, transfer this load to offsite power, isolate and return the diesel generator to standby status.

7. Demonstrated proper performance while switching from one fuel oil supply to another.

8. Demonstrated the capability to supply emergency power within required time was not impaired during periodic testing.

9. Demonstrated required reliability by performing 35 consecutive starts for each generator set.

10. Demonstrated proper functioning of the load sequencers under simulated emergency conditions to trip load breakers, start the diesel generators, select proper source for the emergency bus, and sequentially load the bus.

    A loss of power memory test was also performed on the programmable logic controller (PLC) to verify proper resumption of operation upon restoration of power to the PLC.

11. Verified air start cranking capacity to crank the diesel engine at least five times without recharging the air receiver.

The above tests and results are maintained in the Prairie Island plant files.

Periodic testing and surveillance of the diesel generators are performed in accordance with the requirements contained in the Technical Specifications. The tests specified for the diesel generators will demonstrate their operability and continued capability to start and to carry rated load. Each Emergency Diesel Generator is required to meet a target reliability of 97.5% as determined by NUMARC 87-00, Appendix D, Rev. 1. 04-022

8.9 ENVIRONMENTAL QUALIFICATION OF SAFETY-RELATED ELECTRICAL EQUIPMENT

The Equipment Qualification Branch of the Office of Nuclear Reactor Regulation, Nuclear Regulatory Commission (NRC), has required all licensees of operating reactors to submit a re-evaluation of the qualification of safety related electrical equipment which may be exposed to a harsh environment. This requirement was implemented primarily by the issuance, on January 14, 1980, of IE Bulletin No. 79-01B (Reference 8) with subsequent clarifying supplements in February, September, and October, 1980.

The Bulletin required that a master list of safety related systems and equipment be generated, all accident service conditions be defined, and the equipment be evaluated in accordance with guidelines in the bulletin.

Northern States Power Company has provided responses to the Bulletin in March, May, July and October 1980. The October 31, 1980 (Reference 9) submittal represented the final response to IE Bulletin No. 79-01B. This response included revised system component evaluation worksheets and provided a complete and current “Master List”.

On May 22, 1981, the NRC issued the Prairie Island Nuclear Generating Plant Safety Evaluation Report (SER) (Reference 10) which summarized their assessment of the March, May, July and October 1980 submittals. A response to IE Bulletin No. 79-01B SER was submitted to the NRC in a letter dated August 26, 1981 (Reference 11). This submittal includes a detailed response to the NRC evaluation and provides documentation of the Equipment Qualification Program that is being undertaken by Northern States Power Company. The program ensures that all safety related equipment is capable of performing its safety related function during postulated accident conditions.

A follow-up submittal was made to the NRC on April 30, 1982 (Reference 12). This submittal included a revised Master List and Component Evaluation sheets reflecting updated qualification information and newly identified components, qualification information for TMI Action Plan equipment and a list of outstanding items and schedule for completion. On August 27, 1982, information regarding pressure and temperature profiles outside containment in relation to the environmental qualification review was submitted in response to an NRC request (Reference 14).

On April 25, 1983, the NRC issued a Safety Evaluation for environmental qualification of safety-related electrical equipment which summarized their assessment of the August 26, 1981, February 1, April 21, and April 30, 1982 submittals (Reference 15). A response to this SER dated Nov. 23, 1983 summarized the status of deficiencies noted in the April 25, 1983 safety evaluation.

On January 21, 1983 the NRC published in the Federal Register the final rule on environmental qualification of electric equipment important to safety for nuclear power plants. The rule became effective on February 22, 1983. This rule superseded all previous NRC requirements for environmental qualification of electrical equipment.

This rule, Section 50.49 of 10 CFR 50, specifies the requirements for environmental qualification of electrical equipment important to safety located in a harsh environment. In accordance with this rule, equipment for Prairie Island may be qualified to the criteria specified in either the DOR guidelines or NUREG-0588, except for replacement equipment. Replacement equipment installed subsequent to February 22, 1983 must be qualified in accordance with the guidance of Regulatory Guide 1.89, unless there are sound reasons to the contrary.

A meeting was held with the NRC on December 1, 1983 to discuss all remaining open issues regarding environmental qualification, including acceptability of the environmental conditions for equipment qualification purposes. Discussions also included general methodology for compliance with 10 CFR 50.49, and justification for continued operation for those equipment items for which environmental qualification was not yet completed. The minutes of the meeting and proposed method of resolution for each of the environmental qualification deficiencies are documented in Reference 16.

The proposed resolutions for the equipment environmental qualification deficiencies, identified in earlier correspondence are described in Reference 15. During the December 1, 1983 meeting, the staff discussed the proposed resolution of each deficiency for each equipment item and found the NSP approach for resolving the identified environmental qualification deficiencies acceptable. The majority of deficiencies identified were documentation, similarity, aging, qualified life and replacement schedule. All open items identified in the SER dated April 25, 1983 (Reference 15) were also discussed and the resolution of these items were found acceptable by the NRC Staff.

The methodology used to determine compartment pressure and temperature profiles is described in USAR Appendix I.5.3 (Compartment Pressure and Temperature). Peak pressures and temperatures in principal compartments are identified, and referenced calculations provide peak values in other Auxiliary Building compartments as well as long-term pressure and temperature time histories.

Regulatory Guide 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors,” provides guidance to licensees of operating power reactors on acceptable applications of ASTs; the scope, nature, and documentation of associated analyses and evaluations; consideration of impacts on analyzed risk; and content of submittals. This guide establishes an acceptable AST andidentifies the significant attributes of other ASTs that may be found acceptable by the NRC staff. This guide also identifies acceptable radiological analysis assumptions for use in conjunction with the accepted AST. This RG states that licensees may use either the AST or the TID-14844, “Calculation of Distance Factors for Power and Test Reactor Sites,” assumptions for performing the required environmental qualification analyses to show that the equipment remains bounding. RG 1.183 further states that no plant modifications are required to address the impact of the difference in source term characteristics (i.e., AST versus TID-14844) on environmental qualification doses. 01406407

As part of implementing AST, Prairie Island will continue to use the TID 14844 methodology to determine radiation doses in the EQ analyses.

Three categories of electrical equipment were identified in 10 CFR 50.49 as requiring environmental qualification. Equipment described in paragraph (b)(1) of 10 CFR 50.49 has been identified through a review of the accident analyses provided in the FSAR, a review of the emergency procedures, a review of safety system flow diagrams and Q-List, and a review of the installed equipment locations with respect to postulated harsh environmental zones. Our current master equipment list includes all equipment within the scope of paragraph (b)(1) of 10 CFR 50.49.

Equipment identified in paragraph (b)(2) of 10 CFR 50.49 is non-safety-related electrical equipment whose failure could prevent accomplishment of safety functions of equipment identified in paragraph (b)(1) of 10 CFR 50.49.

This equipment was principally identified through system review criteria and identification of display instrumentation referenced in the LOCA and HELB emergency procedures. The methodology used is summarized below:

- The wiring diagrams of safety related electrical equipment as defined in paragraph (b)(1) of 10 CFR 50.49 were reviewed to identify any auxiliary devices, electrically connected directly into the control or power circuitry, whose failure due to postulated environmental conditions could prevent the required operation of the safety-related equipment.

- The review discussed above addressed the potential failure of safety-related electrical equipment after its qualified operating time but before the end of the postulated accident.

Post-accident monitoring equipment has been identified in accordance with paragraph (b)(3). In addition, our response to NUREG-0737, Supplement 1 - Generic Letter 82-33 was transmitted to the NRC on September 15, 1983. This letter identified the qualification requirements and implementation schedule for Regulatory Guide 1.97 equipment. This equipment was qualified and added to the master equipment list in accordance with the schedule provided in the September 15, 1983 letter.

The master equipment list contains the necessary equipment to mitigate the consequences of all Design Basis Accidents (DBAs) identified in the FSAR, including flooding in the auxiliary building.

Equipment qualification is an on-going process that requires implementation into the activities of plant operation. The master equipment list (EQML) will change over the course of plant life due to system design changes, replacement equipment, or additional (b)(1), (b)(2), and (b)(3) equipment identified through procedural changes, licensing changes, etc. The PINGP EQ Program was developed to establish and maintain the regulatory requirements for the environmental qualification of electrical equipment. The program provides for such activities as the identification of electrical equipment within the program, the environmental specifications by plant location, providing auditable documentation supporting the equipment's environmental qualification, and ensuring appropriate reviews affecting environmentally qualified equipment are performed as required.

Equipment in the D5/D6 Building, a "mild" environment, is not subject to the requirements of 10CFR50.49.

8.10 POWER OPERATED VALVES

8.10.1 Motor Operated Valves

IE Bulletin 85-03 “Motor-Operated Valve Common Mode Failures During Plant Transients due to Improper Switch Settings” and its supplement (Reference 22 and 23) were issued to ensure that switch settings on certain safety-related motor-operated valves (MOVs) were selected, set and maintained correctly to accommodate the maximum differential pressures expected during both normal and abnormal events within the design basis.

In June of 1989, IEB 85-03 was superseded by Generic Letter 89-10 “Safety-Related Motor Operated Valve Testing and Surveillance” (Reference 24). Generic Letter 89-10 recommended that a program be established to ensure that all safety-related MOVs are selected, set and maintained appropriately. Several supplements to Generic Letter 89-10 (Reference 25) have been issued to clarify program scope, schedule, and recommendations. In August 1995, the NRC conducted a closeout inspection to verify the completeness of NSP’s commitments made in response to Generic Letter 89-10 (Reference 26).

In September 1996, the NRC issued Generic Letter 96-05 “Periodic Verification of Design-Basis Capability of Safety related Motor-Operated Valves” (Reference 27) which superseded GL 89-10 and its supplements. The generic letter requested that licensees establish a program, or ensure the effectiveness of its current program, to verify on a periodic basis that safety related MOVs continue to be capable of performing their safety functions within the current licensing basis of the facility.

Prairie Island modified its periodic verification program to meet the intent of the generic letter. The NRC reviewed the Prairie Island periodic verification program and concluded that the program adequately addressed the actions requested in GL 96-05 (Reference 28).

8.10.2 Generic Letter 95-07, “Pressure Locking and Thermal Binding of Safety Related Power-Operated Valves”

Generic Letter 95-07 (Reference 29) was issued by the NRC requesting licensees to provide information concerning; (1) the evaluation of operational configurations of safety-related, power-operated gate valves for susceptibility to pressure locking and thermal binding; and (2) analyses, and needed corrective actions, to ensure that safety-related power-operated gate valves that are susceptible to pressure locking or thermal binding are capable of performing the required safety function.

All Motor Operated Valves (MOVs), Air Operated Valves (AOVs), and Hydraulically Operated Valves (HOVs) were reviewed to determine applicability of this issue.

For those valves which were identified to be potentially susceptible, an evaluation was performed to ensure each valve can perform its intended safety function. The NRC has determined that Prairie Island's evaluation and resulting corrective actions adequately addressed Generic Letter 95-07 (Reference 30).

A plant modification (Reference 40) drilled a 1/8" diameter hole in the upstream disc of the motor operated valve MV32206, and MV32207 (MV32208, MV32209) allows pressure inside the bonnets to equalize with upstream Residual Heat Removal cross-over line. The equalization in pressure will preclude pressure locking.

A Plant Modification (Reference 45) installed bonnet vents on MOVs MV32077 and MV32078. The bonnets of these valves have a vent line installed to eliminate the possibility of pressure in the bonnets. The valves are flex wedge gate valves. The vent will be routed back to the process piping. This equalization in pressure will preclude pressure locking. 01431472

8.11 REFERENCES

1. Letter, T.M. Parker (NSP) to Nuclear Regulatory Commission, “Reply to Questions on Design Report for the Station Blackout/Electrical Safeguards Upgrade Project”, July 10, 1991. (2850/1690)

2. Letter, C E Larson (NSP) to Director of Nuclear Reactor Regulation, “Interim Response to NRC Bulletin 88-10”, March 31, 1989. (2040/2135)

3. Letter, T M Parker (NSP) to Director of Nuclear Reactor Regulation, “Response to NRC Bulletin 88-10, Supplement 1, Nonconforming Molded-case Circuit Breakers”, November 6, 1989. (2040/2148)

4. Letter, D C DiIanni (NRC) to T M Parker (NSP), “Response to Bulletin 88-10 and Supplement 1 ’Nonconforming Molded-case Circuit Breakers’ Prairie Island Nuclear Generating Plant Unit Nos. 1 and 2”, March 7, 1990. (1857/0809)

5. Letter, T M Parker (NSP) to Director of Nuclear Reactor Regulation, “Project for Addition of Two Emergency Diesel Generators”, September 29, 1989.

6. Deleted

7. Letter, D C DiIanni (NRC) to T M Parker (NSP), “Safety Evaluation Related to the Emergency Diesel Generator Qualification Plan (TAC Nos 68588 and 68589)”, January 31, 1990. (30814/0111)

8. IEB 79-01B, Environmental Qualification of Class IE Equipment, January 14, 1980. (1061/0451)

9. Letter, D E Gilberts, (NSP) to J G Keppler (NRC), “Prairie Island Nuclear Generating Plant - Final Response to IE Bulletin No. 79-01B”, October 31, 1980. (1061/0996)

10. Letter, R A Clark to L O Mayer, “Environmental Qualification of Safety-Related Equipment” (includes SER), May 22, 1981. (18309/1155)

11. Letter, L O Mayer (NSP) to Director of Nuclear Reactor Regulation, “Response to IE Bulletin No. 79-01B Safety Evaluation Report”, August 26, 1981. (18309/1900)

12. Letter, L O Mayer (NSP) to Director of Nuclear Reactor Regulation, “Response to IE Bulletin 79-01B Safety Evaluation Report”, April 30, 1982. (18311/1871)

13. Licensee Event Report, RE-93-14, “Cable Separation at Main Control Board”, December 16, 1993. (2869/0157)

14. Letter, D Musolf (NSP) to Director of Nuclear Reactor Regulation, “Pressure and Temperature Profiles Outside Containment”, August 27, 1982. (18312/1023)

15. Letter, R A Clark to D M Musolf, “Safety Evaluation for Environmental Qualification of Safety-Related Electrical Equipment, April 25, 1983. (18347/2178)

16. Letter, D M Musolf (NSP) to Director of Nuclear Reactor Regulation, “Resolution of Safety Evaluation Report for Environmental Qualification of Safety-Related Electrical Equipment”, January 16, 1984. (19896/0388)

17. WCAP-10961-P, “Steamline Break Mass/Energy, Releases for Equipment Environmental Qualification Outside Containments” Report to the Westinghouse Owners Group, October, 1985.

18. Deleted

19. ENG-EE-171, Degraded Voltage Analysis.

20. Letter, NSP to NRC, “Response to NRC Generic Letter 91-06: Resolution of Generic Letter Issue A-30,” “Adequacy of Safety Related DC Power Supplies,” 10-28-91.

21. Calculations 91-02-11, 91-02-12, 91-02-21 and 91-02-22, Battery Sizing and System Voltage Drop and Short Circuit Analyses for Safeguard Batteries 11, 12, 21 and 22 respectively.

22. IE Bulletin 85-03, “Motor-Operated Valve Common Mode Failures During Plant Transients due to Improper Switch Settings”, dated November 15, 1985.

23. IE Bulletin 85-03, Supplement 1, “Motor-Operated Valve Common Mode Failures During Plant Transients due to Improper Switch Settings”, dated April 27, 1988.

24. Generic Letter 89-10, “Safety-Related Motor Operated Valve Testing and Surveillance” dated June 28, 1989.

25. Generic Letter 89-10, “Safety-Related Motor Operated Valve Testing and Surveillance” - Supplements 1 through 7, various dates.

26. NRC correspondence dated August 17, 1995, “Close-out Inspection of Generic Letter 89-10 (NRC Inspection Report No. 50-282/95010(DRS); 50-306/95010(DRS)”

27. Generic Letter 96-05 “Periodic Verification of Design-Basis Capability of Safety related Motor-Operated Valves” dated September 18, 1996.

28. NRC correspondence dated December 29, 1999, “Prairie Island Nuclear Generating Plant, Units 1 and 2 – Closure of Generic Letter 96-05, “Periodic Verification of Design Basis Capability of Safety-Related Motor-Operated Valves” (TAC Nos. M97089 and M97090)

29. Generic Letter 95-07, “Pressure Locking and Thermal Binding of Safety Related Power-Operated Valves” dated August 17, 1995.

30. NRC correspondence dated August 24, 1999, “Prairie Island Nuclear Generating Plant, Units 1 and 2 – Closure of Generic Letter 95-07, “Pressure Locking and Thermal Binding of Safety Related Power-Operated Valves” Prairie Island Nuclear Generating Plant (TAC Nos. M93507 and M93508)

31. Not Used

32. Letter, D. C. Dilanni (NRC) to T.M. Parker (NSP), “Safety Evaluation of the Prairie Island Nuclear Generating Plant Unit Nos. 1 and 2; Station Blackout Rule 10 CFR 50.63 (TAC Nos. 68588 and 68589)”, September 18, 1990 (30814/3052)

33. Letter, D. Musolf (NSP) to Director of Nuclear Reactor Regulation (NRC), “Loss of All Alternating Current Power Information Required by 10 CFR Part 50, Section 50.63(c)(1)”, April 13, 1989

34. Letter ESU-3456, “Fulfill of SBO Rule (10CFR50.63); Verification of Supplying AAC Power to SBO Unit within 10 Minutes”, March 11, 1994 (2759/86)

35. 10CFR50.59 Screening 1828, Rev. 0 (4128/0559)

36. Calculation ENG-EE-045, “Diesel Generator Steady State Loading for a LOOP Coincident with an SBO”

37. Calculation ENG-ME-443, “Condensate Storage Tank Sizing”

38. Engineering Change Evaluation, EC #20717, Rev. 1, Station Position on D5 and D6 Emergency Diesel Generator Operability with Regards to the Number of Starting Air Receivers – Answers Aug. 2012 P.I. & R. (NRC Problem Identification and Resolution Inspection) Question #100

39. Engineering Change Evaluation, EC #20927, Rev. 0, D5/D6 EDG, “Availability” with Regards to the Number of Charged Starting Air Receivers

40. PINGP Modification EC19490, “(PRI 75) Drill RHR to SI Suction Valve Discs to Eliminate Pressure Locking Affected Valves are MV-32206 and MV-32207 in Unit 1 and MV-32208 and MV-32209 in Unit 2.”

41. Calculation ENG-EE-018, “Unit 2 Diesel Generator Sequence Loading for an SI Event (LOCA) Concurrent with a LOOP”.

42. Calculation ENG-EE-021, “Diesel Generator Steady State Loading for an SI Event Concurrent with Loss of Offsite Power (LOOP) for D1, D2, D5, D6”.

43. Calculation ENG-EE-183, “Unit 1 Electrical Transient Analysis for a LOCA Concurrent with a LOOP”.

44. Calculation 32-9218303, Rev. 1, Prairie Island Nuclear Generating Plant Unit 2 Diesel Engine Air Start Calculation. 01423445

45. Modification EC 23491, “Vent RHR Sump B Suction Valve Bonnets to Eliminate Pressure Locking.” 01431472

TABLE 8.4-1, DELETED

TABLE 8.4-2, DELETED

TABLE 8.4-3, DELETED

TABLE 8.4-4, DELETED

TABLE 8.5-1, DELETED

TABLE 8.5-2, DELETED

01407637

**FIGURE 8.2-1,
has been DELETED**

01395778

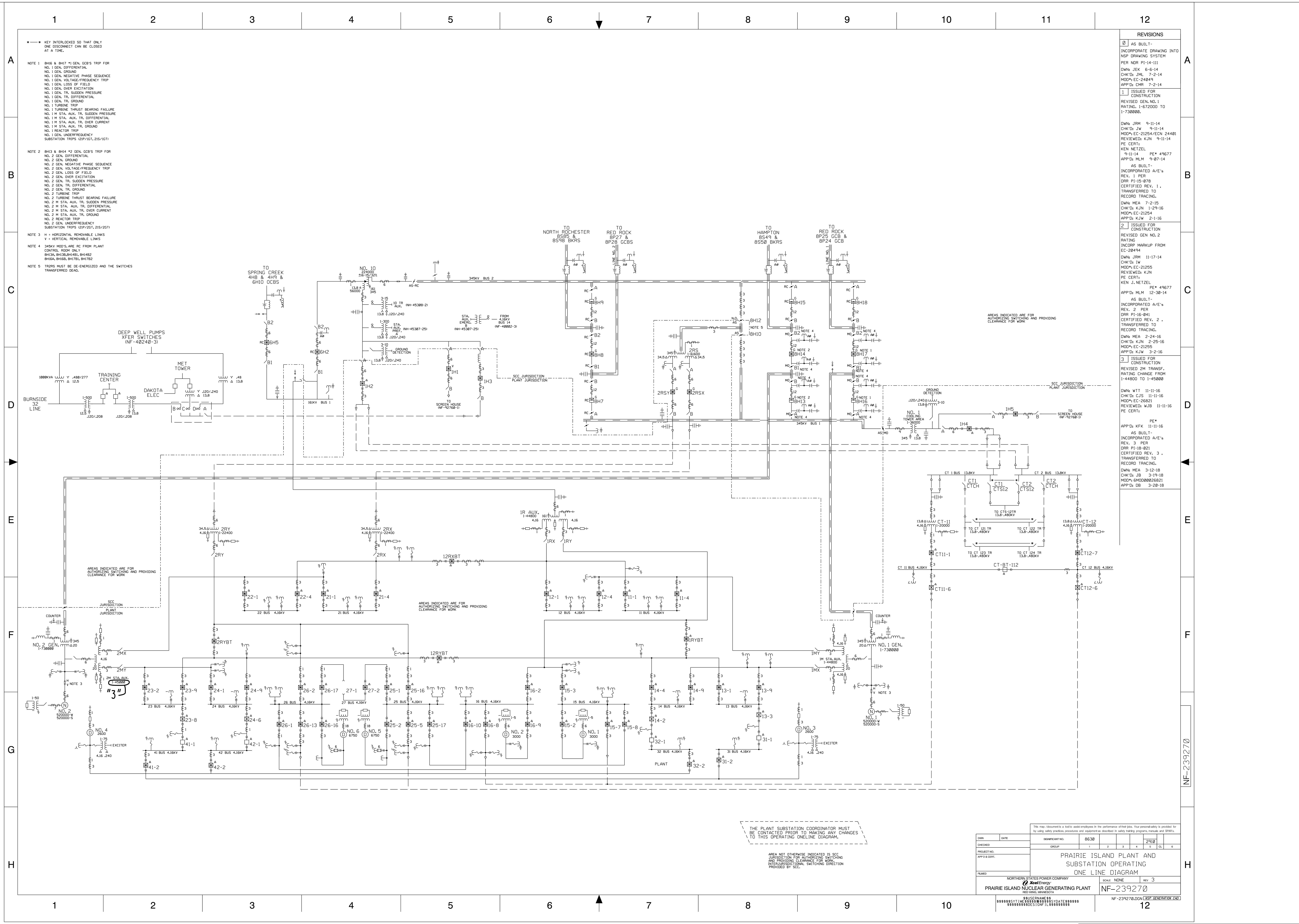
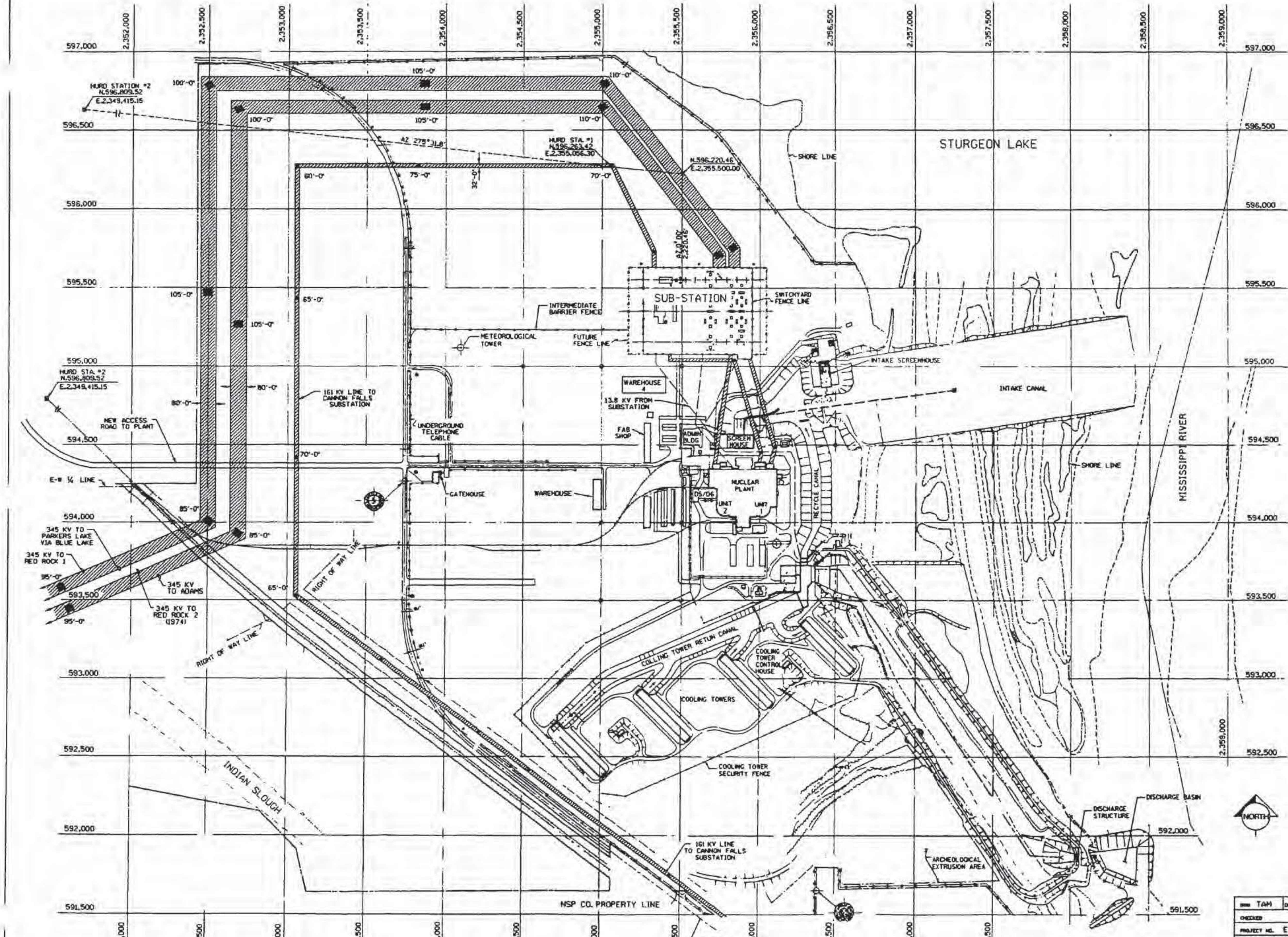


FIGURE 8.2-2 REV. 35

60300001331

CAD FILE: U08202.DGN

REVISIONS



NOTES:

REF LIST OF DWGS - NF-38204-8
YARD PLAN DWGS - NF-38204-1 THRU -10
SITE PLAN - NF-116972

LEGEND	
NAME OF SYSTEM	SYMBOL
N.S.P. Co. PROPERTY LINE	
SHORE LINE	
ROAD	
RAILROAD TRACK	
SECURITY FENCE	
SUB-STA. FENCE	
EXCLUSION FENCE	
UNDERGROUND CABLE	

70'-0" NUMBER (70'-0") INDICATES HEIGHT TO LOWEST TOWER ARM

DWN TAM	DATE 4-30-98	SIGNIFICANT NO.							
CHECKED		GROUP	1	2	3	4	5	CL	6
PROJECT NO. ETNSUR									
APP'D & CERT.									
CAD FILE U08203.DGN U08203.CIT									

SITE ARRANGEMENT OF TRANSMISSION LINES AND UNDERGROUND CABLES

NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA

SCALE NONE

FIGURE 8.2-3 REV. 18

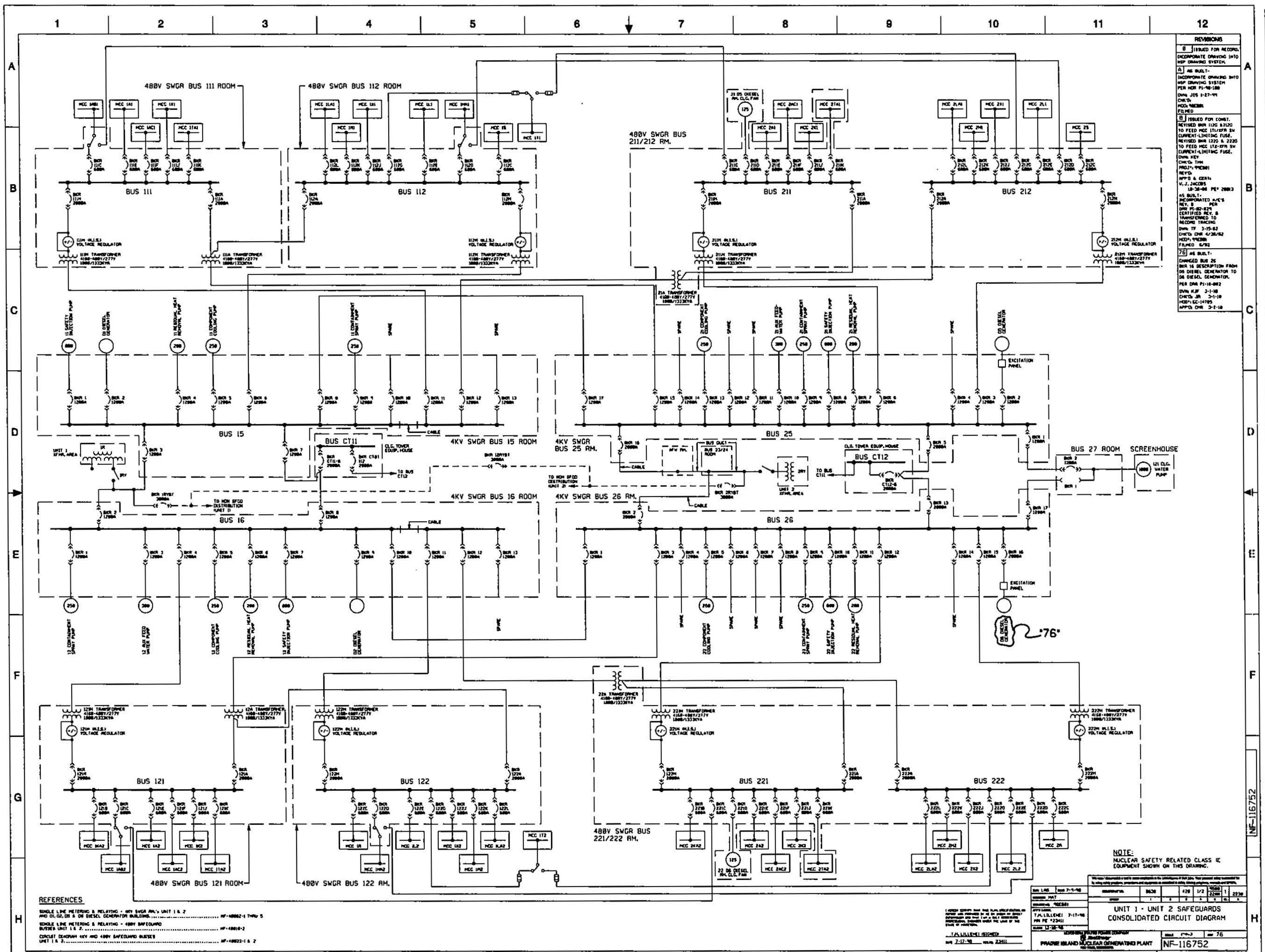
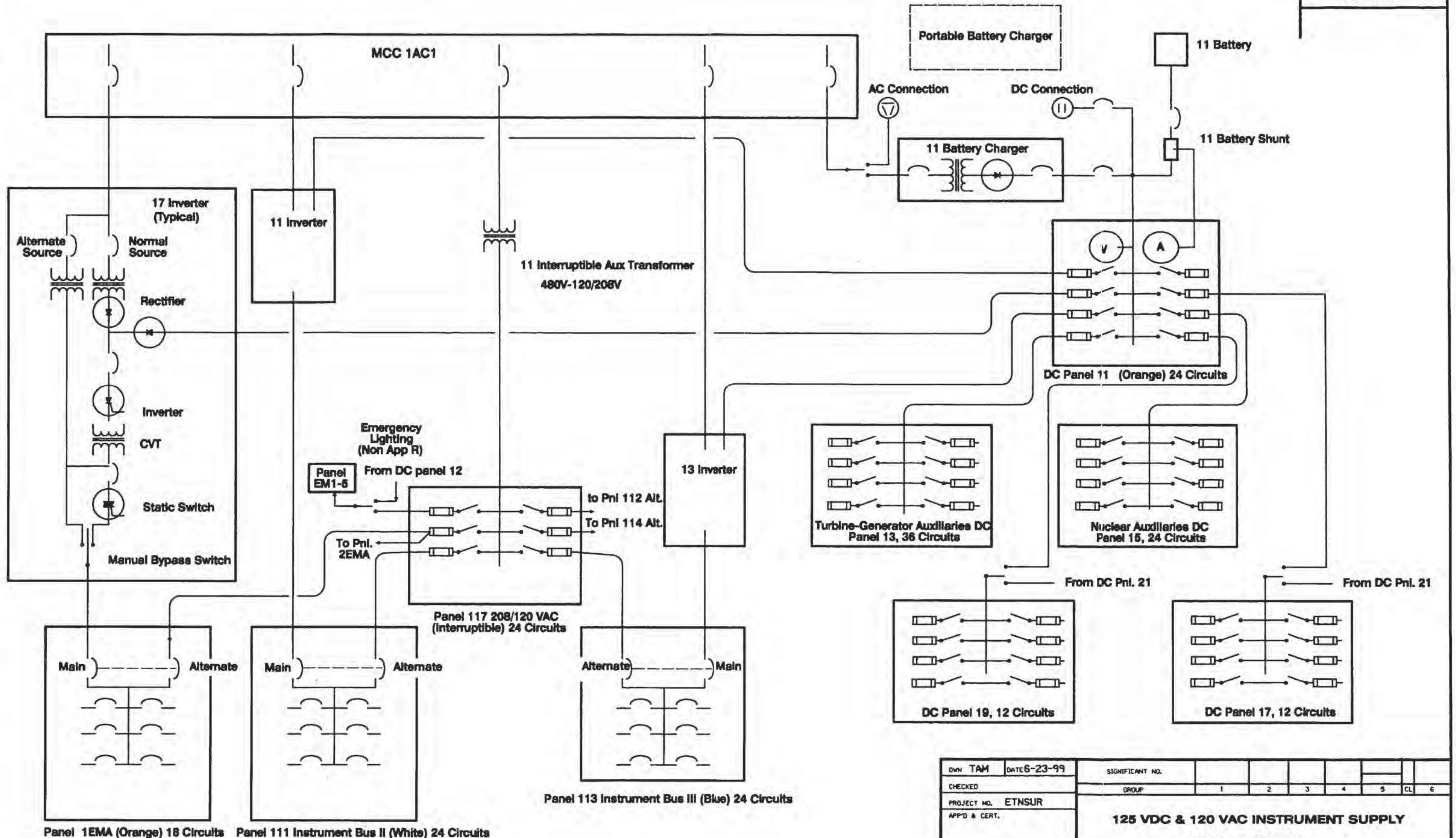


FIGURE 8.3-1 REV.31

01248495



DWN TAM	DATE 6-23-99	SIGNIFICANT NO.							
CHECKED		GROUP	1	2	3	4	5	CL	6
PROJECT NO. ETNSUR									
APP'D & CERT.									
CAD FILE: U0851A.DGN									

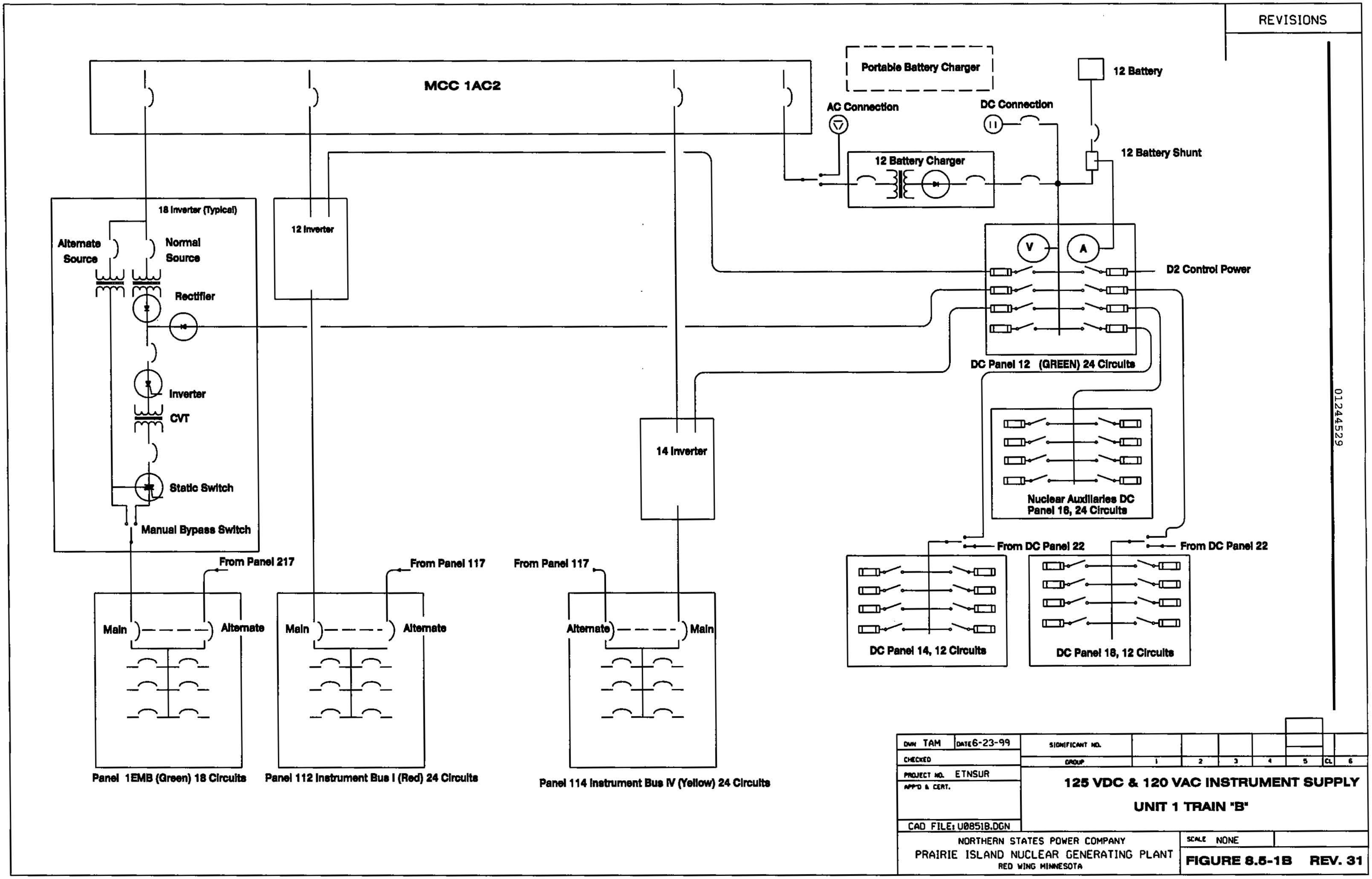
125 VDC & 120 VAC INSTRUMENT SUPPLY

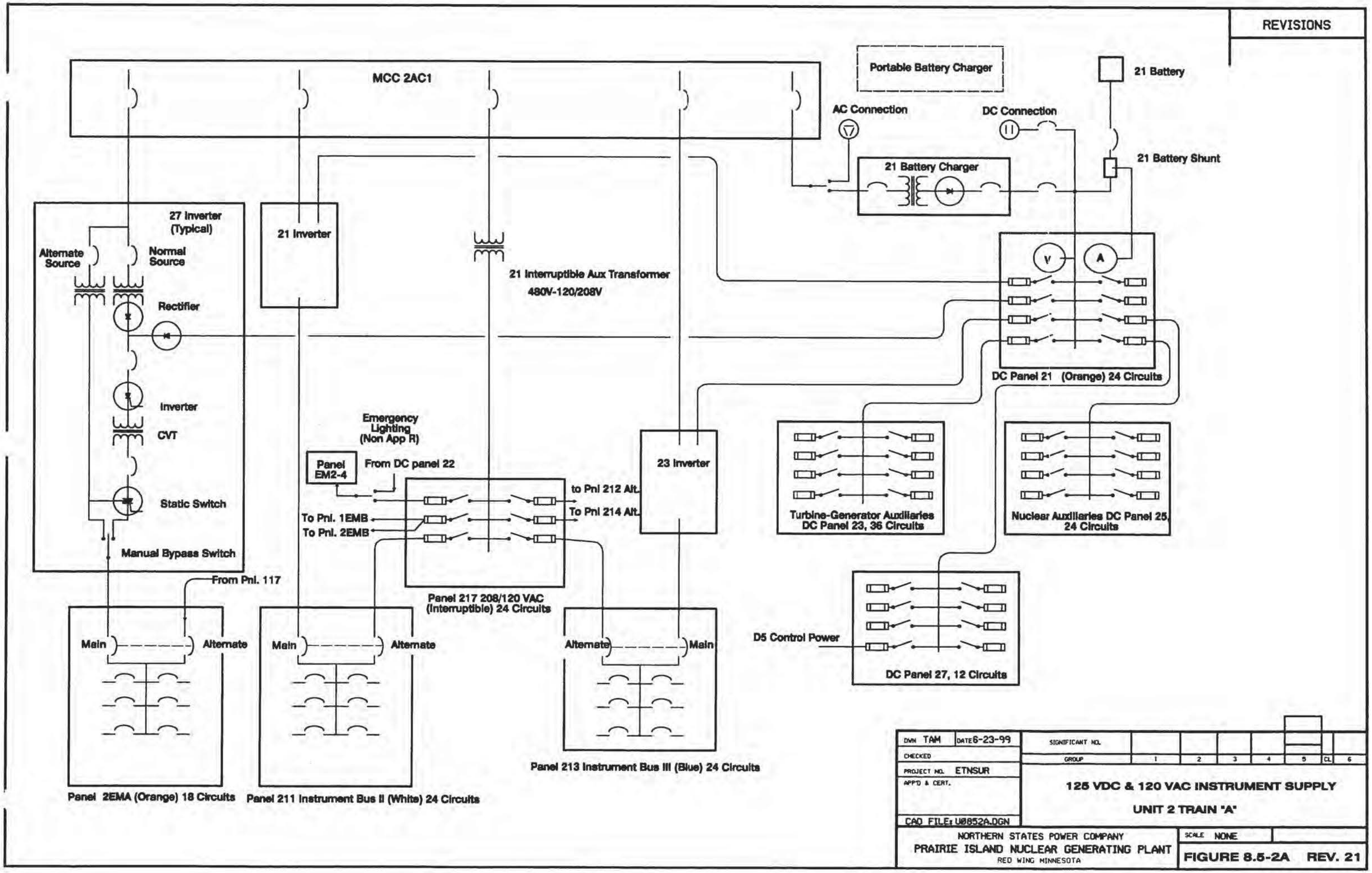
UNIT 1 TRAIN "A"

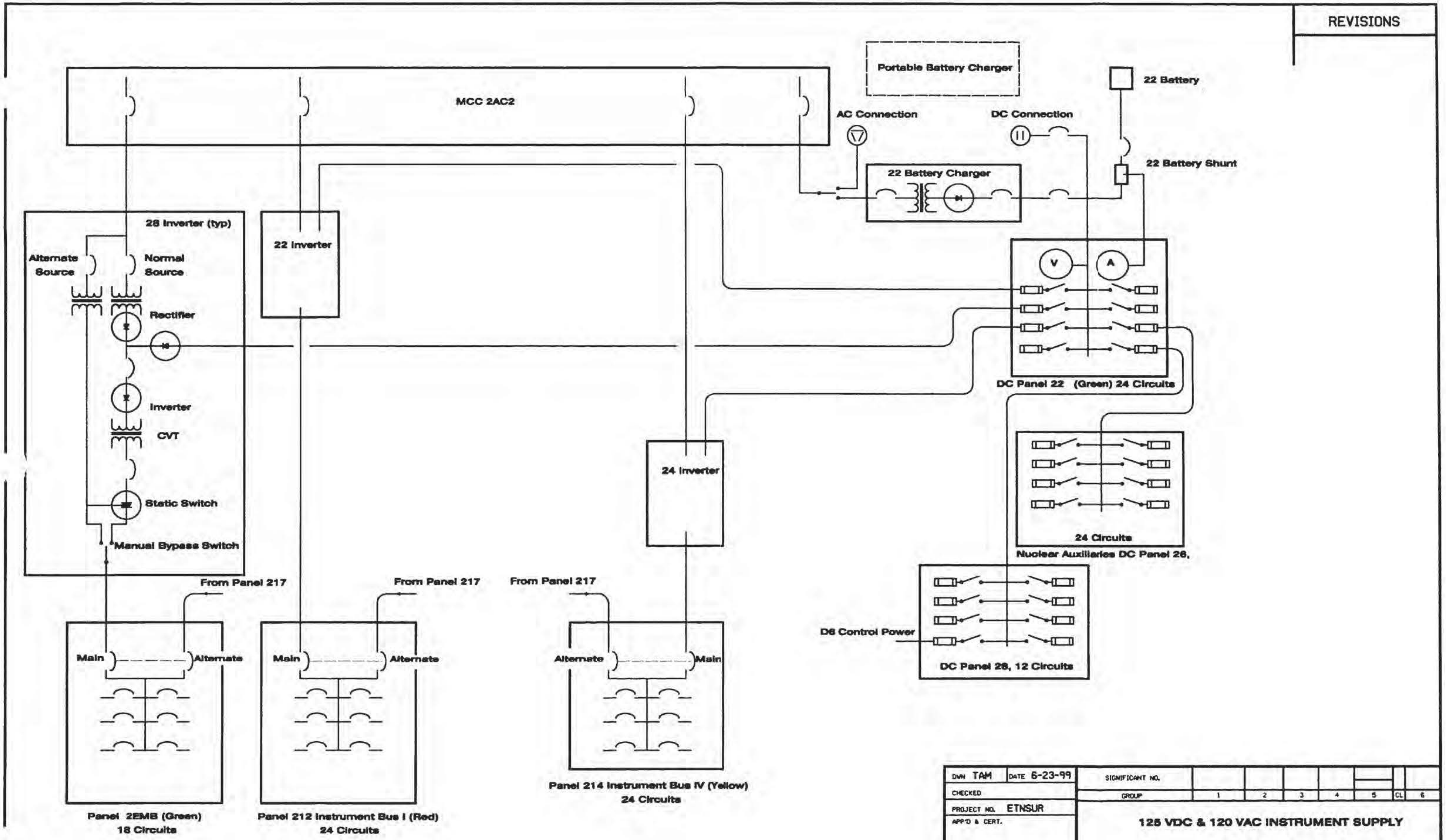
NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA

SCALE NONE

FIGURE 8.5-1A REV. 21


REVISIONS
MCC 1AC2
Portable Battery Charger
12 Battery
AC Connection
DC Connection
12 Battery Shunt
12 Battery Charger
18 Inverter (Typical)
Alternate Source
Normal Source
Rectifier
Inverter
CVT
Static Switch
Manual Bypass Switch
12 Inverter
14 Inverter
D2 Control Power
DC Panel 12 (GREEN) 24 Circuits
Nuclear Auxiliaries DC Panel 16, 24 Circuits
From DC Panel 22
From DC Panel 22
DC Panel 14, 12 Circuits
DC Panel 18, 12 Circuits
From Panel 217
From Panel 117
From Panel 117
Main
Alternate
Main
Alternate
Alternate
Main
Panel 1EMB (Green) 18 Circuits
Panel 112 Instrument Bus I (Red) 24 Circuits
Panel 114 Instrument Bus IV (Yellow) 24 Circuits
01244529
DWN TAM
DATE 6-23-99
CHECKED
PROJECT NO. ETNSUR
APP'D & CERT.
CAD FILE: U0851B.DGN
SIGNIFICANT NO.
GROUP
1 2 3 4 5 CL 6
125 VDC & 120 VAC INSTRUMENT SUPPLY
UNIT 1 TRAIN "B"
NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA
SCALE NONE
FIGURE 8.5-1B
REV. 31


REVISIONS
Portable Battery Charger
21 Battery
MCC 2AC1
AC Connection
DC Connection
21 Battery Shunt
21 Battery Charger
27 Inverter
(Typical)
Alternate Source
Normal Source
Rectifier
Inverter
CVT
Static Switch
Manual Bypass Switch
21 Inverter
21 Interruptible Aux Transformer
480V-120/208V
V
A
DC Panel 21 (Orange) 24 Circuits
Emergency Lighting
(Non App R)
Panel EM2-4
From DC panel 22
to Pnl 212 Alt.
To Pnl 214 Alt.
To Pnl. 1EMB
To Pnl. 2EMB
23 Inverter
Turbine-Generator Auxiliaries DC Panel 23, 36 Circuits
Nuclear Auxiliaries DC Panel 25, 24 Circuits
From Pnl. 117
Panel 217 208/120 VAC
(Interruptible) 24 Circuits
Main
Alternate
Main
Alternate
Alternate
Main
D5 Control Power
DC Panel 27, 12 Circuits
Panel 2EMA (Orange) 18 Circuits
Panel 211 Instrument Bus II (White) 24 Circuits
Panel 213 Instrument Bus III (Blue) 24 Circuits
DWN TAM
DATE 6-23-99
CHECKED
PROJECT NO. ETNSUR
APP'D & CERT.
CAD FILE: U0852A.DGN
SIGNIFICANT NO.
GROUP
1
2
3
4
5
CL
6
125 VDC & 120 VAC INSTRUMENT SUPPLY
UNIT 2 TRAIN 'A'
NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA
SCALE NONE
FIGURE 8.5-2A
REV. 21



DWN TAM	DATE 6-23-99	SIGNIFICANT NO.							
CHECKED		GROUP	1	2	3	4	5	CL	6
PROJECT NO. ETNSUR									
APP'D & CERT.									
CAD FILE: U0852B.DGN									

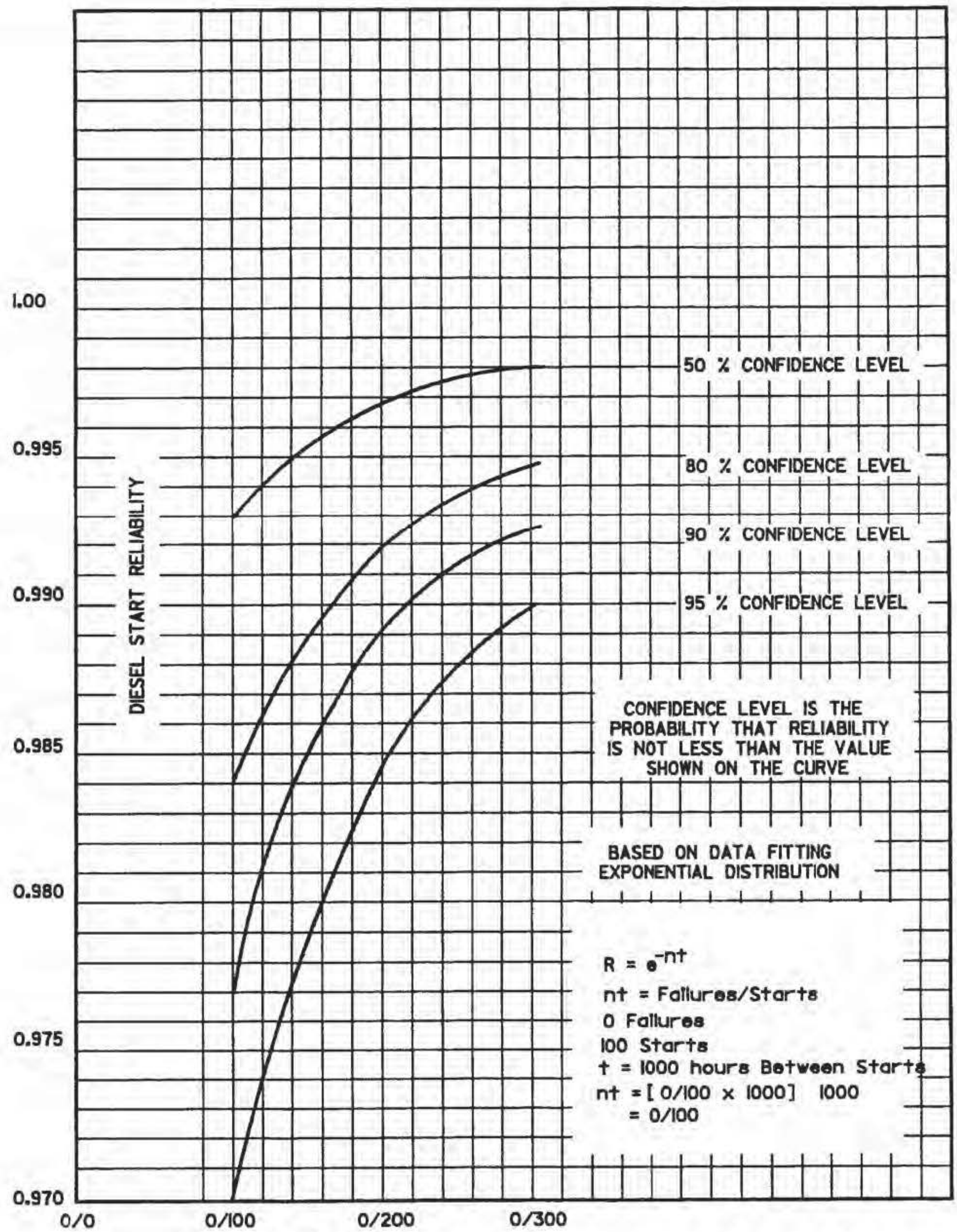
125 VDC & 120 VAC INSTRUMENT SUPPLY

UNIT 2 TRAIN "B"

NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA

SCALE NONE

FIGURE 8.5-2B REV. 21



DIESEL RELIABILITY
STARTS / STOPS

DWN TAM	DATE 6-23-99	NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA	SCALE: NONE
CHECKED	CAD FILE U08801.DGN		FIGURE 8.8-1 REV. 18

SECTION 9
PLANT RADIOACTIVE WASTE CONTROL SYSTEMS

TABLE OF CONTENTS

TABLE OF CONTENTS [Continued]

LIST OF TABLES

TABLE OF CONTENTS [Continued]

LIST OF DRAWINGS

THIS PAGE IS LEFT INTENTIONALLY BLANK

SECTION 9 PLANT RADIOACTIVE WASTE CONTROL SYSTEMS

9.1 SUMMARY DESCRIPTION

9.1.1 General Systems Description

Radioactive fluids entering the Waste Disposal System are collected in intermediate holding tanks for determination of subsequent treatment. They may be sampled and analyzed to determine the quantity of radioactivity, with an isotopic analysis if necessary. The liquid wastes are then processed as required for reuse or released under controlled conditions and in accordance with applicable limits of 10CFR20 and the design objectives of Appendix I to 10CFR50.

The bulk of the radioactive liquid drained from the Reactor Coolant System is processed by the Chemical and Volume Control System recycle train and retained inside the plant. This minimizes liquid input to the Waste Disposal System which processes relatively small quantities of generally low activity level wastes. The processed water from the waste disposal system, from which the majority of the radioactive material has been removed may be reused in plant or released through a monitored line to the canal downstream of the cooling towers. 01-082

Waste gases are processed by one of two interconnected equipment trains. The low level loop, provides sufficient storage capacity for cover gases from the nitrogen blanketing system to minimize the need to vent gases which accumulate as a result of load follow operations. Discharges of fission gases from the system are limited to maintenance vents, unavoidable equipment leaks, and infrequent gas decay tank releases to dispose of gases accumulated by inflows from shutdown operations and miscellaneous vents. Controls are provided to regulate the rate of release from these tanks through the monitored plant vent. 01-081

The high level loop was designed to accumulate, concentrate and contain fission gases at high activity concentrations from continuous purging of the volume control tanks gas space. It would provide continuous removal of fission gases from the letdown coolant to maintain the coolant fission gas concentrations at a low residual level. This loop can perform these functions and/or be used for reserve holdup capacity of low level loop gas. 01-081

The spent resins from demineralizers, filter cartridges and concentrates from the evaporators are packaged and stored onsite until shipment offsite for processing and disposal. 01-082

The Waste Disposal System Process Flow Diagrams are shown in Figures 9.1-1 through 9.1-10 and Performance Data are given in Table 9.1-1. With the exception of the SGB system, containment building sumps and pumps, reactor coolant drain tanks and drain tank pumps, and associated piping and valves, the Waste Disposal System is common to Units 1 and 2. 01-082

The Waste Disposal System collects and processes all potentially radioactive reactor plant wastes for removal from the plant site well within limitations established by regulations.

Fluid wastes are collected, sampled and analyzed to determine the quantity of radioactivity, with an isotopic analysis if necessary. Depending on the results of the analysis, these wastes are processed as required and reused in the plant or released to the environment. 01-082

If the wastes are to be released from the plant site, they are released under controlled conditions. Radiation monitors are provided to maintain surveillance over the release operation, and a permanent record of activity released is provided by radiochemical analysis of the known quantities of waste and substantiated by plant recording instruments. The system is capable of processing all wastes generated during continuous operation of the primary system, assuming that fission products escape to the reactor coolant by diffusion through defects in the cladding of no more than one percent of the fuel rods. 01-082

At least two valves must be manually opened to permit discharge of liquid or gaseous waste from the Waste Disposal System. One of these valves is normally locked closed. An additional control valve will trip closed on a high effluent radioactivity level signal to prevent discharge to the environment.

As secondary functions, system components supply hydrogen and nitrogen to primary system components as required during normal operation, and provide facilities to transfer fluids from the containment to other systems outside the containment.

The system is controlled from local control panels in the auxiliary building and the radwaste building. Malfunctions of the system are locally alarmed in the auxiliary and radwaste buildings, as well as being annunciated in the control room. All system equipment is located in the radwaste building, the auxiliary building, or the reactor containment buildings. 01-082

The design basis for the radwaste building is described in Section 12.2.1.4.3.2, Structural Design Basis for Class I* Structures.

The radwaste building is supplied with outside air which can be preheated by heating coils in the air-handling unit. Exhaust flow is directed through charcoal adsorber beds and a HEPA filter prior to release to the surroundings. The cement dust filter fan exhaust is not directed through the adsorber bed or the HEPA filter. All releases are monitored by the Radwaste Building Radiation Monitor Channel R-35 as described in Table 7.5-1. In addition, unit heaters are provided throughout the radwaste building for heating in the winter. 01-082

Adjacent to the Radwaste Building is the resin disposal building which receives, dewaters and handles spent resins from the condensate polishing system (See Section 11.8.)

9.1.2 Component Design Considerations

Codes applying to components of the Waste Disposal System are shown in Table 9.1-2. Component summary data are shown in Table 9.1-3.

The wetted surfaces of all pumps are stainless steel or other materials of equivalent corrosion resistance.

Piping carrying liquid wastes is stainless steel or fiberglass while gas piping is carbon or stainless steel. Steel piping connections are welded except where flanged connections are necessary to facilitate equipment maintenance. 01-081

Valves exposed to gases are carbon or stainless steel. Those exposed to liquids are stainless steel. 01-081 Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage.

Isolation valves are provided to isolate equipment for maintenance, to direct the flow of waste through the system, and to isolate storage tanks for radioactive decay. 01-081

Relief valves are provided for tanks containing radioactive wastes if the tanks might be overpressurized by improper operation or component malfunction. Tanks containing wastes which are normally free of gaseous activity are vented locally.

Outleakage from the system is minimized by using diaphragm valves, bellows seals, self contained pressure regulators and soft-seated packless valves throughout the radioactive portions of the system.

THIS PAGE IS LEFT INTENTIONALLY BLANK

9.2 LIQUID RADWASTE SYSTEM

9.2.1 Design Basis

Criterion: The facility design shall include those means necessary to maintain control over the plant radioactive effluents, whether gaseous, liquid, or solid. Appropriate holdup capability shall be provided for retention of gaseous, liquid, or solid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for radioactivity control must be justified (a) on the basis of 10CFR20 requirements, for both normal operations and for any transient situation that might reasonably be anticipated to occur and (b) on the basis of 10CFR100 dosage level guidelines for potential reactor accidents of exceedingly low probability of occurrence. (GDC70)

Liquid, gaseous, and solid waste disposal facilities are designed so that discharge of effluents and off-site shipments are a small percentage of the applicable governmental regulations.

The liquid radwaste systems' design objective is to have the capability of processing the discharge of radioactive material under normal operating conditions so as to approach essentially zero (i.e., actual river background) and to ensure that activity released under design basis conditions will be a small fraction of the applicable limits in 10CFR20.

9.2.1.1 Liquid Radwaste

The liquid radwaste system is designed to collect, process and dispose of all radioactive liquid wastes generated in the operation of the plant. The system is designed to accommodate the radioactive input resulting from the design basis maximum fuel leakage condition.

The radioactive waste system has been shown to meet the requirements of Appendix I to 10CFR50. The radwaste systems reduce the activity released to acceptable levels.

9.2.1.2 Monitoring Radioactive Releases

Criterion: Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive. (GDC 17).

The containment atmosphere, the shield building vent, the auxiliary building vent, the control room ventilation system, the spent fuel pool exhaust, the RHR cubicle ventilation exhaust, the condenser air ejector exhaust, the circulating water discharge, the containment fan coolers cooling water discharge, blowdown from the steam generators, the component cooling water, and the Waste Disposal System liquid effluent are monitored for radioactivity concentration during normal operations, anticipated transients, and accident conditions. High radiation in any of these is indicated and alarmed in the control room.

All gaseous effluent from possible sources of accidental radioactive release external to the reactor containment (e.g., the spent fuel pool and waste handling equipment) will be exhausted from an auxiliary building vent, which is monitored. Leaks from piping carrying radioactive liquids are contained within the reactor containment buildings, radwaste building, or auxiliary building. Any contaminated liquid effluent released to the condenser circulating water is monitored. For any leakage from the reactor containment under accident conditions, the plant radiation monitoring system supplemented by portable survey equipment provides adequate monitoring of radioactivity release.

9.2.2 Description

The waste disposal system collects, processes, stores and disposes of radioactive liquid waste originating in the plant. The subsystems comprising the Liquid Radioactive Waste Disposal System are: Reactor Coolant Drain (RCD), Auxiliary and Reactor Building Drain (ARD), Steam Generator Blowdown Treatment (SGBT), Non-Aerated Drain, and Aerated Drains Treatment (ADT). The system has the capability of storing 60,000 gallons.

The major sources of liquid waste are:

- Reactor Coolant System drains and leaks
- Chemical and Volume Control System drains and leaks
- Non-aerated equipment drains and leaks
- Aerated equipment drains and leaks
- Chemical laboratory drains
- Decontamination area drains
- Radiochemical laboratory drains
- Sampling System
- Steam Generator Blowdown
- Auxiliary Coolant System drains

To facilitate storage, processing and disposal, the system is designed to segregate various waste streams at their point of collection into the following categories:

- Non-aerated waste
- Aerated waste
- Chemical drains
- Steam Generator Blowdown
- Resin waste

Non-aerated waste is primarily from Reactor Coolant System drainage which is collected from the following sources and transferred directly to the Chemical and Volume Control System (CVCS) holdup tanks, or the waste holdup tank (depending on fluid composition) for processing:

a. Reactor coolant loops

b. Pressurizer relief tank

c. Reactor coolant pump secondary seals

d. Excess letdown (during startup)

e. Accumulators

f. Reactor vessel flange leakoffs

Fluid directed to the reactor coolant drain tanks is pumped to the CVCS holdup tanks, the waste holdup tank, or the refueling water storage tanks by the reactor coolant drain tank pumps. There is one reactor coolant drain tank with two reactor coolant drain tank pumps located inside of each reactor containment building.

The remaining non-aerated liquid waste originates in the Chemical and Volume Control System charging and letdown paths and the gas decay tank drains. These liquid waste streams are collected and handled in an anaerobic manner to minimize the hydrogen explosion hazard and prevent the escape of gaseous radioactivity. This is accomplished by collecting non-aerated waste in a closed piping system that drains to a non-aerated sump tank. The non-aerated sump tank is isolated from the atmosphere by a flexible diaphram type seal. Normally non-aerated waste is transferred to the CVCS holdup tanks for processing. (see Section 10.2.3)

If the water is not suitable or it is not desirable to send the non-aerated waste to the CVCS holdup tanks, the water can be pumped to the waste holdup tank.

Aerated waste originates primarily from the floor drains, aerated equipment drains and leaks, the laundry equipment drains, and the decontamination area drains.

Where possible, aerated waste is collected by gravity drainage to the aerated sump tank. In other cases, aerated waste is drained to local sumps from where it is pumped to the aerated sump tank. From the aerated sump tank, aerated waste can be pumped to the two aerated monitor tanks, the ADT collection tanks or the waste holdup tank. Normally the discharge from the aerated sump tank pump is aligned to the waste holdup tank due to its capacity and shielded location. When enough water has been collected in the waste holdup tank for processing purposes, the waste holdup tank is gravity drained to the aerated sump tank, which is pumped to the ADT collection tanks.

Waste water in the ADT Collection tanks is normally processed through the ADT Cartridge Filters. The filtrate is collected in the ADT Condensate Receiver Tanks, and then processed through the ADT Ion Exchangers and collected in the ADT Monitor Tanks. The ADT Monitor Tanks are analyzed, and based on the analysis, may be released or reprocessed.

Waste from the hot sampling station and hot chemical laboratory is collected in the chemical drain tank. Periodically this waste is neutralized, if needed, then pumped to the aerated sump tank.

Waste water from the resin disposal building sump is pumped to the miscellaneous drains collection tank or the waste holdup tank. Waste water from the truck loading enclosure sump is pumped to the aerated sump tank.

Control of radioactivity of the laundry and hot shower wastes is gained by using disposable clothing in areas of known high contamination. The laundry and hot shower waste liquid is directed to the aerated sump tank through the floor drain system. The laundry and hot shower liquid waste is then processed through the ADT system.

Steam Generator Blowdown is discharged to a flash tank shared by both steam generators of a unit. The blowdown line from each steam generator is equipped with two motor-operated containment isolation valves, one inside and one outside of containment. As shown in Tables 5.2-1 Part A (U1) and Part B (U2) only the outside valve is credited for Containment Isolation. The other redundant barrier is the Steam Generator (see Appendix G). Flow into the flash tank from each steam generator is controlled by a single control valve. Flow rate from each steam generator is manually controlled from the control room.

The steam generator blowdown motor operated isolation valves are designed to close upon receipt of a containment isolation signal.

The SGB flow control valves are designed to trip closed if one of the following conditions occur:

1. Either Auxiliary Feedwater Pump for the associated unit starts.

2. High activity is detected in the associated steam generator blowdown radiation monitor (R19).

Normally steam generator blowdown from the flash tank is directed to the SGB Holdup Tanks from which it is pumped through a filter and ion exchanger to the respective condenser. This is called "reclaim". Occasionally, to control steam generator chemistry, blowdown is released to the circulating water canal via a radiation monitor. Such is the case during unit startup. In the event that radioactivity exceeds the setpoint of the SGB Radiation Monitor, the discharge valve to the river automatically closes thus securing the release. The steam from the blowdown flash tank is normally routed to the extraction steam inlet to Feedwater Heater No. 3. Steam can also be routed to the main condenser or to the atmosphere. The noncondensible gases removed from the condenser (by an air ejector) pass through a radiation monitor at all times, however the radiation monitor for the air ejector discharge is not considered an effluent monitor. The air ejector discharge monitor alarm set point is based on monitoring primary to secondary leakage and not based on monitoring effluent release.

The air ejector discharge is directed to Auxiliary Building Ventilation. Auxiliary Building Ventilation is equipped with monitoring for effluents. Auxiliary Building Ventilation Monitoring provides alarm and trip functions.

SGB Monitor Tank liquid releases are made based on radiochemical batch analysis of the tank contents and are monitored by the waste disposal system liquid effluent monitor.

Information on concentrations in these effluents that are below the functional alarm levels are provided by the routine radiochemistry analysis and continuous ERCS monitor.

9.2.2.1 Components

9.2.2.1.1 Laundry and Hot Shower Tanks

The laundry and hot shower tanks are constructed of welded stainless steel. The inlets to these tanks have been closed off. Laundry and hot shower waste is now directed to the floor drain system.

9.2.2.1.2 Chemical Drain Tank

The chemical drain tank is stainless steel and collects drainage from the chemistry laboratory. After analysis, the tank contents are treated as aerated waste.

9.2.2.1.3 Reactor Coolant Drain Tanks

The reactor coolant drain tanks are right circular cylinders with spherically dished heads. The tanks, which are all welded stainless steel, serve as a drain collecting point for the Reactor Coolant System drains and other equipment located inside the reactor containments. The tank contents can be discharged to the CVCS, waste holdup tank, or to the refueling water storage tanks.

9.2.2.1.4 Waste Holdup Tank

The waste holdup tank receives radioactive liquids from various aerated plant systems and drains. Various non-aerated equipment can also be aligned to the waste holdup tank. The tank is constructed of welded stainless steel and can be drained to the aerated sump tank or pumped to either the waste evaporator or the waste condensate tanks.

9.2.2.1.5 Aerated Sump Tank and Pumps

The aerated sump tank serves as a collecting point for auxiliary building floor drains and various aerated equipment system drains. A horizontal centrifugal sump pump or shared backup pump are used to transfer the tank contents to the waste holdup tank, ADT collection tanks, or the aerated monitor tanks. All wetted parts of the pumps are stainless steel. The aerated sump tank is constructed of welded stainless steel.

9.2.2.1.6 Non-Aerated Sump Tank

The non-aerated sump tank serves as a collecting point for waste water from the charging pump seal water, gas decay tank drains, demineralizer drains, and other various non-aerated equipment drains. A horizontal centrifugal pump or shared backup pump transfers this collected liquid normally to the CVCS holdup tank, but can be aligned to transfer the contents to the waste holdup tank. The tank is constructed of welded stainless steel with a diaphragm seal to prevent entrained gases from escaping to the atmosphere. This tank can be vented to the waste gas compressor suction.

9.2.2.1.7 Aerated Drains Treatment (ADT) Monitor Tanks

The ADT monitor tanks are constructed of welded stainless steel and can receive water from the ADT ion exchangers and the SGB monitor tanks. The tanks serve as a final collection point for water which has been processed through the liquid radwaste treatment system. Depending upon chemical analysis, the water in the ADT monitor tanks can be released to the environment, reprocessed, or returned to the waste holdup tank or SGB monitor tanks, for decay.

9.2.2.1.8 Aerated Drains Treatment (ADT) Collection Tanks

The aerated drains treatment collection tanks can receive liquid from the aerated sump tank, the miscellaneous drains collection tank, the ADT monitor tanks, or the SGB system for processing in the radwaste building. The ADT collection tank water is normally processed through the ADT cartridge filters, but can be directed to the waste holdup tank for additional decay. The ADT collection tanks are constructed of welded stainless steel.

9.2.2.1.9 Aerated Drains Treatment (ADT) Ion-Exchangers

The ADT system uses three flushable ion-exchangers that can be operated in parallel or series and are shared by Units 1 and 2. Each ion exchanger contains approximately 35 cu. ft. of resin. Each vessel is constructed of stainless steel, with a stainless steel retention screen.

9.2.2.1.10 Miscellaneous Drains Collection Tank

The miscellaneous drains collection tank receives liquids from floor drains of the radwaste building and from the resin disposal building sump. It can be used as excess storage in series with the ADT collection tanks. The miscellaneous drains collection tank is constructed of welded stainless steel.

9.2.2.1.11 SGB Monitor Tanks

The SGB monitor tanks are constructed of welded stainless steel and can serve as a collecting point for the SGB ion exchanger outlet. The tanks are occasionally used for ADT water waiting reprocessing.

9.2.2.1.12 SGB Ion Exchanger

Two flushable ion exchangers, operated in parallel, are shared by Units 1 and 2. Each ion exchanger contains approximately 37 cu. ft. of resin. Each vessel is constructed of stainless steel, with a stainless steel resin retention screen.

9.2.2.1.13 Waste Evaporators

Equipment not used.

9.2.2.1.13.1 2 GPM Radwaste Evaporator

Equipment not used.

9.2.2.1.13.2 Waste Feed

Equipment not used.

9.2.2.1.13.3 Steam Supply

Equipment not used.

9.2.2.1.13.4 Cooling Water Supply

Equipment not used.

9.2.2.1.13.5 Distillate System

Equipment not used.

9.2.2.1.13.6 Concentration Level

Equipment not used.

9.2.2.1.13.7 Nitrogen Blanketing

Equipment not used.

9.2.2.1.14 ADT Evaporator (5 GPM)

Equipment not used.

9.2.2.1.14.1 Evaporator

Equipment not used.

9.2.2.1.14.2 Vapor Condenser

Equipment not used.

9.2.2.1.14.3 Concentrate Cooler

Equipment not used.

9.2.2.1.14.4 Recirculation Pump

Equipment not used.

9.2.2.1.14.5 Distillate Cooler

Equipment not used.

9.2.2.1.14.6 Vent Cooler

Equipment not used.

9.2.2.1.15 Waste Condensate Tanks

The waste condensate tanks are constructed of welded stainless steel and are used for excess holdup capacity for liquids awaiting processing.

9.2.2.1.16 ADT Condensate Receiver Tanks

The ADT condensate receiver tanks are constructed of welded stainless steel and serve as an intermediate holding point for radwaste water processing.

9.2.2.1.17 Aerated Monitor Tanks

The aerated monitor tanks are constructed of welded stainless steel and are available for holdup of excess waste liquid awaiting processing via the liquid radwaste system.

9.2.2.1.18 Waste Liquid Discharge Header

The waste liquid discharge header begins below grade just outside of the auxiliary building and travels to the circulating water distribution basin discharge structure at the head of the circulating water discharge canal. The header then enters the discharge canal and travels along the canal's bottom terminating in a mixing diffuser just upstream of the circulating water canal discharge structure at the Mississippi River.

The buried portion of the header is a polypropylene dual wall containment system with leak detection. Adjacent to the circulating water distribution basin discharge structure the header terminates into a sump system which allows sampling for leakage. The portion of the header within the discharge canal is single wall polypropylene pipe. (References 2,3)

9.2.3 Performance Analysis

Liquid wastes are generated primarily by plant maintenance and unit operation. Under normal conditions, these wastes are treated as necessary to meet release requirements and discharged to the environment.

The Liquid Radwaste System was analyzed and evaluated to show plant capability to meet the design objectives of Appendix I to 10CFR50. See Reference 1 for details. The liquid source terms were calculated using the GALE code and are presented in Table 9.2-3. The following assumptions were used in the analysis.

a. Part of the reactor coolant letdown stream (called "shim bleed") is diverted to the Chemical Volume Control System (CVCS) hold up tank. After further processing, it was assumed that the entire shim bleed is released to the circulating water discharge canal.

b. Equipment and clean wastes, which are collected in the reactor coolant drain tank and the nonaerated drain sump tank, respectively, are processed together with the shim bleed. In the analysis, it was assumed that all the wastes treated were released to the discharge canal downstream of the cooling towers.

c. Dirty wastes originating from the aerated drain system are usually collected in the aerated drain treatment (ADT) collection tank. Following processing, the wastes were assumed processed through two ADT ion exchangers in series and the entire content was discharged to the circulating water discharge canal.

d. Steam generator blowdown is normally processed through the steam generator blowdown (SGB) ion exchanger and then discharged to the condenser. Blowdown is released to the circulating water discharge canal approximately 5 days a month with no processing. For the analysis, it was assumed that the blowdown was continuously processed through the SGB ion exchanger (mixed bed) and pumped to the SGB monitor tank where the entire contents are released to the discharge canal.

e. Detergent wastes which originate from the laundry and hot shower drains are collected in the laundry and hot shower tanks. For the analysis, it was assumed that the wastes were discharged through the laundry tank strainer to the discharge canal without treatment. In addition, the amount of detergent wastes was assumed to be 450 gal/day as indicated in NUREG-0017. Table 9.2-4 contains information pertinent to the above liquid radwastes.

The results of the analysis demonstrated the plant's capability of keeping the levels of radioactivity in effluents as low as reasonably achievable. Maximum offsite dose from all possible pathways was shown to be well within the design objectives of Appendix I of 10CFR50.

Tritium exists as a gas or combined in water. In the presence of water the majority of the tritium will remain with the water and not appear as a gas.

The tritium release rates in the plant offgases and liquid radwaste discharges result in concentration well below the 10 CFR 20 limits. The dose rate to the environs due to tritium is negligible and therefore not considered significant in the radioactive waste systems.

However, as a further means of lowering the potential for tritium to enter local groundwater, the discharge point of liquid radwaste and steam generator blowdown was extended from its original point of discharge at the head of the circulating water discharge canal to just upstream of the circulating water canal discharge structure at the Mississippi River. The extended discharge header ensures that any tritium that may be present in the liquid release is not retained within the discharge canal as it travels down its entire length but is mixed into the circulating water discharge immediately before it enters the river (Reference 3). The extension effectively bypasses the Circulating Water Monitor (R-21). This is discussed in USAR Section 7.5.2.

Protection against accident and/or off standard releases of wastes is provided by appropriate system interlocks; detection instrumentation alarms on off standard conditions and automatically closes the discharge valve. All radwaste tankage, filters and equipment are either contained in a Class I* portion of the plant or specially constructed areas to provide a substantial degree of control of the wastes. These arrangements are provided to assure that in the event of a failure of the liquid waste systems or errors in operation of the system the potential for inadvertent release of liquids is minimal. This assures control and containment of any leaks, spills, or overflows from the equipment.

The liquid waste system components are found in the containment, auxiliary, and radwaste buildings. In addition, all vessels which are used for waste storage are located inside structures such as sumps, dikes or vaults which will retain any spilled liquid. The reactor coolant drain tank is located at the ground floor of the containment and can be pumped to the liquid waste system.

The Miscellaneous Drains Collection Tank, ADT Collection Tanks, ADT Condensate Receiver Tanks, ADT Monitor Tanks, ADT evaporator and waste concentrates tank (located in the radwaste building) were designed Class III*. The waste concentrates tank is in a vaulted room that holds its entire volume. The rest of the tanks are located either in rooms with dikes or drain directly to the radwaste building sump.

The radwaste system was designed to permit operation of the rest of the plant for extended periods without requiring its being continually operable.

The CVCS holdup tanks are also equipped with safety pressure relief valves and designed to withstand the established seismic forces at the site. Liquids in the Chemical and Volume Control System flowing into and out of these tanks are controlled by manual operation and governed by prescribed administrative procedures.

The volume control tank design philosophy is similar in many respects to that applied for the CVCS holdup tanks. Level alarms, pressure relief valves and tank isolation and valve control assure that a safe condition is maintained during system operation. 60400000354
Excess letdown flow is directed either to the CVCS holdup tanks via the reactor coolant drain or the volume control tank. The waste holdup tank is a horizontal tank which is continuously maintained at atmospheric pressure. Its vent is routed to the auxiliary building exhaust ducts. Should a complete failure of any tank containing radioactive liquid wastes occur its contents will be retained. The potential hazard from these processes or waste liquid releases is derived only from the volatilized components. The potential for accidental release is summarized in Section 14.5.2.

All radioactive liquid waste processed through the radioactive waste collection and treatment systems is discharged to the circulating water discharge channel. The probability of unmonitored releases to the discharge channel is exceedingly small because at least two barriers must be abridged to permit release; e.g. steam generator tubes and condenser tubes or residual heat exchanger and component cooling heat exchanger. In addition the pressure differential, in essentially all operating modes, opposes leakage into the discharge and the Circulating Water Monitor would indicate abnormal radiation levels.

After waste disposal system liquid has been sampled for radiochemical batch analysis and is determined acceptable for release, the liquid is transferred through a radiation trip valve to the auxiliary building standpipe, then on to the waste liquid discharge header.

Periodic samples are taken from the discharge channel before it enters the river for radiation monitoring to further confirm proper operation of the circulating water monitor. Although the radiochemical analysis establishes the basis for releases, the radiation monitors provide surveillance over the release operation and automatically close the discharge valve if the liquid activity release rate would exceed the limits of 10CFR20.

The most severe airborne radioactivity concentrations which might be postulated to result from open cycle cooling tower operation was investigated and was compared with the concentration limits specified in Table II of 10CFR20. It was observed that even though the basic assumptions relating to the composition of activity and the associated release rates are factors of 10 to 1000 greater than what might be experienced under any conceivable abnormal situation, the airborne concentrations in the cooling tower vapor at the site boundary would still be well below of the 10CFR20 limits.

Periodic sampling of the intake water for radioactivity and appropriate environs monitoring are performed as a further precaution that no unforeseen abnormal condition results in undesirable radiological effects.

9.3 GASEOUS RADWASTE SYSTEM

9.3.1 Design Basis

9.3.1.1 Gaseous Radwaste System

The gaseous radwaste system is designed to process and control the release of gaseous radioactive effluents to the site environs so that the offsite radiation dose rate does not exceed the limits specified in 10CFR20 and the design objectives of Appendix I to 10CFR50 are met.

9.3.1.2 Monitoring Fuel and Waste Storage Areas

Criterion: Monitoring and alarm instrumentation shall be provided for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels. (GDC 18)

Monitoring and alarm instrumentation is provided for fuel and waste storage and handling areas to detect deviation from normal water level, inadequate cooling and excessive radiation levels. Radiation monitors are provided to maintain surveillance over the release of radioactive gases and liquids, and the permanent record of activity releases is provided by radiochemical analysis of known quantities of waste.

A controlled ventilation system removes gaseous radioactivity from the atmosphere of the fuel storage and waste treating areas of the auxiliary building and discharges it to the atmosphere via the auxiliary building vent. Radiation monitors are in continuous service in these areas to actuate high-radiation alarms on the control board annunciator, as described in Section 7.5.3.

9.3.1.3 Protection Against Radioactivity Release from Spent Fuel and Waste Storage Areas

Criterion: Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity. (GDC 69)

All waste handling and storage facilities are contained and equipment is designed so that accidental releases directly to the atmosphere are monitored and will not exceed the guidelines of 10CFR100, as described in Sections 9.1.2, 14.5.2, and 14.5.3.

9.3.2 Description

During plant operation, potentially radioactive gases are received mainly from the following sources:

a. Displacement of cover gases as liquids accumulate in various tanks.

b. Miscellaneous equipment vents and relief tanks.

c. Sampling operations and automatic gas analysis for hydrogen and oxygen in cover gases.

d. Nitrogen stripping of reactor coolant to remove hydrogen during shutdown operations.

The waste gas system consists of two interconnected process loops. A low level loop and a high level loop. The waste gas system is very similar to the Westinghouse Environmental Assurance System with the exception of the volume of a gas decay tank which is slightly smaller than the EAS.

The low level loop is designed to contain and process influent gases from sources “a” through “d” above. It is also used to process and contain fission gases resulting from occassional hydrogen stripping of the reactor coolant. Gases vented into the low level loop vent header flow to the waste gas compressor suction header. One of two compressors is in continuous operation with the second unit instrumented to act as backup for peak load conditions or failure of the first unit. Under normal operating conditions, the gas flow from the compressor is split through the hydrogen recombiner and to the decay tanks. Outlet flow from the gas decay tanks is varied to maintain proper pressure in the vent header and holdup tank header.

When the tank in service becomes pressurized to approximately 110 psig, a pressure transmitter automatically closes the inlet valve to that tank, opens the inlet valve to the backup tank and sounds an alarm to alert the operator so a new backup tank may be selected. Pressure indicators are provided to aid the operator in selecting the backup tank. Any net flow into or out of the loop accumulates in, or is made up from, the gas decay tanks. A backup supply of gas is provided from the nitrogen header in the event that return flow from the gas decay tanks to the CVCS holdup tanks is not available.

Most of the gas received by the low level loop during normal operation is cover gas displaced from the Chemical and Volume Control System holdup tanks as they fill with liquid. This gas is primarily nitrogen, but it also contains hydrogen originally dissolved in the letdown coolant. As the gas circulates around the loop, hydrogen is oxidized to water vapor and condensed in the recombiner. The gas decay tank capacity is adequate for storing all of the holdup tank cover gas when those tanks are filled with liquid. There is normally no need to vent the system to atmosphere, although an occasional discharge will be required to dispose of gases accumulated from shutdown operations and inflows from miscellaneous vents.

The high level waste gas loop was designed to process and contain gases with high activity received during infrequent hydrogen stripping of the reactor coolant to remove fission gases. Since reactor coolant fission gas is usually at a low activity level, the high level waste gas loop is normally not used. The high level loop compressor is normally aligned to the low level loop and is used during times of high demand. The high level gas decay tanks are normally used for reserve holdup capacity of low level loop gas. This helps to minimize the frequency of gas decay tank releases.

When a low level loop gas decay tank must be discharged to the environment, its contents are sampled and analyzed to determine and record the activity to be released, and then will be discharged to the auxiliary building vent at a controlled rate. The isolation valve in the discharge line is closed automatically by a high activity level indication in the auxiliary building vent.

During operation, gas samples are drawn automatically from the in service low level loop gas decay tank, and the various tanks vented to the low level waste gas system. The sample stream is automatically analyzed to determine the hydrogen and oxygen content. There should be no significant oxygen concentration in any of the tanks. An alarm will warn the operator if any sample shows two percent or higher of oxygen by volume.

The nitrogen and hydrogen supply systems shown on Figure 9.1-6 are designed to provide a supply of gas to various NSSS components. Operation is identical for both systems. Each system consists essentially of multiple banks of gas cylinders, dual manifolds, each with pressure regulator, and branch line to the various pieces of equipment. Each branch line has a shut off valve and a pressure control valve.

Two independent manifolds are provided for each system, one for normal operation and one spare. Each manifold has a pressure regulator, pressure indicator, a common pressure switch and a common alarm. When the gas cylinder banks supplying the operating manifold are low in pressure, an alarm sounds. The exhausted gas cylinders are removed from service and another group of cylinders are placed in service.

9.3.2.1 Components

9.3.2.1.1 Gas Decay Tanks

Fifteen welded carbon steel tanks are provided to accumulate and contain radioactive gases. Nine tanks are supplied in the low level loop to store cover gases displaced from various tanks until they are returned to the tanks. The remaining six tanks are supplied in the high level loop.

9.3.2.1.2 Compressors

Three compressors are provided to circulate gases around the two process loops. These compressors are water-sealed centrifugal machines. All three compressors are available for use in the low level loop. One compressor is normally in service on the low level loop with a second compressor in standby. Operation of two compressors in the low level loop is controlled by the vent header pressure. Two of the compressors are available for use on the high level loop if needed. Construction is primarily carbon steel. A mechanical seal is provided in each of the three units to minimize leakage of seal water.

9.3.2.1.3 Recombiners

One recombiner is provided in each of the two waste gas system process loops. The units are skid mounted packages complete with separate control panels for remote installation. Instrumentation provided in the recombiner will control oxygen addition to maintain effluent hydrogen concentration. The catalyst is palladium on kaolin beads approximately one-eighth inch in diameter.

9.3.2.1.4 Nitrogen Manifold

Nitrogen is supplied at a nominal pressure of 100 psig to purge the vapor spaces of various NSSS components. Purging reduces the hydrogen concentration or replaces the fluid that has been removed. Each of the dual manifolds are provided with gas supply connections from a nitrogen storage facility.

9.3.2.1.5 Hydrogen Manifold

Hydrogen is supplied at a nominal pressure of 100 psig to the main generators, volume control tanks and to other various NSSS components from a central storage facility. Hydrogen is used as the heat transfer medium to cool the main generators and for reducing the oxygen concentration in the volume control tank to less than 5% by volume. Hydrogen is supplied to the plant systems by a remote hydrogen storage facility outside of the turbine building, installed under modification EC12191 (Ref. 5). 01145513

The remote hydrogen storage facility consists of three permanent tube banks connected to a common header. On each of the three banks, the individual tubes are joined together by a manifold. Each of the three banks can be isolated from the common header individually by a single isolation valve between the tube bank manifold and the header. Only one tube bank is placed into service at a given time, in order to limit the volume of hydrogen being supplied to the header. The tube banks are refilled on site by a delivery tube trailer. 01253589 01145513

The design criteria for the storage facility were selected in accordance with the Electrical Power Research Institute report NP-5283-SR-A, “Guidelines for Permanent BWR Hydrogen Water Chemistry Installations – 1987 Revision” (Ref. 4), and associated NRC Safety Evaluation Report, dated July 1987. The hydrogen storage facility meets the design criteria as prescribed within the aforementioned documents.

9.3.2.1.6 Gas Analyzer

An automatic gas analyzer is provided to monitor the concentrations of oxygen and hydrogen in the cover gas of tanks and vessels which might accumulate a hazardous mixture of the two gases.

9.3.3 Performance Analysis

Gaseous wastes consist primarily of hydrogen stripped from coolant discharged to the CVCS holdup tanks during boron dilution, nitrogen and hydrogen gases purged from the volume control tank, and nitrogen from the closed gas blanketing system. Hydrogen is removed by oxidation and condensation in the recombiners. Nitrogen from the gas blanketing system is stored and reused. The majority of gas discharged from the system is nitrogen received as a result of shutdown operations and miscellaneous vents.

The gaseous waste process flow diagram is shown on Tables 9.3-2 and 9.3-3. These tables illustrate flow rates, temperatures, pressures, and specific isotope radioactivity. No minimum holdup time is specified. The design of the high level loop provides for indefinite holdup.

Gaseous source terms were calculated using the GALE code and are presented in Table 9.3-1. Detailed assumptions and methodology used in the calculation are discussed in Reference 1. Maximum offsite dose from all possible pathways was shown to be well within the Design Objectives of Appendix I to 10CFR50. The releases are described and their effects are summarized in Section 14.5.3.1.

THIS PAGE IS LEFT INTENTIONALLY BLANK

9.4 SOLID RADWASTE SYSTEM

9.4.1 Design Basis

The solid radwaste system is designed to package, store and provide shielded storage facilities for solid wastes and to allow temporary storage prior to shipment from the plant for offsite processing or disposal. The system is designed to meet the requirements of 10CFR20, 10CFR71, and 49CFR170-189.

9.4.2 Description

Solid wastes consist mainly of dry active waste (DAW) such as contaminated paper, plastic, wood, etc., contaminated metals and spent resin.

DAW may be compacted for disposal or storage or may be sent off-site for further processing, such as sorting or incineration. The by-product of such off-site processing, for example, incinerator ash, may be returned to the plant site for storage if no disposal site is available.

Contaminated metals may be compacted on-site for storage or disposal. Contaminated metals may also be sent off-site for processing such as decontamination or metal melting. 95130

Spent resin originates in any of several system ion exchangers.

Spent resin is flushed to a resin shipping liner for disposal or off-site processing. Alternatively, resin may be placed in on-site storage if a disposal site is not available.

9.4.3 Performance Analysis

Solid wastes received at disposal sites must meet the requirements of 10CFR61 relating to waste form and classification as well as disposal site-specific regulations.

Annual generation of DAW is estimated at approximately 50,000 lbs.

Annual generation of spent bead resin is estimated at approximately 500 cu. ft.

THIS PAGE IS LEFT INTENTIONALLY BLANK

9.5 REFERENCES

1. Letter, L O Mayer (NSP) to D. L. Ziemann (NRC), Appendix I Submittals, June 4, 1976 and July 21, 1976. (10501/1800) (10501/2070)

2. Prairie Island Modification 92L377, Waste Liquid Discharge Header Replacement.

3. Prairie Island Modification 89Y065, Waste Liquid Discharge Line Extension.

4. EPRI NP-5283-SR-A, “Guidelines for Permanent BWR Hydrogen Water Chemistry Installations – 1987 Revision”, September 1987.

5. Passport Engineering Change #12191, “Hydrogen Storage System.”

01145513

THIS PAGE IS LEFT INTENTIONALLY BLANK

TABLE 9.1-1 WASTE DISPOSAL SYSTEM PERFORMANCE DATA

01353916

Original Plant Design Life	40 years
Normal process capacity, liquids	2 gpm
Estimated Annual liquid input to Radwaste System[(*)]	
Volume (2 units)	531,240 gal.
Activity (2)	
Tritium Design Value (2 units)	5.2×10^3 curies
Tritium, Expected Value (2 units)	8.2×10^2 curies
Other (2 units)	8.04 curies
Annual gaseous release	
Activity (2 units)	1278 curies/year
Annual generation of Dry Active Waste (2 units)	50,000 lbs
Annual generation of spent resin	500 ft^3

01-082

(*) estimated based on FSAR Table 11.1-4, equilibrium cycle

TABLE 9.1-2 WASTE DISPOSAL COMPONENTS CODE REQUIREMENTS

Component	Code	
Chemical Drain Tank	No code	
Reactor Coolant Drain Tank	ASME III, [1] Class C	
Sump Tanks	No code	
Monitor Tanks	No code	
Waste Holdup Tanks	No code	
Collection Tanks	No code	
Waste Condensate Tank	No code	
Ion-Exchange Shells	No code	
Laundry and Hot Shower Tank	No code	
		01-082
Waste Filter	ASME III, [1] Class C	
Piping and Valves	USAS-B31.1 [2] Section 1	
Gas Decay Tank	ASME III, [1] Class C	01-082
Recombiner	ASME III, [1] Class C	

[1] ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels

[2] USAS-B31.1 - Code for pressure piping American Standards Association and special nuclear casses where applicable.

TABLE 9.1-3 COMPONENT SUMMARY DATA

(Page 1 of 4)
Tanks

	Qty	Type	Volume	Design Pressure psig	Design Temp °F	Material(1)
Reactor Coolant Drain (per unit)	1	Horiz	350 gal	25	267	ss
Laundry & Hot Shower	2*	Vert	700 gal	Atm	180	ss
Chemical Drain	1*	Vert	600 gal	Atm	180	ss
Aerated Sump	1*	Vert	600 gal	Atm	180	ss
Non-Aerated Sump	1*	Vert	300 gal	Atm	125	ss
Waste Holdup	1*	Horiz	24,490 gal	Atm	180	ss
Waste Condensate	2*	Vert	1,000 gal	Atm	180	ss
Gas Decay	15*	Vert	470 ft^3	150	150	cs
SGB Flash (per unit)	1	Vert	2,000 gal	100	325	cs
Aerated Drains Monitor	2*	Vert	1,000 gal	Atm	125	ss
SGB Holdup (per unit)	2	Vert	10,000 gal	Atm	135	ss
SGB Monitor (per unit)	2	Vert	10,000 gal	Atm	135	ss
ADT Collection	2*	Vert	3,000 gal	Atm	180	ss
Misc. Drains Collection	1*	Vert	3,000 gal	Atm	180	ss
Laundry Sludge	1*	Vert	800 gal	Atm	180	ss
Coagulation	1*	Vert	900 gal	Atm	180	ss
ADT Condensate	2*	Vert	2,400 gal	Atm	180	ss
ADT Monitor	2*	Vert	5,000 gal	Atm	180	ss
Spent Resin	1*	Vert	2,200 gal	30	180	ss
Waste Concentrate	1*	Vert	1,700 gal	33	180	ss

05-054

05-054

(1) Material contacting fluid
(2) Mechanical seal provided
* Shared by Units 1 and 2

TABLE 9.1-3 COMPONENT SUMMARY DATA

(Page 2 of 4)

Pumps

05-054

	Qty	Type	Flow gpm	Head ft	Design Pressure psig	Design Temp °F	Material[1]
11 Reactor Coolant Drain Tank (per unit)	1	Horiz cent[2]	60	200	150	267	ss
12 Reactor Coolant Drain Tank (per unit)	1	Horiz cent[2]	200	200	150	267	ss
Chemical Drain Tank	1*	Horiz cent[2]	20	100	375	150	ss
Laundry	2*	Horiz cent[2]	20	100	150	150	ss
SGB Flash Tank Transfer (per unit)	1	Horiz cent[2]	120	130	150	140	ss
11 SGB Holdup Tank (per unit)	1	Horiz cent[2]	120	310	150	140	ss
12 SGB Holdup Drain Tk (per unit)	1	Horiz cent[2]	60	125	150	140	ss
SGB Monitor Drain Tk (per unit)	1	Horiz cent[2]	60	125	150	125	ss
Aerated Drains Monitor Tank	1*	Horiz cent[2]	60	150	150	125	ss
Non-Aerated Sump Tank	1*	Horiz cent[2]	60	80	150	125	ss
Laundry & Hot Shower Tank	2*	Horiz cent[2]	60	100	150	125	ss
Aerated Sump Tank	1*	Horiz cent[2]	20	100	150	150	ss
Backup Sump Tank	1*	Horiz cent[2]	20	100	150	150	ss
Waste Evaporator Feed	1*	Horiz cent[2]	20	100	150	150	ss
Waste Condensate Tank	2*	Horiz cent[2]	20	100	150	150	ss

(1) Material contacting fluid
(2) Mechanical seal provided
* Shared by Units 1 and 2

TABLE 9.1-3 COMPONENT SUMMARY DATA

Pumps

05-054

	Qty	Type	Flow gpm	Head ft	Design Pressure psig	Design Temp °F	Material[1]
ADT Collection Tank	2*	Horiz cent[2]	20	110	150	200	ss
Misc. Collection Tank	2*	Vert cent[2]	60	100	150	200	ss
Coagulation Tank	1*	Horiz cent[2]	20	80	150	125	ss
Laundry Sludge Tank	1*	Horiz cent[2]	30	115	150	125	ss
ADT Condensate Receiver Tank	2*	Horiz cent[2]	60	100	150	200	ss
ADT Monitor Tank	2*	Horiz cent[2]	60	100	150	200	ss
121 Spent Resin	1*	Horiz cent[2]	30	145	150	125	ss
122 Spent Resin	1*	Horiz diaphragm	20	200	150	125	ss
Waste Concentrate Tank	1*	Horiz diaphragm	20	200	150	125	ss

Heat Exchangers

	Qty (per unit)	Type	Shell Flow (lb/hr)	Tube Flow (lb/hr)	Btu/hr	Shell Design Press/ Temp (psi)/(°F)	Tube Design Press/ Temp (psi)/(°F)	Shell Matl.	Tube Matl.
SGB Heat Exch. 11	1	Shell & Tube	75,000	6,900**	1,159,200	150/130	150/130	cs	ss
SGB Heat Exch. 12	1	Shell & Tube	57,776	2,481,862	10,377,000	150/130	600/150	cs	ss

** This is a maximum blowdown liquid capacity as a result of blowdown system modifications. This corresponds to a blowdown rate of approximately 15 gpm per steam generator.

(1) Material contacting fluid
(2) Mechanical seal provided
* Shared by Units 1 and 2

TABLE 9.1-3 COMPONENT SUMMARY DATA

Strainer and Filter

	Qty	Flow gpm	Design Pressure psig	Design Temp °F	Housing Material
Filters					
SGB Reclaim	2	20	150	125	cs
Aerated Drain	1*	20	150	125	ss
Non-Aerated Drain	1*	20	150	125	ss
123/124 ADT	2*	40	150	125	ss
123 ADT IX	1*	20	150	125	ss
121/122 ADT	2*	20	150	125	ss
Strainers					
SGB Ion Exchanger	2	60	150	125	ss

Miscellaneous

	Qty	Capacity	Type
Waste Gas Compressors	3*	40 CFM	Horiz (2) cent
ADT Ion Exchanger	3*	60 gpm	

(1) Material contacting fluid
(2) Mechanical seal provided
* Shared by Units 1 and 2

TABLE 9.2-1 PERFORMANCE DATA AND SERVICE REQUIREMENTS

(2 GPM Waste Evaporator)

Equipment not used. 01-082

TABLE 9.2-2 PERFORMANCE DATA AND SERVICE REQUIREMENTS

(5 GPM ADT Evaporator)

Equipment not used.

01-082

TABLE 9.2-3 LIQUID SOURCE TERMS FROM THE PRAIRIE ISLAND PLANT (PER UNIT)

					ANNUAL RELEASES TO DISCHARGE CANAL						
		Coolant Concentrations							Adjusted	Detergent	Total
Nuclide	Half-Life	Primary	Secondary	Boron RS	Misc. Wastes	Secondary	Turb Bldg	Total LWS	Total	Wastes	
	(Days)	(Micro CI/ML)	(Micro CI/ML)	(Curies)	(Curies)	(Curies)	(Curies)	(Curies)	(CI/YR)	(CI/YR)	(CI/YR)
CORROSION AND ACTIVATION PRODUCTS											
CR 51	2.78E+01	1.72E-05	2.27E-07	.00001	.00016	.00027	.00000	.00044	.00054	0.00000	.00054
MN 54	3.03E+02	2.80E-04	5.43E-08	.00000	.00001	.00006	.00000	.00009	.00011	.00100	.00110
FE 55	9.50E+02	1.44E-03	1.90E-07	.00001	.00014	.00023	.00000	.00038	.00046	0.00000	.00046
FE 59	4.50E+01	9.03E-04	1.39E-07	.00000	.00009	.00017	.00000	.00026	.00031	0.00000	.00031
CO 58	7.13E+01	1.44E-02	1.93E-06	.00009	.00139	.00230	.00002	.00379	.00459	.00400	.00460
CO 60	1.92E+03	1.80E-03	2.44E-07	.00001	.00017	.00029	.00000	.00048	.00058	.00870	.00930
NP239	2.35E+00	1.12E-03	1.27E-07	.00000	.00009	.00015	.00000	.00024	.00029	0.00000	.00029
FISSION PRODUCTS											
BR 83	1.00E-01	5.28E-03	2.90E-07	.00000	.00002	.00024	.00001	.00026	.00032	0.00000	.00032
BR 84	2.21E-02	2.97E-03	5.51E-08	0.00000	.00000	.00001	.00000	.00001	.00001	0.00000	.00001
RB 86	1.87E+01	8.05E-05	1.21E-08	.00000	.00038	.00014	.00000	.00052	.00063	0.00000	.00063
RB 88	1.24E-02	2.30E-01	2.34E-06	0.00000	.00000	.00133	.00000	.00133	.00160	0.00000	.00160
SR 89	5.20E+01	3.16E-04	5.55E-08	.00000	.00003	.00007	.00000	.00010	.00012	0.00000	.00012
SR 91	4.03E-01	6.65E-04	6.04E-08	.00000	.00002	.00007	.00000	.00009	.00010	0.00000	.00010
Y 91M	3.47E-02	4.08E-04	7.75E-08	.00000	.00001	.00006	.00000	.00007	.00009	0.00000	.00009
Y 91	5.88E+01	5.78E-05	6.30E-09	.00000	.00001	.00001	.00000	.00002	.00002	0.00000	.00002
ZR 95	6.50E+01	5.42E-05	8.28E-09	.00000	.00001	.00001	.00000	.00002	.00002	0.00000	.00002
NB 95	3.50E+01	4.52E-05	8.43E-09	.00000	.00000	.00001	.00000	.00001	.00002	0.00000	.00002
MO 99	2.79E+00	7.82E-02	1.20E-05	.00004	.00626	.01415	.00011	.02057	.02488	0.00000	.02500
TC 99M	2.50E-01	5.05E-02	3.91E-05	.00000	.00557	.04190	.00025	.04775	.05776	0.00000	.05800
RU 103	3.96E+01	4.07E-05	5.60E-09	.00000	.00000	.00001	.00000	.00001	.00001	.00014	.00015
RM 103M	3.96E-02	5.09E-05	5.04E-08	.00000	.00000	.00003	.00000	.00003	.00004	0.00000	.00004
TE 127M	1.09E+02	2.53E-04	2.46E-08	.00000	.00002	.00003	.00000	.00006	.00007	0.00000	.00007
TE 127	3.92E-01	8.71E-04	2.05E-07	.00000	.00004	.00022	.00000	.00027	.00033	0.00000	.00033
TE 129M	3.40E+01	1.27E-03	1.69E-07	.00001	.00012	.00020	.00000	.00035	.00040	0.00000	.00040
TE 129	4.79E-02	1.80E-05	1.45E-06	.00000	.00008	.00086	.00000	.00094	.00114	0.00000	.00110
I 130	5.17E-01	2.11E-03	2.18E-07	.00000	.00008	.00024	.00002	.00034	.00041	0.00000	.00041

TABLE 9.2-3 LIQUID SOURCE TERMS FROM THE PRAIRIE ISLAND PLANT (PER UNIT)

					ANNUAL RELEASES TO DISCHARGE CANAL						
		Coolant Concentrations							Adjusted	Detergent	Total
Nuclide	**Half-Life**	**Primary**	**Secondary**	**Boron RS**	**Misc. Wastes**	**Secondary**	**Turb Bldg**	**Total LWS**	**Total**	**Wastes**	
	(Days)	**(Micro CI/ML)**	**(Micro CI/ML)**	**(Curies)**	**(Curies)**	**(Curies)**	**(Curies)**	**(Curies)**	**(CI/YR)**	**(CI/YR)**	**(CI/YR)**
TE 131M	1.25E+00	2.40E-03	2.75E-07	.00000	.00015	.00032	.00000	.00047	.00057	0.00000	.00057
TE 131	1.74E-02	1.26E-03	1.41E-06	.00000	.00008	.00024	.00000	.00027	.00033	0.00000	.00033
I 131	8.05E+00	2.45E-01	3.46E-05	.00508	.02216	.04110	.00337	.07171	.00675	.00006	.08700
TE 132	3.25E+00	2.50E-02	3.06E-06	.00002	.00206	.00341	.00003	.00572	.00691	0.00000	.00690
I 132	9.58E-02	1.10E-01	2.19E-05	.00002	.00244	.01880	.00038	.02163	.02617	0.00000	.02600
I 133	8.75E-01	3.70E-01	4.25E-05	.00016	.02002	.04856	.00347	.07221	.08735	0.00000	.08700
I 134	3.67E-02	5.32E-02	1.46E-06	.00000	.00001	.00062	.00000	.00063	.00076	0.00000	.00076
CS 134	7.49E+02	2.35E-02	3.39E-06	.00035	.11364	.04047	.00003	.15449	.18688	.01300	.20000
I 135	2.79E-01	1.98E-01	1.72E-05	.00000	.00392	.01792	.00092	.02276	.02753	0.00000	.02000
CS 136	1.30E+01	1.24E-02	1.56E-06	.00008	.05733	.01862	.00002	.07605	.09199	0.00000	.09200
CS 137	1.10E+04	1.69E-02	2.26E-06	.00025	.08186	.02693	.00002	.10907	.13193	.02400	.16000
BA 137M	1.77E-03	1.85E-02	2.48E-05	.00024	.07654	.02518	.00002	.10198	.12336	0.00000	.12000
BA 140	1.28E+01	2.00E-04	2.70E-08	.00000	.00002	.00003	.00000	.00005	.00006	0.00000	.00006
LA 140	1.68E+00	1.42E-04	3.86E-08	.00000	.00002	.00005	.00000	.00006	.00007	0.00000	.00007
CE 141	3.24E+01	6.33E-05	8.46E-09	.00000	.00001	.00001	.00000	.00002	.00002	0.00000	.00002
PR 143	1.37E+01	4.54E-05	5.95E-09	.00000	.00000	.00001	.00000	.00001	.00001	0.00000	.00001
CE 144	2.84E+02	2.98E-05	5.43E-09	.00000	.00000	.00001	.00000	.00001	.00001	.00520	.00520
PR 144	1.20E-02	3.79E-05	5.83E-08	.00000	.00000	.00001	.00000	.00001	.00001	0.00000	.00002
ALL OTHERS		4.76E-08	3.09E-08	.00000	.00001	.00002	.00000	.00003	.00003	0.0	.00003
TOTAL (EXCEPT TRITIUM)		1.47E+00	2.14E-04	.00642	.39494	.30556	.00868	.71561	.86561	.06234	.93000

TRITIUM RELEASE 330 CURIES PER YEAR

01-082

01-082

TABLE 9.2-4 PRAIRIE ISLAND LIQUID RADWASTE SYSTEM

		SHIM BLEED	EQUIPMENT DRAINS & CLEAN WASTE	DIRTY WASTES	BLOWDOWN WASTES	DETERGENT WASTES	
1.	Sources	Reactor Coolant Letdown	Non-Aerated Drain System & Reactor Coolant Drain Tank	Aerated Darin System	Blowdown from Steam Generator	Laundry and Hot Shower Drains	
2.	Flow Rate (gpd)	1,440	362	1,000	86,300	450	
3.	Activity (FPCA)	1.0	1.0	0.07	- -	- -	
4.	Collection Tank Volume (gal)	65,830	65,830	3,000	2,000	600	
5.	Collection Rate (gpd)	1,802*	1,802*	1,000	86,300	450	
6.	Collection Time (days)	29.2	29.2	1.2	0.009	1.07	
7.	Processing Rate (gpm)	15	15	20	20	20	
8.	Processing Time (days)	2.44	2.44	0.042	0.028	0.017	
9.	Discharge Tank Volume (gal)	10,000	10,000	5,000	10,000	Same as Collection Tank	
10.	Discharge Rate (gpm)	100	100	60	60	Same as Collection Tank	01-082
11.	Discharge Time (days)	0.055	0.055	0.023	0.046	Same as Collection Tank	
12.	Fraction of Processed Stream Released	1.0	1.0	1.0	1.0	1.0	
		2 Evaporator Feed Ion Exchangers (cation)	Evaporator condensate Demineralizer (anion)	2 ADT Ion Exchangers (Mixed Bed)	SGBT Ion Exchanger (Mixed Bed)		
13.	DF's Iodine	1(1)	10^2	10^2 (10)	10^2		
14.	Cs, Rb	10(10)	1	2 (10)	10		01-082
15.	Others	10(10)	1	10^2 (10)	10^2		
16.	Regenerant Time (days)	Not	Not	Not	Not	NA	
17.	Regenerant Volume (gal)	Regenerated	Regenerated	Regenerated	Regenerated		
18.	Regenerant Activity						
19.	Fraction of Regenerants Discharged						
20.	Treatment of Regenerants						
21.	Source Terms	See Table 9.2-3	See Table 9.2-3	See Table 9.2-3	See Table 9.2-3	See Table 9.2-3	

*Sum of Shim Bleed, Equipment Wastes, and Clean Waste input flows.

TABLE 9.3-1 GASEOUS SOURCE TERMS FROM THE PRAIRIE ISLAND PLANT (PER UNIT)

Page 1 of 2

			GASEOUS RELEASE RATE - CURIES PER YEAR							
			Gas Stripping		Building Ventilation					
	PRIMARY COOLANT (MICROCI/GM)	SECONDARY COOLANT (MICROCI/GM)	SHUTDOWN	CONTINUOUS	REACTOR	AUXILIARY	TURBINE	BLOWDOWN VENT OFF GAS	AIR EJECTOR EXHAUST	TOTAL
KR-83M	2.418E-02	1.415E-08	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
KR-85M	1.26E-01	7.529E-08	0.0	0.0	0.0	3.0E+00	0.0	0.0	2.0E+00	5.0E+00
KR-85	7.313E-02	4.338E-08	1.5E+01	1.4E+02	2.2E+01	2.0E+00	0.0	0.0	0.0	1.8E+02
KR-87	6.917E-02	3.908E-08	0.0	0.0	0.0	1.0E+00	0.0	0.0	0.0	1.0E+00
KR-88	2.299E-01	1.340E-07	0.0	0.0	1.0E+00	5.0E+00	0.0	0.0	3.0E+00	9.0E+00
KR-89	5.776E-03	3.427E-09	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
XE-131M	9.248E-02	5.522E-08	0.0	0.0	2.1E+01	2.0E+00	0.0	0.0	1.0E+00	2.4E+01
XE-133M	2.328E-01	1.390E-07	0.0	0.0	2.0E+01	5.0E+00	0.0	0.0	3.0E+00	2.8E+01
XE-133	1.738E+01	1.023E-05	0.0	0.0	2.7E+03	3.7E+02	0.0	0.0	2.3E+02	3.3E+03
XE-135M	1.501E-02	8.808E-09	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
XE-135	3.978E-01	2.336E-07	0.0	0.0	6.0E+00	8.0E+00	0.0	0.0	5.0E+00	1.9E+01
XE-137	1.040E-02	6.119E-09	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
XE-138	5.081E-02	2.936E-08	0.0	0.0	0.0	1.0E+00	0.0	0.0	0.0	1.0E+00
TOTAL NOBLE GASES										3.6E+03
I-131	2.449E-01	3.838E-05	0.0	0.0	5.5E-04	3.9E-02	2.1E-03	0.0	2.4E-02	6.6E-02
I-133	3.697E-01	4.643E-05	0.0	0.0	3.0E-04	5.9E-02	2.5E-03	0.0	3.7E-02	9.9E-02
TRITIUM GASEOUS RELEASE				330 CURIES/YR						

0.0 appearing in the table indicates release is less than 1.0 Ci/yr for noble gas, 0.0001 Ci/yr for Iodine.

01-081

TABLE 9.3-1 GASEOUS SOURCE TERMS FROM THE PRAIRIE ISLND PLANT (PER UNIT)
Page 2 of 2

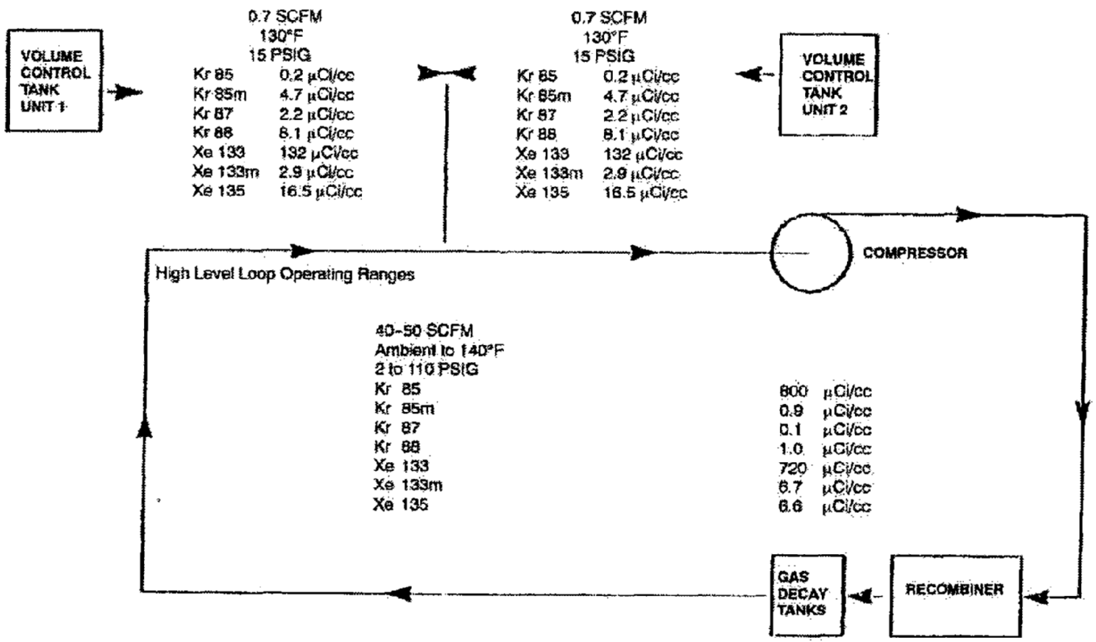
AIRBORNE PARTICULATE RELEASE RATE-CURIES PER YEAR

01-081

NUCLIDE	WASTE GAS SYSTEM	BUILDING VENTILATION REACTOR	BUILDING VENTILATION AUXILIARY	TOTAL
MN-54	4.5E-05	2.0E-05	1.8E-02	1.8E-02
FE-59	1.5E-05	6.7E-06	6.0E-03	6.0E-03
CO-58	1.5E-04	6.7E-05	6.0E-02	6.0E-02
CO-60	7.0E-05	3.0E-05	2.7E-02	2.7E-02
SR-89	3.3E-06	1.5E-06	1.3E-03	1.3E-03
SR-90	6.0E-07	2.7E-07	2.4E-04	2.4E-04
CS-134	4.5E-05	2.0E-05	1.4E-02	1.8E-02
CS-137	7.5E-05	3.4E-05	3.0E-02	3.0E-02

TABLE 9.3-2 PRAIRIE ISLAND - HIGH LEVEL LOOP PROCESS CONDITIONS AND MAXIMUM ISOTOPIC CONCENTRATIONS

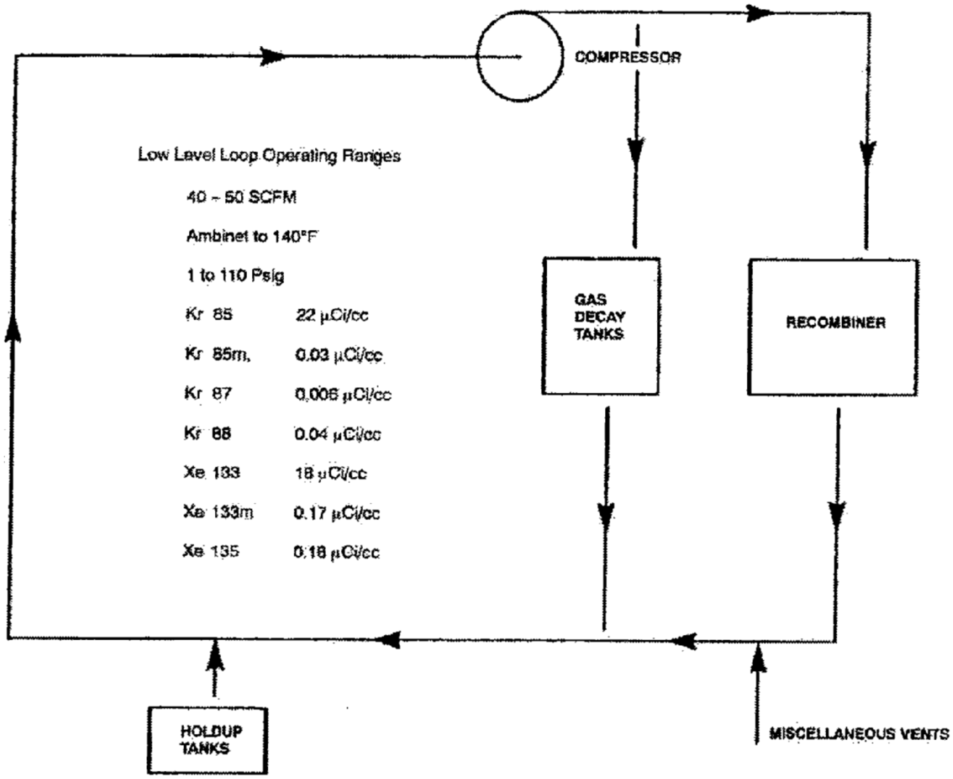
01-081



01-081

TABLE 9.3-3 PRAIRIE ISLAND - LOW LEVEL LOOP PROCESS CONDITIONS AND MAXIMUM ISOTOPIC CONCENTRATIONS

01-081



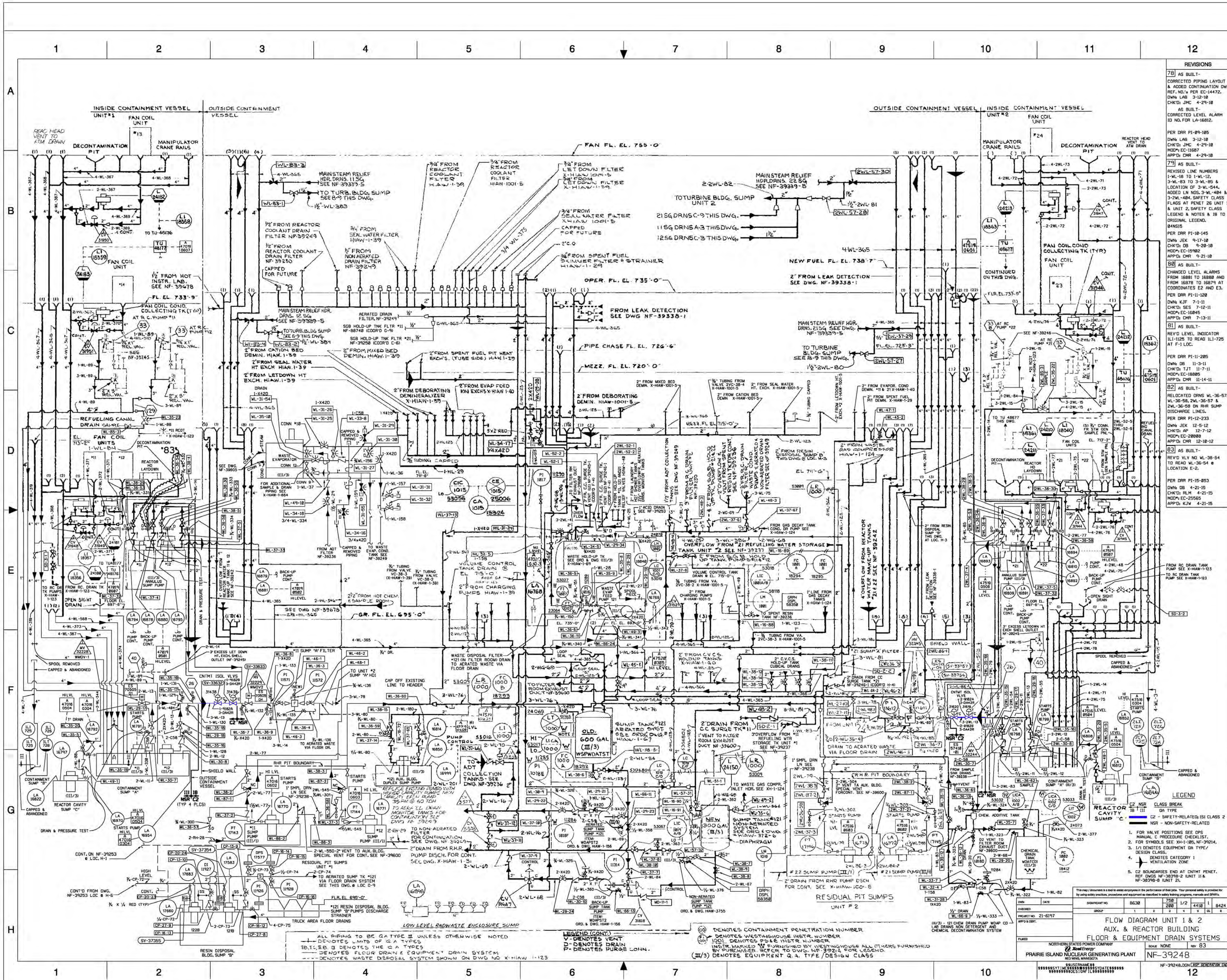
01-081

THIS PAGE IS LEFT INTENTIONALLY BLANK

FIGURE 9.1-1 REV. 34

CAD FILE: U09101.DGN

01516979



01516979

FIGURE 9.1-2 REV. 34

CAD FILE: U09102.DGN

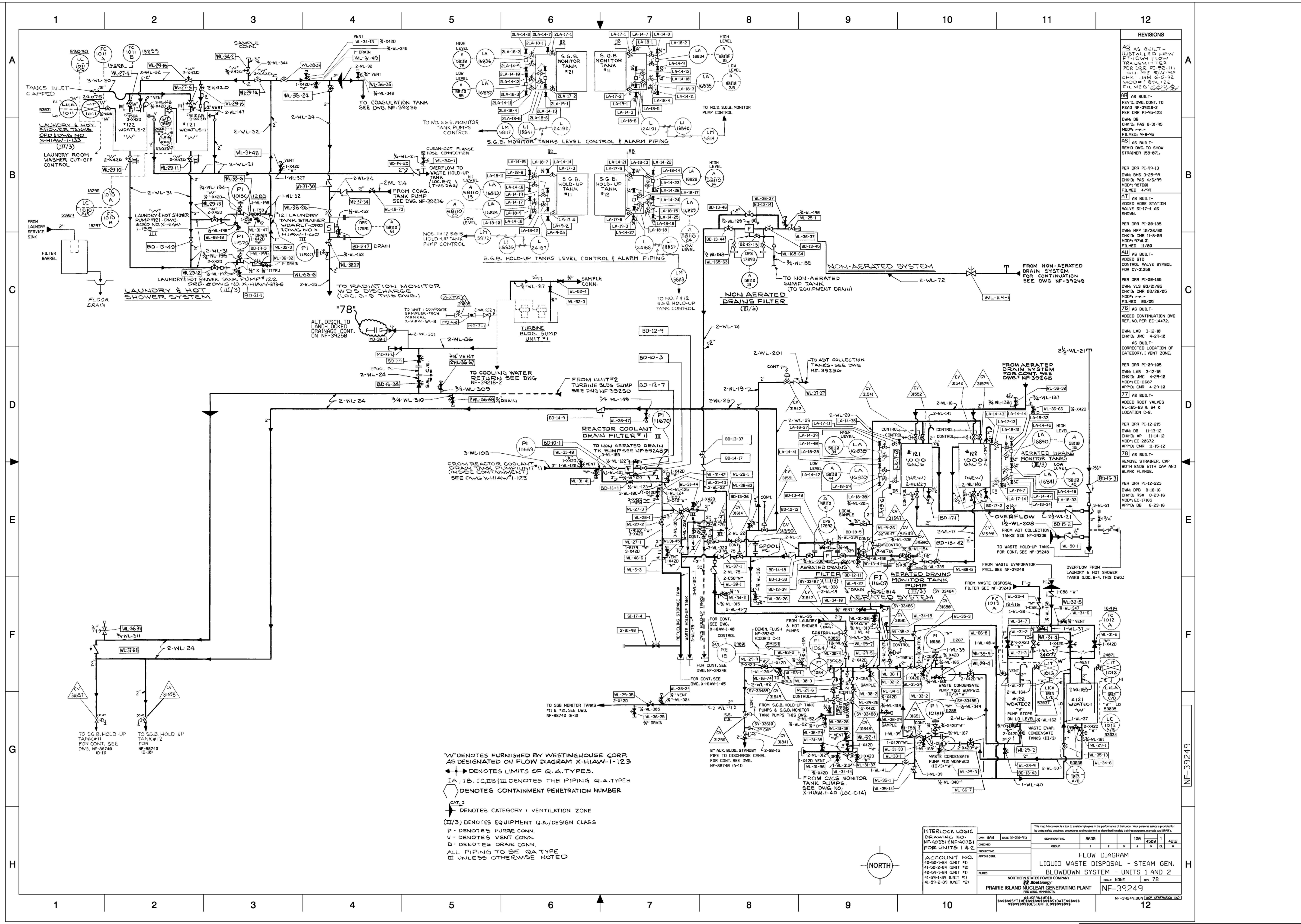


FIGURE 9.1-3 REV. 35

CAD FILE: U09103.DGN

60300001331

FIGURE 9.1-4 REV. 35

60300001331

CAD FILE: U09104.DGN

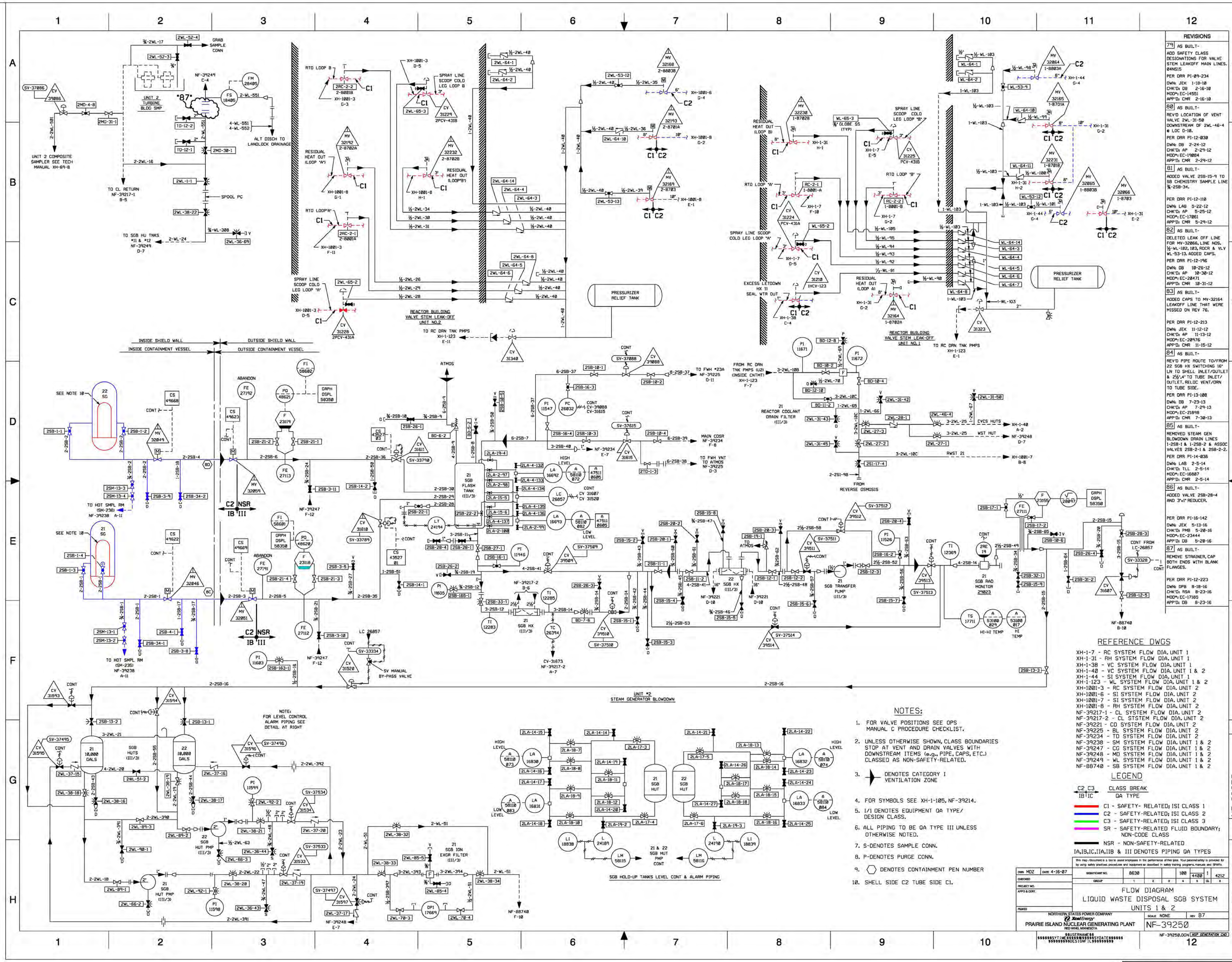


FIGURE 9.1-5 REV. 35

CAD FILE: U09105.DGN

60300001331

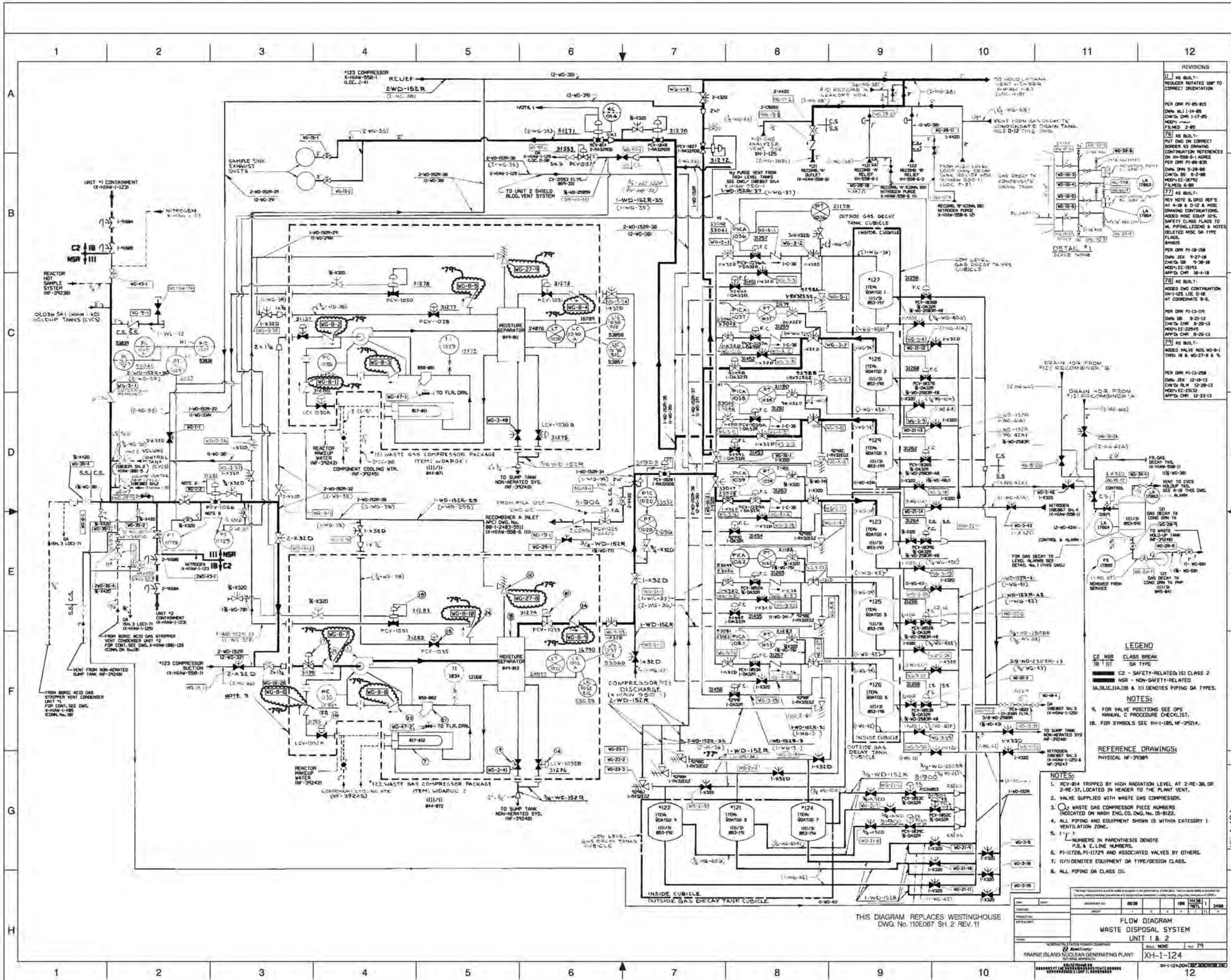


FIGURE 9.1-6 REV. 33

CAD FILE: U09106.DGN

01429088

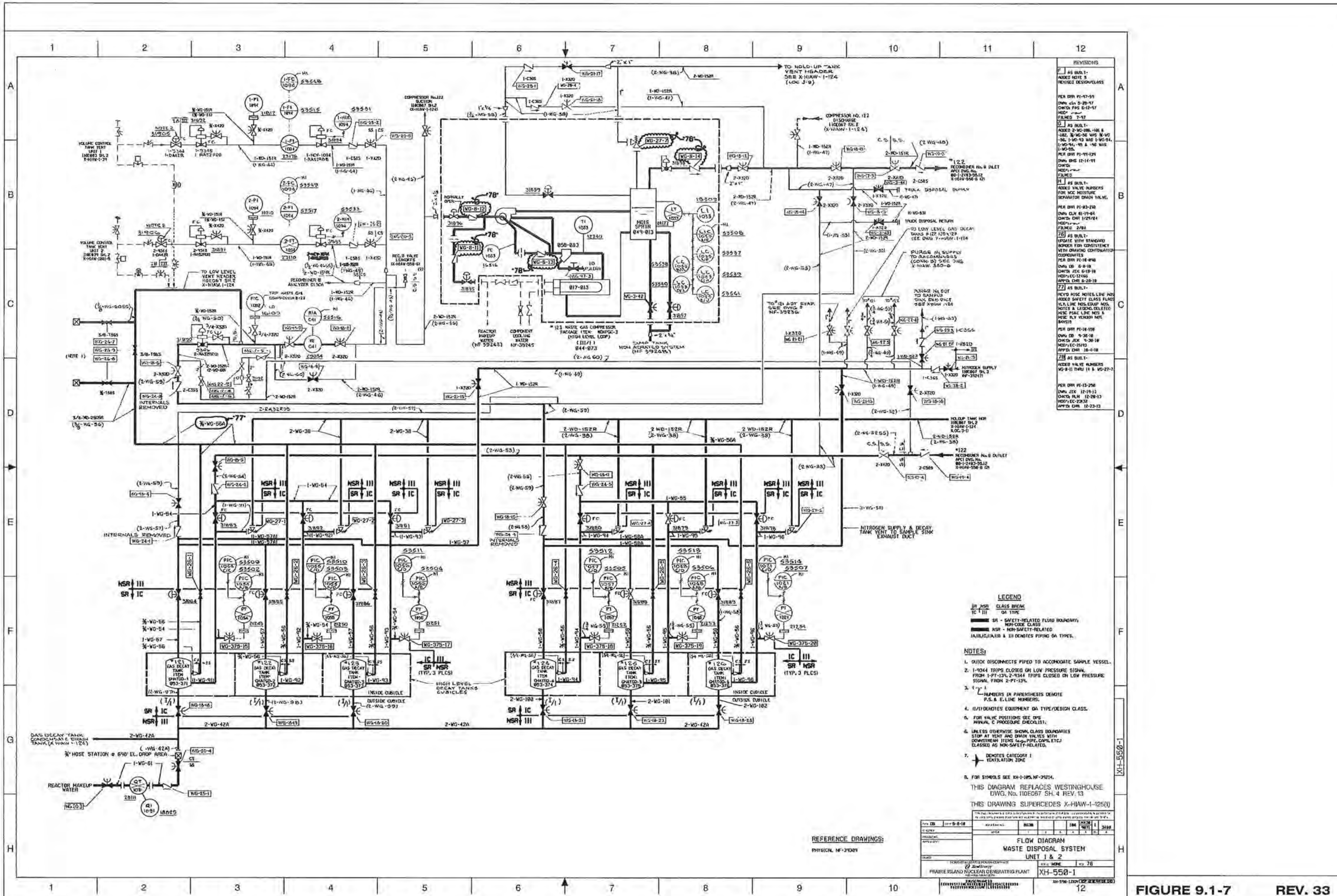


FIGURE 9.1-7 REV. 33

CAD FILE: U09107.DGN

01429088

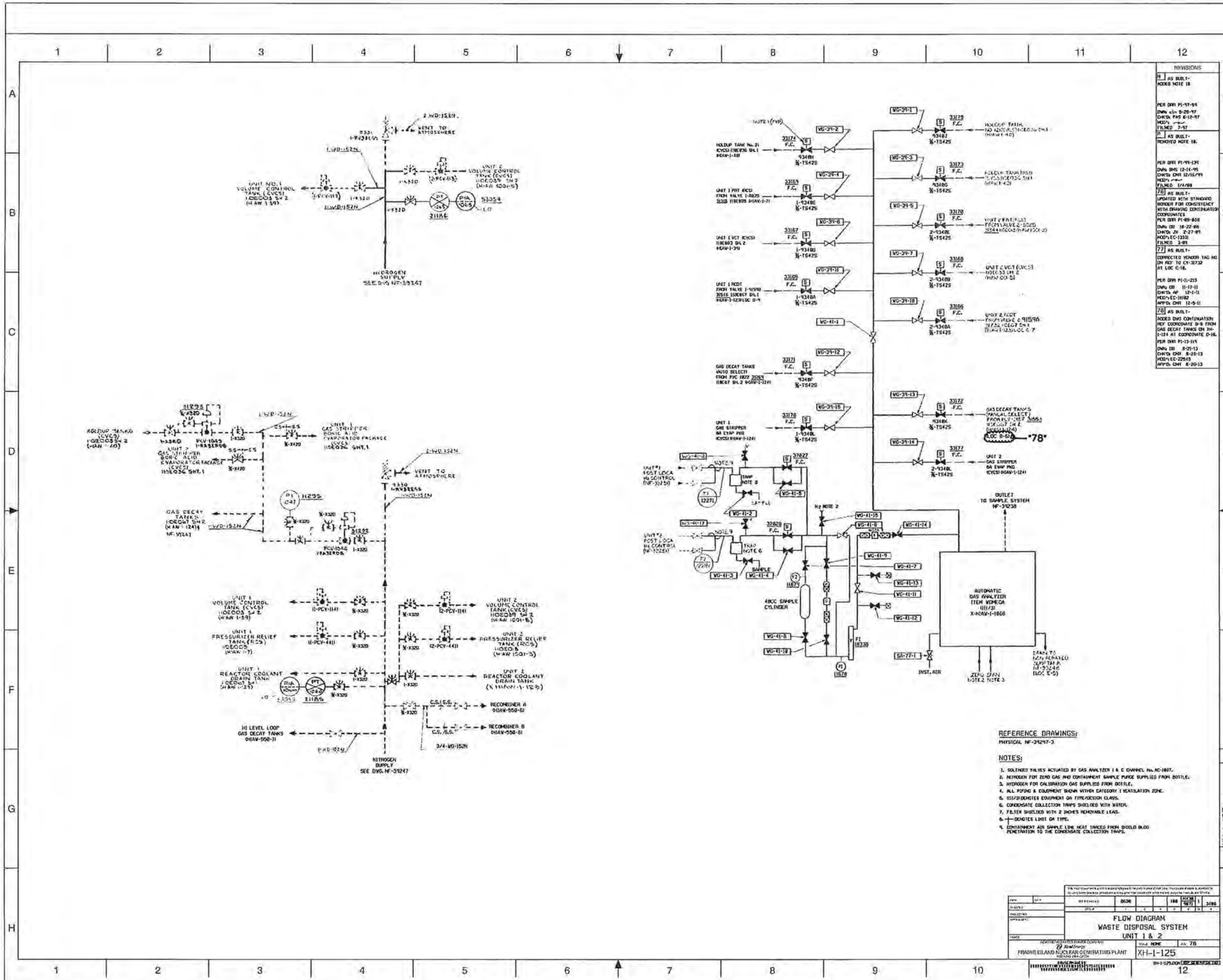


FIGURE 9.1-8 **REV. 33**

01429088

CAD FILE: U09108.DGN

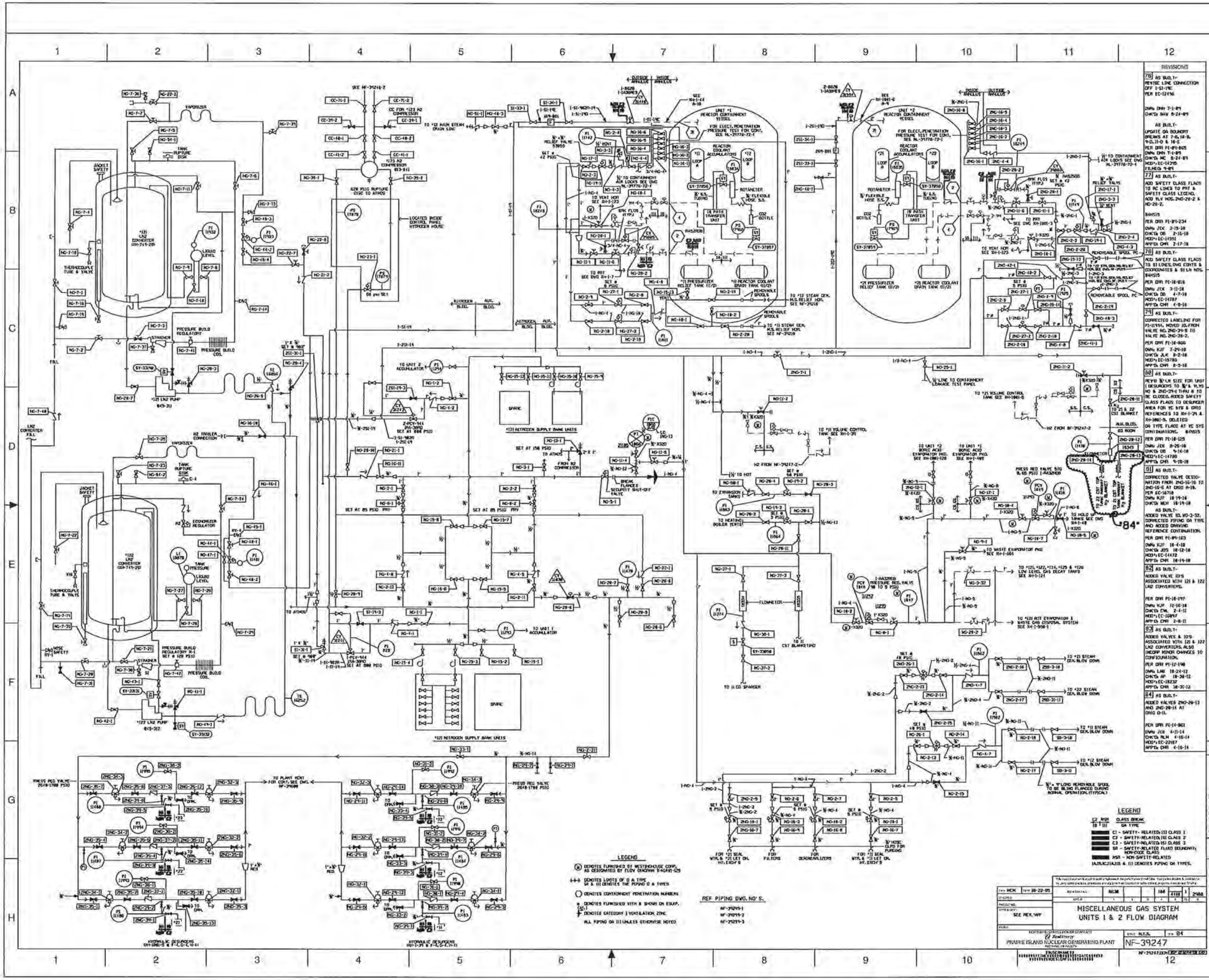


FIGURE 9.1-9 REV. 33

CAD FILE: U09109.DGN

01429088

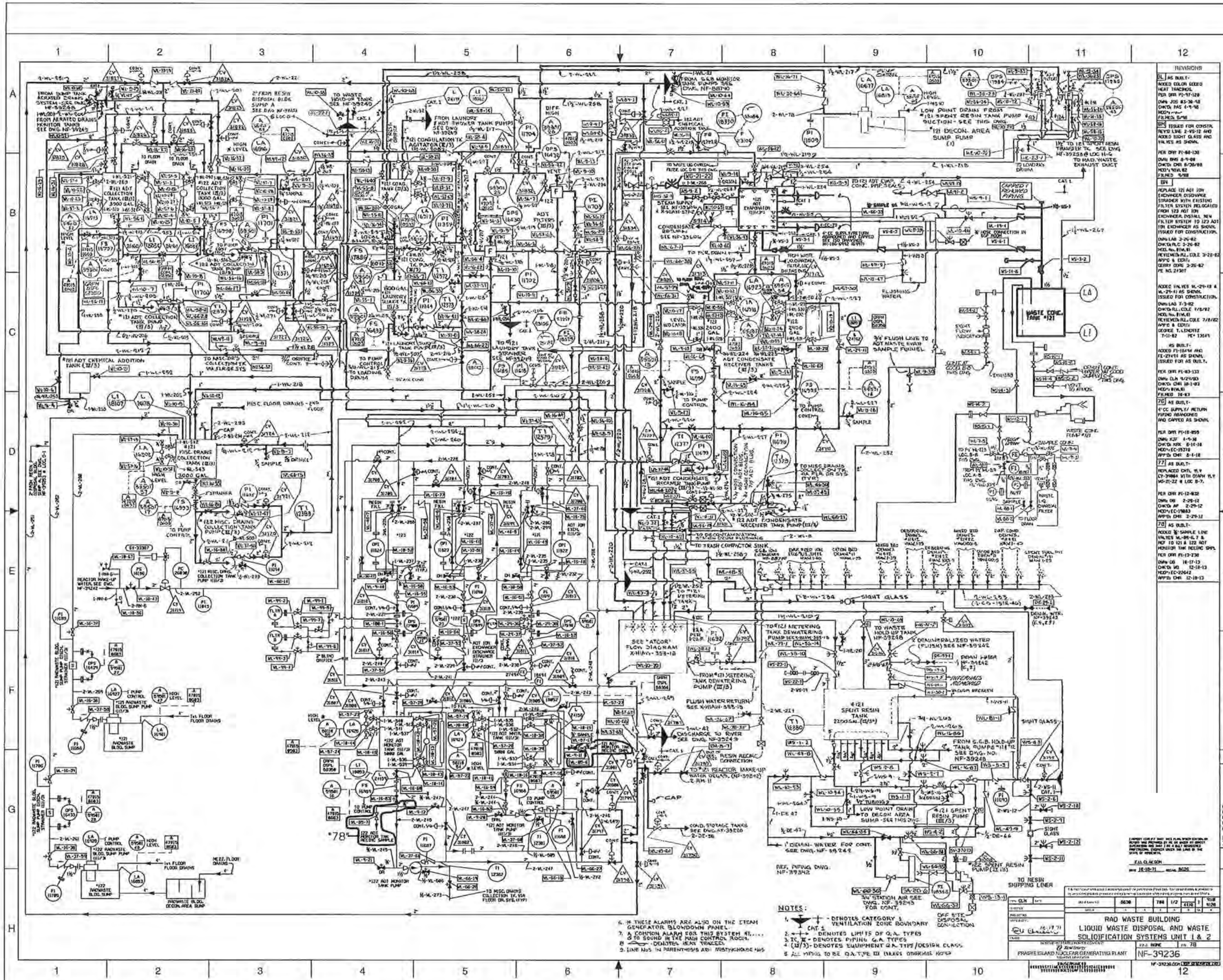


FIGURE 9.1-10 REV. 33

CAD FILE: U09110.DGN

01429088

SECTION 10

PLANT AUXILIARY SYSTEMS

TABLE OF CONTENTS

TABLE OF CONTENTS [Continued]

TABLE OF CONTENTS [Continued]

LIST OF TABLES

TABLE OF CONTENTS [Continued]

LIST OF FIGURES

TABLE OF CONTENTS [Continued]

LIST OF FIGURES

TABLE OF CONTENTS [Continued]

LIST OF FIGURES

SECTION 10 PLANT AUXILIARY SYSTEMS

10.1 SUMMARY DESCRIPTION

The Plant Auxiliary Systems are the supporting systems required to ensure the safe operation or servicing of the Reactor Coolant System (described in Section 4.1). Various components in some of these systems are shared by Units 1 and 2.

In some cases, the dependable operation of several systems is required to protect the Reactor Coolant System by controlling system conditions within specified operating limits. Certain systems are required to operate under emergency conditions. Tables 1.3-1 and 1.3-2 list those systems which have shared components and list the safety relationships.

The following systems are considered in this section:

a. Fuel Storage and Handling System - This system provides for handling fuel assemblies, control rod assemblies, and material irradiation specimens.

b. Reactor Auxiliary Systems

   1. The Residual Heat Removal system removes the residual heat from the core and reduces the temperature of the Reactor Coolant System during the second phase of plant cooldown.

   2. The Spent Fuel Pool Cooling system removes the heat generated by spent fuel elements stored in the spent fuel pool.

   3. Chemical and Volume Control System - This system provides for boric acid injection, chemical additions for corrosion control, reactor coolant cleanup and degasification, reactor coolant makeup, reprocessing of water letdown from the Reactor Coolant System, and reactor coolant pump seal water injection.

   4. Reactor makeup water deoxygenation system maintains the dissolved oxygen content of the reactor makeup water within the limits identified in PINGP Chemistry procedures. 01193402

c. Plant Service Systems - These systems include fire protection, ventilation, air conditioning, emergency lighting, sampling system, and compressed air.

d. Plant Cooling Systems - The Cooling Water System provides cooling water supplies to the auxiliary feedwater pumps, Unit 1 diesel generators, air compressors, component cooling water heat exchangers, containment fan coil units, and the Auxiliary Building unit coolers. The Component Cooling System removes heat from the Reactor Coolant System, via the Residual Heat Removal System, during plant shutdown, cools the letdown flow to the Chemical and Volume Control System during power operation and provides cooling to dissipate waste heat from various primary plant components and the boric acid and waste evaporators.

e. Equipment and System Decontamination

10.2 REACTOR AUXILIARY SYSTEMS

10.2.1 Fuel Storage And Fuel Handling Systems

The Fuel Handling System provides a safe and effective means of transporting and handling fuel from the time it reaches the plant in an unirradiated condition until it leaves the plant after post-irradiation cooling. The system is designed to minimize the possibility of mishandling or maloperations that could cause fuel damage and potential fission product release.

The Fuel Handling System consists basically of:

a. The reactor refueling cavity, which is flooded only during plant shutdown for refueling.

b. The spent fuel pool, shared by the two units, which is kept full of borated water during and after the first refueling and is always accessible to operating personnel.

c. The Fuel Transfer System, consisting of an underwater conveyor that transports fuel assemblies between the reactor refueling cavity and the spent fuel pool.

d. The Spent Fuel Cask Transfer System.

10.2.1.1 Design Basis

Prevention of Fuel Storage Criticality

Criterion: Criticality in new and spent fuel storage shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls. (GDC 66)

The new and spent fuel storage racks which have accommodations as defined in Table 10.2-1 are designed so that it is impossible to insert assemblies between rack modules or between rack modules and the spent fuel pool wall. In addition, the spent fuel pool has an area set aside for accepting the spent fuel shipping casks. Cask loading is also done under water. Borated water is used to fill the spent fuel storage pool to maintain $k_{eff} \leq 0.95$. During refueling the boron concentration of the reactor coolant system and the refueling cavity shall be sufficient to ensure that the more restrictive of the following conditions is met:

a. $K_{eff} \leq 0.95$, or
b. Boron concentration ≥ 2000 ppm
c. Shutdown Margin as specified in the Core Operating Limits Report

The boron concentration of the spent fuel pool during refueling is maintained near the concentration of the refueling cavity to prevent dilution of the refueling cavity.

In both the new and spent fuel storage racks, criticality of fuel assemblies is prevented by the design of the rack which limits fuel assembly interaction. In the spent fuel pool, this is also done by specifying allowable storage arrays and maintaining soluble neutron poison in the spent fuel pool water.

The regulatory basis for preventing criticality in the Spent Fuel Pool and New Fuel Pit is 10 CFR 50.68(b), which explicitly provides subcriticality criteria, a uranium enrichment maximum limit, and other conditions. Adopting the requirements of 50.68(b) is an alternative to the criticality accident monitoring requirements of 10 CFR 70.24. The applicable criticality criteria of 50.68(b) are summarized below:

(1) The estimated ratio of neutron production to neutron absorption and leakage (k-effective) of the fresh fuel in the fresh fuel storage racks shall be calculated assuming the racks are loaded with fuel of the maximum fuel assembly reactivity and flooded with unborated water and must not exceed 0.95, at a 95 percent probability, 95 percent confidence level.

(2) If optimum moderation of fresh fuel in the fresh fuel storage racks occurs when the racks are assumed to be loaded with fuel of the maximum fuel assembly reactivity and filled with low density hydrogenous fluid, the k-effective corresponding to this optimum moderation must not exceed 0.98, at a 95 percent probability, 95 percent confidence level.

(3) As Prairie Island has taken credit for soluble boron in the spent fuel pool, the k-effective of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95 percent confidence level, if flooded with borated water, and the k-effective must remain below 1.0 (subcritical), at a 95 percent probability, 95 percent confidence level, if flooded with unborated water.

The criticality analysis “allowance for uncertainties” is described in Reference 39 for the New Fuel Pit, and in References 45 and 46 for the Spent Fuel Pool.

The Prairie Island spent fuel storage racks were analyzed utilizing the Westinghouse Spent Fuel Rack Criticality Analysis Methodology described in WCAP-17400-NP (Reference 45) and WCAP-17400 Supplement 1 (Reference 46). WCAP-17400 Supplement 1 (Reference 46) was performed to allow for the storage of IFBA-bearing fuel. The approval of this supplemental analysis is documented in Reference 47. 604000000121

As described in the Prairie Island criticality analysis (References 45 and 46), spent fuel storage configurations are designed to ensure that the spent fuel rack K_{eff} will be less than 1.0 (including allowance for uncertainties), without the presence of any soluble boron in the storage pool. Soluble boron credit is used to demonstrate a subcriticality margin for a K_{eff} less than or equal to 0.95 (including allowance for uncertainties) for normal conditions and accident conditions as well. In the spent fuel criticality analysis, consideration is given to fuel assembly design, initial enrichment, burn-up, decay time, operating conditions, rack configuration, pool boron concentration, pool temperature and the presence of burnable poisons. The Prairie Island racks have been analyzed to allow storage of all fuel assembly types described in USAR Section 3.3.1. The analysis was completed for a maximum spent fuel pool water temperature of 150 ºF for normal operations (212 ºF for loss of cooling accident conditions). The analysis does not take credit for the presence of the spent fuel rack Boraflex neutron absorber panels which are believed to be in a degraded condition.

In each array shown in Technical Specification Figure 4.3.1-1 the fuel assemblies are first categorized by their relative reactivity by using Technical Specifications Tables 4.3.1-1 through 4.3.1-3. The concept of an acceptable array is to combine the use of low-reactivity fuel and/or empty cells to offset higher-reactivity fuel. Parameters that define a fuel category include initial enrichment, burn-up, decay time, and if it was operated in Cycles 1 through 4 (all fuel operated in cycles 1-4 was conservatively assumed to contain Burnable Poison Rod Assembly inserts (BPRA's) during operation). Each of the analyzed arrays and the array interface requirements are described in the Technical Specification Bases.

Special Fuel Considerations: In addition to the conventional fuel assemblies and Consolidated Rod Storage Canisters that were specifically analyzed and defined in Technical Specifications, specific analyses or evaluations have been performed to ensure that variants from the conventional fuel are stored safely in the spent fuel pool and continue to satisfy criticality criteria. Significant variants are discussed below:

With the exception of the array associated with Consolidated Rod Storage Canisters, all array cells designated as "empty" cannot contain any material that displaces water along the entire active fuel elevation.

The failed fuel baskets in use (i.e, Fuel Rod Storage Canister (FRSC) with 10 or less damaged fuel rods and the Failed Fuel Pin Basket (FFPB)) were modeled to show that they are significantly less reactive than the least reactive fuel. Therefore, these failed fuel baskets may be located in any cell where a fuel assembly qualifies for placement.

The following additional non-fuel components were addressed and may be stored in a cell where any fuel assembly qualifies for placement.

- Miniature Incore detectors and thimble tubes.
- Fuel Inserts stored in the assembly guide tubes (such as RCCA's neutron sources, Thimble Plugs, and BPRA's).
- Any amount of non-fuel material (including depleted filters and dummy fuel assemblies)

Any fuel assembly with an instrument tube removed may be stored as if the instrument tube were present (i.e., no impact on storage limitations).

Any assembly discharged in or after 2R28 and experiencing more than 100 MWd/MTU of lifetime core average exposure at full power with rods inserted may not credit any of that exposure for use in determining the coefficients used to categorize fuel assemblies as defined in Technical Specification. For the purposes of this condition, rodded operation is considered only if rods are inserted more than 7.8 inches into the active fuel length at full power. Additionally, all fuel discharged prior to 2R28 has been evaluated for up to 1000 MWD/MTU of rodded operation without impacting use of the Technical Specification coefficients.

Administrative controls implemented by Technical Specifications 3.7.17 and 4.3 ensure that fuel will be stored in the spent fuel pool in accordance with the above restrictions.

The Prairie Island spent fuel rack criticality analysis also addressed postulated accidents in the spent fuel pool.

The criticality analysis confirmed that most spent fuel pool accident conditions will not result in an increase in K_{eff} of the spent fuel racks. Examples of such accidents are the drop of a fuel assembly on top of a rack, between rack modules, between rack modules and the pool wall, and the drop or placement of a fuel assembly into the cask loading area. At Prairie Island, the spent fuel assembly rack configuration is such that it precludes the insertion of a fuel assembly between rack modules or between rack modules and the pool wall. A dropped fuel assembly can only land on the top of the racks or in the cask loading area.

From a criticality standpoint, the dropped fuel assembly accident assumes a fuel assembly in its most reactive condition is dropped onto the spent fuel racks. The rack structure pertinent for criticality is not excessively deformed. Previous accident analysis with unborated water showed that a dropped fuel assembly which comes to rest horizontally on top of the spent fuel rack has sufficient water separating it from the active fuel height of stored fuel assemblies to preclude neutronic interaction. For the borated water condition, the interaction is even less since the water contains boron, an additional thermal neutron absorber. The analysis in Reference 45 concluded that a dropped fuel assembly laying horizontally on the racks is bounded by the fuel assembly misload accident discussed below. This analysis also concluded the reactivity increase resulting from dropping or placing a fuel assembly into the cask loading area is also bounded by the fuel assembly misload accident discussed below.

However, four accidents that could result in an increase in reactivity have been addressed:

- Loss of Spent Fuel Pool Cooling
- New fuel assemblies misloaded into incorrect storage rack location 604000000121
- Inadvertent removal of an RCCA from Array G
- Boron dilution of the pool

The loss of normal cooling to the spent fuel pool causes an increase in the temperature of the water passing through the stored fuel assemblies. This causes a decrease in water density which reduces boron density and causes a positive reactivity addition. The analysis was completed for a maximum pool temperature of 212 ºF. The evaluation established the amount of soluble boron necessary to ensure that the spent fuel rack K_{eff} will be maintained less than or equal to 0.95. The result was <887 ppm of boron which is lower than the spent fuel pool boron concentration limit contained in Technical Specification 3.7.16 (2500 ppm). Based on the double contingency principle, the margin for accident conditions included in the Technical Specification 3.7.16 boron concentration limit does not have to account for multiple accidents, such as a boron dilution event, at the same time. 604000000121

A fuel assembly misload accident relates to unintentional placement of fuel in storage locations. Special administrative controls are placed on the patterning of assemblies into spent fuel rack cells. The misloading of a fuel assembly potentially constitutes not meeting the enrichment, burnup or decay time requirements of that cell location. The result of the misloading is to potentially add positive reactivity. Reference 46 evaluated two misload accidents: a single assembly misload and a multiple assembly misload. The limiting single assembly misload configuration required 890 ppm boron to maintain Keff < 0.95. The limiting multiple assembly misload configuration required 2030 ppm boron to maintain Keff < 0.95. The required boron concentrations for both accidents are less than the spent fuel pool boron concentration limit contained in Technical Specification 3.7.16 (2500 ppm boron). Based on the double contingency principle, the margin for accident conditions included in the Technical Specification 3.7.16 boron concentration limit does not have to account for multiple accidents, such as a boron dilution event, at the same time. 604000000121

An inadvertent removal of an RCCA from Technical Specification Figure 4.3.1-1 Array G results in a positive reactivity addition to Array G. The amount of soluble boron required to offset this accident was determined to be bounded by the fuel assembly misload accident.

To address an uncontrolled boron dilution event, calculations were performed in order to define the dilution time and volumes for the spent fuel pool (Reference 48). The dilution sources available at Prairie Island were compiled and evaluated against the calculated dilution volume, to determine the potential of a spent fuel pool dilution event. The evaluations show that a large volume of water (approximately 345,000 gallons) is necessary to dilute the spent fuel pool to a soluble boron concentration well above where criticality would be approached in the spent fuel pool.

Technical Specification 4.3.1.1.c requires that the spent fuel rack K_{eff} be less than or equal to 0.95 when flooded with water borated to 400 ppm. The dilution analysis concluded that large volumes of water are necessary to dilute the spent fuel pool water from a boron concentration of 1800 ppm to 750 ppm. The availability of such large water supplies on site is limited. In addition, the transferability of the available water supplies to the pool is very low due to the small number of possible flow paths and in many cases impossible due to the physical arrangement of the spent fuel pool relative to the supplies. 60400000121

A boron dilution event large enough to result in a significant reduction in the spent fuel pool boron concentration will involve the transfer of a large quantity of water from a dilution source and a significant increase in spent fuel pool level which would ultimately result in pool overflow. Such a large water volume turnover, and the likely overflow of the spent fuel pool, would be readily detected and terminated by plant personnel.

In addition, because of the low dilution flow rates available at Prairie Island, and the large quantities of water required, any significant dilution of the spent fuel pool would only occur over a long period of time (hours to days). Detection of a spent fuel pool dilution via level alarms and/or visual inspections would be expected long before a significant dilution would occur.

Therefore, it is highly unlikely that any dilution event in the spent fuel pool could result in the reduction of the spent fuel pool boron concentration from 1800 ppm to less than the 750 ppm analytical endpoint, which leaves ample margin to the Technical Specification value of 400 ppm and the analyzed value of 359 ppm that are both associated with the limiting normal condition.

The spent fuel pool dilution analysis assumes thorough mixing of all the non-borated water added to the spent fuel pool. It is unlikely, with cooling flow and convection from the spent fuel decay heat, that thorough mixing would not occur. However, if mixing was not adequate, it would be conceivable that a localized pocket of non-borated water could form somewhere in the spent fuel pool. This possibility is addressed by the criticality analysis (References 45 and 46) which shows that the spent fuel rack K_{eff} will be less than 1.0 on a 95/95 basis with the spent fuel pool filled with non-borated water. Thus, even if a pocket of non-borated water formed in the spent fuel pool, K_{eff} would be expected to be less than 1.0 anywhere in the pool. 604000000121

The criticality analysis performed on the Prairie Island new fuel racks (Reference 39) found K_{eff} to be less than 0.95 including uncertainties at a 95/95 probability/confidence level for fuel enriched to a batch average 5.0 wt% U-235 and assuming full density moderation. However, the analysis of the new fuel racks under the low density optimum moderation conditions found that the maximum rack reactivity exceeded the design limit of 0.98 if the new fuel rack 8 by 11 storage cell array was assumed to be completely filled. Further evaluation found that if the center 2x7 array of storage cells were removed, thereby reducing the fuel rack storage capacity to 74 assemblies, (Figure 2, Reference 39), the 0.98 K_{eff} limit would be met under low density optimum moderation conditions. Therefore, the new fuel racks have been modified to preclude the storage of fuel assemblies in the center 2x7 array of storage cells assumed to be empty by the criticality analysis.

During cask handling in the spent fuel pool a minimum of 2450 ppm of boron is maintained. The 2450 ppm boron will ensure that k_{eff} for the spent fuel cask, including statistical uncertainties, will be less than or equal to 0.95 for all postulated arrangements of fuel within the cask. This boron concentration was derived from the criticality analyses for the TN-40HT cask design and conservatively bounds the boron requirements for a TN-40 cask. Detailed instructions are available for use by refueling personnel. These instructions, the minimum operating conditions, and the design of the fuel handling equipment incorporating built-in interlocks and safety features, provide assurance that no incident could occur during the refueling operations that would result in a hazard to public health and safety.

The reactor refueling cavity, fuel transfer canal and spent fuel storage pool are reinforced concrete structures with a seam-welded stainless steel plate liner. These structures are designed as Class I structures to withstand the anticipated earthquake loadings so that the liner prevents leakage even in the event the reinforced concrete develops cracks. In addition, a Class I Fuel Pool Enclosure with a special ventilation system is provided to further reduce the consequences of an accidental release of radioactivity.

10.2.1.2 Description

Various sections of the Fuel Handling System are shared by Units 1 and 2. These include a common spent fuel storage pool and a common new fuel handling and storage area.

The reactor is refueled with equipment designed to handle the spent fuel under water from the time it leaves the reactor vessel until it is placed in a cask for removal from the spent fuel pool. Boric acid is added to the spent fuel pools to ensure subcritical conditions at all times. During refueling the concentration of the spent fuel pools is maintained near the concentration of the refueling cavity to prevent dilution of the refueling cavity. During non-refueling times a minimum of 2500 ppm of boron is required to ensure that spent fuel pool k_{eff} including statistical uncertainties, will be less than or equal to 0.95 with the required storage configurations in place. 60400000121

The Fuel Handling System, shown in Figure 10.2-1, may be generally divided into two areas: the reactor refueling cavity which is flooded during plant shutdown for refueling and the spent fuel pool which is kept full of water during and after the first refueling and is always accessible to operating personnel. These two areas are connected by the Fuel Transfer System consisting of an underwater conveyor that carries the fuel through the transfer tube.

The reactor refueling cavity is flooded with borated water from the refueling water storage tank. In the reactor refueling cavity, fuel is removed from the reactor vessel, transferred through the water and placed in the fuel transfer system by a manipulator crane. Upon arrival in the spent fuel pool, spent fuel will be removed from the transfer system and placed, one assembly at a time, in storage racks using a long-handled manual tool suspended from the spent fuel pool bridge crane. After sufficient decay, the fuel will be loaded into storage casks for storage in the Independent Spent Fuel Storage Installation or into shipping casks for removal from the site. Both the manipulator crane and the long handled tool can handle only one assembly at a time.

New fuel assemblies are received and normally stored in racks in the new fuel storage pit or in the spent fuel pool. New fuel is delivered to the reactor by lowering it into the spent fuel pool and taking it through the transfer system. Seventy-four fuel assemblies can be stored in the new fuel storage pit.

Fuel handling data is given in Table 10.2-1.

10.2.1.2.1 Major Structures Required for Fuel Handling

a. Reactor Refueling Cavity

   The reactor refueling cavity is a reinforced concrete structure that forms a pool above the reactor when it is filled with borated water for refueling. The cavity is filled to a depth that limits the radiation at the surface of the water to 50 milliroentgens per hour during those brief periods when a fuel assembly is transferred over the reactor vessel flange.

   The reactor vessel flange is sealed between the bottom of the reactor refueling cavity by an elastomeric seal ring which prevents leakage of refueling water from the refueling cavity. This seal is installed after reactor cooldown but prior to flooding the cavity for refueling operations.

The refueling cavity is large enough to provide storage space for the reactor upper internals, the control cluster drive shafts, and miscellaneous refueling tools. Space is also allowed for the storage of the lower internals if required.

A portion of the cavity is at a lower elevation than the reactor vessel flange to provide the greater depth required for the fuel transfer system tipping device and the rod control cluster changing fixture located in the cavity. The fuel transfer tube penetrates the reactor containment and connects the refueling cavity with the fuel transfer canal.

The floor and sides of the refueling cavity are lined with stainless steel or an equivalent corrosion resistant material.

b. Refueling Water Storage Tank

Refueling water used to fill the reactor refueling cavity is stored in the refueling water storage tank which is described under Section 6.

c. Spent Fuel Storage Pool

The spent fuel storage pool is designed for the underwater storage of spent fuel assemblies and control rods after their removal from the reactor. The spent fuel storage facility is a two-compartment pool that, if completely filled with fuel storage racks, would provide up to 1582 storage locations. With the four storage racks in the southeast corner of pool 1 removed a total of 1386 storage locations would be provided. The storage compartments and the fuel transfer canal are connected by fuel transfer slots that can be closed off with pneumatically sealed gates. The elevations of the slot bottoms are above the tops of the active fuel in the fuel assemblies when stored in the racks.

As shown in Figure 10.2-2 spent fuel assemblies are handled by a long handled tool suspended from an overhead monorail electric hoist and manipulated by an operator standing on a moveable bridge over the pool.

The spent fuel pool structure with its 3 to 6 foot thick walls is designed as Class I structure that fully meets the seismic and tornado design criteria given in Section 12. The fuel pool structure is also designed to withstand the hydraulic pressure of the contained water, as well as other credible static and dynamic loadings.

The fuel pool concrete, reinforcing steel and liner were analyzed to account for the additional loadings imposed by the new racks. The structural adequacy was verified using conventional concrete building codes (ACI 318). Results of the analysis for the most severe loading conditions indicate that the maximum stresses are within the allowables, and that the structural members of the fuel pool are adequate to withstand the additional loads imposed by the new 4/20/81 racks and additional fuel. (Reference 59)

The spent fuel storage structure has been designed to minimize the loss of water due to a dropped cask accident. The bottom of the pool is a reinforced concrete slab 5′-11″ thick that conforms to the ACI Standard Code Requirements for Reinforced Concrete (ACI-318-63) and attains a minimum compressive strength of 4000 psi. All reinforcing bars are made from intermediate grade, new billet steel and conform to A615 Grade 40 specifications. In critically loaded areas, of the slab, the reinforcement is arranged with 3 layers of #11 bar (1 3/8″ dia) at the top and bottom in the N-S direction and 1 layer of #11 bars at top and bottom in E-W direction. In addition, the auxiliary building crane has been upgraded to provide a handling system for handling heavy loads in the spent fuel pool area that satisfies the single-failure-proof guidelines of Section 5.1.6 of NUREG-0612, and thus eliminates the need to analyze the effects of drops of heavy loads per the criteria of Section 5.1 of NUREG-0612.

All inside surfaces of the spent fuel pool are lined with Type 304 stainless steel plate with a minimum thickness of 3/16″. A leakage detection and collection system is also provided.

In the unlikely event of dropping a fuel assembly directly on the pool floor, analysis shows that the structural damage to the floor will be insignificant; leakage through the concrete will not occur. (See Reference 1).

For the purpose of moving objects in the spent fuel pool, a heavy load is defined as any object that weighs more than a fuel assembly and its associated handling tool. Anything that weighs more than this must conform to special heavy load procedures. Any object that weighs less than this may be moved about the spent fuel pool with no special restrictions. (Reference 37).

d. New Fuel Storage

New fuel assemblies and rod control clusters are stored in a separate new fuel storage pit, adjacent to the spent fuel storage pool, as shown in Figure 10.2-2. The new fuel storage pit is designed as a Class I structure that fully meets the seismic design criteria given in Section 12. New fuel though may also be stored in the spent fuel pool. This separate storage pit was originally designed to hold 88 new fuel assemblies in specially constructed racks with parallel rows having a center-to-center distance of 21 inches.

However, a criticality analysis was performed in 1993 to increase the maximum fuel enrichment that could be stored in the new fuel storage racks (Reference 39). That analysis found that under the low density optimum moderation conditions the maximum rack reactivity exceeded the design limit of 0.98 if the entire 88 storage cell array was utilized to store the higher enrichment fuel. Further evaluation found that if the center 2x7 array of storage cells were removed, thereby reducing the fuel rack storage capacity to 74 assemblies, the 0.98 K_{eff} limit would be met under low density optimum moderation conditions. Therefore, the new fuel racks have been modified to preclude the storage of fuel assemblies in the center 2x7 array of storage cells assumed to be empty by the criticality analysis.

e. Fuel Pool Enclosure

The fuel pool enclosure is a Class I reinforced concrete building with 12 to 18 inch thick walls and roof, which is integrally connected to the fuel pool structure. The fuel pool enclosure covers both new and spent fuel storage facilities and is completely contained in the auxiliary building. The design of the fuel pool enclosure is shown in Figure 10.2-3. Normal and special ventilation systems are provided for the fuel pool enclosure as described in Section 10.3.7.

As shown in Figure 10.2-3, the fuel pool enclosure is provided with crane access slots and equipment handling doors which physically limits the area of spent fuel pool over which spent fuel casks or heavy objects can be moved. Administrative procedures prohibit movement of heavy objects when fuel is stored in this area unless one of the following measures is used: 1) a single-failure-proof crane with rigging and procedures which implement Prairie Island commitments to NUREG-0612; or 2) spent fuel pool covers with their implementing plant procedures for installation and use.

10.2.1.2.2 Major Equipment Required for Fuel Handling

a. Reactor Vessel Stud Tensioner

The stud tensioner is a hydraulically operated (oil as the working fluid) device provided to permit preloading and unloading of the reactor vessel closure studs at cold shutdown conditions. Stud tensioners were chosen in order to minimize the time required for the tensioning or unloading operations. Three tensioners are provided and they are applied simultaneously to three studs 120° apart. One hydraulic pumping unit operates the tensioners which are hydraulically connected in parallel. The studs are tensioned to their operational load in two steps to prevent high stresses in the flange region and unequal loadings in the studs. Relief valves are provided on each tensioner to prevent over tensioning of the studs due to excessive pressure.

b. Reactor Vessel Head Lifting Device

The reactor vessel head lifting device consists of a welded and bolted structural steel frame with suitable rigging to enable the crane operator to lift the head and store it during refueling operations. The lifting device is permanently attached to the reactor vessel head.

c. Reactor Internals Lifting Device

The reactor internals lifting device is a structural frame used in moving the reactor internals. The device is lowered onto the guide tube support plate of the internals and is manually bolted to the support plate by three bolts. Bushings on the fixture engage guide studs mounted on the vessel flange to provide close guidance during removal and replacement of the internals package.

d. Manipulator Crane

The manipulator crane is a rectilinear bridge and trolley crane with a vertical mast extending down into the refueling water. The bridge spans the refueling cavity and runs on rails set into the floor along the edge of the refueling cavity. The bridge and trolley motions are used to position the vertical mast over a fuel assembly in the core. A long tube with a pneumatic gripper on the end is lowered out of the mast to grip the fuel assembly. The gripper tube is long enough so the upper end is still contained in the mast when the gripper end contacts the fuel. A winch mounted on the trolley raises the gripper tube and fuel assembly up into the mast tube. The fuel is transported while inside the mast tube to its new position. The manipulator can lift only one fuel assembly at a time.

All controls for the manipulator crane are mounted on a console on the trolley. The bridge and trolley are positioned by marks on a mechanical pointer and viewed by the operator on a monitor at the console. The drives for the bridge, trolley, and winch are variable speed and include a separate inching control. Electrical interlocks and limit switches on the bridge and trolley drives protect the equipment. In an emergency, the bridge, trolley, and winch can be operated manually using a handwheel on the motor shaft.

Safety features are incorporated in the system as follows:

1. Travel limit switches on the bridge and trolley drives.

2. Bridge, trolley, and winch drives which are mutually interlocked to prevent simultaneous operation of any two drives.

3. A position safety switch, the GRIPPER TUBE UP position switch, which prevents bridge and trolley main motor drive operation except when it is actuated.

4. An interlock which prevents the opening of a solenoid valve in the air line to the gripper except when zero suspended weight is indicated by a force gauge. As back-up protection for this interlock, the mechanical weight actuated lock in the gripper prevents operation of the gripper under load even if air pressure is applied to the operating cylinder.

5. An EXCESSIVE SUSPENDED WEIGHT trip, which opens the hoist drive circuit in the UP direction when the loading is in excess of either preset limit. The appropriate preset limit, LIGHT or HEAVY as dictated by type of fuel movement, is selected with a 2-position switch.

6. A reduced intermediate hoist speed to reduce fuel assembly grid interaction consequences while inserting a fuel assembly into a core location.

7. A redundant full UP interlock to prevent crane movement when an assembly is not fully inside the protective mast.

8. A hoist underload trip to prevent grid damage on DOWN travel when excessive resistance is encountered. The appropriate preset underload limit, LIGHT or HEAVY as dictated by type of fuel movement, is selected with a 2-position switch.

9. An interlock on the hoist drive circuit in the up and down directions, which permits the hoist to be operated only when either the OPEN or CLOSED indicating switch on the gripper is actuated.

10. An interlock of the bridge and trolley drives, which prevents the bridge drive from traveling beyond the edge of the core unless the trolley is aligned with the refueling canal centerline. The trolley drive is locked out when the bridge is beyond the edge of the core.

    Suitable restraints are provided between the bridge and trolley structures and their respective rails to prevent derailing and the manipulator crane is designed to prevent disengagement of a fuel assembly from the gripper in the event of a Design Basis earthquake.

e. Spent Fuel Pool Bridge Crane

The spent fuel pool bridge crane is a wheel-mounted walkway, spanning the spent fuel pool which carries electric monorail hoists on an overhead structure. The fuel assemblies are moved within the spent fuel pool by means of a long handled tool suspended from the hoist. The hoist travel and tool length are designed to limit the maximum lift of a fuel assembly to a safe shielding depth.

The spent fuel pool bridge crane has 2 hoists, designated the East Hoist and the West Hoist. The East Hoist is a 2-ton capacity hoist used for general fuel handling and Unit 1 refuelings. The West Hoist is a redundant, 3-ton design rated load (DRL), 3700 pound maximum critical load (MCL) hoist used for general fuel handling, Unit 2 refuelings, and heavy load lifting. The hoist is specifically designed for moving the heavy loads contained in the spent fuel pool enclosure, e.g., the pool divider gates (2600 lbs). In addition, the West Hoist has the capability to transfer out to the New Fuel Crane located outside the pool for movement of new fuel assemblies from the new fuel containers to the New Fuel Pit.

f. The Auxiliary Building Crane

The Prairie Island Auxiliary Building Crane, which is used for handling spent fuel casks, has been upgraded to be in compliance with Section 5.1.6 and Appendix C of NUREG-0612, Control of Heavy Loads at Nuclear Power Plants. This upgrade to the auxiliary building crane has been made to provide a handling system for handling heavy loads in the spent fuel pool area that satisfies the single-failure-proof guidelines of Section 5.1.6 of NUREG-0612, and thus eliminates the need to analyze the effects of drops of heavy loads per the evaluation criteria of Section 5.1 of NUREG-0612. The original crane was designed to handle a load of 125 Tons. The main hoist capacity has not changed with the upgrade, but the auxiliary hoist capacity has been changed from 25 Tons to 15 Tons. The single-failure-proof features have not been incorporated into the design of the auxiliary hoist. All crane structural members have been designed to withstand impact loads per applicable specifications. A seismic evaluation has been performed for the loaded condition. Numerous safety features have been incorporated into the new design of the crane. Among these are the following:

1. Design of the hoist cables are in accordance with that required by Ederer Generic Licensing Topical Report EDR-1(P)-A (Reference 38).

2. All parts subjected to dynamic strains such as gears, shafts, drums, blocks, and other integral parts have a safety factor of five.

3. Two separate magnetic brakes are provided as well as an emergency drum band brake. Each magnetic brake provides a braking force of at least 150% of rated load. The emergency drum brake assures that the load can be safely lowered even if power is lost to the crane.

4. The crane is capable of raising, lowering and transporting occasional loads, for testing purposes, of 125 percent of rated load without damage or distortion to any crane part.

5. The crane is provided with a balanced dual reeving system with each wire rope capable of supporting the maximum critical load. The hydraulic load equalizing system allows transfer of the load to the remaining rope, without overstressing it, in the event of a failure of one rope.

6. The main hook has a design safety factor of 10 and was subjected to a 200% overload test followed by magnetic particle inspection.

7. The five step motor control was retained for the bridge and trolley drives. D.E. stepless drive systems have been provided for the main and auxiliary hoists.

8. Both the main and the auxiliary hoists are provided with field weakening for increased hoisting and lowering speeds at reduced loads. Unloaded speed is 200% greater for an unloaded hoist than a fully loaded hoist.

9. The main hoist has been provided with a Hoist Integrated Protection System (HIPS) which includes:

   A. Energy Absorbing Torque Limiter (EATL) - The EATL limits the load imposed on the wire rope in case of load hangup or two-blocking. The kinetic energy on the rotating equipment is dissipated in the form of heat while protecting the reeving system.

   B. Emergency Drum Brake System - The Emergency Drum Brake System is activated by the Failure Detection System or by manual operation of the emergency stop pushbutton.

   C. Failure Detection System - The Failure Detection System is actuated by a loss of mechanical continuity, detection of actuation of the EATL (two-blocking or load hangup), improper rope spooling, broken wire rope, reeving continuity and by drum overspeed.

10. Each hoist has a load cell to protect against load hangup and overload. This is part of the conventional hoist safety system and is not safety related.

11. End of travel limits for bridge and trolley motion have been added.

12. Limit switches have been added to the area of the slot in the roof of the fuel pool enclosure. These limits protect the wire rope by restricting movement of the trolley while operating the main hoist in the slot area.

13. A fail-safe remote radio control system is provided for the crane. The radio controls parallel the master switch connections and all of the safety features built into the control system also apply when the radio transmitter is used. The radio has a very complex system for transmitting and receiving signals so it is impossible to duplicate this signal by any other means. Also, the signal differs for every crane so the transmitter for some other crane would not actuate the receiver panel for this crane.

g. Fuel Transfer System

The fuel transfer system, shown in Figure 10.2-1 is an underwater conveyor car that runs on tracks extending from the refueling canal through the transfer tube and into the fuel transfer canal. The conveyor car receives a fuel assembly in the vertical position from the manipulator crane. The fuel assembly is lowered to a horizontal position for passage through the tube, and then is raised to a vertical position in the fuel transfer canal.

During plant operation, the conveyor car is normally stored in the fuel transfer canal. A blind flange is bolted on the refueling canal end of transfer tube to seal the reactor containment. The terminus of the tube outside the containment is closed by a gate valve.

h. Spent Fuel Storage Racks

Two sizes of spent fuel storage racks are provided; a 7x7 space rack and a 7x8 space rack. Each storage rack consists of storage tubes interconnected with each other through their upper and lower grids. These grids also ensure proper location of the storage tubes on 9.5 inch pitch in both directions. The upper and lower grids are tied together by vertical and diagonal members. Reactivity control is provided by the 9.5 inch storage tube pitch and by fuel loading restrictions described in Technical Specifications. Each storage tube consists of three components: an inner type 304 stainless steel tube, a layer of neutron absorbing material, and an outer skin of type 304 stainless steel. The neutron absorber material is believed to be degraded and is therefore not credited in the spent fuel pool criticality analysis. The rack base is composed of heavy box beams connected at the four corners to box section legs with adjustable feet. The box beams of the base are elevated above the pool floor to allow flow of cooling water below the rack and up into the storage tubes. All material used for rack construction is made of Type 304 stainless steel with the exception of the neutron absorber which is composed of a silicon polymer base material with sufficient boron in the form of boron carbide (Boraflex). This polymer material is degraded and no credit is presently taken for this neutron absorber in criticality analyses.

i. Rod Cluster Control Changing Fixture

A fixture is mounted on the refueling cavity wall for removing rod cluster control (RCC) assemblies from spent fuel assemblies and inserting them into new fuel assemblies. The fixture consists of two main components; a guide tube mounted to the wall for containing and guiding the RCC assemblies, and a wheel-mounted carriage for holding the fuel assemblies and positioning fuel assemblies under the guide tube. The guide tube contains a pneumatic gripper on a winch that grips the RCC assemblies and lifts it out of the fuel assembly. By repositioning the carriage, a new fuel assembly is brought under the guide tube and the gripper lowers the RCC element and releases it. The manipulator crane loads and removes the fuel assemblies into and out of the carriage.

j. Pool No. 1 Protective Cover

In order to protect fuel assemblies in the small spent fuel pool against the accidental drop of a heavy load, a protective cover over the pool is provided. The pool cover is made of 3/16 inch stainless steel plate welded to a grid of structural tees and built-up wide-flange beams which are made of structural steel ASTM A588 Grade A. Underneath each end of the beams, one pad made of one-inch thick compressible material is used between the cover and the concrete floor.

An evaluation was performed on the protective cover when subjected to a postulated drop of 24,800 pounds at a height of 6 inches above the cover.

The results of the evaluation show that although local plastic deformation may occur, the overall structural integrity of the cover will be maintained. Thus, the effect of the postulated drop of this heavy load is considered to be within the acceptable limit.

The spent fuel pool covers are installed and removed in accordance with plant procedures which assure that the covers can not be dropped into the spent fuel pool.

k. Spent Fuel Cask

Prairie Island has an Independent Spent Fuel Storage Installation (ISFSI) licensed under 10 CFR Part 72, issued under materials license SNM-2506. License SNM-2506 authorizes storage of 715.29 TeU of spent fuel assemblies using the TN-40 and TN-40HT storage cask design. Prairie Island also has a General License to use Certified storage cask designs under the provisions of 10 CFR 72.210.

Prairie Island has a General License to use Certified spent fuel transportation casks under the provisions of 10 CFR71.12.

10.2.1.2.3 Refueling Sequence of Operation

In preparation for refueling, the following typical sequence of events occurs:

a. The reactor is shut down and cooled to ≤200°F (Mode 5).

b. A radiation survey is made and the containment vessel is entered.

c. CRDM cables are disconnected.

d. Reactor vessel head insulation and instrument leads are removed.

e. Checkout of the fuel transfer device and manipulator crane is started.

f. Reactor vessel water level is lowered to a foot below the reactor vessel flange.

g. The reactor vessel head nuts are loosened with the hydraulic tensioners.

h. The reactor vessel head studs are removed to storage.

i. Guide studs are installed in three holes and the remainder of the stud holes are plugged.

j. The reactor vessel to cavity seal ring is installed.

k. Final preparation of underwater lights and tools is made. Checkout of manipulator crane and fuel transfer system is completed.

l. The fuel transfer tube flange is removed.

m. The reactor vessel head is unseated and raised a sufficient amount to ensure that rod drive shafts are disengaged, then the reactor vessel head is taken to the storage pedestal.

n. The refueling cavity is filled with water from the refueling water storage tank. The normal Residual Heat Removal System inlet valves from the Reactor Coolant System are closed.

o. When the cavity is filled, the residual heat removal system is restored to normal operation.

p. The full length control rod drive shafts are unlatched.

q. The reactor vessel internals lifting rig is lowered into position and latched to the support plate.

r. The reactor vessel flange protector ring is disengaged from the internals lifting rig.

s. The reactor vessel internals are lifted out of the vessel and placed in the underwater storage rack.

t. The core is now ready for refueling.

The refueling sequence is started utilizing the manipulator crane. The general sequence for fuel assemblies in noncontrol positions is as follows:

a. Spent fuel is removed from the core and placed into the fuel transfer system for removal to the spent fuel pool.

b. Partially spent fuel is rearranged in the core.

c. Replacement fuel assemblies are brought in from the new fuel storage pit through the transfer system and loaded into the core.

d. Whenever new fuel is added to the reactor core, a reciprocal curve of source range neutron count rate is plotted to verify the sub-criticality of the core.

The refueling sequence is modified for fuel assemblies containing Rod Cluster Control (RCC) assemblies, as required. If a transfer of the RCC assembly between fuel assemblies is required, the RCC assembly from one spent-fuel assembly is transferred to another fuel assembly. Such an exchange is required whenever a spent fuel assembly containing RCC assemblies is removed from the core and whenever a fuel assembly is placed in or taken out of a control position during refueling rearrangement.

After refueling is completed, the reactor is prepared for operation by essentially reversing the above sequence (items a. through t.) which was followed in preparing for the refueling.

10.2.1.3 Performance Analysis

Underwater transfer of spent fuel provides essential ease and safety in handling operations. Water is an effective, economic, and transparent radiation shield and a reliable cooling medium for removal of decay heat.

Basic provisions to ensure the safety of refueling operations are:

a. Gamma radiation levels in the containment refueling area and fuel storage areas are continuously monitored (see Section 7.5.2). These monitors provide an audible alarm at the initiating detector indicating an unsafe condition. Continuous monitoring of reactor neutron flux provides immediate indication and alarm in the control room of an abnormal core flux level.

b. Violation of refueling integrity per IT.S.3.9 is not permitted when the reactor vessel head is removed.

c. Whenever new fuel is added to the reactor core, a reciprocal curve of source range neutron count rate is plotted to verify the sub-criticality of the core.

d. The design of the spent fuel storage facility incorporates a Class I fuel pool enclosure for additional protection against the effects of a tornado.

   In all, four barriers protect stored spent fuel against the effects of a tornado. They are:

   1. The Class I fuel pool structure
   2. The twenty-five feet of water that normally covers the spent fuel
   3. The fuel storage racks
   4. The Class I fuel pool enclosure

   The potential effects of a tornado striking the fuel storage pool of existing light-water reactors, i.e., with no Class I fuel pool enclosure, has been thoroughly investigated (References 2, 3, 4). Two key areas were examined:

   a. whether sufficient water could be removed from the pool to prevent cooling of the fuel and

   b. whether missiles could potentially enter the pool and damage the stored fuel.

As concluded by investigation (References 2, 3, 4), existing fuel pool designs are inherently capable of withstanding the effects of a tornado. The design of the fuel pool makes the removal of more than five feet of water due to tornado action highly improbable. With 25 feet of water covering the fuel, the removal of five feet of water is of no concern. Protection is provided against a wide spectrum of tornado-generated missiles by the water which covers the fuel racks.

Results of an evaluation of a spectrum of tornado-driven missiles indicates that a four inch or smaller pipe, wooden debris from the cooling towers or metal panel siding ripped off the building are the most probable sources of missiles.

Such debris would not damage the fuel because of the buoyant force exerted by the twenty-five feet of water covering the fuel. Only by arbitrarily assuming long cylindrical objects to be hurled to the fuel pool by winds acting on their maximum cross-sectional area and then impacting the pool with minimum cross-sectional area could a potential for damage be shown (Reference 3). The probability of such an event has been shown to be less than 10^{-7}. Even in this highly unlikely case, a wide spectrum of these missiles can hit the pool without resulting in fuel damage or liner penetration.

In addition to the inherent protection provided by the fuel pool structure, the 25 feet of water covering the spent fuel, and the fuel storage racks, a Class I fuel pool enclosure has been provided for additional protection. It is, therefore, concluded that adequate protection for tornado-generated missiles and potential pool dewatering has been provided.

e. The auxiliary building crane has been upgraded to provide a handling system for handling heavy loads in the spent fuel pool area that satisfies the single-failure-proof guidelines of Section 5.1.6 of NUREG-0612, and thus eliminates the need to analyze the effects of drops of heavy loads per the criteria of Section 5.1 of NUREG-0612.

The maximum load motion following a drive train failure on the single-failure-proof main hoist of the auxiliary building crane is less than 1.5 foot and the maximum kinetic energy of the load is less than that resulting from 1 inch of free fall of the maximum critical load. The spent fuel pool floor has been analyzed and has been shown to be able to withstand the impact of 1 inch of free fall of the maximum critical load.

Incident Protection

Direct communication between the control room and the refueling cavity manipulator crane operator is available whenever changes in core geometry are taking place. This provision allows the control room operator to inform the manipulator crane operator of any impending unsafe condition detected from the main control board indicators during fuel movement.

Malfunction Analysis

An analysis is presented in Section 14 concerning damage to one complete assembly, assumed as a conservative limit for evaluating environmental consequences of a fuel handling accident.

Effect of Fuel Failure on the Spent Fuel Pool

Experience indicates that there is little radionuclide leakage from spent fuel stored in pools after the fuel has cooled for several months. The predominance of radionuclides in the spent fuel pool water appears to be radionuclides that were present in the reactor coolant system prior to refueling (which becomes mixed with water in the spent fuel pool during refueling operations) or crud dislodged from the surface of the spent fuel during transfer from the reactor core to the SFP. During and after refueling, the spent fuel pool cleanup system reduces the radioactivity concentrations considerably. It is theorized that most failed fuel contains small, pinhole-like perforations in the fuel cladding at the reactor operating condition of approximately 800°F. A few weeks after refueling, the spent fuel cools in the spent fuel pool so that fuel clad temperature is relatively cool, approximately 180°F. This substantial temperature reduction should reduce the rate of release of fission products from the fuel pellets and decrease the gas pressure in the gap between pellets and clad, thereby tending to retain the fission products within the gap. In addition, most of the gaseous fission products have short half-lives and decay to insignificant levels within a few months.

Based on the operational experience there has not been any significant leakage of fission products from spent light water reactor fuel stored in the Morris Operation (MO) (formerly Midwest Recovery Plant) at Morris, Illinois, or at the Nuclear Fuel Services' (NFS) storage pool at West Valley, New York. Spent fuel has been stored in these two pools which, while it was in a reactor, was determined to have significant leakage and was therefore removed from the core. After storage in the onsite SFP, this fuel was later shipped to either MO or NFS for extended storage. Although the fuel exhibited significant leakage at reactor operating conditions, there was no significant leakage from this fuel in the offsite storage facility.

Experience indicates that there is little radionuclide leakage from Zircaloy-clad spent fuel stored in pools for decades. Operators at several reactors have discharged, stored, and/or shipped relatively large numbers of Zircaloy-clad fuel elements which developed defects during reactor exposure. Several hundred Zircaloy-clad assemblies which developed one or more defects in-reactor are stored in the MO pool without need for isolation in special cans. Detailed analysis of the radioactivity in the pool water indicates that the defects are not continuing to release significant quantities of radioactivity.

A Battelle Northwest Laboratory (BNL) report states that radioactivity concentrations may approach a value up to 0.5 μCi/ml during fuel discharge in the SFP. After the refueling, the SFP ion exchange and filtration units will reduce and maintain the pool water in the range of 10^{-3} to 10^{-4} μCi/ml.

In handling defective fuel, the BNL study found that the vast majority of failed fuel does not require special handling and is stored in the same manner as intact fuel. Two aspects of the defective fuel account for its favorable storage characteristics. First, when a fuel rod perforates in-reactor, the radioactive gas inventory is released to the reactor primary coolant. Therefore, upon discharge, little additional gas release occurs. Only if the failure occurs by mechanical damage in the pool are radioactive gases released in detectable amounts, and this type of damage is extremely rare. In addition, most of the gaseous fission products have short half-lives and decay to insignificant levels. The second favorable aspect is the inert character of the uranium oxide pellets in contact with water. This has been determined in laboratory studies and also by casual observations of pellet behavior when broken rods are stored in pools.

10.2.1.4 Inspection and Testing

Upon completion of core loading and installation of the reactor vessel head, certain mechanical and electrical tests are performed prior to criticality. The electrical wiring for the rod drive circuits, the rod position indicators, the reactor trip circuits, and the incore thermocouples are tested before plant operation.

Following the failure of a fuel assembly’s stainless steel sleeve (which connects the guide tubes to upper nozzle) and the resulting dropping of a fuel assembly, the NRC recommended in a letter dated July 11, 1983 [Ref. 61] that a sulfate analysis be included in the routine primary and spent fuel pool water chemistry monitoring and analysis program. Current RCS sulfate limits are based on the EPRI Primary Water Chemistry Guidelines. 604000000010

10.2.1.5 Spent Fuel Consolidation Demonstration Project

10.2.1.5.1 Introduction

NSP and Westinghouse conducted a fuel consolidation demonstration at Prairie Island in the fall of 1987. The goal of fuel consolidation was to store more fuel in a given pool space, thereby increasing the overall spent fuel pool storage capacity. The consolidation process entailed removal of all the fuel rods from two assemblies, reconfiguring them into a close-packed triangular array, and then placing them into a canister of about the same outside dimensions as an assembly. The canister was then stored in a rack cell formerly occupied by a single spent fuel assembly.

10.2.1.5.2 Safety Evaluation

The demonstration project was limited to a maximum of 50 assemblies. The Prairie Island Operations Committee reviewed the project safety evaluation and determined that it could be performed under the provisions of 10CFR50.59, i.e., it did not involve an unreviewed safety question, and no Technical Specification changes were required. Reference 34 transmitted to the NRC the project description, safety evaluation and project topical report. The demonstration project would not increase the amount of spent fuel stored in the pool, it would alter the configuration of some fuel already being stored in the pool. Following is a summary of the analyses performed as part of the safety evaluation; refer to Reference 34 for further details.

10.2.1.5.2.1 Criticality

During the consolidation process, the fuel configuration was significantly changed. A criticality analysis was performed to verify that criticality would not occur during the process in both normal and accident conditions. A more recent criticality analysis addresses storage of the Consolidated Rod Storage Canisters (CRSCs) in the array shown in Technical Specifications Figure 4.3.1-1. This analysis also addressed storage of partially loaded CRSCs containing up to 10 fuel rods

10.2.1.5.2.2 Thermal Hydraulic

A thermal hydraulic analysis of the consolidated fuel storage canister was performed to determine the maximum allowable spent fuel decay heat rate which would satisfy the design criteria. The design criteria was to avoid boiling of the pool water under normal conditions, at any time during the process. The analysis determined the required cooling time, as a function of burnup, for any assembly to be consolidated. This also became a limiting condition for consolidation.

10.2.1.5.2.3 Radiological Consequences of Handling Accidents

This analysis evaluated the radiological consequences of a handling accident during consolidation. The analysis assumed total release from two assemblies worth of spent fuel rods, and that the fuel had been out of the reactor for two years. The results of the analysis showed that the radiological consequences of such an accident are much less than the design basis accident, which involves total release from a freshly discharged assembly. A minimum cooling time of two years became a limiting condition for consolidation.

10.2.1.5.2.4 Rack Structural Analysis

The structural capacity of a rack cell to contain a full consolidated fuel storage canister during a seismic event was evaluated and found to be adequate. Placement of the canisters into rack cells for storage was controlled so that no rack contained more mass than what was assumed in the existing licensing basis analysis.

10.2.1.5.3 Demonstration Results

Prior to beginning consolidation, the fuel assemblies were sipped to ensure there were no leaking fuel rods. The candidate assemblies were all of the Westinghouse standard design and included assemblies from regions A, B and C of both units, plus one region D and one region E assembly. The region D assembly was one which exhibited severe rod bow. Assembly average exposures ranged from 28 to 40 GWD/MTU. The minimum cooling time was approximately three years, and most assemblies had been out of core for about ten years.

The Westinghouse consolidation equipment and process is explained in the project topical report (Reference 34). Fuel consolidation began at Prairie Island on October 9, 1987 and continued through November 13, 1987. During this period, 36 spent fuel assemblies were consolidated into 18 canisters. The 18 canisters were placed into a 7 x 8 storage rack in a checkerboard pattern. The assembly cage components were placed into rack storage cells to await later processing.

The cage processing effort included waste classification of the cage components, volume reduction, and appropriate segregation and packaging of the waste material for either in pool storage or disposal. Volume reduction of 6 assembly cages was performed. These assembly cages were reduced to 2 cans which are now stored in the spent fuel pool along with other cage components.

THIS PAGE IS LEFT INTENTIONALLY BLANK

10.2.2 Spent Fuel Pool Cooling System

10.2.2.1 Design Basis

The spent fuel pool cooling system is designed to remove, from the shared spent fuel pool, the heat generated by stored spent fuel elements.

System design does not incorporate redundant components except for the spent fuel pool pump and the heat exchanger. Alternate cooling capability can be made available under anticipated malfunctions or failures. System piping is so arranged that failure of any pipeline does not drain the spent fuel pool below the top of the stored spent fuel elements.

The system is capable of handling a maximum heat load corresponding to both pools being filled with a combined total of 1362 normally discharged fuel assemblies plus a freshly off loaded core consisting of 121 fuel assemblies.

All piping and components of the Spent Fuel Cooling System are designed to the applicable codes and standards listed in Table 10.2-2. Design data for all major components is listed in Table 10.2-3.

10.2.2.2 Description

Spent fuel is placed in the spent fuel pool during refueling and is stored until it is placed in dry cask storage or shipped to a government repository. Residual heat from the stored fuel is removed by the spent fuel pool cooling system.

The spent fuel pool cooling system consists of two pumps, two heat exchangers, three filters, demineralizer, piping and associated valves and instrumentation. The spent fuel pool pumps draw water from the pool, circulate it through a heat exchanger and return it to the pool. Component cooling water cools the heat exchanger.

The system design incorporates redundant spent fuel pool pumps and heat exchangers. One of the heat exchangers normally serves as an alternate heat sink in the highly unlikely loss of the operating heat exchanger. System piping is arranged to permit manual cut-in of the backup heat exchanger.

The clarity and purity of the spent fuel pool water is maintained by passing approximately 60 gpm of the system flow through a purification loop. The purification loop consists of the two demineralizer inlet filters, the demineralizer, and a demineralizer outlet filter. The two demineralizer inlet filters can also be used independently of the demineralizer by placing the filters in a bypass configuration. Additionally the purification loop can be used to maintain the purity in both units' RWSTs. A separate RWST purification pump for each unit circulates the refueling water storage tanks through the purification loop.

The spent fuel pool pump suction line is located above the fuel assemblies which prevents uncovering fuel assemblies during loss of water as a result of a possible suction line rupture.

The spent fuel pool cooling system is shown in Figure 10.2-4. Description of the major components is discussed below.

a. Heat Exchangers

The spent fuel pool heat exchangers are of the shell and U-tube type with the tubes welded to the tube sheet. Component cooling water circulates through the shell, and spent fuel pool water circulates through the tubes. The tubes are austenitic stainless steel and the shell is carbon steel.

b. Pumps

One or both of the two spent fuel pool pumps circulate water in the spent fuel pool cooling system. All wetted surfaces of the pumps are austenitic stainless steel, or equivalent corrosion resistant material. Pump operation is manually controlled from a local station. The flow in the spent fuel pool cooling line is not continuously monitored. This monitoring is not required for safety or operation. The local instrument is sufficient. The high spent fuel pool temperature alarm is set low enough to give the operator ample time (hours) to make corrections.

c. Strainer

A stainless steel strainer is located at the inlet of each spent fuel pool system suction line for removal of relatively large particles which might otherwise clog the spent fuel pool demineralizer.

d. Filter

Two spent fuel pool filters are located upstream of the spent fuel pool demineralizer to remove particulates in the spent fuel pool water before it goes into the demineralizer. Another spent fuel pool filter is provided downstream of the spent fuel pool demineralizer to remove any particulate matter from the spent fuel pool water coming from the demineralizer.

e. Demineralizer

The demineralizer is sized to pass approximately 60 gpm of the system circulation flow, to provide adequate purification of the spent fuel pool water for unrestricted access to the working area, and to maintain optical clarity.

f. Skimmer

A skimmer pump and filter are provided for surface skimming of the spent fuel pool water. Flow from this pump is returned to the spent fuel pool.

g. Valves

Manual stop valves are used to isolate equipment and lines, and manual throttle valves provide flow control. Valves in contact with spent fuel pool water are austenitic stainless steel or equivalent corrosion resistant material.

h. Piping

All piping in contact with spent fuel pool water is austenitic stainless steel. The piping is welded except where flanged connections are used to facilitate maintenance.

10.2.2.3 Performance Analysis

Whenever a leaking fuel assembly is transferred from the fuel transfer canal to the spent fuel storage pool, a small quantity of fission products may enter the spent fuel pool water. A purification process consisting of filtration and ion-exchange is provided for removing these fission products and other contaminants from the water.

The most serious failure of this system is complete loss of water in the storage pool. To protect against this possibility, piping connections enter the top of the spent fuel pool as stated above except for the drain connection from the transfer canal to the holdup tank recirculation pump. Even if the water in the transfer canal were completely drained, the active portion of the spent fuel would not be uncovered due to the elevation of the bottom of the gate connection in the wall separating the transfer canal from the spent fuel pool. Complete siphon draining of the pool is impossible. The spent fuel pool pump suction connection only goes approximately 4 feet below the normal water level. The cooling water return line which extends 10 feet below the normal water level is prevented from siphon draining the pool by a 0.5 inch hole in the pipe located 4 feet below the normal water level.

The spent fuel pool cooling system consists of two pumps and two heat exchangers. These are cross-connected such that the loss of any one pump or heat exchanger does not prevent the operation of the remaining components. The decay heat is removed from the spent fuel pool heat exchangers by either Unit 1 or Unit 2's Component Cooling Water System. The Unit 1 Component Cooling system supplies the 122 Spent Fuel Pool Heat Exchanger and the Unit 2 Component Cooling System supplies the 121 Spent Fuel Pool Heat Exchanger. Cross-connect valves exist to allow either Spent Fuel Pool to be supplied by either Unit of Component Cooling. Each unit's Component Cooling Water System consists of two, 100% capacity, parallel loops each comprised of one pump and one heat exchanger having a rating of $29x10^6$ BTU/HR. In the unlikely event that a LOCA should occur in the unit whose Component Cooling Water System is connected to the Spent Fuel Pool Cooling System, the operator would conservatively have more than one hour to transfer the pool cooling system to the unaffected unit's Component Cooling Water System.

The free volume of pool #2 is slightly less than 2.5 times the free volume of pool #1. The volume of water, storage racks and spent fuel in the respective pools are essentially in the same ratio. The water volumes in pool #1 and pool #2 are 12,125 ft^3 and 28,477 ft^3 respectively. Each pool has a high and low water level sensor which provides input to each control room's control board. The spent fuel pool liner seam leakage is directed to a common open sight drain trough for monitoring and then to the waste disposal system.

Temperature detectors are installed at both pools. A high temperature alarm for each pool, nominally set at 130°F, is located on each control room alarm panel. The auxiliary building operator, as a routine shift responsibility, monitors the spent fuel pool water level, temperature, radiation and the leak detection system. The control room operators, as part of their routine shift responsibility, monitor the spent fuel pool radiation levels.

In 1980 the pumps, piping and valving were modified to increase the system heat removal capacity. The heat removal capability was re-analyzed based on a pool heat load determined using the methods in NRC Branch Technical Position ASB 9-2. These were reviewed and approved by the NRC in Reference 59. Subsequently, 122 heat exchanger was replaced with a heat exchanger with the same capability as 121 heat exchanger. New analyses were performed using the same method for determining pool heat load (References 74 and 75).

The peak heat loads in the pool are specified in Table 10.2-3. In all cases, fuel is offloaded into both pools 1 and 2. The assumed conditions and resultant maximum analyzed pool water temperatures are as follows:

a. NORMAL – This case represents normal conditions between refueling outages, but can also be representative of a core shuffle during a refueling outage. Up to one half of the core (60 assemblies) is offloaded to the pool for a total of 1362 normally discharged assemblies. The pools are cooled by one heat exchanger and one pump. The maximum pool water temperature will not exceed 140 °F.

b. ABNORMAL – This case represents a full core offload of 121 assemblies into a pool that already contains 1362 normally discharged assemblies. This case addresses the unusual occurrence of an unplanned core offload that may occur shortly after a normal refueling outage. The pools are cooled by both heat exchangers and both pumps. The maximum pool water temperature will not exceed 200 °F.

c. FAULTED – This case represents the ABNORMAL case above with a single failure of one pump. The maximum pool water temperature will not exceed 200 °F.

A common practice for a refueling outage is to perform a full core offload with half of the core subsequently reloaded to the reactor vessel, which is not reflected in the NORMAL case above. This routine full core offload has been analyzed in References 75 and 116, and the associated heat load is bounded by the heat load of the ABNORMAL case. 60400000342

The time to boiling following the loss of all external pool cooling was analyzed in References 76 and 78 assuming that complete mixing of the water in pools 1 and 2 would occur. The analyses optimized the core offload windows to maintain time to boiling greater than eight hours, which is an adequate amount of time to perform minor maintenance on the cooling system and restore it to an operable condition. At the maximum heat load, the maximum boil off rate would be 65.6 gpm at 212 °F, which requires a minimum make-up rate of 66 gpm to maintain pool inventory. During a core offload (full or otherwise), maintaining the time to boiling greater than eight hours will be achieved by managing the time at which fuel assemblies are offloaded to the pools and by limiting the pool temperature to 130 °F.

If 121 assemblies were to be offloaded into pool #1, the time to boiling would be less than 8 hours (Reference 76). To ensure that times to boiling are always greater than 8 hours when 121 of the fuel assemblies (or a majority) are discharged from the reactor into the spent fuel pool, no more than 45 of the assemblies will be placed in pool #1 and the remaining assemblies will be placed in pool #2 (Reference 59).

In the unlikely event that all spent fuel pool cooling is lost and boiling occurs, at least six sources of makeup water are available.

One hour or less is required to line up the valves or to carry out the steps necessary in order to make the water available. Six sources of makeup water and their makeup pump or hose station ratings are as follows: (a) Chemical and Volume Control System - 300 gpm, (b) Chemical and Volume Control System Blender - 100 gpm, (c) Refueling Water Storage Tank - 80 gpm, (d) Reactor Makeup Storage Tanks - 80 pm, (e) five demineralized water hose stations, each station rated at 20 gpm, and (f) the fire protection system - there are two fire hose stations near the spent fuel pool each rated at 95 gpm. 604000000342

A failure analysis of components is given in Table 10.2-4.

10.2.3 Chemical and Volume Control System

The Chemical and Volume Control System a) adjusts the concentration of chemical neutron absorber for chemical reactivity control, b) maintains the proper water inventory in the Reactor Coolant System, c) provides the required seal water flow for the reactor coolant pump shaft seals, d) processes reactor coolant letdown through filtration and ion exchange, e) maintains the proper concentration of corrosion inhibiting chemicals in the reactor coolant and f) keeps the reactor coolant activity to within design levels. The system is also used to fill and hydrostatically test the Reactor Coolant System. During normal operation, therefore, this system has provisions for supplying:

a. Hydrogen to the volume control tank

b. Nitrogen as required for purging the volume control tank

c. Hydrazine, boron or pH control chemical, as required, via the chemical mixing tank to the charging pumps suction. 60400000358

d. Hydrogen Peroxide injection, as required, to the RCS via the charging line to the regenerative heat exchanger.

10.2.3.1 Design Basis

a. Redundancy of Reactivity Control

Criterion: At least two independent reactivity control systems, preferably of different principles, shall be provided. (GDC 27)

In addition to the reactivity control achieved by the Rod Cluster Control (RCC) described in Section 7, reactivity control is provided by the Chemical and Volume Control System which regulates the concentration of boric acid solution in the Reactor Coolant system. The system is designed to prevent uncontrolled or inadvertent reactivity changes which might cause system parameters to exceed design limits.

In the event that injection using the Charging Pumps is not available, the Safety Injection system can perform this function using borated water from the refueling water storage tank. If necessary, the RCS can be sufficiently depressurized to allow injection with the SI Pumps.

b. Reactivity Hot Shutdown (IT.S. Mode 3, Hot Standby) Capability

Criterion: At least two of the reactivity control systems provided shall independently be capable of making and holding the core subcritical from any hot standby or hot operating condition, including those resulting from power changes, sufficiently fast to prevent exceeding acceptable fuel damage limits. (GDC 28)

The reactivity control systems provided are capable of making and holding the core subcritical from any hot standby (Mode 2, Startup) or hot operating (Mode 1, Power Operation) condition, including conditions resulting from power changes. The maximum excess reactivity expected for the core occurs for the cold, clean condition at the beginning of life of the core. The full length RCC assemblies are divided into two categories comprising control and shutdown groups.

The control group, used in combination with chemical shim, provides control of the reactivity changes of the core throughout the life of the core at power conditions. This group of RCC assemblies is used to compensate for short term reactivity changes at power such as those produced due to variations in reactor power requirements or in coolant temperature. The chemical shim control is used to compensate for the more slowly occurring changes in reactivity throughout core life such as those due to fuel depletion, fission product buildup and decay, and load follow.

c. Reactivity Shutdown Capability

Criterion: At least one of the reactivity control systems provided shall be capable of making the core subcritical under any condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margins greater than the maximum worth of the most effective control rod when fully withdrawn shall be provided. (GDC 29)

The reactor core, together with the reactor control and protection system is designed so that the minimum allowable DNBR is no less than the applicable limit and there is no fuel melting during normal operation including anticipated transients.

The shutdown groups are provided to supplement the control group of RCC assemblies to make the reactor at least one per cent subcritical (k_{eff} = 0.99) following trip from any credible operating condition to the hot, zero power condition assuming the most reactive RCC assembly remains in the fully withdrawn position.

Sufficient shutdown capability is also provided to maintain the core subcritical, with the most reactive rod assumed to be fully withdrawn, for the most severe anticipated cooldown transient associated with a single active failure, e.g., accidental opening of a steam bypass or relief valve. This is achieved with a combination of control rods and automatic boron addition via the Safety Injection System.

d. Reactivity Hold-Down Capability

Criterion: At least one of the reactivity control systems provided shall be capable of making and holding core subcritical under any conditions with appropriate margins for contingencies. (GDC 30)

Normal reactivity shutdown capability is provided by control rods, with boric acid injection used to compensate for the xenon transients, and for plant cooldown. When the plant is at power, the quantity of boric acid retained in the boric acid tanks and ready for injection always exceeds that quantity required for normal cold shutdown. This quantity always exceeds the quantity of boric acid required to bring the reactor to Mode 3, Hot Standby and to compensate for subsequent xenon decay.

The boric acid solution is transferred from the boric acid tanks by boric acid transfer pumps to the suction of the charging pumps which inject the solution into the reactor coolant system. Power for the charging pumps and the boric acid transfer pumps is automatically transferred to diesel generator power on loss of AC power. The charging pumps trip off on a loss of offsite power and must be manually restarted while the boric acid transfer pumps will automatically restart. Boric acid can be injected by one charging pump and one boric acid transfer pump at a rate which shuts the reactor down hot with no rods inserted in less than eighty (80) minutes. In eighty (80) additional minutes, enough boric acid can be injected to compensate for xenon decay although xenon decay below the equilibrium operating level does not begin immediately, but could occur up to 26 hours after shutdown, depending upon power history. If two boric acid pumps and two charging pumps are available, these time periods are halved. Additional boric acid is employed if it is desired to bring the reactor to Mode 5, Cold Shutdown conditions.

On the basis of the above, the injection of boric acid is shown to afford backup reactivity shutdown capability, independent of control rod clusters which normally serve this function in the short term situation. Shutdown for long term and reduced temperature conditions can be accomplished with boric acid injection using redundant components.

e. Codes and Classifications

Criterion: Those systems and components of reactor facilities which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes or standards on design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance levels to be used shall be identified. A showing of sufficiency and applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance levels used is required. (GDC 1)

All pressure retaining components (or compartments of components) which are exposed to reactor coolant, comply with the following codes:

1. System pressure vessels - ASME Boiler and Pressure Vessel Code, Section III, Class C.

2. System valves, fittings and piping - USAS B31.1, including nuclear code cases.

System component code requirements are tabulated in Table 10.2-5.

The tube and shell sides on the regenerative heat exchanger and the tube side of the excess letdown heat exchanger are designed to ASME III, Class C. This designation is based on the following considerations: (a) each exchanger is connected to the Reactor Coolant System by lines equal to or less than 2″, and (b) each is located inside the reactor containment. Analyses show that the accident associated with a 2″ line break does not result in clad damage or failure. Additionally, previously contaminated reactor coolant, escaping from the Reactor Coolant System during such accident is confined to the reactor containment building and no public hazard results.

10.2.3.1.1 Generic Letter 87-02

By letter dated November 20th, 1995 in response to Generic Letter 87-02 Prairie Island formally transmitted the selected systems and system functions which were reviewed in accordance with the Seismic Qualification Utility Group (SQUG) developed Generic Implementation Procedure (GIP) for Seismic Verification of Nuclear Plant Equipment (Reference 95). The non-safety related Chemical and Volume Control System (CVCS) was credited for performing functions for reactor shutdown and to maintain the plant in a hot shutdown condition. CVCS was selected to perform these functions based on the original seismic design requirements of the system and ability to exclude other multiple safety systems from review because of the diverse nature of CVCS capability. Other systems are not similarly described in the USAR for response to Generic Letter 87-02 based on their previously described functions which remained unchanged as a result of Generic Letter 87-02. It is not the intent of the GIP that operators are directed to use the alternate shutdown path as a first priority or change any symptom-based emergency operating procedure.

By submittal of the site response to Generic Letter 87-02, CVCS is described as being capable of providing injection of soluble poison to assure the continuation of hot shutdown conditions following a seismic event, through boron injection with one charging pump at minimum speed, drawing borated water from the Refueling Water Storage Tank (RWST).

By submittal of the site response to Generic Letter 87-02, CVCS is described as being capable of maintaining reactor coolant makeup following a seismic event, by injection through the Reactor Coolant Pump (RCP) seals during the early portion of the event with one pump running at minimum speed. The reactor coolant cold leg injection path will also be utilized as the event progresses but charging flow through the RCP seals will be maintained should thermal barrier cooling to the RCP seals be affected. To prevent the possibility of a solid pressurizer, letdown through the reactor head vent to the Pressurizer Relief Tank (PRT) is utilized as normal letdown would be isolated. If instrument air is lost the normal source for charging pump suction from the Volume Control Tank (VCT) will be manually transferred to the RWST.

10.2.3.2 Description

Various components of the Chemical and Volume Control system are shared by the two units. These components are shown in Table 10.2-6. The following discussion is for the Chemical and Volume Control System for one unit but applies equally to either unit.

The Chemical and Volume Control System, shown in Figures 10.2-5 through 10.2-10B, provides a means for injection of the neutron control chemical in the form of boric acid solution, chemical additions for corrosion control, and reactor coolant cleanup and degasification. This system also adds makeup water to the Reactor Coolant System, reprocesses water letdown from the Reactor Coolant System, and provides seal water injection to the reactor coolant pump seals. Materials in contact with the reactor coolant are austenitic stainless steel or equivalent corrosion resistant materials.

System components whose design pressure and temperature are less than the Reactor Coolant System design limits are provided with overpressure protective devices.

System discharges from overpressure protective devices (safety valves) and system leakages are directed to closed systems. Effluents removed from such closed systems are monitored and discharged under controlled conditions.

During plant operation, reactor coolant flows through the letdown line from a loop intermediate leg on the suction side of the reactor coolant pump and, after processing is returned to the cold leg of the loop on the discharge side of the pump via a charging line and through the inleakage in the reactor coolant pump seals. An excess letdown line is also provided for removing coolant from the Reactor Coolant System.

The letdown line, charging line and the seal water injection lines which are maintained open during normal plant operation have the following redundant valves between the main coolant loop and the CVCS:

a. The letdown line is provided with two fail-closed, air operated valves near the reactor coolant loop. The RCS boundary extends to the second isolation valve. In the event of low pressurizer level, these valves are automatically closed.

b. The charging line is provided with one check valve and one fail-closed, air-operated isolation valve near the reactor coolant loop. The Reactor Coolant System boundary extends to the air operated valve which can be closed from the main control board.

c. The seal injection lines are each provided with two check valves in series. The RCS boundary extends to the second check valve.

The excess letdown line is maintained in the closed position during normal plant operation and is provided with one isolation valve which forms the RCS pressure boundary. The barrier is a normally closed, air-operated isolation valve which can be operated from the main control board.

Reactor coolant entering the Chemical and Volume Control System flows through the shell side of the regenerative heat exchanger where its temperature is reduced. The coolant then flows through letdown orifices which reduce the coolant pressure. The cooled, low pressure water leaves the reactor containment and enters the auxiliary building where it undergoes a second temperature reduction in the tube side of the letdown heat exchanger followed by a second pressure reduction by the low pressure letdown valve. After passing through a letdown filter (when in use) and one of the mixed bed demineralizers, where ionic impurities are removed, coolant flows through the reactor coolant filters and enters the volume control tank through a spray nozzle.

The vapor space in the volume control tank, which is predominantly hydrogen and water vapor pressure is normally maintained by adding hydrogen using the batch method. The hydrogen within this tank is supplied to the reactor coolant for maintaining a low oxygen concentration. Fission gases are periodically removed from the system by venting the volume control tank to the Waste Disposal System.

From the volume control tank the coolant flows to the charging pumps which raise the pressure above that in the Reactor Coolant System. The coolant then enters the containment, passes through the tube side of the regenerative heat exchanger, and is returned to the Reactor Coolant System.

The cation bed demineralizer, located downstream of the mixed bed demineralizers, is provided to control cesium activity in the coolant and also to remove excess lithium which is formed from B^{10} (n, α) Li^{7} reaction.

Boric acid is dissolved in hot water in the batching tank to a concentration of approximately 12 percent by weight. The lower portion of the batching tank is jacketed to permit heating of the batching tank solution with low pressure steam. A transfer pump is used to transfer the batch to the boric acid tanks. Small quantities of boric acid solution are metered from the discharge of an operating transfer pump for blending with reactor makeup water as makeup for normal leakage or for increasing the reactor coolant boron concentration during normal operation. Electric heaters maintain the temperature of the boric acid tanks solution high enough to prevent precipitation. The boric acid piping is heat traced to prevent precipitation.

Excess liquid effluents from the Reactor Coolant System are collected in holdup tanks. As liquid enters the CVCS holdup tanks, the nitrogen cover gas is displaced to the gas decay tanks in the Waste Disposal System through the waste gas vent header. The concentration of boric acid in the holdup tanks varies throughout core life from the refueling concentration to essentially zero at the end of the core cycle.

Liquid effluent in the holdup tanks is processed as a batch operation. This liquid is pumped through ion exchangers and filters which remove corrosion products and fission-products such as long-lived cesium. (Note: The gas stripper/boric acid evaporator packages for Unit 1 and 2, though piped into the system as shown on Figure 10.2-10A, are generally not utilized to process the liquid effluent from the holdup tanks.)

Following effluent processing, the effluent is directed into one of the three CVCS monitor tanks. Subsequent handling of the monitor tank contents is dependent on the results of sample analysis. Discharge from the monitor tanks may be used elsewhere in the plant, reprocessed through the evaporator condensate demineralizers, returned to the holdup tanks for reprocessing or discharged to the environment with the condenser circulating water, when within the allowable activity concentration. If the sample analysis of the monitor tank contents indicates that it may be discharged safely to the environment, at least two valves must be opened to provide a discharge path. As the effluent if being discharged, it is continuously monitored by the Waste Disposal System liquid effluent monitor. If an unexplained increase in radioactivity is sensed, one of the valves in the discharge line to the circulating water discharge header closes automatically and an alarm sounds in the control room.

The deborating demineralizers can be used intermittently to remove boron from the reactor coolant near the end of the core life. When the deborating demineralizers are in operation, the letdown stream passes from the mixed bed demineralizers, through the deborating demineralizers and into the volume control tank after passing through the reactor coolant filter.

During plant cooldown when the residual heat removal system is operating and the letdown orifices are not in service, a flow path is provided to remove corrosion impurities and fission products. A portion of the flow leaving the residual heat exchangers passes through the letdown heat exchanger, letdown filter (when in use), mixed bed demineralizers, reactor coolant filter, and volume control tank. The fluid is then pumped, via the charging pump, through the tube side of the regenerative heat exchanger into the Reactor Coolant System.

An alternate flow path is provided for Unit 2 to allow the RHR pumps to drive a portion of the RHR flow to the CVCS letdown path for cleanup in Modes 5, 6, and defueled. The intention of the alternate flow path is to reduce the time required to accomplish RHR purification activities.

Note that this alternate flow path will not be operated in Modes 1-4. The flow path is controlled via manual valves, and operation will only be when RCS temperatures are less than 200F.

*604000000361

10.2.3.2.1 Expected Operating Conditions

Tables 10.2-6 and 10.2-7 list the data for individual system components and the system performance requirements respectively. Reactor coolant equilibrium activities are given in Appendix D.

Reactor Coolant Activity Concentration

The parameters used in the calculation of the reactor coolant fission product inventory, including pertinent information concerning the expected coolant cleanup flow rate and demineralizer effectiveness, are discussed in Appendix D.

10.2.3.2.2 Reactor Makeup Control

The reactor makeup control consists of a group of instruments arranged to provide a manually pre-selected makeup water composition to the charging pump suction header or the volume control tank. The makeup control functions are to maintain desired operating fluid inventory in the volume control tank and to adjust reactor coolant boron concentration for reactivity and shim control.

Makeup for normal plant leakage is regulated by the reactor makeup control which is set by the operator to blend water from the reactor makeup water tank with concentrated boric acid to match the reactor coolant boron concentration. The reactor makeup water pumps have been sized and rated to service the dilution water requirements of the boric acid blender connection.

The makeup system also provides concentrated boric acid or reactor makeup water to either increase or decrease the boric acid concentration in the Reactor Coolant System. To maintain the reactor coolant volume constant, an equal amount of reactor coolant at existing reactor coolant boric acid concentration is letdown to the holdup tanks. Should the letdown line be out of service during operation, sufficient volume exists in the pressurizer to accept the amount of boric acid necessary for Mode 5, Cold Shutdown.

Makeup water to the Reactor Coolant System is provided by the Chemical and Volume Control System from the following sources:

a. The reactor makeup water tanks, which provide water for dilution when the reactor coolant boron concentration is to be reduced

b. The boric acid tanks, which supply concentrated boric acid solution when reactor coolant boron concentration is to be increased

c. The refueling water storage tank, which supplies borated water for emergency makeup

d. The chemical mixing tank, which is used to inject small quantities of solution when additions of hydrazine, boron or pH control chemical are necessary. 60400000358

e. A temporary chemical injection skid, which may be used in lieu of the chemical mixing tank to manually add hydrogen peroxide as necessary to initiate a crud burst.

The reactor makeup control is operated from the control room by manually pre-selecting makeup composition to the charging pump suction header or the volume control tank in order to adjust the reactor coolant boron concentration for reactivity control. Makeup is provided to maintain the desired operating fluid inventory in the Reactor Coolant System. The operator can stop the makeup operation at any time in any operating mode. One boric acid transfer pump is normally lined up for automatic operation as required by the makeup controller. One reactor makeup pump is normally running.

A portion of the high pressure charging flow is injected into the reactor coolant pumps between the pump impeller and the shaft seal so that the seals are not exposed to high temperature reactor coolant. Part of the flow is the shaft seal leakage flow and the remainder enters the Reactor Coolant System through a labyrinth seal on the pump shaft. The shaft seal leakage flow cools the lower radial bearing, passes through the seals, is cooled in the seal water heat exchanger, filtered, and returned to the volume control tank.

Seal water inleakage to the Reactor Coolant System requires a continuous letdown of reactor coolant to maintain the desired inventory. In addition, bleed and feed of reactor coolant are required for removal of impurities and adjustment of boric acid in the reactor coolant.

Automatic Makeup

The “automatic makeup” mode of operation of the reactor makeup control provides boric acid solution preset by the operator to match the boron concentration in the Reactor Coolant System. The automatic makeup compensates for minor leakage of reactor coolant without causing significant changes in the coolant boron concentration.

Under steady state plant operating conditions, the mode selector switch is set in the “Automatic Makeup” position. A preset low level signal from the volume control tank level controller causes the automatic makeup control action to open the makeup stop valve to the charging pump suction, open the concentrated boric acid control valve and the reactor makeup water control valve. The makeup control also starts and/or switches to high speed any associated BATPs not in “pull-to-lock.” The flow controllers then blend the makeup stream according to the preset concentration. Makeup addition to the charging pump suction header causes the water level in the volume control tank to rise. At a preset high level set-point, the makeup is stopped; the reactor makeup water control valve closes, the concentrated boric acid control valve closes, the makeup stop valve to charging pump suction closes, and the boric acid transfer pumps return to the pre-selected operating condition.

Dilution

The “dilute” mode of operation permits the addition of a pre-selected quantity of reactor makeup water at pre-selected flow rate to the Reactor Coolant System. The operator sets the mode selector switch to “dilute”, the reactor makeup water flow controller set point to the desired flow rate, and the reactor makeup water batch integrator to the desired quantity. Upon manual start of the system the stop valve to the volume control tank opens. Makeup water is added to the volume control tank and then goes to the charging pump suction header. Excessive rise of the volume control tank water level is prevented by automatic actuation (by the tank level controller) of a three-way diversion valve, which routes the reactor coolant letdown flow to the holdup tanks. When the preset quantity of reactor makeup water has been added, the batch integrator causes the makeup water stop valve in the charging pump suction to close and the stop valve to the volume control tank to close.

Alternate Dilute

The “alternate dilute” mode is similar to the dilute mode except the dilution water, after passing through the blender, splits and a portion flows directly to the charging pump suction and a portion flows into the volume control tank via the spray nozzle and then flows to the charging pump suction. The operator sets the mode selector switch to “alternate dilute”, the reactor makeup water flow controller set point to the desired flow rate, the reactor makeup water batch integrator to the desired quantity and actuates the makeup start. The start signal causes the makeup control action to open the makeup stop valve to the volume control tank and the makeup stop valve to the charging pump suction header and the reactor makeup control valve. Reactor makeup water is simultaneously added to the volume control tank and to the charging pump suction header. This mode is used for load follow and permits the dilution water to follow the initial xenon transient and simultaneously dilute the volume control tank. Excessive water level in the volume control tank is prevented by automatic actuation of the volume control tank level controller which routes the reactor coolant letdown flow to the holdup tanks. When the preset quantity of reactor makeup water has been added, the batch integrator causes the reactor makeup water control valve and the reactor makeup stop valves to close. This operation may be stopped manually by actuating the makeup stop.

Boration

The “borate” mode of operation permits the addition of a pre-selected quantity of concentrated boric acid solution at a pre-selected flow rate to the Reactor Coolant System. The operator sets the mode selector switch to “borate”, the concentrated boric acid flow controller set point to the desired flow rate, and the concentrated boric acid batch integrator to the desired quantity. Upon manual start of the system the stop valve to the charging pumps opens, and the concentrated boric acid control valve opens. The makeup control also starts and/or switches to high speed any associated BATPs not in “pull-to-lock” and the concentrated boric acid is added to the charging pump suction header. The total quantity added in most cases is so small that it has only a minor effect on the volume control tank level. When the preset quantity of concentrated boric acid solution has been added the associated boric acid transfer pump(s) return to their pre-borate condition, the batch integrator causes the boric acid control valve to close and the makeup stop valve to the charging pump suction to close.

The capability to add boron to the reactor coolant is such that it imposes no limitation on the rate of cooldown of the reactor upon shutdown. The maximum rates of boration and the equivalent coolant cooldown rates are given in Table 10.2-7. One set of values is given for the addition of boric acid from a boric acid tank with one transfer and one charging pump operating. The other set assumed the use of refueling water but with two of the three charging pumps operating. The rates are based on full operating temperature and on the end of the core life when the moderator temperature coefficient is most negative.

Alarm Functions

The reactor makeup control is provided with alarm functions for the following conditions:

a. Deviation of reactor makeup water flow rate from the control setpoint

b. Deviation of concentrated boric acid flow rate from the control setpoint

c. Low level (makeup initiation point) in the volume control tank if the level decreases below the low level makeup initiation setpoint.

Boron Analyzer

A boron analyzer is located on the letdown line. The analyzer provides a continuous indication of the boron concentration in the letdown flow. The boron analyzer is designed to provide a semi-continuous indication of boron concentration in the letdown line during normal operation. The boron concentration indicator is supplied as an option and is not required to operate the plant. Normal sampling procedures, combined with control rod position indication, is the normal method of monitoring boron concentration. The boron concentration indicator is a redundant means of determining the boron concentration. As a general operating aid it should provide information as to when additional check-analysis is warranted rather than a basis for fundamental operating decisions.

The Westinghouse Boron Concentration Measurement System (BCMS) is an electronuclear system which employs neutron-counting principles and electronic circuitry to measure the neutron absorption of boric acid in water, and digitally display the result in terms of ppm boron (parts total boron per million parts of water).

The system employs a sample measurement unit which contains a neutron source and a neutron detector located in a shield tank. Piping within the shield tank is arranged to maintain coolant sample flow between the neutron source and the neutron detector. Neutron absorption by the boron in the coolant sample flow reduces the number of neutrons which contact the detector per unit time. Therefore, the time required to count a fixed number of neutron contacts is a variable which is dependent upon the concentration of boron solution. Electronic circuitry in the console portion of the Boron Concentration Measurement System accepts an amplified signal from the sample measurement unit and converts the signal to a digital display of ppm boron. The digital display is housed in the console, which may be located up to 500 feet from the sample measurement unit. Thus, output signals from the sample measurement unit may be displayed at almost any convenient place within the plant.

Boron Concentration Measurement System Performance Data:

°Range of System Operation	0 to 5000 ppm boron
°System Accuracy	10 ppm for boron concentration between 2800 ppm and 5000 ppm boron
°Measurement Display Frequency	Continuous display of latest concentration measurement
Sample Requirements	
°Pressure	12-225 psig
°Flow	0.2 gpm nominal
°Temperature	70-140°F

The BCMS is calibrated using a known concentration of boric acid.

The BCMS and the CVCS piping system is designed to allow isolation of the BCMS and flushing.

The BCMS is utilized as an advisory system only. It is not connected in any manner to plant control or protective systems. Erroneous readings caused by maloperation of the system would be detected by the operator as boron concentration changes would affect reactivity control and changes in reactivity would be indicated on other instruments.

All piping penetrations are located on the top of the sample tank negating an accidental leakage of the tank water.

A maloperation of the sample tank heater causing it to stay energized would cause the tank water to evaporate resulting in a loss of sample tank water. A local low water level alarm is provided to indicate this condition. Local temperature and level instruments are also provided. Continued energizing of the sample tank heater with the low level would cause the heater to burn out. The abnormal reactor coolant sample temperature would cause erroneous boron concentration readings.

10.2.3.2.3 Charging Pump Control

Three positive displacement variable speed drive charging pumps are used to supply charging flow to the Reactor Coolant System.

The speed of each pump can be controlled manually or automatically. During normal operation, one of the three pumps is operated with its speed control in automatic. A second pump may be operated with its speed control in manual, maintaining a constant speed. The speed of the pump in automatic modulates according to deviation between pressurizer level and level control program. During load changes the pressurizer level set point is varied automatically to compensate partially for the expansion or contraction of the reactor coolant associated with the Tavg changes. The pressurizer level control circuitry provides a demand signal to the charging pump VFD drive (Auto mode) to vary pump speed and to maintain a constant pressurizer level.

If the pressurizer level increases above program, the speed of the pump decreases; likewise, if the level decreases below program, the speed increases. If the charging pump on automatic control reaches the low or high speed limit, an alarm is actuated. Additional charging pumps may be started or stopped as necessary to control pressurizer level. These additional pumps are operated in manual speed control in response to pressurizer level changes.

To ensure that the charging pump flow is always sufficient to meet both the seal water and minimum charging flow requirements, the pump has a variable control stop which does not permit pump flow lower than the specified minimum. This control stop is adjustable to permit higher minimum flow limits to be set if mechanical seal leakage increases during plant life.

10.2.3.2.4 <u>Components</u>

A summary of principal component data is given in Table 10.2-6.

a. Regenerative Heat Exchanger

   The regenerative heat exchanger is designed to recover the heat from the letdown stream by reheating the charging stream during normal operation. This exchanger also limits the temperature rise which occurs at the letdown orifices during periods when letdown flow exceeds charging flow by a greater margin than at normal letdown conditions.

   The letdown stream flows through the shell of the regenerative heat exchanger and the charging stream flows through the tubes. The unit is made of austenitic stainless steel, and is of all-welded construction.

b. Letdown Orifices

One of the three letdown orifices controls flow of the letdown stream during normal operation and reduces the pressure to a value compatible with the letdown heat exchanger design. Either of two letdown orifices, each 40 gpm, is used to pass normal letdown flow. The third orifice, 80 gpm, is designed to be used for high flow purification flow at normal Reactor Coolant System operating pressure and can pass twice the normal letdown flow. The orifices are placed in and taken out of service by remote manual operation of their respective isolation valves. One or both of the standby orifices may be used in parallel with the normally operating orifice in order to bring the letdown flow up to normal when the Reactor Coolant System pressure driving force is below normal. This arrangement provides a full standby capacity for control of letdown flow. Each orifice consists of bored pipe made of austenitic stainless steel.

c. Letdown Heat Exchanger

The letdown heat exchanger cools the letdown stream to the operating temperature of the mixed bed demineralizers. Reactor coolant flows through the tube side of the exchanger while component cooling water flows through the shell side. The letdown stream outlet temperature is automatically controlled by a temperature control valve in the component cooling water outlet stream. The unit is a multiple-tube, multiple-pass shell heat exchanger. All surfaces in contact with the reactor coolant are austenitic stainless steel, and the shell is carbon steel. Since the maximum operating temperature for the components in question is considerably less than 200°F (maximum operating temperatures are 120°F for the letdown heat exchanger shell, 130°F for the charging pump, and 110°F for the monitor tank pump), a design temperature of 200°F provides adequate margin. An increase in design temperature to 250°F would not provide any significant change in equipment design and would not affect reactor safety.

If a significant leak develops in the letdown heat exchanger such that the charging system is unable to maintain pressurizer water level, the letdown line isolation valves near the reactor coolant loop trip closed. The excess letdown path can then be placed in service while maintenance is performed on the letdown heat exchanger.

d. Mixed Bed Demineralizers

Two flushable mixed bed demineralizers maintain reactor coolant purity. A Lithium-7 (or H^+ form) cation resin and a hydroxyl form anion resin are initially charged into the demineralizers. Both forms of resin remove fission and corrosion products, and in addition, the reactor coolant causes the anion resin to be converted to the borate form. The resin bed is designed to reduce the concentration of ionic isotopes in the purification stream, except for cesium, yttrium, and molybdenum, by a minimum factor of 10.

Each demineralizer is sized to accommodate the normal letdown flow. One demineralizer serves as a standby unit for use should the operating demineralizer become exhausted during operation.

The demineralizer vessels are made of austenitic stainless steel, and are provided with suitable connections to facilitate resin replacement when required. The vessels are equipped with a resin retention screen. Each demineralizer has sufficient capacity, after operation for one core cycle with one per cent defective fuel rods, to reduce the activity of the primary coolant to refueling concentration.

e. Cation Bed Demineralizer

A flushable cation resin bed in the hydrogen form is located downstream of the mixed bed demineralizers and is used intermittently to control the concentration of lithium which builds up in the coolant from the B^{10} (n, α) Li^7 reaction. The demineralizer also has sufficient capacity to maintain the Cesium-137 concentration in the coolant below 1.0 μCi/cc with one percent defective fuel. The demineralizer would be used intermittently to control cesium.

The demineralizer is made of austenitic stainless steel and is provided with suitable connections to facilitate resin replacement when required. The vessel is equipped with a resin retention screen.

f. Deborating Demineralizers

When required, two anion demineralizers remove boric acid from the Reactor Coolant System fluid. The demineralizers are provided for use near the end of a core cycle, but can be used at any time.

Hydroxyl-form ion-exchange resin is used to reduce Reactor Coolant System boron concentration. Facilities are provided for regeneration. When regeneration is no longer feasible, the resin is flushed to the spent resin shipping cask.

Each demineralizer can remove the quantity of boric acid that must be removed from the Reactor Coolant System to maintain full power operation near the end of core life without the use of the holdup tanks or evaporators.

g. Reactor Coolant Filter

The filter collects resin fines and particulates larger than 25 microns from the letdown stream. The filter vessel is made of austenitic stainless steel, and is provided with connections for draining and venting. Design flow capacity of the filter is equal to the maximum purification flow rate. Disposable filter elements are used.

h. Letdown Filter (when in use)

The letdown filter collects particulates larger than 5 microns from the letdown stream before it enters the demineralizers. The vessel is made of austenitic stainless steel, and is provided with the connections for draining and venting. Design flow capacity of the filter is equal to the maximum purification flow rate. Disposable filter elements are used. 60400000331

i. Volume Control Tank

The volume control tank collects the excess water released from zero power to full power, that is not accommodated by the pressurizer. It also receives the excess coolant release caused by the deadband in the reactor control temperature instrumentation. Overpressure of hydrogen gas is maintained in the volume control tank to control the hydrogen concentration in the reactor coolant at 25 to 50 cc per Kg of water (standard conditions).

A spray nozzle is located inside the tank on the inlet line from the reactor coolant filter. This spray nozzle provides intimate contact to equilibrate the gas and liquid phases. A remotely operated vent valve discharging to the Waste Disposal System permits removal of gaseous fission products which are stripped from the reactor coolant and collected in this tank. The volume control tank also acts as a head tank for the charging pumps and a reservoir for the leakage from the reactor coolant pump controlled leakage seal. The tank is constructed of austenitic stainless steel.

j. Charging Pumps

Three charging pumps are provided for injecting coolant into the Reactor Coolant System. The pumps are the variable speed positive displacement type, and all parts in contact with the reactor coolant are fabricated of austenitic stainless steel and other material of adequate corrosion resistance. Special low-chloride packing is used in the pump glands. These pumps have mechanical packing followed by a leakoff to collect reactor coolant before it can leak to the outside atmosphere. Pump leakage is piped to a local drain for disposal to the Waste Disposal System. The pump design precludes the possibility of lubricating oil contaminating the charging flow, and the integral discharge valves act as check valves.

Each pump is designed to provide the full charging flow and the reactor coolant pump seal water supply during normal seal leakage. Each pump is designed to provide rated flow against a pressure equal to the sum of the Reactor Coolant System maximum pressure (existing when the pressurizer power operated relief valve is operating) and the piping, valve and equipment pressure losses of the charging system at the design charging flows. Pulsation dampers are provided at the pump suction and discharge.

One of the three charging pumps can be used to hydrotest the Reactor Coolant System.

k. Chemical Mixing Tank

The primary use of the chemical mixing tank is in the preparation of pH control chemical solutions and hydrazine for oxygen scavenging.

A secondary use of the chemical mixing tank is for precise addition of small amounts of boron to the RCS. 60400000358

The capacity of the chemical mixing tank is determined by the quantity of 35 percent hydrazine solution necessary to increase the concentration in the reactor coolant by 10 ppm. This capacity is more than sufficient to prepare the solution of pH control chemical for the Reactor Coolant System. The chemical mixing tank is made of austenitic stainless steel.

l. Excess Letdown Heat Exchanger

The excess letdown heat exchanger cools reactor coolant letdown flow at a rate equal to the nominal injection rate through the reactor coolant pump labyrinth seal, if letdown through the normal letdown path is blocked. The unit is designed to reduce the letdown stream temperature from the cold leg temperature to 195°F. The letdown stream flows through the tube side and component cooling water is circulated through the shell side. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel. All tube joints are welded.

m. Seal Water Heat Exchanger

The seal water heat exchanger removes heat from the reactor coolant pump seal water returning to the volume control tank and reactor coolant discharge from the excess letdown heat exchanger. Reactor coolant flows through the tubes and component cooling water is circulated through the shell side. The tubes are welded to the tube sheet to prevent leakage in either direction, which would result in undesirable contamination of the reactor coolant or component cooling water. All surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

The unit is designed to cool the excess letdown flow and the seal water flow to the temperature normally maintained in the volume control tank if all the reactor coolant pump seals are leaking at the maximum design leakage rate.

n. Seal Water Filter

The filters in parallel collect particulates from the reactor coolant pump seal water return and from the excess letdown heat exchanger flow. Each filter is designed to pass the sum of the excess letdown flow and the maximum design leakage from the reactor coolant pump controlled-leakage seals. The filter vessels are constructed of austenitic stainless steel and are provided with connections for draining and venting. Disposable synthetic filter cartridges are used.

o. Seal Water Injection Filters

Two filters are provided in parallel, each sized for the injection flow. They collect particulates from the water supplied to the reactor coolant pump seals.

p. Boric Acid Filter

The boric acid filter collects particulates from the boric acid solution being pumped to the charging pump suction line. The filter is designed to pass the design flow of two boric acid transfer pumps operating simultaneously. The vessel is constructed of austenitic stainless steel and the filter elements are disposable synthetic cartridges. Provisions are available for venting and draining the filter.

q. Boric Acid Tanks

The boric acid tank capacities can be shared by Unit 1 and Unit 2 and are sized to store sufficient boric acid solution for refueling plus enough boric acid solution for a cold shutdown shortly after full power operation is achieved. In addition, each unit-designated tank is sized to provide sufficient boric acid solution to achieve Mode 5, Cold Shutdown, if the most reactive RCCA is not inserted. However, to meet surveillance procedures for readily-available quantities of boric acid to meet Cold Shutdown requirements, credit may be taken for the portion of the available standby tank not reserved for the opposite unit. One tank is normally used with each unit and a third tank acts as a standby.

The concentration of boric acid solution in storage is maintained between 11.5 and 13% by weight. Periodic manual sampling is performed and corrective action is taken, if necessary, to ensure that these limits are maintained. As a consequence, measured amounts of boric acid solution can be delivered to the reactor coolant to control the chemical poison concentration. The combination overflow and breather vent connection has a water loop seal to minimize vapor discharge during storage of the solution. The tanks are constructed of austenitic stainless steel.

The volume of boric acid solution required for Mode 5, Cold Shutdown can be found in Table 10.2-7. Refilling the boric acid tanks is a batch process. 60400000335

r. Boric Acid Tank Heaters

Two 100% capacity electric heaters located near the bottom of each boric acid tank are designed to maintain the temperature of the boric acid solution at 165°F with an ambient air temperature of 40°F thus ensuring a temperature in excess of the solubility limit (for 12 percent boric acid this is 133°F). The temperature is monitored and low temperature is alarmed in the control room. The heaters are sheathed in incoloy. For 11 and 121 Boric Acid Storage Tanks, one heater for each tank is fed from a bus supplied by Diesel Generator 1 and the second heater is fed from a bus supplied by Diesel Generator 2. For 21 Boric Acid Storage Tank, one heater is fed from a bus supplied by Diesel Generator 5 and the second heater is fed from a bus supplied by Diesel Generator 6. Redundant heat tracing circuits are also provided for Boric Tanks and associated lines. Train A heat trace is powered from transferable MCC 1T1 which can be supplied from 480V Diesel Generator 1 (via Bus 112) or Diesel Generator 5 (via Bus 212). Train B heat trace is powered from transferable MCC 1T2 which can be supplied from Diesel Generator 2 (via Bus 122) or Diesel Generator 6 (via Bus 222). Separation criteria established for Train A and Train B safeguards in this plant are applied to power feeds to these redundant systems. Redundant step down transformers, distribution panels, thermostat controllers and failure alarm relays for the heat tracing systems are mounted on the same panel. Separation between redundant heater wires wrapped around the pipe to be traced is maintained by the construction of the heater cables. 604000000341

s. Batching Tank

The batching tank, shared by Units 1 and 2 is sized to hold one week's makeup supply of boric acid solution for the boric acid tank. The basis for makeup is reactor coolant leakage of 1/2 gpm at beginning of core life. The tank may also be used for solution storage. A local sampling point is provided for verifying the solution concentration prior to transferring it to the boric acid tank.

The tank manway is provided with a removable screen to prevent entry of foreign material. In addition, the tank is provided with an agitator to improve mixing during batching operation. The tank is constructed of austenitic stainless steel, and is not used to handle radioactive substances. The tank is provided with a steam jacket for heating the boric acid solution to 165°F.

The source of heat for the steam-jacketed boric acid batching tank is process steam which is piped to and from the steam jacket.

The boric acid batching tank is not required under post-accident conditions.

Boric acid can be added to the recirculated emergency coolant using the normal boron makeup system. There is sufficient capacity in the remaining boric acid tanks to provide any necessary makeup.

t. Boric Acid Transfer Pumps

Each unit has two centrifugal pumps with two speed motors (one on each unit may be cross-connected to the other unit) that are used to circulate or transfer boric acid. The pumps circulate boric acid solution through the boric acid tanks and transfer boric acid into the charging pump suction header.

Although one pump is normally used for boric acid batching and transfer and the other for boric acid injection, either pump may function as standby for the other. The design capacity of each pump is equal to the normal letdown flow rate. The design head at high speed is sufficient, considering line and valve losses, to deliver rated flow to the charging pump suction header when volume control tank pressure is at the maximum operating value (relief valve setting). All parts in contact with the solutions are austenitic stainless steel and other adequately corrosion-resistant material.

The transfer pumps are operated either automatically or manually from the main control room. The pumps may also be operated in manual from a local control point. Any pump not in pull-to-lock will be started or transfer to high speed when boric acid solution is required for makeup or boration.

u. Boric Acid Blender

The boric acid blender enhances thorough mixing of boric acid solution and reactor makeup water from the reactor makeup supply circuit. The blender consists of a conventional pipe elbow fitted with a perforated tube insert. All material is austenitic stainless steel.

v. Holdup Tanks

Three holdup tanks which can be shared by Units 1 and 2, are provided to collect water resulting from various Reactor Coolant System evolutions, such as: startup, shutdown, load changes, and from boron dilutions to compensate for burnup. The contents of the non-aerated sump tank are usually directed to the CVCS holdup tanks also. The contents of the holdup tanks are processed as needed using ion exchangers and filtration to achieve desired effluent activity limits and maintain adequate holdup capacity.

The design pressure for these large volume, low pressure storage tanks was selected to allow the use of the API-620 code. This code provides more definitive guidelines for the design of this class of vessel.

w. Holdup Tank Recirculation Pump

The holdup tank recirculation pump is used to mix the contents of a holdup tank, transfer the contents of one holdup tank to another, or transfer holdup tank water to the spent fuel pit.

The wetted surface of this pump is constructed of austenitic stainless steel.

x. Gas Stripper Feed Pumps

The three gas stripper feed pumps, which can be shared by Units 1 and 2, provide feed from a holdup tank to the evaporator feed ion exchanger/filtration process. Water is generally processed in a batch mode using one pump. The non-operating pumps are available for operation in the event the operating pump malfunctions. These centrifugal pumps are constructed of austenitic stainless steel.

y. Evaporator Feed Ion Exchangers

Four flushable ion exchangers can be shared by Units 1 and 2 to remove impurities from the holdup tank effluent. The resin is selected as needed to achieve desired decontamination factors. (See Appendix D for typical cesium decontamination factors.) These ion exchangers may be operated in parallel or series. Each vessel is constructed of austenitic stainless steel and contains a resin retention screen.

z. Ion Exchanger Filters

These filters collect resin fines and particulates from the evaporator feed ion exchangers. The vessel is made of austenitic stainless steel and is provided with connections for draining and venting. Disposable filter cartridges are used.

aa. Gas Stripper/Boric Acid Evaporator Equipment

Although normally not used, the gas stripper/boric acid evaporators can be shared by the two units to remove N_2, H_2, and fission gasses and concentrate boric acid for reuse in the Reactor Coolant System. The boric acid evaporators currently are retired in place and are not used for processing CVCS water.

bb. Evaporator Condensate Demineralizers

Two condensate demineralizers, which can be shared by Unit 1 and 2, are available to provide cleanup of water processed from the CVCS Holdup Tanks. The demineralizers are constructed of stainless steel.

cc. Condensate Filter

This filter removes resin fines and particulate from water processed from the CVCS Holdup Tanks. The vessel is made of stainless steel, is provided with connections for venting and draining, and uses disposable filter elements.

dd. Monitor Tanks

The monitor tanks, which can be shared by Unit 1 and Unit 2, permit continuous processing of CVCS Holdup Tank water. When one tank is filled, the contents are analyzed and either reprocessed, discharged via the Waste Disposal System or used elsewhere in the plant as needed. These tanks are stainless steel.

ee. Monitor Tank Pumps

Two monitor tank pumps, shared by Units 1 and 2, discharge water from the monitor tanks. The wetted surfaces of these pumps are constructed of austenitic stainless steel.

ff. Reactor Makeup Water Tanks

Two reactor makeup water tanks per unit are provided and furnish the suction supply to the two reactor makeup pumps of each unit. The tanks receive this makeup water from the monitor tanks via the monitor tank pumps, or the condensate makeup storage tank via the condensate recycle and transfer pumps or from the demineralized water system. These tanks are constructed of coated carbon steel.

gg. Reactor Makeup Water Pumps

Two reactor makeup water pumps per unit are provided and furnish demineralized water to the pressurizer relief tank, to the boric acid blender and chemical mixing tank, to the spent fuel pool, and makeup to the component cooling surge tank. These pumps take suction supply from the reactor makeup water tanks. The wetted surfaces of these pumps are constructed of austenitic stainless steel. Each pump is sized to match the high flow letdown purification flow of 80 gpm.

hh. Concentrates Filter

A disposable synthetic cartridge type filter removes particulates from the evaporator concentrates. Design flow capacity of the filter is equal to the boric acid evaporator concentrates transfer pump capacity. The vessel is made of austenitic stainless steel.

ii. Concentrates Holding Tank

The concentrates holding tank, shared by Units 1 and 2, is sized to hold the production of concentrates from one batch of evaporator operation. The tank is supplied with an electrical heater which prevents boric acid precipitation and is constructed of austenitic stainless steel.

jj. Concentrates Holding Tank Transfer Pumps

Two holding tank transfer pumps, shared by Units 1 and 2, discharge boric acid to the boric acid tanks. The wetted surfaces of these pumps are constructed of austenitic stainless steel.

kk. Electrical Heat Tracing

Electrical heat tracing is installed under the insulation on all piping, valves, line-mounted instrumentation, and components normally containing concentrated boric acid solution. The heat tracing compensates for heat loss due to cooling and prevents boric acid precipitation. The lines and components of the Chemical and Volume Control System (CVCS) which are provided with heat tracing are shown in Figures 10.2-6, 10.2-8 and 10.2-10b.

The boric acid tanks, boric acid batching tank, and the Concentrates holding tank are provided with individual means of heating and need not be heat traced.

Redundant electrical heat tracing is installed on all sections of the CVCS normally containing boric acid solution, to provide standby capacity if the operating section malfunctions. The power supply for the redundant lines of heat tracing is connected to the diesel-powered buses to ensure continuous operation during a prolonged outage of normal power supplies.

The combination of electrical heat tracing and insulation maintains the temperature of the piping and contents at 160° to 180°F with an ambient air temperature of 40°F. Separate thermostatic controls are provided for each of the duplicate sets of heat tracing to maintain the temperature within the specified control band. High and low alarms are provided in the control room for selected heat trace circuits to warn of failure to maintain the normal temperature control band for the piping and equipment containing concentrated boric acid solution. Transfer of control between the redundant heat tracing is an automatic operation.

II. Valves

The potential for valve stem leakage is reduced by monitoring valves for leakage, early detection, and repacking without leakoff per current maintenance standards. Post maintenance testing, inservice system leak tests, periodic walkdown surveillances, radiation monitoring, fluid inventory surveillance, and leakage control programs address early leak detection and repair. Globe valves are installed with flow over the seats when such an arrangement reduces the possibility of leakage. Basic material of construction is stainless steel for all valves except the batching tank steam jacket valves which are carbon steel.

Isolation valves are provided at all connections to the Reactor Coolant System. Lines with flow into the reactor containment also have check valves inside the containment to prevent reverse flow from the containment. Further discussion of isolation criteria is presented in Section 5.2.1.2.1.

Relief valves are provided for lines and components that might be pressurized above design pressure by improper operation or component malfunction. Pressure relief for the tube side of the regenerative heat exchanger is provided by the check valve which bypasses the charging line isolation valve.

mm. Piping

All Chemical and Volume Control System piping handling radioactive liquid is austenitic stainless steel. All piping joints and connections are welded, except where flanged connections are required to facilitate equipment removal for maintenance and hydrostatic testing. Piping, valves, equipment and line-mounted instrumentation, which normally contain concentrated boric solution, are heated by redundant electrical tracing to ensure solubility of the boric acid.

nn. Temporary chemical injection skid

A temporary chemical injection skid may be connected to the charging line to the regenerative heat exchanger. Use of the skid is controlled as a recurring temporary modification.

The primary use of the temporary chemical injection skid is to bypass the seal water injection flowpath for the injection of hydrogen peroxide in order to initiate a crud burst.

The skid is designed to interface with the permanently installed equipment through a vent/drain valve to limit the possible leakage from the RCS should any failure occur. The skid is only to be used in mode 5 in order to limit the impact on containment operability. The skid is designed to maintain a CVCS pressure of up to 2,735 PSIG. The injection pressure of the skid is designed only to provide flow at the expected CVCS pressure during Mode 5.

10.2.3.3 Performance Analysis

10.2.3.3.1 Availability and Reliability

A high degree of functional reliability is assured in this system by providing standby components where performance is vital to safety and by assuring fail-safe response to the most probable mode of failure. Special provisions include duplicate heat tracing with alarm protection of lines, valves, and components normally containing concentrated boric acid.

Each unit has three high pressure charging pumps, each capable of supplying the normal reactor coolant pump seal and makeup flow.

The electrical equipment of the Chemical and Volume Control System is arranged so that multiple items receive their power from various 480 volt buses (see Section 8).

The two boric acid transfer pumps are powered from separate 480 volt buses. One charging pump and one boric acid transfer pump are capable of meeting Mode 5, Cold Shutdown requirements shortly after full power operation. In cases of loss of AC power, the charging pumps and the boric acid transfer pumps can be manually transferred to diesel generator power.

10.2.3.3.2 Control of Tritium

The Chemical and Volume Control System is used to control the concentration of tritium in the Reactor Coolant System. Essentially all of the tritium is in chemical combination with oxygen as a form of water. Therefore, any leakage of coolant to the containment atmosphere carries tritium in the same proportion as it exists in the coolant. Thus, the level of tritium in the containment atmosphere, when it is sealed from outside air ventilation, is a function of tritium level in the reactor coolant, the cooling water temperature at the cooling coils, which determines the dew point temperature of the air, and the presence of leakage other than reactor coolant as a source of moisture in the containment air.

There are two major considerations with regard to the presence of tritium:

a. Exposure of plant personnel to tritium during access to the containment. Leakage of reactor coolant during operation with a closed containment causes an accumulation of tritium in the containment atmosphere. It is desirable to limit the accumulation to allow containment access for short times for in-core instrumentation maintenance and equipment inspection.

b. Exposure to the public due to release of tritium.

Neither of these considerations is limiting in this plant.

The uncertainties associated with estimating the amounts of tritium generated are discussed in Appendix D.

Periodic determinations of tritium concentrations is made by liquid scintillation counting of condensed water vapor from the containment.

Tritium releases to the atmosphere via the containment purge system are made in accordance with limits given in the Offsite Dose Calculation Manual (ODCM). Normally, tritium releases are expected to be much lower than allowed by the referenced limits.

10.2.3.3.3 Leakage Prevention

Quality control of the material and the installation of the Chemical and Volume Control System valves and piping, which are designated for radioactive service, is provided in order to essentially eliminate leakage to the atmosphere. The components designated for radioactive service are provided with welded connections to prevent leakage to the atmosphere. However, flanged connections are provided in each charging pump suction and discharge, on each boric acid pump suction and discharge, on the relief valves inlet and outlet, on three-way valves, on the flow meters and elsewhere where necessary for maintenance.

The positive displacement charging pumps stuffing boxes are provided with leakoffs to collect reactor coolant before it can leak to the atmosphere. The potential for valve stem leakage is reduced by monitoring valves for leakage, early detection, and repacking without leakoff per current maintenance standards. Post maintenance testing, inservice system leak tests, periodic walkdown surveillances, radiation monitoring, fluid inventory surveillances, and leakage control programs address early leak detection and repair.

Diaphragm valves are provided where the operating pressure and the operating temperature permit the use of these valves. Leakage to the atmosphere is essentially zero for these valves. In some cases, due to heat-traced piping and other environmental conditions, diaphragm valves have a tendency to fail. In these cases, other types of valves such as globe valves, gate valves, etc. are used.

10.2.3.3.4 Incident Control

The letdown line and the reactor coolant pumps seal water return lines penetrate the reactor containment. The letdown line contains two air-operated valves inside the reactor containment upstream of the regenerative heat exchanger. These two valves form the RCS pressure boundary and close on low pressurizer level. In addition, three parallel air-operated orifice block valves inside the reactor containment are backed up by an air-operated valve outside the reactor containment. These four valves are automatically closed by the containment isolation signal.

If the charging system is unable to maintain pressurizer water level, the letdown line isolation valves located close to the reactor coolant loop are tripped closed by a low level signal from the pressurizer level instrumentation. Redundant valves in series and redundant level channels powered by separate and independent buses are provided to ensure letdown isolation even in the event of a single active failure. The isolation valves provided are air-operated, fail-closed valves (i.e., in the event of a loss of air or an electrical failure to the solenoid valves in the air supply line, the valves fail to the closed position). Isolation of the letdown line following a LOCA is accomplished at the containment penetration which has fail-closed, air-operated valves inside containment downstream of the letdown orifices and one fail-closed, air-operated valve outside the containment near the penetration.

If a valve failure causes the letdown line to be isolated, the charging line must also be removed from service. However, the charging pumps can continue to supply seal injection flow to the reactor coolant pumps. The excess letdown line can be placed in service, as required, to letdown the labyrinth seal in leakage to the Reactor Coolant System. Therefore, the failure of these isolation valves has no effect on the safety of the plant and operation of the plant can continue until corrective action is taken and normal letdown is restored.

The reactor coolant pumps seal water return line contains one motor-operated isolation valve outside the reactor containment which is automatically closed by the containment isolation signal.

The two seal water injection lines to the reactor coolant pumps and the charging line are inflow lines penetrating the reactor containment. Each line contains two check valves inside the reactor containment to provide isolation of the reactor containment if a break occurs in these lines outside the reactor containment.

The check valves inside the containment on the seal water injection lines are capable of withstanding the full pressure differential resulting from a pipe break in the seal injection line outside the reactor containment.

The first check valve in the seal water supply lines prevents loss of reactor coolant due to a line break inside the loop compartment walls. The second check valve located as close as practicable to the containment wall provides the first containment isolation barrier. The seal water injection lines and header are connected to a closed system outside containment. This closed system serves as the secondary containment isolation boundary. Check valves, and one locked closed manual valve, provide the closed system boundary at the suction side of the charging pumps. The boundary valves are tested per ASME OM Code requirements. However, there are manually operated needle valves in the seal water injection lines which may be closed to provide a second isolation barrier outside containment.
60400000315

In the event that the manual closure of these valves is required, an operator would be exposed to the post LOCA radiation field from the shielded containment vessel. Conservatively assuming that 15 minutes is required to operate these valves at one hour post LOCA, an operator would receive about 10 rem whole body exposure.

10.2.3.3.5 Malfunction Analysis

To evaluate system safety, failures or malfunctions were assumed concurrent with a loss-of-coolant accident and the consequences analyzed and presented in Table 10.2-8. As a result of this evaluation, it is concluded that proper consideration has been given to plant safety in the design of the system.

If a rupture were to take place between the reactor coolant loop and the first isolation valve or check valve, this incident would lead to an uncontrolled loss of reactor coolant. The analysis of loss-of-coolant accidents is discussed in Section 14.6 and 14.7.

Should a rupture occur in the Chemical and Volume Control System outside the containment, or at any point beyond the first check valve or remotely operated isolation valve, actuation of the valve would limit the release of coolant and assure continued functioning of the normal means of heat dissipation from the core. For the general case of rupture outside the containment, the largest source of radioactive fluid subject to release is the contents of the volume control tank. The consequences of such a release are considered in Section 14.

When the reactor is subcritical, the relative reactivity status (neutron source multiplication) is continuously monitored and indicated by BF_3 counters and count rate indicators. Any appreciable increase in the neutron source multiplication, including that caused by the maximum physical boron dilution rate, is slow enough to give ample time to start a corrective action (boron dilution stop and/or emergency boron injection) to prevent the core from becoming critical. The maximum dilution rate is based on the abnormal condition of three charging pumps operating at full speed delivering unborated primary water to the Reactor Coolant System at a particular time during refueling when the boron concentration is at the maximum value and the water volume in the system is at a minimum. (See Section 14 for results of analysis).

At least two separate and independent flowpaths are available for reactor coolant boration; i.e., the charging line or through the two reactor coolant pump labyrinths. The malfunction or failure of one component does not result in the inability to borate the Reactor Coolant System. An alternate flow path is always available for emergency boration of the reactor coolant. As backup to the boration system, the refueling water storage tank outlet can be aligned to the suction of the charging pumps.

Concentrated boric acid can be injected into the reactor coolant system by means of the charging pumps through two flow paths; (a) Normal charging line (30 gpm) and (b) Seal water supply lines to the two reactor coolant pumps while bypassing seal injection filters (8 gpm per pump - 2.5 gpm of which leaks back into the CVCS and 5.5 gpm of which passes into the RCS). Each flow path is provided with a flow indicator. Normally, both charging paths are used for a combined charging rate of 40 gpm. However, if the charging line is isolated, the same charging can be achieved by increasing the leakage through the reactor coolant pump labyrinth seals to the reactor coolant system.

Suction to the charging pumps can be delivered through three flow paths; (a) the blender and flow control valve, (b) a local manual valve path, or (c) an emergency boration path through the motor operated valve. Each flow path is provided with a flow meter.

A letdown or charging line break would be indicated by excessive auto makeup to the volume control tank. A break in the charging line or upstream of the letdown orifices in the letdown line would also result in an increase in charging pump speed and a possible hi-speed alarm, depending on the break size. If the break size is such that the charging/letdown system is unable to maintain pressurizer water level, the letdown line isolation valves near the reactor coolant loop would be tripped closed by a low level signal from the pressurizer level instrumentation (redundant valves and level channels are provided to ensure letdown isolation in the event of a single active failure).

A single charging pump has sufficient capacity (60 gpm) to compensate for normal letdown purification flow (40 gpm) and seal return (normally 2.5 gpm/pump) and thus maintain the proper reactor coolant total inventory, temperature and pressure.

The refueling water storage tank becomes the source of makeup in the event that leakage makeup is required when the reactor makeup water storage tank is empty.

In the event that the letdown line must be isolated, the charging line is also isolated to avoid thermal shocking of the charging line penetrations into the Reactor Coolant System. If the charging line must be isolated, the letdown line is also isolated to avoid flashing of the letdown stream as the pressure of the high temperature flow is reduced.

With the letdown and charging lines isolated, the Reactor Coolant System can be borated via the reactor coolant pump labyrinth seals by allowing the pressurizer water level to increase, i.e., the pressurizer has sufficient volume to accept the amount of 12 wt% boric acid solution required to borate the system for a cold shutdown. As the system is cooled down, makeup for contraction would be provided through the labyrinth seals at the Mode 5, Cold Shutdown boron concentration. Therefore, the letdown and normal charging path are not required to go to Mode 5, Cold Shutdown condition. If letdown of reactor coolant is necessary, the excess letdown line is capable of letting down a flow equivalent to the total labyrinth seal inleakage from both reactor coolant pumps.

Design seal injection to each reactor coolant pump is 8 gpm with the majority of the flow passing through labyrinth seals into the reactor coolant system and the remainder passing through the shaft seals. The shaft seals are designed to divert nominally 2.5 gpm back to the chemical and volume control system, with a small fraction flowing into the waste liquid system via the reactor coolant drain tank (RCDT).
(References 98 and 99)

With the charging line isolated, the rate of injection of 12 wt.% boric acid solution into the reactor coolant system could be increased to 12 gpm if required (6 gpm from the labyrinth seal leakage through each reactor coolant pump). This charging rate can borate the reactor coolant system to the concentration necessary for Mode 5, Cold Shutdown in approximately three hours and is equivalent to a cooldown rate of 1.5°F/min as given in Table 10.2-7. 604000000185

If the normal letdown line is not in service, the charging line must also be isolated to avoid thermal shocking of the charging line penetration into the Reactor Coolant System. As stated above, with the charging and letdown lines out of service, the length of time necessary to bring the reactor to Mode 5, Cold Shutdown, is not affected because of the capability of increasing leakage through the reactor coolant pump seals to the reactor coolant system. If the charging flow through the reactor coolant pump labyrinth seals is not increased following isolation of the charging line, the time necessary to borate the reactor coolant sufficiently for a cold shutdown is approximately 4 hours. 604000000185

In the event that injection using the Charging Pumps is not available, the Safety Injection system can perform this function using borated water from the refueling water storage tank. If necessary, the RCS can be sufficiently depressurized to allow injection with the SI Pumps.

On loss of seal injection water to the reactor coolant pump seals, seal water flow may be re-established by manually starting a standby charging pump. Even if the seal water injection flow is not immediately re-established, the plant can continue to operate temporarily since the thermal barrier cooler has sufficient capacity to cool the reactor coolant flow which would pass through the thermal barrier cooler and seal leakoff from the pump volute.

Short term operation is possible but, in order to prevent the reactor coolant pump seals from being exposed to prolonged flow of unfiltered reactor coolant and potentially exceeding their operating temperature limit, it is recommended that this condition be minimized. The effect of continuous reactor coolant pump operation without injection water would be to possibly cause clogging or damage of the seals with the introduction of unfiltered water.

The thermal barrier cooling coil is a backup to seal injection for cooling the reactor coolant pump bearings and seals and no overheating would result from continued operation without seal injection water for a period of at least one hour following the onset of a loss of seal injection event.

10.2.3.3.6 Deleted

10.2.3.3.7 Fuel Element Failure Detection

The fuel element failure detection system monitors letdown flow using one channel (R-9) of the Area Radiation Monitoring System (see Section 7.5.3.2 and Table 7.5-1).

Delay time for the monitor in detecting fuel element failure ranges from approximately one minute to approximately three minutes, depending on the letdown flow rate. At the high flow letdown flow rate (80 gpm), approximately 1-1/2 minutes pass before the reactor coolant, contaminated by fission product release from the failed fuel element, reaches the monitor. At the normal letdown rate (40 gpm), approximately three minutes pass before the contaminated flow reaches the detection area.

The monitor detects fuel element failure release of fission products against a background of:

a.	N-16 source (assuming a 60 second decay)	4.5×10^1 mR/hr
b.	Nominal corrosion product sources	1.1×10^1 mR/hr
c.	Previous fuel element defects	Determined during operation

Fuel failure severity can be determined by relating any increase in radiation detected to a corresponding increase in either rod gap release or general fuel element defects:

a.	.01% fuel element defects	7.2×10^1 mR/hr
b.	1 rod gap release	3.2×10^2 mR/hr

THIS PAGE IS LEFT INTENTIONALLY BLANK

10.2.4 Residual Heat Removal System

10.2.4.1 Design Basis

The residual heat removal system is shown in Figures 10.2-11 and 10.2-12. The residual heat removal system is designed to remove residual and sensible heat from the core and reduce the temperature of the Reactor Coolant System during the second phase of plant cooldown. During the first phase of cooldown, the temperature of the Reactor Coolant System is reduced by transferring heat from the Reactor Coolant System to the Steam and Power Conversion System.

Separate and independent residual heat removal systems are supplied for the two units. The description contained herein is equally applicable to either unit.

All active system components which are relied upon to perform their function during an accident are redundant.

The system design precludes any significant reduction in the overall reactor shutdown margin when the system is brought into operation for residual heat removal or for emergency core cooling by recirculation.

The system design includes provisions to enable hydrostatic testing to applicable code test pressures during shutdown.

The system design and operation has been evaluated against Generic Letter 87- 12, “Potential for Loss of Residual Heat Removal (RHR) While the Reactor Coolant System (RCS) is Partially Filled”. It was concluded that the procedures currently in place, in conjunction with the additional procedures, training and modifications described in NSP’s response to that Generic Letter, (Reference 33) provide assurance that this problem will not occur at Prairie Island.

System components, whose design pressure and temperature are less than the Reactor Coolant System design limits, are provided with overpressure protective devices and redundant isolation means.

The equipment utilized for residual heat removal is also used for emergency core cooling during loss-of-coolant accident conditions. This is described in Section 6.

It is the intent of the design of the safety related actions of the Residual Heat Removal System to meet the requirements of IEEE 279 “Standard, Nuclear Power Plant Protection Systems”, August 1968.

10.2.4.2 Description

Two pumps and two residual heat exchangers perform the residual heat removal functions for the reactor. After the Reactor Coolant System temperature and pressure have been reduced to 350°F and 425 psig respectively, residual heat removal is initiated by aligning a pump to take suction from the hot legs of both reactor coolant loops and discharge through the heat exchangers into the cold leg of one reactor coolant loop. Due to the piping configuration of the shutdown cooling cold leg return line, each Unit has only one train capable of maintaining the required ECCS functions while the other is aligned for the shutdown cooling function in Mode 4. For a typical case of 85°F cooling water, the total time of cooldown to refueling shutdown can be as much as 159 hours. 01551325

When aligned for shutdown cooling, reactor coolant flows from the Reactor Coolant System to the residual heat removal pumps, through the tube side of the residual heat exchangers and back to the Reactor Coolant System. The heat load is transferred by the residual heat exchangers to the component cooling water. The cooldown rate of the reactor is controlled by regulating the reactor coolant flow through the tube side of the residual heat exchangers. A by-pass line and an automatic flow control valve around the residual heat exchangers are used to maintain a constant flow through the residual heat removal system.

Redundant, remotely operated valving in the residual heat removal system inlet lines is provided to isolate the system from the Reactor Coolant System. One set of isolation valves, those adjoining the reactor coolant system, are interlocked with a pressure signal to prevent their being opened whenever the system pressure is greater than 425 psig. The valves will also be automatically closed whenever the system pressure increases above 600 psig. This interlock and automatic closing action is derived from one process control channel.

The other set of valves, those adjoining the residual heat removal system, are similarly interlocked and automatically closed with the actions being derived from a second process control channel. A remotely operated valve and a check valve isolate the line to the Reactor Coolant System cold leg. Overpressure in the system is prevented by a relief valve in the inlet piping which discharges to the pressurizer relief tank and by a relief line from the outlet piping to the CVCS letdown line.

Design parameters for the residual heat removal system components are presented in Table 10.2-9.

10.2.4.2.1 Components

a. Residual Heat Exchangers

The two residual heat exchangers are of the shell and U-tube type with the tubes welded to the tube sheet. Reactor coolant circulates through the tubes, while component cooling water circulates through the shell side. The tubes and other surfaces in contact with reactor coolant are austenitic stainless steel and the shell is carbon steel.

b. Residual Heat Removal Pumps

The two residual heat removal pumps are vertical centrifugal units with special seals to prevent reactor coolant leakage to the atmosphere. All pump parts in contact with reactor coolant are austenitic stainless steel or equivalent corrosion resistant material.

c. Residual Heat Removal Valves

The valves used in the residual heat removal system are constructed of austenitic stainless steel or equivalent corrosion resistant material.

Manual stop valves are provided to isolate equipment for maintenance. Throttle valves are provided for remote and manual control of the residual heat exchanger tube side flow. Check valves prevent reverse flow through the residual heat removal pumps.

The potential for valve stem leakage is reduced by monitoring valves for leakage, early detection, and repacking without leakoff per current maintenance standards. Post maintenance testing, inservice system leak tests, periodic walkdown surveillances, radiation monitoring, fluid inventory surveillances, and leakage control programs address early leak detection and repair.

Manually operated valves have backseats to facilitate repacking and to limit the stem leakage when the valves are open.

d. Residual Heat Removal System Piping

All residual heat removal system piping is austenitic stainless steel. The piping is welded with flanged connections at some components for ease of maintenance.

10.2.4.3 Performance Analysis

The residual heat removal system is connected to the hot legs of both reactor coolant loops on the suction side and to the cold leg of one reactor coolant loop on the discharge side. On the suction side the connections are through two electric motor operated gate valves in series with both valves automatically closed when the Reactor Coolant System pressure exceeds a selected fraction of the design pressure of the Residual Heat Removal System. Once closed, each valve is interlocked to prevent opening unless the Reactor Coolant System pressure is below the Residual Heat Removal System design pressure. On the discharge side the connection is through a check valve in series with an electric motor-operated gate valve. All of these motor-operated valves are closed during normal operation.

Two pumps and two heat exchangers are used to remove decay heat during shutdown operations. However, during Mode 4 cooldown, one train is required to be maintained ready for ECCS injection as described in Section 6. The entire system is seismic Class I design and the Components are designed to the codes given in Table 10.2-2. 01551325

Welded construction is used where possible throughout the residual heat removal system piping, valves, and equipment to minimize the possibility of leakage. Each of the two residual heat removal pumps and associated piping is located in a shielded compartment as described in Section 6. An analysis of potential leakage and the resulting offsite radiological effect has been evaluated and is discussed in Sections 6 and 14. A failure analysis of components is given in Table 10.2-4.

10.2.5 Reactor Makeup Water Deoxygenation System

The Reactor Makeup Water Deoxygenating System is a part of the Reactor Makeup (RM) System. It is common to both units 1 and 2 and is designed to remove oxygen from water stored in any of the four Reactor Makeup Water Tanks. The System can be aligned to degas the water in any one of the tanks at a time.

10.2.5.1 Design Basis

The Reactor Makeup Water Deoxygenation System is designed to: a) maintain the dissolved oxygen content of the Reactor Makeup Water within the limits identified in PINGP Chemistry procedures; and b) deoxygenate all aerated water prior to storage in the Reactor Makeup Tanks, or deoxygenate in a batch process once in the storage tank.

10.2.5.1.1 Codes and Classifications

All components and piping are designed in accordance with the ASME Boiler and Pressure Vessel Code Section VIII and ANSI B31.1 respectively. The system is designated QA Type III. Seller's inspection/test program for the components in this system are in accordance with the requirements of FPI TS QA III, Rev. 2, 1976.

10.2.5.2 Description

The Reactor Makeup Water Deoxygenation System is shown in Figure 10.2-9, and periodically is used to deoxygenate the contents of each Reactor Makeup Water Tank.

The existing Reactor Makeup Water Pump piping is designed so that the pumps can supply water either to the Reactor Makeup services or to the degasifier.

The deoxygenating equipment consists of a packed column degasifier. The water is introduced near the top of the degasifier and is broken up into drops as it trickles down over the plastic packing and collects in the storage section at the bottom of the degasifier.

A full capacity vacuum pump maintains the necessary vacuum in the column. Oxygen and other gases given up by the water are discharged outside the Turbine Building into the atmosphere. The vacuum pump has a pump of equal capacity installed as a backup.

The deoxygenated water, collected in the storage section of the column, is transferred into a predetermined Reactor Makeup water tank by means of a transfer pump. A second transfer pump is installed as a backup.

The degasification equipment is shared between Units 1 and 2.

All components in the Reactor Makeup water deoxygenation system are located in the Unit 1 turbine building. The degasifier, the transfer pumps and the vacuum pumps are located on the ground floor, 695′ - 0″ elevation.

10.2.5.2.1 Components

A summary of principal component data is given in Table 10.2-10.

Degasifier

The Reactor Makeup Water Degasifier is designed for continuous processing of water at a rate of 80 gpm. It is designed to provide a water effluent of 50 ppb (max) dissolved oxygen content based on 2 ppm oxygen content and ammonia free demineralized water influent at 60°F.

Transfer Pumps

Two magnetic drive positive displacement vane type pumps are provided. All wetted parts of the pumps are constructed from stainless steel. The pumps are provided with drains and shut-off valves in both suction and discharge lines for ease of maintenance. 01400506

Vacuum Pumps

Two Rotary Piston, oil lubricated, belt driven vacuum pumps are provided.

10.2.5.3 Performance Analysis

The Reactor Makeup Water Deoxygenation System is not an engineered safety features system since it is not required for safe shutdown.

10.2.5.3.1 Instrumentation and Controls

The Reactor Makeup Water Pumps are manually aligned with the degasifier and manually started. The level in the degasifier is controlled by a control valve in the inlet line. This control valve closes upon detection of low inlet pressure.

One of the two vacuum degasifier transfer pumps may be manually started by means of local switches. Low level in the degasifier automatically trips the operating vacuum degasifier transfer pump in the RM degasifier area. To resume operation, the operator should manually restart the pump. The second pump is held in standby, and if needed, may be manually put in operation.

The discharge flow is controlled by throttling the manual valve in the vacuum degasifier Transfer Pumps discharge.

The vacuum degasifier vacuum pumps are manually started by means of local switches. High levels in the degasifier automatically trip the operating vacuum pump. At the same time an alarm sounds in the control room. To resume operation, the operator should manually restart the pump. The second pump is held in standby, and if needed, may be manually put in operation.

A pressure gage is provided in the discharge of the vacuum degasifier transfer pumps. A vacuum gage and a level gage is also provided on the degasifier. A pressure switch is located upstream of the inlet control valve. Upon low pressure detection by this switch, the inlet control valve closes and an alarm sounds in the control room. The level in the degasifier will drop. The degasifier transfer pump stops on low level and an alarm is sounded in the control room.

An alarm is sounded in the control room when a vacuum loss is sensed in the degasifier with either transfer pump running.

THIS PAGE IS LEFT INTENTIONALLY BLANK

10.3 PLANT SERVICE SYSTEMS

10.3.1 Plant Fire Protection Program

The fire protection program is based on the NRC requirements and guidelines, Nuclear Electric Insurance Limited (NEIL) Property Loss Prevention Standards and related industry standards. With regard to NRC criteria, the fire protection program meets the requirements of 10 CFR 50.48(c), which endorses, with exceptions, the National Fire Protection Association's (NFPA) 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants" – 2001 Edition. Prairie Island Nuclear Generating Plant (PINGP) Units 1 & 2 have further used the guidance of NEI 04-02, "Guidance for Implementing a Risk-Informed, Performance-Based Fire Protection Program under 10 CFR 50.48(c)" as endorsed by Regulatory Guide 1.205, "Risk-Informed, Performance-Based Fire Protection for Existing Light-Water Nuclear Power Plants."

Adoption of NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants", 2001 Edition in accordance with 10 CFR 50.48(c) serves as the method of satisfying 10 CFR 50.48(a) and General Design Criterion 3. Prior to adoption of NFPA 805, General Design Criterion 3, "Fire Protection" of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Licensing of Production and Utilization Facilities," was followed in the design of safety and non-safety related structures, systems, and components, as required by 10 CFR 50.48(a).

NFPA 805 does not supersede the requirements of GDC 3, 10 CFR 50.48(a), or 10 CFR 50.48(f). Those regulatory requirements continue to apply. However, under NFPA 805, the means by which GDC 3 or 10 CFR 50.48(a) requirements are met may be different than under 10 CFR 50.48(b). Specifically, whereas GDC 3 refers to SSCs important to safety, NFPA 805 identifies fire protection systems and features required to meet the Chapter 1 performance criteria through the methodology in Chapter 4 of NFPA 805. Also, under NFPA 805, the 10 CFR 50.48(a)(2)(iii) requirement to limit fire damage to SSCs important to safety so that the capability to safely shut down the plant is satisfied by meeting the performance criteria in Section 1.5.1 of NFPA 805.

A Safety Evaluation was issued on 08/08/2017 by the NRC, that transitioned the existing fire protection program to a risk-informed, performance-based program based on NFPA 805, in accordance with 10 CFR 50.48(c). See References 100 through 115 for the licensing correspondence related to the adoption of NFPA 805 as the new fire protection program licensing basis.

10.3.1.1 Design Basis Summary

10.3.1.1.1 Defense-in-Depth

The fire protection program is focused on protecting the safety of the public, the environment, and plant personnel from a plant fire and its potential effect on safe reactor operations. The fire protection program is based on the concept of defense-in-depth. Defense-in-depth shall be achieved when an adequate balance of each of the following elements is provided:

(1) Preventing fires from starting,

(2) Rapidly detecting fires and controlling and extinguishing promptly those fires that do occur, thereby limiting fire damage,

(3) Providing an adequate level of fire protection for structures, systems, and components important to safety, so that a fire that is not promptly extinguished will not prevent essential plant safety functions from being performed.

10.3.1.1.2 NFPA 805 Performance Criteria

The design basis for the fire protection program is based on the following nuclear safety and radiological release performance criteria contained in Section 1.5 of NFPA 805:

- Nuclear Safety Performance Criteria. Fire protection features shall be capable of providing reasonable assurance that, in the event of a fire, the plant is not placed in an unrecoverable condition. To demonstrate this, the following performance criteria shall be met.

(a) Reactivity Control. Reactivity control shall be capable of inserting negative reactivity to achieve and maintain subcritical conditions. Negative reactivity inserting shall occur rapidly enough such that fuel design limits are not exceeded.

(b) Inventory and Pressure Control. With fuel in the reactor vessel, head on and tensioned, inventory and pressure control shall be capable of controlling coolant level such that subcooling is maintained such that fuel clad damage as a result of a fire is prevented for a PWR.

(c) Decay Heat Removal. Decay heat removal shall be capable of removing sufficient heat from the reactor core or spent fuel such that fuel is maintained in a safe and stable condition.

*604000000193

(d) Vital Auxiliaries. Vital auxiliaries shall be capable of providing the necessary auxiliary support equipment and systems to assure that the systems required under (a), (b), (c), and (e) are capable of performing their required nuclear safety function.

(e) Process Monitoring. Process monitoring shall be capable of providing the necessary indication to assure the criteria addressed in (a) through (d) have been achieved and are being maintained.

- Radioactive Release Performance Criteria. Radiation release to any unrestricted area due to the direct effects of fire suppression activities (but not involving fuel damage) shall be as low as reasonably achievable and shall not exceed applicable 10 CFR, Part 20, Limits.

Chapter 2 of NFPA 805 establishes the process for demonstrating compliance with NFPA 805.

Chapter 3 of NFPA 805 contains the fundamental elements of the fire protection program and specifies the minimum design requirements for fire protection systems and features.

Chapter 4 of NFPA 805 establishes the methodology to determine the fire protection systems and features required to achieve the nuclear safety performance criteria outlined above. The methodology shall be permitted to be either deterministic or performance-based. Deterministic requirements shall be “deemed to satisfy” the performance criteria, defense-in-depth, and safety margin and require no further engineering analysis. Once a determination has been made that a fire protection system or feature is required to achieve the nuclear safety performance criteria of Section 1.5, its design and qualification shall meet the applicable requirement of Chapter 3. *604000000193

10.3.1.1.3 Codes of Record

The codes, standards and guidelines used for the design and installation of plant fire protection systems are documented in H77, Fire Protection Program, and H77.1, Fire Protection Program NFPA 805 Chapter 3 Compliance Summary (NEI 04-02 Table B-1).

10.3.1.2 System Description

10.3.1.2.1 Required Systems

Nuclear Safety Capability Systems, Equipment, and Cables

Section 2.4.2 of NFPA 805 defines the methodology for performing the nuclear safety capability assessment. The systems, equipment, and cables required for the nuclear safety capability assessment are contained in H77.3, Fire Protection Program Fire Area Assessments.

Fire Protection Systems and Features

Chapter 3 of NFPA 805 contains the fundamental elements of the fire protection program and specifies the minimum design requirements for fire protection systems and features. Compliance with Chapter 3 is documented in H77.1, Fire Protection Program NFPA 805 Chapter 3 Compliance Summary (NEI 04-02 Table B-1).

Chapter 4 of NFPA 805 establishes the methodology and criteria to determine the fire protection systems and features required to achieve the nuclear safety performance criteria of Section 1.5 of NFPA 805. These fire protection systems and features shall meet the applicable requirements of NFPA 805 Chapter 3. These fire protection systems and features are documented in H77.3, Fire Protection Program Fire Area Assessments.

Radioactive Release

Structures, systems, and components relied upon to meet the radioactive release criteria are documented in H77, Fire Protection Program.

10.3.1.2.2 Definition of “Power Block” Structures

Where used in NFPA 805 Chapter 3 the terms “Power Block” and “Plant” refer to structures that have equipment required for nuclear plant operations. For the purposes of establishing the structures included in the fire protection program in accordance with 10 CFR 50.48(c) and NFPA 805, the plant structures listed in H77 Fire Protection Program, are considered to be part of the ‘power block’.

*604000000193

10.3.1.3 Safety Evaluation

H77, Fire Protection Program, documents the achievement of the nuclear safety and radioactive release performance criteria of NFPA 805 as required by 10 CFR 50.48(c). This document fulfills the requirements of Section 2.7.1.2 “Fire Protection Program Design Basis Document” of NFPA 805. The document contains the following:

- Identification of significant fire hazards in the fire area. This is based on NFPA 805 approach to analyze the plant from an ignition source and fuel package perspective.

- Summary of the Nuclear Safety Capability Assessment (at power and non-power) compliance strategies.

    - Deterministic compliance strategies

- Performance-based compliance strategies (including defense-in-depth and safety margin)

- Summary of the Non-Power Operations Modes compliance strategies.
- Summary of the Radioactive Release compliance strategies.
- Summary of the Fire Probabilistic Risk Assessments.
- Key analysis assumptions to be included in the NFPA 805 monitoring program.

10.3.1.4 Fire Protection Program Documentation, Configuration Control and Quality Assurance

In accordance with Chapter 3 of NFPA 805 a fire protection plan documented in Procedure H77, Fire Protection Program, defines the management policy and program direction and defines the responsibilities of those individuals responsible for the plan's implementation. The Fire Protection Program procedure:

- Designates the senior management position with immediate authority and responsibility for the fire protection program.
- Designates a position responsible for the daily administration and coordination of the fire protection program and its implementation.
- Defines the fire protection interfaces with other organizations and assigns responsibilities for the coordination of activities. In addition, the Fire Protection Program procedure identifies the various plant positions having the authority for implementing the various areas of the fire protection program.
- Identifies the appropriate authority having jurisdiction for the various areas of the fire protection program.
- Identifies the procedures established for the implementation of the fire protection program, including the post-transition change process and the fire protection monitoring program.
- Identifies the qualifications required for various fire protection program personnel.
- Identifies the quality requirements of Chapter 2 of NFPA 805.

Detailed compliance with the programmatic requirements of Chapters 2 and 3 of NFPA 805 are contained in H77, Fire Protection Program, and H77.1, Fire Protection Program NFPA 805 Chapter 3 Compliance Summary (NEI 04-02 Table B-1).

604000000193

10.3.2 Auxiliary Building Normal Ventilation Systems

10.3.2.1 Design Basis

The Auxiliary Building Normal Ventilation System is designed to provide maximum safety and convenience for operating personnel, with equipment arranged so that potentially contaminated areas are separated from clean areas.

The ventilation equipment complies with accepted industry standards for power plant equipment and with all applicable state and local codes and regulations. Redundant equipment is provided for those systems where, in case of malfunctions, public health and safety may be endangered or where safeguard equipment operation may be impaired. Particulate filters, where used, are of the high-efficiency type capable of removing at least 99.97% of 0.3 micron diameter DOP smoke particles. These filters meet all requirements of AEC Health and Safety Bulletin 212, dated June 25, 1965.

The design of the Auxiliary Building Normal Ventilation (ZD) system is to maintain temperatures of 10°F or less above the outdoor ambient in critical area; i.e., motors, instrumentation, etc. 60400000186

The ventilating equipment is accessible for periodic testing and inspection during normal operation.

10.3.2.2 Description

The Auxiliary Building has separate normal ventilation systems to serve the auxiliary equipment areas, the Spent Fuel Pool Area, and the nonradioactive area, as shown in Figure 10.3-6. The path of ventilating air is from clean, or low activity areas toward areas of progressively higher activity. Ventilation air is drawn from outside, through two makeup air units (two each per unit). The system is balanced to maintain the Auxiliary Building at a pressure slightly negative with respect to atmospheric and adjacent Turbine Building pressures.

Special provisions are also included to exhaust air through activated charcoal beds and high-efficiency filters from areas subject to possible radioactive contamination. This is accomplished through local ventilation systems and the use of the Auxiliary Building Special Ventilation System. The Auxiliary Building Special Ventilation System is actuated by either a Safety Injection Signal, or a high radiation signal from the Auxiliary Building vent monitor. This system is described in Section 10.3.4.

The Spent Fuel Pool has been provided with normal and special ventilation systems. The completely enclosed pool area is normally ventilated and exhausted through roughing and HEPA filters. In the event of high radiation in the pool area, the normal system is isolated and the special exhaust system is actuated, directing air flow through redundant, roughing, HEPA and charcoal filters as described in Section 10.3.7.

10.3.3 Control Room Ventilation System

10.3.3.1 Design Basis

The control room ventilation system shall isolate the outside atmosphere and recirculate a portion of the control room atmosphere through PAC filters to maintain the dose to the control room operator less than the limits specified in 10 CFR 50, Appendix A, GDC 19, for a design basis accident. Isolation and recirculation is accomplished through an automatic start signal generated from either a SI signal or a high radiation signal. Dose to control room operators are maintained less than the limits through minimizing inleakage to the control room envelope and clean up of the activity that may enter the control room.

The control room shall be maintained at suitable temperature conditions for personnel habitability and equipment operability. This is accomplished by providing safeguards chilled water (Section 10.4.3) to the control room ventilation air handling units.

The control room ventilation system is capable of performing the design functions in the event of a single active failure. Redundant trains of control room ventilation are provided for this purpose.

The control room ventilation system is capable of performing the required functions in the event of a loss of off-site power. In the event of a loss of off-site power, the ventilation system is automatically powered from the Emergency Diesel Generators (Section 8.4.3).

The control room envelope, the control room ventilation system and the structure housing it is designed to withstand a seismic event (Section 12).

The control room ventilation system components are capable of performing their safety functions under the worst case design basis environmental conditions. The control room ventilation system and boundary shall be capable of providing adequate protection in a high energy line break event (Appendix I). The control room ventilation system is located in a mild environment.

The control room ventilation system and boundary shall be capable of providing adequate protection to the operators in a toxic gas release event (Section 2.9.4).

The control room ventilation system and boundary shall be capable of providing adequate protection in a smoke event such that the operators can achieve and maintain safe shutdown from either the control room or the hot shutdown panels.

10.3.3.2 System Description

10.3.3.2.1 Control Room Envelope

The control room envelope consists of the control room and the two chiller rooms. The control room is a common structure that contains the controls for both Unit 1 and Unit 2. The control room is located at elevation 735′ within the Auxiliary Building approximately equidistance between Unit 1 and Unit 2. The chiller rooms are located directly above the control room at elevation 755′. The cable spreading room on the 715′ elevation (directly below the control room) is not part of the control room envelope. HVAC ducting between the cable spreading room and the control room has been isolated by closing the dampers and installing blanks. The control room ventilation system is entirely located within the two chiller rooms (one train of ventilation system in each room), with the exception of the outside air supply. The outside air supply ducting is routed through the Auxiliary Building. The outside air supply dampers are located at the envelope boundary. There are no other ventilation systems that penetrate the control room envelope.

The Auxiliary Building is a Class I structure, designed to withstand a seismic event; described in USAR, Section 12. The Control Room and Chiller Rooms are protected from adverse environmental conditions by the ceilings, walls and floors. In areas where the ventilation system provides possible communication paths, dampers in the ventilation system automatically close to isolate the envelope from a steam environment (referred to as Steam Exclusion). Protection from a High Energy Line Break is described in more detail in USAR, Appendix I. The concrete walls and roof provide shielding for the Control Room (Section 12.3.2.2.2).

The walls, floor and ceiling of the Control Room are of fire resistant construction and have a three-hour fire rating. Ratings for doors, penetrations and ventilation dampers are discussed in H77. 60400000193

10.3.3.2.2 Control Room Ventilation System

The Control Room ventilation system is designed to provide a reliable means of cooling and filtering air supplied to the Control Room under both normal and post-accident conditions. Figure 10.3-7 shows a simplified drawing of the Control Room Ventilation system. The Control Room ventilation system has two modes; a normal mode and an emergency mode.

<u>Normal Mode</u>

During normal operation one train is running and the other train is in standby. For the operating train, the air handler would be operating and the clean-up fan would be in standby with no air flow through the PAC filter. The operating train recirculates the control room envelope air and draws in fresh air. This recirculation flow rate is not filtered; i.e., the Air Handler Unit roll filter is not credited. Air is exhausted from the Control Room Envelope at a rate equivalent to the quantity of fresh air brought in. The design flow rates are 10,000 cfm recirculation flow rate and 2000 cfm fresh air for a total air handler flow rate of 12,000 cfm. For the dose analysis, the normal recirculation flow rate is not credited and, thus, is not an input. The input for normal operation in the dose analyses and toxic gas analyses is the fresh air supply flow rate. 60400000221

<u>Emergency Mode</u>

In response to a Safety Injection or high radiation signal, both trains start. Starting both trains automatically isolates the fresh air supply and exhaust and starts the Clean-Up fan. The portion of the air that is drawn by the clean-up fan passes through a PAC filter that is credited in the dose analysis. In this alignment, the system is recirculating and filtering the control room atmosphere. To account for a single active failure, only one train of control room ventilation system is credited in the dose analysis. In the emergency mode, the clean-up fan is designed to provide 4000 cfm ±10%.

The safety injection signal is generated from low Pressurizer Pressure, low Main Steam Line Pressure or high Containment Pressure. The high radiation signal is generated from radiation monitors (R-23 and R-24) located in the control room. The radiation monitors sensing lines penetrate the control room supply ductwork downstream of the control room HVAC filter unit inside the Control Room in the supply distribution ductwork. A "high" signal from either detector will automatically switch the control room ventilation system from the normal mode of operation to the emergency mode.

On a Steam Exclusion signal (high temperature in the outside air supply or exhaust ductwork) redundant outside air dampers automatically close to protect the control room from a potential steam environment. The RTDs that sense the high temperature conditions are set to actuate the dampers at a temperature less than 120°F. It has been demonstrated (Reference 84) that the outside supply air ducting that routes through the Auxiliary Building is capable of withstanding maximum external pressures predicted for the high energy line break events. *604000000193

Performance Analysis

The discussion of performance analysis is separated into overall design evaluations and equipment performance requirements. Overall design evaluations (Section 10.3.3.3.1) are the radiological, toxic chemical and smoke analysis and assessments. Equipment performance requirements (Section 10.3.3.3.2) provide the discussion of the performance capabilities of various components.

10.3.3.3.1 Design Evaluations

Control room habitability is evaluated for radiological, toxic chemical and smoke considerations.

10.3.3.3.1.1 Radiological Analysis

Radiological analyses are performed to demonstrate that the dose to the control room operators is less than the limitations in 10CFR 50.67. Specifically, the acceptance criteria in the dose analyses for the control room operators is 5 Rem TEDE.

The dose analyses are discussed in more detail in Section 14.

10.3.3.3.1.2 Toxic Chemical Analysis

As discussed in more detail in Section 2.9.4, protection from toxic chemicals is provided by detection (smell) and the ability to don SCBAs prior to the chemical concentration in the control room reaching debilitating levels.

10.3.3.3.1.3 Smoke

Using the guidance in NEI 99-03, Rev 1 (Reference 85), Appendix A, it has been shown that a single smoke event originating from inside or outside the Control Room would not affect both the Control Room and Hot Shutdown Panel areas. Operators would be able to achieve and maintain safe shutdown (reactor control capability) from either the Control Room or the Hot Shutdown Panels if needed. In the event that control room evacuation were necessary, the plant can be shutdown from outside the control room as described in USAR, Section 7.8.5. This is for control room evacuation for a non- fire related event. For shutdown outside the control room for a fire event, the methods are described in the Prairie Island (post-fire) safe shutdown analysis and associated procedures. This is discussed in more detail for non-fire events in the Prairie Island response to Generic Letter 2003-01, Control Room Habitability (Reference 86).

*604000000193

10.3.3.3.2 Equipment Performance Capabilities

The control room ventilation system design basis functions are met by performance of the following functions.

10.3.3.3.2.1 Automatic Actuation

The control room ventilation system is aligned to the emergency mode by either a SI or High Radiation signal. In most instances, the high radiation signal and the SI signal are redundant. The exceptions are that, for the following scenarios, the high radiation signal is relied on to back-up the SI signal.

- If 121 CR Vent is initially running and Train A SI signal fails to actuate, the High Radiation signal (R-23 and/or R-24) is relied on to close the 121 CR Vent outside air dampers.

- If 122 CR Vent is initially running and Train B SI signal fails to actuate, the High Radiation signal (R-23 and/or R-24) is relied on to close the 122 CR Vent outside air dampers.

The timing of the actuation signals is a consideration in the dose analyses. Until the outside air dampers are closed, the potential exists for activity to enter the control room envelope through the normal outside air supply ducting. In order to actuate the high radiation signal, the activity level needs to build-up to reach the radiation monitor setpoint. The time to reach the high radiation setpoint could be longer than the time to actuate SI. The dose analyses accounts for the longer time delay of the SI and high radiation signals.

10.3.3.3.2.2 Air Handling Units

The air handling unit is provided for control room cooling. Safeguards chilled water system provides the heat sink for the air handling units. There are two redundant air handling units; either one is capable of providing the required cooling. An air handling unit is automatically started upon start of the associated Clean-Up fan or the air handling unit may be started manually. Starting the air handling unit opens the associated discharge damper.

10.3.3.3.2.3 Clean-Up Fans

The clean-up fans are provided, in the event of a radiological accident, to recirculate a portion of the control room atmosphere through PAC filters to reduce the dose to the control room operators. Two redundant clean-up fans are provided; either one is capable of providing the credited flow rate. A clean-up fan is automatically started by SI signal from either unit or high radiation signal detected in the control room. Manual initiation of the clean-up fans is also provided. Starting a clean-up fan opens the associated suction and discharge dampers. The radiological analyses credits a clean-up fan air flow rate of 3600 cfm; corresponding to one train at minimum flow. No credit is taken for clean-up fan flow in the toxic chemical or smoke assessments.

10.3.3.3.2.4 PAC Filters

The PAC filters are provided, in the event of a radiological accident, to filter the associated clean-up fan air flow. Two redundant PAC filters are provided; either one is capable of providing the credited filtration. Each PAC filter consists of particulate, absolute and charcoal filters. Each PAC filter is designed for 4000 cfm air flow. Filter efficiency testing is based on maximum air flow (4400 cfm) with a residence time of 0.185 seconds. Per the ventilation filter testing program (T.S.5.5.9), the HEPA filter is tested to 0.05% penetration and system bypass and the charcoal is tested to 2.5% penetration. Charcoal adsorber samples are laboratory tested at a face velocity of 54 fpm, 30°C [86°F], and 95% RH. (Reference 90)

10.3.3.3.2.5 Outside Air Dampers

During normal operation the outside supply air dampers associated with the operating air handling unit and the discharge dampers from 122 Chiller Room to the Auxiliary Building Special Ventilation Zone are typically open. Two redundant outside air dampers are provided in each flow path. The outside air dampers are automatically closed by a SI signal, high radiation signal in the Control Room or a Steam Exclusion signal. Time delays for closing of the outside air dampers are factored into the dose analyses in conjunction with the time delays for the actuation signal. The operations of other dampers in the system are discussed within the discussion of the associated fans.

For post-accident operation, the operator may elect to stay in the 100% recirculation mode, or the operator can add outside air to the Control Room. By proper damper manipulation, the operator may direct outside makeup air through the PAC filter, using the clean-up fan, then to the associated air handling unit. The outside air sources are physically separated to permit taking fresh air from an area of low airborne contamination.

10.3.3.3.2.6 Unfiltered Inleakage

Unfiltered inleakage to the control room envelope was determined using tracer gas testing techniques in 1998 and 2004 (LOOP results are documented in Reference 87). The results for total unfiltered inleakage to the control room envelope from 2004 are as follows:

System Configuration	Inleakage Rate (cfm)
High Radiation	115 ± 36
SI	114 ± 21

The system configuration for the High-Radiation vs. the SI signal affects the ventilation systems in the adjacent spaces (Aux Bldg and Turbine Bldg); but, it does not affect the emergency alignment of the control room ventilation system. The alignment of the ventilation systems in the adjacent spaces affects the differential pressures across the control room envelope boundaries; which can affect the unfiltered inleakage. With the High Radiation signal, the configurations of the ventilation systems in the adjacent areas is more representative of a FHA. With the SI signal, the configuration of the ventilation systems in the adjacent areas is more representative of a MSLB or LOCA event.

10.3.3.4 Inspection and Testing

The control room ventilation system is tested per the associated Technical Specification Surveillance Requirements. These include testing of the PAC filter, flow verification of the clean-up fan and verification that the system actuations are functioning properly.

Door seals for doors that are part of the control room envelope boundary are maintained in good condition. The door seals are inspected and replaced (if necessary) on an annual basis as part of the Preventative Maintenance program.

Periodic inspections are performed of the outside air damper (supply and exhaust) seating surfaces to ensure that the dampers that provide control room envelope integrity are in good condition.

Electrical and Mechanical control room boundary penetrations are inspected and maintained in accordance with the Fire Protection preventative maintenance program.

The Control Room Habitability Program ensures the Control Room Envelope (CRE) is adequately maintained. Unfiltered in-leakage testing of the CRE is performed in accordance with the Control Room Habitability Program.

Each of the Control Room Chiller Rooms has a single floor drain that is part of the Waste Liquid System (WL). The floor drains have loop seals that are designated as Auxiliary Building Cat I Vent Zone boundaries. Control Room in-leakage testing acceptance criteria can be met with the loop seals full or empty but they are kept full to provide additional Control Room Envelope in-leakage margin.

10.3.4 Auxiliary Building Special Ventilation System (Category I Ventilation Zone)

10.3.4.1 Design Basis

The Auxiliary Building Special Ventilation System conforms to the intent of Proposed IEEE Criteria for Nuclear Power Plant Protection Systems IEEE 279-68 and is designed to reliably collect significant portions of any potential containment system leakage that might bypass the Shield Building annulus, as discussed in Section 5.4.3, and to cause it to pass through charcoal filters before reaching the environment. The system is also provided to filter any leakage from systems which could recirculate primary coolant during LOCA mitigation. The filter assemblies of the auxiliary building special ventilation system and the shield building ventilation system are similar in design parameters. Table 5.3-3 and Figure 5.3-3 apply to both systems. These design parameters were originally used for equipment sizing and selection, and do not necessarily reflect operating conditions. To ensure confinement of such by-pass leakage, and its removal by the Auxiliary Building Ventilation System, the areas within the Auxiliary Building where there is the potential for such leakage are designated as a Category I Ventilation Zone. Plan and elevation views of the Auxiliary Building Category I Ventilation Zone are given in Figures 1.1-5, -6, -7, -8, -15 and -16. As shown, the Shield Buildings of Units 1 and 2 comprise partial boundaries of this zone. Some of the major systems within this zone are:

a. Residual Heat Removal System

b. Safety Injection System

c. Containment Vessel Internal Spray System

d. Component Cooling System

e. Chemical and Volume Control System

f. Waste Gas Handling System

The nature of the potential leakage paths from the Containment System to the Auxiliary Building is discussed in detail in Appendix G. From this above discussion it is apparent that the only leakage of any consequence that could by-pass the Shield Building would be from Group VI penetrations and through packings, etc., of some of the other penetration groups. Because these potential sources of leakage are minor (mostly small valves or stem packing) it is expected that leakage during a LOCA into the Auxiliary Building Special Ventilation Zone would be much less than the assumed value in the offsite dose analysis (see Section 14.9).

The entire Category I Ventilation Zone is housed within Class I structures and is designed to function reliably under the environment conditions discussed in Section 12. The system is capable of drawing a measurable vacuum in the zone within 20 minutes after initiation.

10.3.4.2 Description

The entire perimeter of the Auxiliary Building special ventilation zone is defined as a medium-leakage type barrier. Most walls, ceilings and floors are constructed of poured concrete with sealed joints where required. Doors penetrating the perimeter of the Auxiliary Building Category I Ventilation Zone are fitted and weather-stripped to minimize leakage.

The floor drains in the Auxiliary Building are part of the Waste Liquid System (WL). Various loop seals located within the Auxiliary Building are designated as Auxiliary Building Cat I Vent Zone boundaries. Auxiliary Building Special Ventilation testing has proven effective with the loop seals either empty or full.

The Auxiliary Building Special Ventilation System is provided with redundant exhaust ducts that connect redundant filter assemblies to the exhaust ductwork; electric heaters; roughing, absolute, and charcoal filters; and then to redundant exhaust fans, as shown in Figure 10.3-6 and discussed in Section 5.3.2.

The Auxiliary Building Special Ventilation System provides a sub-atmospheric pressure in, ventilation for, and fission-product removal from the Auxiliary Building Category I Ventilation Zone. The single system of trunk and branch ducting has 100% redundant roughing-particulate-charcoal filters, exhaust fans, and discharge ducting to the Shield Building's vent stacks.

The initiating signal for the Auxiliary Building Special Ventilation System is a Safety Injection Signal, described in Section 7, or a signal from the detection of high radiation in the Auxiliary Building Vent. When the Auxiliary Building Special Ventilation System is actuated, the normal supply and exhaust ducts from the Category I zone are closed automatically, and the normal supply and exhaust fans for the Auxiliary Building are tripped.

To provide continued cooling for safety features components located within the Category I zone under these conditions, small unit coolers are located throughout the Auxiliary Building to recirculate and cool the air as required. These units receive cooling water from the Class 1 Cooling Water System or from the Containment and Auxiliary Building Cooling System shown in Figure 10.3-17. Specific analyses has demonstrated that the cooling units in the SI, CS and CC Pump areas are not required to ensure component operation in an accident scenario.

10.3.4.2.1 Doors

The Category I ventilation zone is bounded by a system of single doors and pairs of doors for low traffic usage. A local audible alarm will sound if a door of the single door configuration is opened. A control room visual alarm will illuminate if a door of the single door configuration is held open for more than 30 seconds. The air lock type passage doors (pair-configuration) may be normally open one at a time. When both doors are open, an alarm sounds locally. A control room visual alarm will illuminate if both doors of the pair-configuration are held open for more than 30 seconds. All Category I zone doors are furnished with heavy duty closers. Air flow into the Category I zone due to the differential pressure assures that these doors remain closed for proper functioning of the Auxiliary Building Special Ventilation System.

10.3.4.2.2 Fans

The Category I ventilation zone exhaust fans are axial flow type, direct-connected fans of standard construction.

10.3.4.2.3 Filter Assemblies

The filter assemblies are composite units consisting of electric heating elements, roughing filters, HEPA filter section, impregnated charcoal bed filter sections. Each section is designed as follows:

a. The heating coil is designed to dry incoming air at 100% saturation by increasing the temperature of the air entering the charcoal bed. The air is then dry enough to support the charcoal adsorber iodine removal efficiency requirements. An interlock with the Category I ventilation fans is provided to assure that the electric heater is functional before the fan starts.

b. The roughing filter is designed as a standard particulate removal air filter.

c. The high-efficiency particulate filters are designed to be capable of removing 99.97 percent minimum of particulate matter, 0.3 micron or larger in size. Filter design is water and fire resistant and meets all requirements of AEC Health and Safety Bulletin 212-1965.

d. The iodine filter is an impregnated activated-charcoal bed, designed to remove 99.9 percent minimum of elemental iodine and 95% minimum of methyl iodine. These filters were sized based upon an atmosphere of 150°F, 70 percent relative humidity, a filter depth of 2 inches and a residence time of 0.25 seconds. The ignition temperature for the charcoal used is greater than 330°C.

Filter design, evaluation, reliability, and testing is the same as the Shield Building Ventilation System described in Sections 5.3.2.2.4, 5.3.2.3, and 5.3.2.4, except as noted above. Filter testing conditions, per the ventilation filter testing program (T.S.5.5.9) envelope expected worst-case operating conditions. (Reference 90)

The charcoal filters were sized based on ventilation flow requirements. This gave filters that are similar (including fission product retention capability) to those being used in the Shield Building Ventilation System described in Section 5.3.2.2.4. Since the iodine handling capability of these charcoal filters is so much greater than any possible iodine loading in this system, no further calculations are required.

Sufficient charcoal is provided to accommodate 100% of the radioiodine postulated to leak from the primary containment. This amount of leakage does not load the Auxiliary Building charcoal in excess of 10 mg/gram of elemental iodine or 3 mg/gram of organic iodine. For purposes of charcoal bed sizing, it was assumed that 10% of the total iodine would occur in organic form.

The exhaust air is discharged through the Shield Building Vent Stack which extends through the roof of the Shield Building. The Auxiliary Building Special Ventilation System flow capacity is sufficient to provide a measurable negative pressure in the Category I Ventilation Zone under the credible environmental and operating conditions. Shield walls are provided to protect personnel from radiation exposure due to contaminated charcoal filters during post accident operation of vital motor control center areas.

10.3.4.3 Performance Analysis

The leakage specification for the Category I Ventilation Zone stipulates there be no exfiltration of air from the Category I boundary with only one of the redundant trains of the Auxiliary Building Special Ventilation System in operation. Initial acceptance tests demonstrated the integrity of the Category I Ventilation Zone Perimeter, as well as the capacity of the Ventilation System. Because of the steep head versus capacity characteristic curve for the system fans, the flow is relatively unaffected by the vacuum attained, therefore vacuum has little significance in demonstrating the functional performance of Category I Ventilation Zone and the associated Auxiliary Building Special Ventilation System.

The steady state leakage with one train operating represents an inleakage of approximately 600%/day.

The significant parameter in demonstrating the performance of the Category I Ventilation Zone is the face velocity across openings in the perimeter. The industrial ventilation practice as given by the American Conference of Government Industrial Hygienists recommends a minimum face velocity of 50 ft/min for exhaust hoods. Margin has been provided for the Prairie Island Design by sizing the Auxiliary Building Special Ventilation System to produce an adequate negative pressure, so that with a door open, air flow through the opening has a minimum face velocity of 80 ft/min.

The capacity of the Auxiliary Building Special Ventilation System was increased by replacing the original 4800 cfm units with 9000 cfm fans. The modification enables the system to attain the design conditions of negative pressure within the Category I Ventilation Zone. Measured train flow was increased to range from approximately 7500 cfm to approximately 9000 cfm. Train flow is subject to the leaktightness of the building, variations in air density, etc. Such variability is expected.

10.3.4.4 Inspection and Testing

The following inspections and tests were performed to provide assurance that the functional intent of the system is achieved during the manufacture of the components and the construction of the system.

a. All ducting and filter assemblies were given a pneumatic test and leak test.

b. Each filter assembly received a filter performance test. Each HEPA and charcoal filter was tested in place to verify performance.

c. Dimensional tolerances on filter assemblies and frame assemblies were checked to assure that suitable gasket compression was uniformly achieved on the filter sealing faces.

d. Charcoal filters used Barnebey Cheney Type 727 or equivalent activated charcoal. This material was qualified by previous NRC testing. Each batch was tested by the manufacturer to assure it has removal capability equivalent to the activated charcoal that was used in the qualification testing.

e. Each charcoal bed filter was assembled at the manufacturer’s shop and given a Flow Resistance Test and a Leak Test.

f. High efficiency particulate absolute filters were randomly tested to demonstrate the filter’s ability to withstand a pressure differential of 10 inches of water without loss of filtering efficiency.

g. HEPA filter of identical design to those in the filter assemblies was subjected to a rough handling test (3/4-inch amplitude at 200 cycles/min.) following which the filter must demonstrate no loss of filtering efficiency.

A pre-operational acceptance test was performed to demonstrate the capability of the Auxiliary Building Special Ventilation System to accomplish the following functions:

a. To start both trains of redundant equipment upon initiation by a simulated normal actuation signal with coincident isolation of the normal ventilation supply and exhaust ducts for the Special Ventilation Zone.

b. To demonstrate by means of smoke tests, for each redundant train, that there is no exfiltration of air from various size openings in the Category I boundary. Further to establish a limiting size for openings and to serve as an operating limit whenever containment operability is required. NOTE: These tests were performed with a simulated dirty filter condition which would be the normal minimum flow for the system.

The acceptance test also determined the limiting total leakage area in the Category I ventilation zone which, with only one filter train and fan operating, will still obtain sufficient in leakage velocities to prevent air exfiltration from the Category I Ventilation Zone. This limiting area was established as an operating limit whenever containment operability, as defined in Technical Specification is required.

Detailed visual inspection of the filters is done during surveillance procedures for each filter. The procedures require inspecting for broken or damaged filters and improper fitting of gaskets. Dioctyl phthalate (DOP) and iodine removal efficiency testing is performed in accordance with the Technical Specifications. Filter efficiency testing is based on maximum air flow (8800 cfm) with a residence time of 0.139 seconds. Per the ventilation filter testing program (T.S.5.5.9), the HEPA filter is tested to 0.05% penetration and system bypass and the charcoal is tested to 10% penetration. Charcoal adsorber samples are laboratory tested at a face velocity of 72 fpm, 30°C [86°F], and 95% RH. (Reference 90)

10.3.5 Sampling System

10.3.5.1 Design Basis

a. Performance Requirements

This system provides samples for laboratory analysis to evaluate reactor coolant and other reactor auxiliary systems chemistry during normal operation. It has no emergency function. This system is normally isolated at the containment boundary.

Sampling system discharge flows are limited under normal and anticipated fault conditions (malfunctions or failure) to preclude any fission product releases beyond the limits of 10CFR20. Each unit has an identical sampling system and no equipment is shared between units except the drains and vents to the waste disposal system. The description contained herein is equally applicable to either unit.

b. Design Characteristics

The system is capable of obtaining reactor coolant samples during reactor operation and during cooldown when the system pressure is low and the residual heat removal loop is in operation. Access to the containment is not required.

Sampling of other process coolants, such as of tanks in the Waste Disposal System, is accomplished locally. Equipment for sampling secondary and non-radioactive fluids is separated from the equipment provided for reactor coolant samples. Leakage and drainage resulting from the sampling operations are collected and drained to tanks located in the Waste Disposal System, the Volume Control Tank and the Steam Generator Blowdown System.

Two types of samples are obtained by the system: 1) high temperature, high pressure Reactor Coolant System and steam generator blowdown samples which originate inside containment; and 2) low temperature, low pressure samples from the Chemical and Volume Control and Auxiliary Coolant Systems.

1. High Pressure - High Temperature Samples

   A sample connection is provided from each of the following:

   a. The pressurizer steam space

   b. The pressurizer liquid space

c. One hot leg

d. Blowdown from each steam generator

The omission of a sampling line for sampling the discharge from the charging pumps for Prairie Island has no safety significance. This sampling line is not included in Westinghouse standard design and is not considered to be a critical part of the sampling system.

2. Low Pressure - Low Temperature Samples

A sample connection is provided from each of the following:

a. The mixed-bed demineralizer inlet header

b. The mixed-bed demineralizer outlet header

c. The residual heat removal loop, just downstream of the heat exchangers

d. The volume control tank gas space

e. The automatic gas analyzer vent line (common to Units 1 and 2)

c. Expected Operating Temperatures

The high pressure, high temperature samples and the residual heat removal loop samples leaving the sample heat exchangers are held to a temperature of 120°F to minimize the generation of radioactive aerosols.

d. Codes and Standards

System component code requirements are given in Table 10.3-1.

10.3.5.2 Description

The Sampling System, shown in Figure 10.3-10, provides the representative samples for laboratory analysis. Analysis results provide guidance in the operation of the Reactor Coolant, Residual Heat Removal, Steam and Chemical and Volume Control Systems. Analyses show both chemical and radiochemical conditions. Typical information obtained includes reactor coolant boron and chloride concentrations, fission product radioactivity level; hydrogen, oxygen, and fission gas content; corrosion product concentration; and chemical additive concentration.

The information is used in regulating boron concentration adjustments, in evaluating fuel element integrity, mixed-bed demineralizer performance, and in regulating additions of corrosion controlling chemicals to the systems. The Sampling System is designed to be operated manually on an intermittent basis. Samples can be withdrawn under conditions ranging from full power to Mode 5, Cold Shutdown.

Reactor coolant liquid lines, which are normally inaccessible and which require frequent sampling, are sampled by means of permanently installed tubing leading to the sampling room.

Sampling System equipment is located inside the auxiliary building with most of it in the sampling room. The sample lines with remotely operated valves are located inside the reactor containment.

Reactor-coolant hot-leg liquid, pressurizer liquid, and pressurizer steam samples originating inside containment flow through separate sample lines to the sampling room. Each of these connections to the Reactor Coolant System has a remotely operated valve located close to the sample source, plus a remotely operated isolation valve immediately outside the reactor containment. Each sample line isolation valve shown on Figure 10.3-10 receives an isolation trip signal automatically following a loss-of-coolant accident. The samples pass through the containment, to the Auxiliary Building, and into the sampling room, where they are cooled (pressurizer steam samples are condensed and cooled) in the sample coolers. The sample steam pressure is reduced by manual throttling valves located in each sample line train. The sample stream is purged to the Volume Control Tank in the Chemical and Volume Control System until sufficient purge volume has passed to permit collection of a representative sample. After sufficient purging, the sample pressure vessel is isolated and then disconnected for laboratory analysis of the contents.

Alternately, liquid samples may be collected by bypassing the sample pressure vessels. After sufficient purge volume has passed to permit collection of a representative sample, a portion of the sample flow is diverted to the sample sink where the sample is collected.

The reactor coolant sample originating from the Residual Heat Removal loop is connected into the sample line coming from the hot leg at a point upstream of the sample cooler. Samples from this source can be collected either in a sample pressure vessel or at the sample sink as with hot leg samples.

Liquid samples originating at the Chemical and Volume Control System letdown line at the mixed-bed demineralizer inlet and outlet pass directly through the purge line to the volume control tank. Samples are obtained by diverting a portion of the flow to the sample sink. The sample line from the gas space of the volume control tank delivers gas samples to the volume control tank sample pressure vessel in the sampling room. Purge flow for volume control tank vapor space sample is discharged to the vent header to the waste gas compressor.

The sampling system can also be used to add lithium hydroxide to the Reactor Coolant System by directing sample flow through a sample pressure vessel. Sample flow comes from either the Chemical Volume and Control System Letdown or the Reactor Coolant System Hot Leg Loop B sampling lines. 60400000346

Samples of the steam generator liquid are obtained from the blowdown lines of each steam generator by separate sample lines. These lines are missile protected within the containment and are equipped with double shut-off valves at the sample lines take-off and remote operated isolation valves on both sides of the containment penetrations. The remotely operated valves are automatically closed upon receipt of a signal from the containment isolation system.

The blowdown sample lines are routed to the sample room where they are split into two branches: the first is cooled, pressure-reduced, and routed to the sample sink to provide periodic samples for chemical and radiochemical analyses; the second branch is routed to an automatic analysis apparatus. This automatic analysis apparatus handles a continuous flow for the continuous automatic determination of pH, conductivity, and sodium.

The sample sink, which is contained in the laboratory bench as a part of the sampling hood, has a drain line to the Waste Disposal System.

Local instrumentation is provided to permit manual control of sampling operations and to ensure that the samples are at suitable temperatures and pressures before diverting flow to the sample sink.

10.3.5.2.1 Components

A summary of principal component data is given in Table 10.3-2.

a. Sample Heat Exchangers

   Five sample heat exchangers reduce the temperature of samples from the pressurizer steam space, the pressurizer liquid space, each steam generator, and the reactor coolant to 120°F before samples reach the sample vessels and sample sink. The tube side of the heat exchangers is austenitic stainless steel.

   The inlet and outlet tube sides have Conax joints for connections to the high pressure sample lines. Connections to the component cooling water lines are screwed joints. The samples flow through the tube side, and cooling water from the component cooling system circulates through the shell side.

b. Sample Pressure Cylinders

The high-pressure sample trains, the residual heat removal loop sample train, and the volume control tank gas space sample train each contain sample pressure cylinder connections which are used to obtain liquid or gas samples. The hot leg and the residual heat removal loop sample lines have a single sample pressure vessel in common. Integral isolation valves are furnished with O-ring seal type disconnects connected to nipples extending from the valves on each end. The vessels, valves, and couplings are austenitic stainless steel.

The hot leg and letdown loop sample lines can also be used to inject lithium hydroxide into the reactor coolant system via a sample cylinder connected between the sample pressure cylinder connections. 60400000346

c. Sample Sinks

The sample sinks are located in the chemical fume hoods which are equipped with exhaust ventilators that discharge through particulate absolute and charcoal (PAC) filters. The work area around the sinks and the enclosures is large enough for sample collection and some analytical work. The sinks have raised edges to contain any spilled liquid.

d. Piping and Fittings

All liquid and gas sample lines are austenitic stainless steel tubing and are designed for high pressure service.

Socket welded joints are used throughout the sampling system within containment. The remaining sampling system lines have compression fittings. Lines are so located as to protect them from accidental damage during routine operation and maintenance.

e. Valves

Remotely operated valves are used to isolate all sample points from inside containment. Remotely operated containment isolation valves are provided in accordance with the requirements of Section 5.2.1.2.1. Manual stop valves are provided for component isolation and flow path control at all normally accessible Sampling System locations. Manual throttle valves are provided to adjust the sample flow rate as indicated on Figure 10.3-10.

Check valves prevent gross reverse flow of gas from the volume control tank into the sample sink.

All valves in the system are constructed of austenitic stainless steel or equivalent corrosion resistant material.

An isolation valve is provided, outside the containment on all sample lines leaving the containment, which trips closed upon actuation of the containment isolation signal.

10.3.5.3 Performance Analysis

Leakage of radioactive reactor coolant from this system within the containment is evaporated to the containment atmosphere and removed by the cooling coils of the Containment Air Cooling System. Leakage of radioactive material from the most likely places outside the containment is collected by placing the entire sampling station under a hood provided with a ventilation connection to the Unit 2 Auxiliary Building normal exhaust via the Sample Room PAC Filters. Liquid leakage from the valves in the hood is normally drained to the waste disposal system.

The Sampling System operates on an intermittent basis, and under administrative manual control.

To evaluate system safety, the failures or malfunctions are assumed concurrent with a loss-of-coolant accident, and the consequences analyzed. The results are presented in Table 10.3-3.

10.3.6 Emergency Lighting

Normal lighting in the control room is divided approximately equally, with the first group fed from 480V MCC 1T1 and the second group from 480V MCC 1T2. These MCC's can be fed from either Unit No. 1 or Unit No. 2 safeguards buses.

Emergency lighting in the control room is provided by strategically placed automatic standby units, each consisting of sealed-beam lamp heads, rechargeable battery and trickle charger. Lights operate instantly on loss of AC power and are extinguished when AC power is restored.

To further facilitate access to remote areas of the plant by the fire brigade, two battery powered portable handlights are provided in the fire brigade dress-out area.

Emergency lighting is provided to illuminate the areas containing equipment needed to achieve and maintain fuel in a safe and stable condition during a fire as well as the access and egress routes which must be taken to reach the necessary equipment. Hard-hats equipped with battery powered head-lamps are available and located in the Control Room and operations stations to provide supplemental emergency lighting. *604000000193

10.3.7 Spent Fuel Pool Ventilation Systems

10.3.7.1 Design Basis

The Spent Fuel Pool Special Ventilation System (SFPSVS) is designed to provide specialized ventilation of the Spent Fuel Pool area in the event that high radiation is detected. This is a safeguards system and complies to the requirements of Proposed Criteria for Nuclear Power Plant Protection Systems IEEE 279-68, as well as accepted industry standards for power plant equipment and with all applicable state and local codes and regulations. The minimum flow requirements of this system were sized to maintain a negative pressure in the Spent Fuel Pool enclosure.

The Spent Fuel Special and Containment In-Service Purge exhaust fans, see Figure 6.3-1A (Figure 6.3-1B), are used to exhaust air flow through PAC filters before exhausting out the Shield Building vent stack. This system is redundant having two complete trains, each capable of meeting the design requirements. One train exhausts through the Unit 1 Shield Building exhaust stack while the other train exhausts through the Unit 2 Shield Building Exhaust stack. This air is filtered through high efficiency and activated charcoal filters identical to the filters provided for the Shield Building ventilation (See Section 5.3.2 and Section 10.3.4.) with the exception that the temperature switch in the filter heater control circuit is bypassed.

10.3.7.2 Description

The completely enclosed Spent Fuel Pool area is normally ventilated and exhausted through roughing and HEPA filter. In the event of high radiation in the pool area, signals from radiation monitors in the normal ventilation exhaust duct isolate and shut down the normal ventilation system and initiate spent fuel pool special ventilating system. Ventilation is then accomplished via the Spent Fuel Pool Special Ventilation System which shares the exhaust portion of the Containment In-Service Purge System. The air flow is therefore directed through these redundant roughing, HEPA, and charcoal filters in this system.

Each PAC filter consists of particulate, absolute and charcoal filters. Each PAC filter is designed for 5200 cfm air flow. This system is not included in the ventilation filter testing program as the system is not credited in the radiological consequence analyses.

The Spent Fuel Pool Special Ventilation System (SFPSVS) is actuated automatically by a high radiation signal from one of the radiation monitors (R-25 for train A and R-31 for train B) located in the exhaust ducts of the system. This high radiation signal also automatically shuts down the Spent Fuel Pool Normal Ventilation System. (See Section 7.5.)

Since this system is completely redundant, either of the two trains can be tripped manually from the control room. This system is shown in Figure 6.3-1A (Figure 6.3-1B).

The SFPSVS was designed to maintain negative pressure with all SFP enclosure doors closed. Opening of these doors is acceptable for personnel use providing the doors are not blocked open.

10.3.7.3 Performance Analysis

The consequences of a fuel handling accident are discussed in Section 14.5.1. The analyses do not credit operation of the Spent Fuel Pool Special Ventilation System.

10.3.8 Emergency Communication Systems

A fixed public address system interfaced with a UPS powered Private Branch Exchange (PBX) telephone system provide normal and emergency communications. In the event of a PBX failure, extensions operating on the Xcel Energy Sherco Plant Telephone Switch could be utilized to conduct emergency communications. In addition, a sound powered communications system is installed with communications jacks located throughout the plant. The sound powered system requires no external power, and headsets for use with the system are readily available.

Due to high ambient noise in some plant areas, and the potential for fire damage to wired systems, portable wireless communications is sometimes desirable. The site radio system utilizes hand-held portable radios, mobile radios, and stationary radio consoles to facilitate two way communications between out-plant personnel and control points such as the Control Room, Central Alarm Station, or Technical Support Center. The radio transmitters and the radio system controller are UPS powered with backup transmitters located outside the plant in the Guardhouse and Microwave building.

10.3.9 Technical Support Center Air Conditioning System

10.3.9.1 Design Basis

The air conditioning systems supply air to the upper and lower level of the Administration Building Annex, which is designated as the Technical Support Center (TSC). The system is designed to provide the TSC with tempered air resulting in a room temperature between 65°F in the winter and 78°F in the summer. The temperature is maintained independent of the outside air temperature variation of -16°F to 92°F. Approximately 1000 cfm of outside air provides a supply of fresh air and pressurization air to the TSC.

10.3.9.2 Description

The TSC Air Conditioning System is shown in Figure 10.3-12.

During normal operation, outside air is mixed with return air through control dampers and is supplied to the TSC through two air handling units. Each unit consists of a filter, a cooling coil (with an air cooled condensing unit), a heating coil, and a fan. The air is returned to the air handling unit through a return fan.

During emergency operation, the normal outside air inlet will be closed and the return fan will be shut off. Fresh air will be supplied to the air handling units at the return air opening through a HVAC filter, a carbon filter, a downstream HEPA, and a fan. The air into the HVAC Cleanup Unit is a combination of outside air and return air such that the TSC will be under a positive pressure.

10.3.9.3 Performance Analysis

This system operates to satisfy the heating, cooling, and pressurization requirements of the TSC. A two-position maintained control switch (EMERGENCY/NORMAL) is provided on the TSC control panel to allow manual changeover from normal to emergency mode of operation or vice versa. The control switch is set to “Emergency” position when the TSC is activated. A portion of TSC return and outside air is diverted through the TSC cleanup unit and a constant air flow of approximately 3000 scfm is provided through the system. The TSC will be pressurized to about 1/8 inch W.C. with respect to atmosphere pressure. All outside air to the TSC passes through the cleanup unit before being conditioned and entering the room.

10.3.10 Compressed Air System

10.3.10.1 Design Basis

The primary design function of the Instrument and Station Air System is to provide both units with a continuous supply of oil-free, dry compressed air to the plant instruments and controls. The system also provides compressed air to hose stations throughout the plant for maintenance operations and oil-free compressed air to the condensate polishing (CP) system.

The Instrument Air system design and operation have been evaluated against the requirements of Generic Letter 88-14, “Instrument Air Supply System Problems Affecting Safety-Related Equipment”. The evaluation included the verification of air quality; a review of the adequacy of air system maintenance, emergency procedures and training; and a review of the system design and valve failure positions. The evaluation concluded that minor procedural and system changes would be required to fully address the Generic Letter recommendations. Those changes are described in NSP’s response to Generic Letter 88-14 (Reference 35).

10.3.10.2 Description

10.3.10.2.1 Instrument and Station Air System

The Instrument and Station Air System consists of two independent subsystems: Station Air (SA) and Instrument Air (IA). The two systems can be cross-connected. (See Figures 10.3-15 and 10.3-16.)

Valve and piping configuration is provided in the air supply systems to allow isolation of individual components for maintenance, duty rotation, and repairs.

10.3.10.2.1.1 Instrument Air System

Compressed air is supplied to the IA system by three 50% capacity water cooled, oil lubricated rotary screw compressors, each with its own oil mist eliminator, after-cooler, moisture separator and air receiver. The compressors are water cooled from either unit's cooling water system.

The IA compressors discharge to an IA header which is common to both units. The common IA header supplies a separate IA header for each unit. Each unit's IA header is provided with an air dryer and supplies instrument air to that unit's turbine building, reactor building, and auxiliary building.

The Unit 1 IA header normally supplies the screenhouse, water treatment system, the control room, and the auxiliary building common areas. A cross-tie is provided between the Unit 1 and 2 IA headers. The cross-tie is normally-closed via a motor-operated valve.

Primary control of each air compressor is from a local controller display module. The controller internal sequencing is designed to operate a group of multiple compressors feeding a common header. As air demands change, the compressors are controlled to deliver the required compressed air in an efficient manner by sequencing the compressors based on run hours and maintaining system pressure from 88 to 103 psig. The controller designates a Lead, 1st Backup and 2nd Backup, or a compressor can be manually set to run independent of the other compressors.

Operators have the ability to manually inhibit the start of a compressor through the Pull Out switch position from the control room if its safeguards bus is de-energized. This Pull Out position initiates a remote "Lockout" contact that removes control power to each of the compressors. In the event that normal control is lost or the control room is evacuated, remote/local transfer switches are provided at the compressor skids in order to maintain the ability to operate the compressors locally. The compressors are designed to start back up into manual operation after a loss of power. In manual operation the compressor maintains the new set point range of 93 to 103 psig.

10.3.10.2.1.2 Station Air System

Compressed air is supplied to the SA system by two 100% capacity air cooled rotary screw compressors.

The SA compressors discharge to an SA header which is common to both units. The SA system supplies compressed air to the turbine areas, including the louver valve assemblies and the Condensate Polishing (CP) systems for resin backwashing operations, the auxiliary building, the reactor building, the radwaste building, the resin disposal building, the chlorine house, the screenhouse, the hydrogen house, and the neutralizing tank house. Fittings are also provided to supply SA to containment; these are blind-flanged outside containment during normal operation.

The SA compressors have controllers which can communicate to determine which air compressor is the lead and which is in standby. The lead compressor starts when the SA header pressure drops to approximately 95 psig and the standby air compressors starts after a variable time delay at approximately 95 psig. The compressors can be manually set to run independent of the other compressor in manual or Auto mode, using procedurally controlled setpoints.

10.3.10.2.2 System Operation

When Instrument and Station Air Systems are separated, only two of the three IA compressors are required to supply the IA header requirements for both units, and only one of the two SA air compressors is required to supply the SA header requirements for both units. The other two compressors serve as standbys.

The SA compressors can be independently operated in manual or auto modes using procedurally controlled setpoints. The lead compressor can be manually swapped.

The SA compressors can be networked together through a digital control system and can be sequenced based on compressor run time. The IA compressors can also be networked together and can be sequenced based on run hours through a digital controller.

If required, IA may be aligned to supply SA by opening isolation valve MV-32318. The isolation valve automatically closes if IA header pressure drops below 85 psig.

If desired, SA may be aligned to supply IA by opening manual valve CP-40-7 or opening isolation valve MV-32318.

SA may be aligned to supply IA through either of two flow paths. The CP-40-7 flow path from the SA dryers to a connection on the common header upstream of the IA dryers. Air flow back through CP-40-7 to the SA system is prevented by a check valve upstream of CP-40-7. This prevents a low pressure condition on the SA system from affecting the IA system.

The second flow path through MV-32318 supplies SA to a connection on the Unit 2 IA header downstream of the IA dryers. Two pressure regulating valves (PRVs) are provided in the tie-in between the SA compressors and the SA header. The PRVs were designed to function such that SA compressors supply air to the SA header only if 1) the Condensate Polishing system air requirements are already being fully met, and 2) the three IA compressors are already being used to full capacity or are not cross connected to the SA header.

When the IA system is cross connected to the SA header through MV-32318, the PRVs operate in the following manner: PRV “B” is actuated by SA pressure and begins to close if the upstream pressure (from SA compressors) drops to approximately 80 psig. PRV “A” is actuated by SA header pressure and begins to open if the SA header pressure drops to approximately 88 psig.

If air demand exceeds the capacity of all five compressors, IA header pressure will drop below 85 psig and cause the SA header to isolate from the IA header. In this event IA compressors are dedicated to supplying instrument air, and the SA compressors are the sole source of station air. PRV “A” will remain open and PRV “B” will throttle to maintain Condensate Polishing air pressure at approximately 80 psig.

During heavy use periods, such as outages, it is possible to tie an auxiliary compressor into the system.

10.3.10.3 Performance Evaluation

The compressed air system has sufficient capacity to provide a continuous supply of instrument and station air under the most extreme plant air demands. The failure of one compressor or an air line leak are the events most likely to cause loss of instrument air. Isolation valves and standby compressors are provided to ensure isolation of cause and to maintain air supply to the undamaged portion of the system.

The IA supply to the containment is non safety-related and is isolated via solenoid-operated valves upon receipt of a signal developed by the combination of a main steam isolation signal and a containment isolation signal. In the event that the containment is isolated, air requirements inside containment are supplied by accumulators. The accumulators have sufficient capacity to enable their associated equipment to perform its function while the containment is isolated. The accumulators are kept charged by the IA system during normal operation.

10.3.11 Post Accident Sampling System

The Post Accident Sampling System (PASS) has sampling and analysis capability to promptly obtain and analyze reactor coolant samples and containment atmosphere samples. The PASS provides for a grab sample of reactor coolant for pH, dissolved hydrogen, chloride, boron and radionuclide analysis. Containment atmosphere grab samples provide measurements of containment atmosphere hydrogen and radionuclides. Provisions for ensuring samples are representative have been made. Instrumentation and analytical procedures meet the recommended ranges provided in NSPs response to NUREG-0737 Item II.B.3. Training is conducted on an annual basis.

10.3.12 D5/D6 Building and Room Ventilation Systems

10.3.12.1 Design Basis

The D5/D6 Building HVAC System, Figures 10.3-13 and 10.3-14, is designed to provide for removal of electrical equipment heat loads to maintain equipment within qualification limits and operating limits during all plant operating conditions. It also provides sufficient air flow to prevent buildup of unwanted gases.

The D5/D6 Diesel Generator Room Ventilation System is designed to limit ambient temperature within the Diesel Generator Rooms to maintain equipment ratings.

10.3.12.2 Description

The D5/D6 Building HVAC System includes the following subsystems for each diesel generator train:

a. Lube Oil Storage Tank and Fuel Oil Day Tank Rooms Exhaust System

b. Emergency Switchgear Areas Ventilation system

c. Diesel Generator Control Room and Switchgear Area Auxiliary Cooling System

d. Diesel Generator Engine Room

The HVAC System is designed to limit the D5/D6 Control Room/Excitation Room and 4KV electrical equipment areas to ambient temperatures of 104°F without supplementary cooling. The system mixes outside air with recirculated air to limit the minimum air supply temperature to 50°F. Supply air is filtered by a roughing filter.

The D5/D6 Control Room/Excitation Room and 4KV electrical equipment areas have been evaluated for ambient temperatures up to 120°F (Ref. 97).

The Control Rooms and 480V switchgear areas are provided with a direct expansion type mechanical cooling system for non-safety related auxiliary cooling. Each cooling system consists of an outdoor compressor/condenser unit, a room-mounted evaporator/fan unit, interconnecting tubing, control equipment, and power supply.

The safety-related building ventilation system includes two 100% capacity vane axial type supply fans and two 100% capacity exhaust fans per train. The fans have direct-drive totally enclosed, air over (TEAO) motors. One supply and one exhaust fan per train are normally operating, with the other fan in standby. All safety-related equipment is powered from safeguards buses.

The Lube Oil and Fuel Oil Tank Rooms are provided with exhaust fans to prevent the buildup of fumes.

The D5/D6 Diesel Generator Room Ventilation system includes the non-safety related normal mode ventilation fans, provided for human comfort; the safety-related cooling fans (one per train) which operate upon receipt of a diesel generator start signal; and the associated ductwork and controls. The diesel generator room cooling fans will function to limit the maximum ambient temperature to 120°F in conformance with equipment operating temperature ratings, and supply the volumetric flow of air necessary to cool the generator bearings. The outside air is modulated with return air to maintain a minimum temperature of 50°F in the Diesel Generator Engine Room. The diesel generator room cooling fans are vane axial type with direct-drive TEAO motors, and are supplied from safeguards buses. The ventilating equipment is accessible for periodic testing and inspection during normal operation.

10.3.13 Fuel Oil System

10.3.13.1 Design Basis

10.3.13.1.1 Function

The fuel oil system receives and stores diesel fuel oil and delivers it to the fuel oil systems of both safety and non-safety related components consisting of six diesel generators, two diesel driven cooling water pumps, one heating boiler, and a diesel driven fire pump. Since four of the diesel generators, D1/D2 and D5/D6, and the cooling water pumps are safety related components, provisions are made in the design and installation to ensure that these components will operate in the event of an abnormal or emergency condition. The fuel oil system for Unit 1 provides fuel oil for the operation of all but two safety related emergency diesel generators, D5/D6; the fuel oil system for Unit 2 provides fuel oil solely for the operational needs of emergency diesel generators D5/D6.

The fuel oil system also provides a means of transferring fuel oil between fuel oil storage tanks and a means of filtering new and transferred oil.

10.3.13.1.2 Design Minimum Storage Capacity

10.3.13.1.2.1 Unit 1

The Unit 1 design minimum required diesel fuel oil volume for a DBA is based on a 7 day diesel fuel oil volume for each emergency diesel generator (EDG), D1 and D2, and each diesel driven cooling water pump (DDCLP), 12 and 22, in accordance with Technical Specifications. The Unit 1 design minimum required diesel fuel oil volume for the maximum external flooding event, discussed in USAR Section 02, is based on a 14 day diesel fuel oil supply to operate one EDG, D1 or D2, and one DDCLP, 12 or 22, at a bounding diesel loading. (Reference 72). The 7 day and 14 day minimum fuel oil volumes are both licensing requirements; therefore, the most limiting calculated fuel oil volume will always be maintained. The onsite Unit 1 fuel oil supply is sufficient to operate one EDG and one DDCLP for longer than the time to replenish the onsite supply from outside sources.

10.3.13.1.2.2 Unit 2

The Unit 2 design minimum required diesel fuel oil volume for a DBA is based on a 7 day diesel fuel oil volume for each EDG, D5 or D6, in accordance with Technical Specifications. The Unit 2 design minimum required diesel fuel oil volume for the maximum external flooding event, discussed in USAR Section 02, is based on a 14 day diesel fuel oil supply to operate one EDG, D5 or D6, at a bounding diesel loading (Reference 73). The 7 day and 14 day minimum diesel fuel oil volumes are both licensing requirements; therefore, the most limiting calculated fuel oil volume will always be maintained. The onsite Unit 2 fuel oil supply is sufficient to operate one EDG for longer than the time to replenish the onsite supply from outside sources.

10.3.13.2 Description

10.3.13.2.1 Unit 1

Four Design Class I fuel oil storage tanks supply fuel oil to the two emergency diesel generators (EDGs) D1/D2. Each tank is equipped with a transfer pump to pump fuel from the tank to the nominal capacity 500 gallon day tank of either EDG. For the two diesel driven cooling water pumps, fuel oil supply is from two Design Class I fuel oil storage tanks. Similarly each tank is provided with a transfer pump to transfer fuel to either diesel driven cooling water pump nominal capacity 500 gallon day tank. Two non-Design Class I fuel oil storage tanks supply fuel oil to the heating boiler booster pumps and/or the D3/D4 fuel oil day tanks supply pumps. A small 4,000 gallon non-Design Class I fuel oil storage tank supplies the day tank for the diesel fire pump. Interconnecting piping, valves, and instrumentation are shown in Figure 10.3-18.

The fuel oil storage tanks are normally filled from the fuel oil transfer house through a filter. The safety related diesel generator fuel oil storage tanks are filled either from the normal fill connection or from an alternate fill connection. The diesel cooling water and diesel fire pump fuel oil storage tanks are also filled from either the normal fill connection or alternate fill connection. An alternate fill connection is provided for each of the heating boiler oil storage tanks.

Piping and valving is provided to transfer fuel oil from any one fuel oil storage tank to any other fuel oil storage tank by using the proper valve lineup. A submersible pump associated with each fuel oil storage tank pumps the fuel oil to the transfer house where the oil is then routed to the desired fuel oil storage tank. The boundary between safety and non-safety related components is provided by normally closed isolation valves. In addition, any fuel storage tank can be pumped to any diesel’s day tank by performing a special valve lineup.

10.3.13.2.2 Unit 2

The Unit 2 fuel oil system consists of a non-Design Class I fuel oil receiving tank, four Design Class I fuel oil storage tanks, four fuel oil transfer pumps, two fuel oil day tanks, one fuel oil recirculating pump, four fuel oil transfer recirculation filters, a receiving tank recirculating filter, and associated piping, valving and instrumentation. The basic drawing of the Unit 2 fuel oil system is shown in Figure 10.3-19.

The fuel oil receiving tank supplies fuel oil to the fuel oil storage tanks and the fuel oil recirculation pump. The four fuel oil storage tanks supply fuel oil to the fuel oil day tanks via the fuel oil transfer pumps. The two fuel oil day tanks each have a nominal capacity of 600 gallons.

The fuel oil receiving tank is filled from a truck fill connection. The fuel oil storage tanks are filled from the fuel oil receiving tank by gravity feed. Also, there is an emergency fuel oil storage tank fill connection located in the D5/D6 building. The emergency fill connection can be utilized in the event of flooding which could render the receiving tank fill connection inaccessible. The fuel oil day tanks can only be filled from the fuel oil storage tanks.

Piping is provided to permit the transfer of fuel oil from one storage tank to another storage tank or to the receiving tank by using the appropriate valve lineup. The transfer can be accomplished by performing a tank recirculation lineup through the fuel oil transfer recirculation filters and pumping the tank contents through the recirculation header to another tank.

The fuel oil storage tanks of each diesel generator building are located in a Seismic Category I reinforced concrete fuel oil storage vault. The fuel oil storage vaults are located below ground level. The vaults provide the required three-hour rated fire protection barrier and are designed to withstand the effects of tornado generated missiles, site flood and buoyancy force considerations. The storage vaults are provided with leak detection sumps. If a sump fills with water and/or fuel oil, an alarm will activate on the main diesel generator local control panel.

The base of the fuel oil receiving tank is located below ground level and the tank is in a concrete lined retention basin. The basin is sized to contain the tank volumetric contents, should a leak occur.

The fuel oil day tank associated with one EDG can be filled directly from the fuel oil storage tanks of the other EDG by performing a valve lineup through the receiving tank return line. However, each fuel oil day tank is dedicated to its respective EDG and cannot supply fuel oil to the other EDG directly.

10.3.13.3 Performance Analysis

10.3.13.3.1 Unit 1

There are four Design Class I fuel oil storage tanks (19,500 gallons nominal each) for the Unit 1 EDGs and two Design Class I fuel oil storage tanks (19,500 nominal gallons each) for the diesel driven cooling water pumps. The six Design Class I tanks are interconnected such that any tank can be manually aligned to supply any diesel storage tank. Therefore, any combination of the tanks will meet the 14 day fuel oil supply requirements. The 7 day fuel oil supply configuration requirements will be maintained in accordance with Technical Specifications. The Unit 1 Design Class I fuel oil storage tanks can also be refilled from either of the two non-Design Class I heating boiler fuel oil storage tanks (35,000 nominal gallons each).

10.3.13.3.2 Unit 2

There are four Unit 2 Design Class I fuel oil storage tanks (32,800 nominal gallons each). The four tanks are interconnected such that any storage tank can be manually aligned to supply either diesel day tank. Therefore, any combination of the tanks will meet the storage capacity requirements for the 14 day fuel oil supply requirements. The 7 day fuel oil supply configuration requirements will be maintained in accordance with Technical Specifications.

10.3.13.4 Testing and Inspection

Fuel oil sampling is done in accordance with the Diesel Fuel Oil Testing Program for each Design Class I fuel oil storage tank and verified by analysis that the samples are within acceptable limits. In addition, the operability of the fuel oil transfer pumps and fuel flow paths from associated storage tanks to associated days tanks are verified in accordance with the Technical Specifications.

The interconnecting capability for the 14 day fuel oil supply requirement will be tested every refueling cycle for the associated Unit. The testing will verify flow path integrity for all the various storage tank to day tank configurations.

The Diesel Fuel Oil Testing Program is credited as part of the License Renewal Fuel Oil Chemistry Aging Management Program as described in Appendix L.

10.3.13.5 Instrumentation and Control

10.3.13.5.1 Unit 1

The fuel oil storage tanks are provided with level instrumentation to indicate tank liquid level at the control room (except for the heating boiler fuel oil storage tank) and filter house. High level will actuate an alarm in the control room except for the heating boiler fuel oil storage tank.

Level switches are provided in the fuel oil day tanks for automatic makeup.

10.3.13.5.2 Unit 2

The fuel oil storage tanks are provided with level instrumentation, mounted on the diesel generator benchboard control panel and monitored by a computer. Tank high and low levels annunciate in the diesel generator control room. A separate leak detection monitoring instrument system is provided for each pair of tanks serving a single diesel generator set.

Level instrumentation is provided with each fuel oil day tank for automatic makeup.

THIS PAGE IS LEFT INTENTIONALLY BLANK

10.4 PLANT COOLING SYSTEM

10.4.1 Cooling Water System

10.4.1.1 Design Basis

The Cooling Water System has been designed to provide redundant cooling water supplies with isolation valves to auxiliary feedwater pumps, Unit 1 diesel generators, air compressors, component cooling water heat exchangers, containment fan-coil units, and the Auxiliary Building unit coolers.

The Mississippi River is the source of cooling water. The design maximum temperature for the Cooling Water System is 85°F. This value was chosen based on historical data gathered at several sites on the Mississippi River. The value is that temperature that is not expected to be exceeded more than 1% of the time. Safeguards components are operable with cooling water inlet temperature up to 95°F. Thus, it is acceptable to continue plant operation with cooling water inlet temperature up to 95°F, when external conditions (e.g., several hot, humid days) cause cooling water inlet temperature to exceed 85°F.

The system is sized to assure adequate heat removal based on highest expected cooling-water temperatures, maximum loading, and leakage allowances. The system is monitored and operated from the Control Room. Isolation valves are incorporated in all cooling water lines penetrating the containment.

Electrical power requirements for the Cooling Water System are supplied by the power sources described in Section 8.

The preferred source of water to the containment fan coil units and some Auxiliary Building unit coolers is provided by chilled water. The Cooling Water System provides an alternate source of water to these components.

10.4.1.2 Description

The Cooling Water System flow diagrams are shown on Figures 10.4-1a through 10.4-1d and 10.4-2a through 10.4-2c. The diesel cooling water pumps, vertical motor driven pump and their associated equipment are located in the Class I portion of the cooling water screenhouse and separated by a concrete wall. A ring header which is shared by Units 1 and 2 can be isolated automatically to provide two redundant independent sources of cooling water for all essential services. One-half of essential services for each Unit is supplied from each side of the isolable loop. Each side of the loop is designed to supply the needs for all essential services for both Units. Thus, failure of one side of the loop still provides for the operation of all equipment required for the safe shutdown of both Units.

Table 10.4-1 lists the nominal design flow rates of the components serviced by the cooling water system for Mode 1, Power Operation, Mode 2, Startup, Mode 3, Hot Standby, normal cooldown and slow cooldown.

Normal operation utilizes two horizontal pumps with the vertical motor-driven pump as a standby. Two vertical diesel driven pumps are provided for emergency operation. The diesel driven pumps are used whenever an engineered safety features sequence is initiated, when discharge header pressure drops below its setpoint, or on a loss of offsite power (due to loss of motor driven pumps and resultant low discharge header pressure).

The vertical motor driven pump also functions as a replacement when a diesel driven pump is taken out of service. The pump is aligned manually to the appropriate train of Unit 2 safeguards power, depending upon which diesel pump is out of service. The motor operated valves are placed in the desired position and administratively disabled.

The capacity of each motor-driven pump and each diesel driven pump is nominally 17,500 gpm. This exceeds the maximum flow required for a single pump serving one unit in hot shutdown and a second unit in the long-term post-accident condition, which is calculated to be less than 14,500 gpm (Reference 41).

As stated above, two diesel driven pumps are provided common to both Units 1 and 2. Train “A” Safety Injection signal from either unit will start 12 diesel driven pump. Train “B” Safety Injection signal from either unit will start 22 diesel driven pump. The vertical motor driven pump will also start upon any of these signals, but will trip if both diesel driven pumps operate. If a diesel driven pump fails to start, the vertical motor driven pump will continue to operate. The diesel driven pumps also start automatically on a drop in their respective cooling water discharge header pressure below 75 psig for longer than 15 seconds: low pressure in cooling water discharge header A(B) starts 12(22) diesel driven pump. Each diesel driven pump is provided with both local and control room manual controls.

Electrical control for the diesel driven cooling water pumps is installed in accordance with the separation criteria established for redundant Class IE Circuits as outlined in Section 8.7. The safeguards power supply cable to the vertical motor driven pump (from Bus 27 to the motor) is run separate from both the Unit 2 A and B safeguards trains.

Each diesel engine was factory tested which consisted of the regular run-in plus full load testing on a dynamometer for 50 hours. During the factory testing, engine operating data was recorded at periodic intervals.

A separate test of each diesel engine and its accessories and auxiliaries such as the jacket water heat exchanger, control panel and air starting package was conducted. This test consisted of a minimum of 15 cold starts, coming up to a minimum of 50% load and running for a minimum of 10 minutes after each start. Tests were also run to check the effectiveness of all protective and monitoring devices such as engine overspeed, low lube oil pressure, high jacket water temperature, etc. These tests confirmed each engine's ability to start, attain speed and carry load in 15 seconds or less.

Each diesel engine provides 1000 hp continuous at 1200 rpm and 1200 hp intermittent at 1200 rpm. The engines have the capability of attaining the rated speed and pump design horsepower within 15 seconds or less.

Fuel oil is supplied to the diesel engine from a 500 gallon day tank (one per diesel engine) by an engine driven gear-type fuel oil transfer pump which circulates the fuel oil through a filter to the engine cylinders with excess fuel oil returning to the day tank. The day tank fuel oil is normally supplied from external underground storage tanks (one 19,500 gal. tank per diesel engine) by a motor operated transfer pump. Refer to Figure 10.3-18.

A manual fuel priming pump is provided to fill the engine fuel system after maintenance has been performed on the piping or for initial filling of the system.

Compressed air is used for starting the diesel engine and is stored at approximately 250 psig in two air accumulators. An A.C. motor driven air compressor unit is used to maintain air pressure in the accumulators. A manually operated interconnecting tie is provided between the air compressors of diesel engines No. 12 and No. 22. Two solenoid valves, connected in parallel, admit air to two starter motors for cranking.

During shutdown of the diesel engine, the jacket water is warmed by two electric immersion heaters which maintain the water at 110°F minimum. The heated jacket water flows by natural circulation throughout the engine flow passages. As the heated jacket water flows through the lube oil cooler, the circulating lube oil is warmed by the jacket water.

Control power for starting and stopping the diesel engines is supplied from separate trains of safeguards 125V DC systems. 12[22] DDCLP is fed from 125V DC panel 17[18]. Panel 17[18] is fed from a manual transfer switch which can be aligned to DC panel 11[12] or 21[22].

The cooling water pumps normally are supplied with water from behind the circulating water traveling screens. An alternate source of water (Figures 10.4-3a and 10.4-3b) is provided for the vertical pumps. This alternate source of water is drawn through a Class I intake canal which communicates with the river so that if the normal intake canal became obstructed, a source of water will always be available for the pumps.

All valves in the piping that provides cooling to components required for safe shutdown including engineering safety systems are either open (manual valves), receive an “open valve” signal directly or indirectly from the Safety Injection signal (motor-operated and control valves) or are fail open valves (control valves). Valves in the header which are required to split the system are redundant and receive a “close valve” signal. These valves may also be positioned by the operator from the Control Room after resetting the safety features signal.

There are two cooling water strainers in each cooling water header. Their purpose is to remove particulate from the cooling water before it enters the cooling water header. The backwash valves on each strainer provide for the clearing of debris from the strainers to prevent loss of flow due to debris build up. The motive force for these valves is provided by the instrument air system. Air pressure maintains the valves closed and upon a loss of air pressure, the valves fail open. The potential for all backwash valves simultaneously failing open has been evaluated as acceptable by calculation ENG-ME-820 (Reference 41). Two backup compressed air systems provide additional reliability. Each backup air supply serves one strainer backwash valve on each cooling water header.

The temperature control valves on the outlet of the component cooling heat exchangers are air operated valves that are positioned by a control signal from a temperature controller. Normally, a temperature setpoint is set on the temperature controller, and the control valve is opened or closed based on a deviation from the setpoint. If air pressure or control power is lost, the valve fails to the open position. Since the air system is not safety-related, it may not be available during a design basis accident. The temperature control valve would fail to the open position. Analysis (Reference 41) has shown that this passes a disproportionate amount of cooling water flow through the component cooling heat exchangers. Additional analysis (Reference 42) was done to determine the required cooling water flow rate to support the assumed component cooling water heat exchanger heat transfer rate. From this information, a maximum valve position was determined. The valve actuator is furnished with threaded openings for use of either a minimum or maximum flow stop. The valve stop is mechanical, typically a threaded bolt with some combination of bolts and/or pins. The maximum flow stop was positioned through a Design Change (Reference 43). Analysis was performed of the capability to provide long term cooling following a LOCA with the valve stop installed. This analysis (Reference 77) concluded that under bounding conditions, adequate cooling could be provided as long as the valve stop was removed (or backed out) within the first 24 hours following the accident.

The ring supply header of the cooling water system shown in Figure 10.4-1a is normally fed by the two horizontal electrical pumps to supply normal cooling loads. A safety injection signal from one unit automatically accomplishes all of the following:

a. Starts both diesel driven pumps, causing them to supply the ring header directly.

b. Starts the vertical motor driven pump, which will trip if both diesel pumps reach operating speed.

c. Isolates the portion of the ring header between the diesel pumps by closing two normally open motor-operated valves and ensures isolation of the far side of the ring by providing closure signal to two motor-operated valves, such that the ring header is split into two independent supply paths, each supplied by a diesel-driven pump and each serving half the essential equipment in each reactor.

d. Causes the three motor-driven valves associated with each fan coil unit and the orifice bypass valves in the fan coil unit return line of each train on the affected unit to go full open. The motor valves are normally open but one can be partly closed for throttling. Other essential equipment in the affected unit is open to the cooling water supply, or is indirectly opened by the safety injection signal.

The return side of the cooling water system disposes of the water to the circulating water conduits. Each of the two discharge headers of the turbine building is provided with a 30-inch standpipe. The emergency dump connection is located physically above the normal circulating water discharge on the standpipe. In the event the normal discharge line is blocked, the cooling water level in the standpipe rises until it reaches the emergency dump connection. From there, the cooling water flows through the 24-inch dump line, outside the building, and is dumped to grade. This dump line is a passive device in that it requires no manual or automatic actuation.

The auxiliary building header is provided with an emergency dump valve to be used in the event that both dump lines in the turbine building fail. This valve is motor-operated and controlled, either locally or from the Control Room.

By proper sloping of the grade outside the turbine building, natural drainage is provided back to the intake and recirculating canals. Concrete splash blocks are provided at each Turbine Building dump line discharge.

A maximum of about 15,000 gpm is discharged from each standpipe or a total of 30,000 gpm. When the auxiliary building emergency dump valve is used, a maximum of 15,000 gpm is discharged.

The fan coil units are supplied by lines which are split outside the containment so that each unit can be individually isolated, controlled, and monitored. With all systems operating normally, the water pressure always exceeds containment pressure. A small by-pass line is provided to pressurize the space between the two fan coil outlet valves so that there is no leakage of the containment atmosphere to the environment. Outlets from the fan coil units are individually monitored for radiation to permit isolation of failed units.

Component Cooling water heat exchangers are temperature controlled. The control valves are air operated valves, which fail to the open position upon loss of air pressure or control power.

Cooling water is supplied to D-1 Diesel Generator from Loop A Cooling Water header, and D-2 Diesel Generator is supplied from Loop B. The Unit 2 diesel generators have dedicated radiator cooling systems.

Cooling water is available to the auxiliary feedwater pumps and provides the secondary source of auxiliary feedwater.

A minimum flow of cooling water is furnished to the turbine generators to prevent wiping of bearings and consequent damage during coast-down of the turbines. This source of water may be manually isolated.

The cooling water system also provides water for safeguards-related equipment such as pump oil coolers, pump gland seals, auxiliary feedwater pump room unit coolers, and the control room air-conditioning chillers. 604000000186

Because the cooling water pumps are diesel driven, water is available for all services at the time required by the equipment served. If auxiliary power is available, the normal cooling water pumps continue to operate. Only one cooling water pump is required for the safe shutdown of both units (accident in only one unit). Since the cooling water system is in operation at all times it is in a high state of readiness and available for normal or emergency types of operations.

In the event of a design basis accident, adequate flow to essential equipment is maintained. Non-essential equipment in the Turbine Building is isolated by automatic action, when necessary. Actuation circuitry will automatically close the 24″ motor operated valve that supplies the Turbine Building. Low cooling water supply header pressure coincident with an SI signal for a preset time delay will actuate the isolation logic.

In the event of a loss of offsite power, the loss of the motor driven pumps results in lowering discharge header pressure. When the low pressure setpoint is reached, the associated diesel driven pump starts and will provide adequate cooling to the associated Unit 1 diesel generator and other cooling loads. Further, the 121 vertical motor-driven cooling water pump, upgraded to a safeguards status, having an essential safeguards diesel-backed power supply provides a diverse means of providing cooling water independent of diesel-driven pumps. One diesel driven pump is sufficient to meet all the cooling system loads required for the safe shutdown of both units (accident in only one unit).

10.4.1.2.1 Auxiliary Building and Containment Chilled Water System

A common non-safety related chilled water system was added for both units 1 and 2. The system provides chilled water during normal plant operation for the containment air cooling fan coil units and the control rod drive mechanism shroud cooling coils, as well as for the new and existing unit coolers located within the auxiliary building. The chilled water system was integrated with the cooling water system. The combined system provides chilled water during normal plant operation but upon loss of power or safety signal actuation, the system will return to its original design integrity and configuration by isolating the chilled water system from the cooling water equipment. The chilled water system was refurbished and upgraded by modification 01ZX01. Changes to the system include corrosion resistant coating in the piping and a chemical feed tank.

10.4.1.2.2 Emergency Cooling Water Intake

The Emergency Cooling Water Intake provides water to maintain safe shutdown for both units after a Design Basis Earthquake. This intake is a 36-in. pipe buried approximately 40 feet below the Circulating Water Intake Canal water level in nonliquefiable soil, connecting the screenwell to a submerged intake crib in a branch channel of the Mississippi River. This Emergency Cooling Water Intake is a Class I structure as is the Approach canal which supplies its intake crib from the main channel of the Mississippi. The intake crib is designed to exclude trash, and means are provided for back flushing. This emergency intake supplies a bay in the screenwell which has Class I traveling screens and which provides suction for the Class I cooling water pumps.

To maintain both units in safe shutdown, the safeguards cooling water pumps must provide sufficient flow to remove heat from the required components. The supply to the safeguards pumps' suction must be greater than or equal to that demand. In the event of a design basis seismic event, non-seismic qualified components cannot be relied upon to maintain safe shutdown. The effect on the cooling water system is that only the safeguards pumps are available, off-site power is lost, and the instrument air system is not available. Since many control valves fail to the open position upon loss of air or control power, the flow demand in the cooling water system increases. With two safeguards cooling water pumps operating, the cooling water system demand will exceed the supply capacity of the emergency intake line (EIL).

At the onset of the seismic event, the emergency intake line and the intake canal both supply the suction of the safeguards pumps. The design basis seismic event assumes that Lock & Dam No. 3 is destroyed by the seismic event. Failure of Lock & Dam No. 3 causes the upstream and downstream pools to equalize. Over time the upstream pool level is postulated to decrease to 666′ -6″, the normal level of the downstream pool. This provides 4.5 feet of submergence above the emergency intake line. Due to discrepancies between original design calculations and pre-operational testing results regarding intake line capacity vs. head loss, a test was performed on the emergency intake line (Reference 91). The results from this test indicate that there has been some degradation since original construction. Original design calculations predicted a minimum supply capacity of 18000 gpm. However, the new test results, when extrapolated for minimum submergence, demonstrated that only 12,850 gpm is actually available. (Reference 96)

Upon occurrence of the design basis seismic event, the cooling water system flow demand is approximately 40,000 gpm (Reference 41). This is with the two diesel driven safeguards cooling water pumps operating, since this creates the highest demand on the suction supply. There is an additional 2000 gpm demand from the diesel fire pump. Initially, the supply to the safeguards cooling water pumps is from both the intake canal and the emergency intake line. The stability of the intake canal banks has been evaluated (References 54 & 55). The evaluations demonstrate that the intake canal will support the safeguards function of the cooling water system. The volume in the intake canal provides approximately 3.3 hours for a flow demand of 47,000 gpm (Reference 55).

Assuming no makeup from the river to the intake canal, the volume in the intake canal is depleted in approximately 3.3 hours. After this time, the emergency intake line will be the sole supply of water to the cooling water pumps. It is necessary for the operators to reduce the cooling water system flow demand to a value within the capacity of the emergency intake line. Procedural guidance directs the operator which cooling water system loads to secure to reduce demand. Instrumentation provides the operator with cooling water header flow and pressure. The procedure ensures components needed to maintain safe shutdown are available.

An evaluation was performed (Reference 56) comparing the minimum water volume of the Intake Canal required for operator action to the minimum water volume of the Intake Canal available post-DBE. The minimum water volume available in the Intake Canal after a DBE, for both the design basis and bounding analysis cases, is nearly twice the minimum volume required for operator action. This demonstrates a significant operating margin.

The capacity of the EIL must support the minimum equipment required for safe shutdown. As stated above, it is assumed the equipment that is not qualified to seismic criteria does not function. Therefore, off-site power is lost and the instrument air system is not available. The following is the minimum equipment for safe shutdown and the design flow rate.

1 - Unit 1 Emergency Diesel Generator	900 gpm
2 - Auxiliary Feedwater Pumps (1 per unit)	440 gpm
2 - Component Cooling Heat Exchangers (1 per unit)	3600 gpm
1 - Control Room Chiller	320 gpm
2 - Containment Fan Coil Units (1 per unit)	900 gpm
Total	6160 gpm

Taken by itself, this would be the minimum required flow capacity of the EIL. However, cooling water system loads that are not isolated from the control room must also be considered as cooling water system demand. Through operator action, this flow rate can be redistributed within the cooling water system based on the specific event.

The basic design intent for the emergency pipe was to provide enough flexibility in the system to withstand earthquakes. This was accomplished by introducing four flexonics expansion joints, two near the screenhouse and the other two in the pipe riser at the intake crib. The articulation provided by the joints is expected to act in a fashion similar to paired flexible joints in steam lines.

In order for the emergency intake pipe to behave elastically, as intended, the portion of the pipe embedded in the screenhouse was wrapped with rodoform to alleviate localized stresses due to the settlement of the soil. Special backfill material was placed around the pipe to prevent liquefaction of the soil which would result in flotation of the pipe. All natural material has been replaced by nonliquifiable backfill materials up to the liquefaction level in accordance with the recommendations of Dames & Moore in Appendix E.

The design of the 36″ emergency intake pipe and the approach canal are based upon recommendations by earthquake consultants J. A. Blume & Associates and Dames & Moore. Professor H. Bolton Seed of the University of California at Berkeley, in his letter dated June 3, 1970 to Mr. Garrison Kost of John A. Blume & Associates in San Francisco, stipulates the following minimum criteria to ensure that the emergency service water intake pipe at Prairie Island would not be disrupted by displacements due to soil liquefaction:

a. “The slope of any liquefiable material should not exceed about 1 degree.

b. The pipe line should be supported or protected against settlement or uplift due to liquefaction of the underlying soils.

c. The pipe should be located at least 25 times the height of any bank beyond the toe of the bank in order to protect it from lateral forces due to movement of liquefied soil.”

Professor Seed then proceeds to make the following specific recommendations: It will be possible to design:

a. “A section near the plant where the pipe would be placed in non-liquefiable soils.

b. A section to be stabilized against liquefaction by densification and in which the pipe would be brought up to a higher elevation, and

c. A section designed in accordance with the criteria listed above so that the pipe would not be disrupted even if the underlying and adjacent soil should liquefy.”

The design of the 36″ emergency intake pipe and the approach canal applies to the following criteria:

Near the screenhouse, where the pipe line is above the liquefiable horizon, we have removed all liquefiable material around the pipe and replaced it by non-liquefiable material.

The east-west run of the emergency intake pipe has been placed below the horizon of the liquefiable soil. Trench backfill materials are non-liquefiable up to the horizon of liquefaction.

At the intake, where the pipe line rises vertically through potentially liquefiable strata, we have provided secure anchorage of the intake crib by piling into the non-liquefiable strata. In order to protect the riser pipe itself, we have designed a considerable degree of flexibility into the riser by installing two Flexonics joints which are capable of swiveling 6° in any direction.

In accordance with the explanation and criteria set forth by Dr. Seed, lateral movements of liquefied soil layers are not expected in the intake area, nor do we expect a covering of the intake itself, because the intake crib is located in a 575 ft. wide intake canal which has been sized by applying the 25 to 1 slough angle cited by Dr. Seed. The bottom of the canal has been kept flat.

The bed of the branch channel of the Mississippi River in which the emergency intake crib is located has been backfilled to Elevation 660 in order to minimize any potential gradients which might cause a flow of liquefied materials. The slough angle of 25 to 1 has again been observed at the underwater bank which rises from Elevation 660 to Elevation 664.5.

The non-compacted, non-liquefiable backfill has been designed and specified according to recommendations by John Blume Associates, according to which the sieve analysis is:

70% passing 0.742 in. screen opening
36% - 50% passing #4 screen,
10% passing #10 screen.

The material used for the non-liquefiable backfill closely approximates that recommendation.

The profile of the Approach Canal to the emergency intake pipe is monitored periodically per surveillance testing to ensure the design function is maintained.

10.4.1.2.3 Waterhammer in FCU Piping (GL 96-06)

NRC Generic Letter 96-06 (Reference 79) identified a concern regarding the potential for waterhammer to occur in the service water (cooling water at Prairie Island) piping associated with the containment fan coil units. The specific concern in Generic Letter 96-06 related to the potential for excessive piping and piping support loads due to the formation of steam in the fan coil units and associated piping during the initial time period following an accident (LOCA, MSLB) with subsequent condensation induced water hammer during refill.

EPRI developed a methodology to evaluate the waterhammer issues identified in the generic letter (EPRI technical reports TR-113594, Volumes 1 and 2; which were subsequently renumbered as EPRI Technical Reports 1006456 and 1003098, respectively). NRC acceptance of TR-113594 along with limitations for use of the methodology are documented in the NRC Safety Evaluation Report (Reference 80).

The methods in TR-113594, Volumes 1 and 2, were applied to determine the potential waterhammer loads in the CL Piping associated with the containment fan coil units (FCUs) (References 81 and 82). This review/evaluation was performed as follows:

- Limiting system configurations were determined, paying particular attention to system alignments, single failures and component operation that could maximize the severity of the postulated waterhammer. Each of the components that could impact the severity of the event was identified with their corresponding operating times (after event initiation) initially assuming the component was operating normally. Through this review, it was confirmed that the limiting waterhammer event would be a column closure waterhammer.
- Following identification of the limiting system alignments, the limiting location of the waterhammer event was identified. It was determined that the potential existed for a column closure event in several of the FCU supply lines. A waterhammer event in the supply line would be more limiting than in a return line because a higher refill velocity would exist in the supply line due to the lower total flow resistance from the supply header to the point of void collapse.

- The closure velocity at the predicted void closure location was determined for each of the limiting configurations based on the hydraulic characteristics of the system and the pump operating curve. To maximize the refill capacity, the maximum safeguards cooling water pump curve was used (maximum is defined by upper capacity limit from the In-Service Testing pump curves).
- Based on the calculated closure velocity, the magnitude, the rise time and time duration of the waterhammer pressure pulse was determined. Due to different system configurations (based on time line, operating configurations and postulated single active failures), several different cases were considered.
- The results from the different cases were then evaluated for the effect on the piping and pipe supports. The cases were analyzed using piping model to determine the system response. In the model, the pressure pulse was characterized as a trapezoid. Piping analyses showed that the piping and supports satisfied the acceptance criteria in USAR, Section 12.

In Reference 83, the NRC documented that the staff was satisfied with the response to GL 96-06 and considers the waterhammer element of GL 96-06 closed.

10.4.1.2.4 System Functionality Following a Seismic Event

The Cooling Water (CL) System is shared between the two units and provides cooling to both safety related and non-safety related loads, as shown on Figures 10.4-1A through 10.4-2C. The single largest non-safety related supply line (one per unit), which supplies the majority of the non safety loads in the Turbine Building, can be isolated by closing a safety related motor operated valve. The isolation valve in each unit closes automatically on a safety injection signal coincident with a low-pressure condition in the safety related supply header (for post-accident response) or can be remotely closed from the Control Room. The other valves that could be used to isolate the non-safety related lines from the safety related supply headers are manual valves. During a seismic event, without a SI signal, all of the valves (both the motor operated Turbine Building isolation valves and the manual valves) would remain open unless closed by operator action.

The safety related portions of the CL system are designed to withstand a seismic event (Class I piping). Consistent with the plant design requirements (Section 12.2.1.5.2.1), portions of the non-Class I piping may be analyzed with seismic loads to support the Class I piping analysis. The other areas of the non-Class I piping are not typically analyzed for seismic loads. Therefore, following a seismic event, there will be several runs of non-Class I non-analyzed piping that remain connected to the Class I piping.

To account for the non-Class I piping that has not been analyzed for seismic loads, continued functionality of the Cooling Water system following a seismic event is demonstrated using hydraulic analysis techniques. The hydraulic analysis is performed assuming a complete failure (rupture) of a non-seismic pipe at the worst-case location. The intent of assuming a complete failure of one pipe is to bound possible cases where partial failures (cracks) may occur in multiple lines. The size of the non-seismic piping break can be reduced using stress analyses techniques of the non-Class I cooling water piping for seismic loads as discussed in Section 12.2.1.5.2.4.

The worst case may not necessarily be the largest pipe if the pressure at smaller pipe locations is significantly higher. The analysis includes evaluation of other potential break locations to ensure the worst-case location is identified. In response to a seismic event, the function of the cooling water system is to support achieving and maintaining safe shutdown. Thus, an accident is not assumed concurrent with the seismic event.

The results from the hydraulic analysis (Reference 41) show:

- Sufficient flow is provided to the Unit 1 Emergency Diesel Generators.
- Sufficient flow is provided to Diesel Driven Cooling Water Pump Auxiliaries (e.g., Jacket Water Heat Exchanger).
- Flow demand on the CL Pumps is within the pump capacity.
- Sufficient flow and pressure is available for suction to the AFW Pumps.

10.4.1.3 Performance Analysis

The cooling water system is designed to prevent a component failure from curtailing normal station operation. The system has been designed and equipment furnished to provide the highest degree of reliability and availability. The combination of redundancy, isolation and system monitoring assures that, in the event of a major failure, safe shutdown of the station is not compromised. Any equipment can be isolated without shutting down the system. Sufficient pumping capacity has been provided for two-unit operation.

The cooling water system can accommodate a passive failure such as rupture of a pipe and still perform its intended function during long-term cooling following a loss-of-coolant accident. Cooling water supply for both units branch out of the main supply header. On a safety injection signal, this single header is automatically split into two headers by closure of redundant isolation valves. Each of these two supply headers then supplies both units, and either is capable of meeting the cooling water requirements for long-term cooling of both units with an accident having occurred in one. Thus, in spite of a passive failure in one loop, the other loop is available to supply sufficient cooling water for long-term cooling.

The following components of the Cooling Water system have safeguards functions:

Containment Fan Coil Units

Component Cooling Heat Exchangers

Safeguard Traveling Water Screens

Auxiliary Feedwater Pumps (alternate suction)

Auxiliary Feedwater Pump Room Unit Coolers 604000000186

Unit 1 Emergency Diesel Generator Cooling (D1/D2)

Control Room Chillers

Safeguards Cooling Water Pumps

Safeguards Isolation Valves and Dump Valves

The preoperational tests for the cooling water system to assure its operation as required to function, following a loss-of-coolant accident, included the following.

The cooling water system was operated in its various safeguards modes with the supply valves to all components opened. Total system flows and flows to the containment fan coil units and the component cooling heat exchangers were measured, using existing flow meters, and compared to the required maximum flows. System pressures were measured across the remaining safeguards components to assure that flow is proportionally distributed under maximum flow conditions. The temperature controls which modulate the control valves for the coolers were checked when heat loads were available. System tests were performed with supply water being taken through the emergency intake line.

Safeguards modes of operation checked included:

Two pumps operating supplying water to both safeguard trains.

One pump operating supplying water to one safeguard train.

Both above modes of operations using normal return flow path and alternate safeguards return path.

The auxiliary feedwater pumps were operated using cooling water and discharging through the recirculation line. There was sufficient recirculation capacity to obtain the full required flow.

10.4.1.3.1 Auxiliary Feedwater Pump Room Cooling

The unit coolers in the Auxiliary Feedwater Pump Rooms are sized to remove the heat generated by operating equipment in order to maintain air temperatures within the design ratings of the equipment located within the rooms. Two unit coolers are installed in each Auxiliary Feedwater Pump Room. The coolers are train separated such that a single failure will not result in a complete loss of cooling in either room. Analysis demonstrates that a single unit cooler in either room is capable of maintaining acceptable room temperatures during all scenarios where the Auxiliary Feedwater Pumps are required to perform safety functions (References 30 and 31).

*60400000186

If the unit coolers in the Auxiliary Feedwater Pump Rooms degrade or malfunction, procedures are available to monitor area temperatures and, if necessary, open doors to the Turbine Building to allow for natural convective cooling through the doorways. Equipment in the Auxiliary Feedwater Pump Rooms can perform their necessary functions without an immediate need for equipment heat removal. Operating procedures and supporting analyses establish and maintain normal room temperature limits such that, should an event occur while room cooling is nonfunctional, there is sufficient time to open doors prior to exceeding the air temperature limits for the equipment located within the rooms. These limits include considerations for allowing a potential steam environment in the Turbine Building to subside following a high energy line rupture such that individuals are able transit through the Turbine Building and open doors without exposing themselves or the equipment to a harsh environment (Reference 30). Analysis demonstrates that opening the Turbine Building doors is sufficient to maintain acceptable room temperatures even in the most extreme scenario where all unit coolers are non-functional prior to and throughout an event (References 30 and 31).

10.4.1.4 Testing and Inspection

The safeguard motor driven and the two diesel driven cooling water pumps were preoperationally tested.

The pre op test functionally tested the system and its components.

For the diesel driven pumps the first portion of the test proved that each control, protective shutdown or alarm device functions properly and properly actuates its end device. Such functions as governor speed changer function, low oil pressure shutdown and/or alarm and engine coolant temperature high alarm were proven for the diesel driven pumps.

The second portion tested the ability of the diesel engines to start, accelerate to operating speed and pump its rated flow of cooling water into the plant system. This part of the test included gathering a complete set of baseline data on the diesel engine and pump after both the engine and pump reached steady state operation.

A third part of the test provided the data proving the diesel engine will:

a. Start reliably.

b. Start and reach operating conditions in the required time.

This portion of the pre-op test provided starting data from 150 starts on each diesel engine. A copy of the test and test data sheets is available to Directorate of Reactor Licensing (DRL) review.

Following a turbine trip from 100% power, the cutback in cooling water flow was measured and the cooling water system capability to supply safeguards flow determined.

10.4.2 Component Cooling System

10.4.2.1 Design Basis

The component cooling system is shown in Figures 10.4-4A through 10.4-4B and 10.4-5A through 10.4-5B. The component cooling system is designed to remove heat from major components in the Nuclear Steam Supply System under normal conditions and from all components associated with removal of reactor core decay heat under accident conditions.

The component cooling system consists of two pumps and two heat exchangers for 100% redundancy within each unit. A single active or passive failure does not impair the function of the system for post-accident operation. The Unit 1 and Unit 2 systems communicate via an expansion line connecting the surge tanks of each component cooling system.

The system design provides for detection of radioactivity entering the system from reactor coolant sources.

It is the intent of the design of the safety related actions of the Component Cooling System to meet the requirements of IEEE 279 “Standard, Nuclear Power Plant Protection System”, August 1968 [Ref. 60].

10.4.2.2 Description

The component cooling system consists of heat exchangers, pumps, surge tank, piping and the necessary valves and instrumentation. During operation component cooling water is circulated through the shell side of the component cooling water heat exchanger and then to the various system components. The temperature of the component cooling water at the outlet of the heat exchanger is normally maintained between 80°F and 105°F. A maximum temperature of 120°F is permissible for a 2 hour period. Cooling water flows through the tubeside of the component cooling water heat exchanger. The returns from the components are pumped through the component cooling water heat exchanger and circulated back to the system components. The surge tank is provided to accommodate the expansion and contraction of the component cooling water, to assure a continuous supply of component cooling water, and adequate NPSH for CC pump.

Component cooling is provided for the following heat sources:

a. Residual Heat Removal Heat Exchangers

b. Residual Heat Removal Pumps

c. Safety Injection Pumps

d. Containment Spray Pumps

e. Reactor Coolant Pumps

f. Spent Fuel Pool Heat Exchangers

g. Letdown Heat Exchanger

h. Excess Letdown Heat Exchanger

i. Seal Water Heat Exchanger

j. Boric Acid Evaporator Package

k. Primary Sample Coolers

l. Steam Generator Blowdown Sample Panel

m. Hot Chemistry Lab Chiller

n. Waste Gas Compressors

o. Waste Evaporator Package

p. Waste Gas Recombiners

Nominal design flow rates for these heat loads for various modes of operation are listed in Tables 10.4-2a and 10.4-2b.

One pump and one component cooling heat exchanger fulfill the heat removal function during normal full load operation for various components located in the auxiliary and containment buildings. During plant cooldown, two pumps and two heat exchangers are utilized to remove the residual heat. If one of the heat exchangers is not operative, only one RHR loop is effective and cooldown then is at a slower rate. Makeup water is taken from the reactor makeup tanks or demineralized water system and delivered to the component cooling surge tank.

A portion of the Unit 1 Component Cooling piping is located outside of a Class 1 structure and is susceptible to tornado generated missiles. The piping at risk includes part of the supply piping and part of the return piping for the 122 Spent Fuel Pool Heat Exchanger. To prevent Component Cooling system inventory loss during a postulated tornado event, two air operated valves (AOVs) on the supply to the heat exchanger will automatically close either on a loss of Component Cooling discharge pressure from the 122 SFP HX or on a low level in the 11 Component Cooling Surge Tank, and two check valves on the return from the heat exchanger will close on low pressure in the upstream piping.

As indicated in Figures 10.4-4A and 10.4-4B (Figures 10.4-5A and 10.4-5B), the two component cooling loops associated with one unit are interconnected downstream from the heat exchangers so as to effectively form an open loop supply header both for loads which are essential and those that are nonessential. Some of the nonessential loads are isolated by the Safety Injection signal, (e.g., Evaporators, excess letdown etc.).

A safety injection signal causes automatic closure of two valves in this loop, which splits it in three parts, effectively isolating the middle section. The isolated loads normally served by this middle section are those that are nonessential during the post-accident period. The unisolated loads served by each segment immediately downstream from each heat exchanger are the essential loads, consisting primarily of the safety injection pumps, the residual heat removal pumps and heat exchangers, containment spray pumps, reactor coolant pumps, spent fuel pit heat exchangers, and sample coolers. These loads are arranged redundantly so that each heat exchanger supplies a complete set of the engineered safety features cooled by component cooling water.

The essential loads other than the residual heat exchangers are normally valved open to the supply header, and they discharge to the suction of the component cooling pump with which they are normally associated, so that component cooling water is circulated continuously through the essential loads during normal operation. The safety injection signal causes both component cooling pumps to start, although at least one would normally be running. In addition the component cooling pumps are capable of being automatically started by a low discharge pressure signal. If a running component cooling pump fails, the low pressure switch associated with the other pump, if it is in standby, senses the loss of pressure and automatically starts the standby pump.

Each of the component cooling inlet lines to the residual heat exchangers has a normally closed remotely operated valve which is opened automatically by startup of the RHR pump upon a safety injection signal. The Unit 1 CC inlet lines to the RHR HXs will also open when the AOVs on the supply to the 122 Spent Fuel Pool Heat Exchanger auto close and two Unit 1 CC Pumps are running. If the accident sequence continues into the recirculation mode, the RHR pumps discharge to the RHR heat exchangers where the residual heat is delivered to the component cooling water flow.

To prevent one component cooling pump from overpowering the other pump during two pump operation, flow needs to be aligned to one of the spent fuel pool heat exchangers or to one RHR heat exchanger. If the Unit 1 component cooling flow to the 122 Spent Fuel Pool Heat Exchanger is automatically isolated by one or both of the supply AOVs during two pump operation, the corresponding train RHR inlet MOV will open.

In anticipation of a potentially large cooling demand during Post-Accident Conditions, the control room operator can isolate the component cooling inlet to the spent fuel pool heat exchangers or shift to the other unit’s component cooling system using remotely operated (from control room) and/or manually operated valves. Temperature alarm switches, which sense the spent fuel pool temperature, provide alarm in the main control room for high temperature in the spent fuel pool. The boric acid evaporator supply is isolated by a Safety Injection signal to MV-32120 (MV-32122) and MV-32121 (MV-32123).

The operation of the system is monitored with the following instrumentation:

a. A temperature detector in the outlet lines of the component cooling heat exchangers;

b. A pressure detector on the line between the component cooling pumps and the component cooling heat exchanger.

c. A flow indicator in the outlet lines from the component cooling heat exchangers.

d. A radiation monitor for the outlet flow from either component cooling heat exchanger and/or the system flow to the component cooling pumps suctions.

e. A level detector on the surge tank.

Design parameters for the component cooling system components are presented in Table 10.4-2.

10.4.2.2.1 Components

a. Component Cooling Heat Exchangers

Two component cooling water heat exchangers per unit are provided to cool the discharge of the component cooling water pumps before circulating the water through the system. Component cooling water flows through the shell side and cooling water flows through the tube side of the heat exchanger. The tube-tube sheet joint is rolled and the tubes are stainless steel. The shell of the heat exchanger is carbon steel.

b. Component Cooling Pumps

Two component cooling water pumps per unit are provided to circulate component cooling water. Makeup water to the system is from the component cooling surge tank. The pump casing and impeller are constructed of carbon steel and bronze respectively.

c. Component Cooling Surge Tank

One surge tank is provided per unit to provide makeup water to the component cooling water system. The makeup water is provided from either the demineralized water system or the reactor makeup water pumps. Each unit's surge tank communicates with the other via an open expansion line that serves to equalize volume and pressure in the two tanks. The tank is fabricated of pressure vessel quality steel.

d. Component Cooling Valves

The valves used in the component cooling system are constructed of carbon steel with stainless steel trim. Since the component cooling water is not normally radioactive, special valve features (such as special leakoff lines to the Waste Disposal System) to prevent leakage to the atmosphere are not provided.

Self-actuated spring loaded relief valves are provided for lines and components that could be pressurized to their design pressure by improper operation.

e. Component Cooling Piping

All component cooling system piping is carbon steel with welded joints and connections except at certain components where flanged connections are used to facilitate maintenance.

10.4.2.3 Performance Analysis

Each unit has its own component cooling system, consisting of two parallel loops that are normally interconnected. The two loops associated with each unit are isolated into independent loops upon a safety injection signal for that unit, with each loop serving a redundant set of essential equipment and each alone capable of providing the long term cooling required by this equipment following a loss-of-coolant accident.

Thus, a single active or passive failure in any component or part of one loop, including either of the valves that isolate the loops from each other, can result at most in loss of capability of that loop and the equipment which it serves. The remaining loop would still be available to provide adequate long-term cooling. This capability is demonstrated in Reference 77.

This capability to tolerate any single active or passive failure extends also to one condition of sustained component outage, the case where two units are operating with one of the four component cooling pumps unavailable. The pumps are interconnected so that either pump from either unit can be manually aligned to serve any heat exchanger, and the capability of manually switching the pumps enables the two unit system to tolerate loss of an additional pump with one pump already out of service.

The heat exchangers are not similarly interconnected, so loss or outage of a heat exchanger disables one set of essential equipment in one unit, and loss of a second heat exchanger in that unit then cannot be accommodated.

In summary, outage of a single heat exchanger can exhaust redundancy with regard to ability to meet a single failure, but outage of one pump can be tolerated in the case of two unit operation. The conditions of permissible sustained outage are accordingly limited by the Technical Specifications.

A test (References 92 & 93) was performed that demonstrated even with low water level in the surge tank there was sufficient volume of water in each of the loops for adequate component cooling until such time as the operator takes appropriate action.

Both of the redundant systems are started following a loss of coolant incident. All electrical equipment is supplied with power from engineered safeguard buses. During normal power operation, this system is in service and is in a state of readiness at all times.

Following a loss of offsite power event, the load restoration provides a permissive start signal to the component cooling pump; the low pressure switch provides the actual signal to automatically start the component cooling pump. The resulting component cooling flow to the reactor coolant pump (RCP) prevents the loss of offsite power event from progressing to a LOCA due to loss of RCP seals (see Section 4.3.3.2.3).

For continued cooling of the reactor coolant pumps and the excess letdown heat exchanger inside the containment, most of the piping, valves, and instrumentation are located outside the primary system concrete shield at an elevation well above the anticipated post-accident water level in the bottom of the containment. Outside the containment, the residual heat removal pumps, the residual heat exchangers, the spent fuel pool heat exchanger, the component cooling pumps and heat exchangers, and associated valves, piping and instrumentation can be maintained and inspected during power operation. System design provides for the replacement of one component cooling pump while the other three pumps are in service.

The system materials are, in general, carbon steel. The component cooling water contains a corrosion inhibitor to protect the carbon steel. Welded joints and connections are used except where flanged closures are employed to facilitate maintenance. The entire system is seismic Class I design. The components are designed to the codes given in Table 10.2-2. In addition the components are not subjected to any high pressures (see Table 10.4-2) or stresses; hence a rupture or failure of the system is very unlikely.

As stated in the definition of Single Failure (USAR Section 1.5), examples of passive failures in piping systems include the failure of a check valve to move to its correct position when required or leakage from failed components (such as a pump seal or valve packing). Such leakage failures are limited to 50 gpm, maximum. That is, random piping breaks are not considered credible in addition to the initiating event.

The CC system is not high energy and Appendix I type pipe breaks are not required to be considered. Current regulatory guidance (NUREG 0800, Section 3.6.2, BTP MEB 3-1, Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment, dated July 1981) would consider the system to be of moderate energy and only a limited crack would be considered for this piping. The PINGP is not committed to NUREG 0800.

With the above discussion in mind, the following describes the effects of line breaks within the CC system. Line breaks can disable one entire loop which includes one heat exchanger and the pump that is normally associated with it and which remains open to the return flow from the heat exchanger regardless of how the pumps are aligned. Thus, accommodation of a break in one loop requires that the heat exchanger of the redundant loop in that unit be available and not out of service. If the pump of the redundant loop of that unit were out of service, however, its function could be performed by manually switching over a pump from the second unit.

Should a rupture of the reactor coolant pump thermal barrier occur, high flow would result and an air operated, remotely controlled gate valve on the component cooling water outlet of the thermal barrier heat exchanger would close, isolating all thermal barrier cooling flow. Therefore, all piping from the check valve on the pump inlet to the air-operated control valve on the pump outlet would be subjected to reactor coolant system pressure and temperature. A safety valve discharging to the reactor containment sump is provided on each pump outlet line to relieve excess pressure.

Should the component cooling water become contaminated with radioactive water due to a leak in any heat exchanger tube in the Chemical and Volume Control, the Sampling, Residual Heat Removal Systems, or a leak in the cooling coil for the reactor coolant pump thermal barrier, the leak would be detected by a combination of surge tank level variations and radiation monitoring.

Should a large tube side to shell side leak develop in a residual heat exchanger, the water level in the component cooling surge tanks would rise, and the operator would be alerted by a high water alarm. The atmospheric vents on the tanks are automatically closed in the event of high radiation level at the component cooling heat exchanger outlet header. If the leaking residual heat exchanger is not isolated from the component cooling system before the inflow completely fills the surge tanks, the excess water will flow through the surge tank overflow line. This overflow line is routed to the auxiliary building waste holdup tank.

Leakage from the component cooling system can be detected by a falling level in the component cooling surge tanks. Redundant air operated valves on the Unit 1 component cooling supply to the 122 Spent Fuel Pool heat exchanger will automatically close either on a loss of Component Cooling discharge pressure from the 122 SFP HX or on low surge tank level. The rate of water level decrease and the area of the water surface in the tank permit determination of the leakage rate. The component which is leaking can be located by sequential isolation or inspection of equipment in the system. During normal operation the leaking exchanger could be left in service with leakage out of the component cooling system up to the capacity of the makeup line to the system from the Demineralized Water or Reactor Makeup systems. By manual transfer, emergency power is available for makeup pump operation.

Containment isolation valves are automatically closed on a safety injection signal. The component cooling water supply line to the excess letdown heat exchanger contains a check valve inside and a remotely operated valve outside the containment wall (the check valve is not credited for containment isolation purposes; see Tables 5.2-1 and 5.2-2). Except for the normally closed makeup line and equipment vent and drain lines, there are no direct connections between the component cooling water and other systems. Most of the equipment vent and drain lines outside the containment have manual valves which are normally closed unless the equipment is being vented or drained for maintenance or repair operations. Most of the vent lines are also capped when not in use as an additional safety feature.

Following a loss-of-coolant accident, one component cooling pump and one component cooling heat exchanger can accommodate the heat removal loads. If either a component cooling pump or component cooling heat exchanger fails, the redundant pump and the redundant heat exchanger provide 100% backup. Valves on the component cooling return lines from the safety injection, containment spray and residual heat removal pumps are normally open. Each of the component cooling inlet lines to the residual heat exchangers has a normally closed remotely operated valve. If one of the valves fails to open at initiation of long-term recirculation, the valve which does open supplies a heat exchanger with sufficient cooling capacity to remove the heat load.

If a break of a component cooling line occurs inside the containment, adequate valving is available outside the containment on the component cooling supply and return lines to isolate the leak, see Figures 10.4-4A and 10.4-4B (Figures 10.4-5A and 10.4-5B). None of the components inside the containment require component cooling water during recirculation. If a break occurs outside the containment, the leak could either be isolated and repaired, or the system could be shutdown for repairs depending on the position in the system at which the break occurred. During this period, no heat removal from the containment by the residual heat removal system is required since the fan coolers capability using cooling water exceeds decay heat generation.

Once the leak is isolated or the break has been repaired, makeup water is supplied from the plant makeup water system or by the reactor makeup system. A failure analysis of components is given in Table 10.2-4.

10.4.2.4 Inspection and Testing

Each pump was preoperationally tested during plant construction. The pumps are tested per the Technical Specifications. Preventive maintenance is performed on the pumps and driver systems at yearly intervals. Corrective maintenance is performed on the pumps and driver systems when necessary.

The preoperational test on each pump included tests to determine the suction head available and the shutoff head delivered. The pumps were initially operated for one hour and then operational data was recorded. The operational data recorded included suction head, discharge head, flow rates, pump speeds, bearing temperatures, and vibration data. The pumps performed as designed during the preoperational test.

10.4.3 Safeguards Chilled Water System

10.4.3.1 Design Basis

10.4.3.1.1 Function

The Safeguards Chilled Water System circulates chilled water to provide ambient air cooling to essential areas. These areas include the control room; safeguards switchgear (Unit 1 4160 VAC (4kV) and 480 VAC bus) rooms; the residual heat removal (RHR) pump pits; the relay room, including the old P-250 computer room; and the event monitoring (EM) equipment room. The system functions during both normal plant operations and accident conditions. Function of the system is to remove heat generated by safety related equipment and any accident condition. The system provides sufficient ventilation and cooling to maintain equipment operability. It does this by controlling temperatures within design ratings of the installed safety related systems. The system performs a safeguard function in that it cools critical equipment. It is Design Class III and QA Type I due to its support function of safety-related equipment.

60400000030 60400000186

10.4.3.2 Description

The safeguards chilled water system is a shared system between the two units. It consists of two separate, but normally cross-connected, closed 100% capacity loops, designated loop A and loop B, as shown on Figure 10.3-9. Each loop consists of a header with water chiller (two-stage centrifugal compressor, evaporator, water-cooled condenser, economizer with expansion tube), expansion tank to accommodate surge volume for temperature and volume variations, chilled water pump to supply the chilled water to air conditioning unit cooling coils and unit coolers as required, various unit coolers, and associated equipment, piping, valves instrumentation, and controls. The chilled water condenser is cooled by the cooling water system.

During normal operation, either water chiller and either chilled water pump can supply water to both headers and, thus, to all components of the system when cross-over valves are open. However, in the event of initiation of a safety injection signal these valves automatically close, splitting the two headers to form two separate loops, each header supplied by its associated chiller and pump. The signal also provides an automatic start signal to the idle water chiller unit(s) and the idle chilled water pump(s). These actions align the system to allow each loop to supply its own safeguards equipment and prevents a single failure from causing the loss of both chilled water loops. Loop A cools the equipment on electrical safeguards Train A and loop B similarly serves safeguards Train B. The cross-over valves must be manually reset at the valves to reopen.

The various areas cooled are supplied with chilled water fan coil unit coolers or air conditioners cooled by redundant loops. Constant flow valves are located in the discharge lines from each unit cooler. These valves maintain a constant loop total flow regardless of pressure difference across the valve. This eliminates the need for a pump minimum flow recirculation line. It also offers better control of the chiller outlet temperature since large changes in inlet temperature and flow are minimized.

Water flow through each unit cooler is controlled by a three-way divert valve. This valve is temperature controlled to pass through the cooler the amount of supply water flow needed to maintain the area temperature and bypass the remainder around the cooler.

The RHR pump motor unit coolers are unique in that they no longer have the three-way divert valve. Design Change 03ZH01 modified the safeguard chilled water supply to the unit coolers by removing the divert valves and associated temperature controllers, solenoid valves and bypass piping. In this configuration, the RHR pump motor coolers continually pass full flow of safeguard chilled water.

Power to the water chiller units, related chiller unit oil pumps, and the chilled water pumps is provided by the safety related 480 VAC miscellaneous auxiliaries electrical system.

A pneumatic source, compressed air, is required for the functioning of various valves throughout the safeguards chilled water system as well as the cooling water outlet control valves. Instrument air normally provides this pneumatic source. In a loss of instrument air event, the functions of the chillers are supported by a safety related backup compressed air system, provided by Design Change #97ZH02, that automatically supplies a 50 to 65 psig pneumatic source for a minimum 8 hr period. The system consists of two compressed air cylinders in parallel tied into the existing instrument air system. The system is capable of supplying a continuous pneumatic source providing the cylinders are maintained per plant operating procedures.

10.4.3.3 Performance Analysis

The ability of the safeguards chilled water system to adequately remove equipment heat from the various rooms during worst case room heat up scenarios is evaluated through analysis. Even while considering conservative equipment heat loads and removal of redundant room coolers where applicable, the various unit coolers are able to maintain acceptable room temperatures during all design basis events. Furthermore, the maximum total loading on the control room chillers is not exceeded, ensuring a well-controlled output temperature from the chillers (References 30 and 31). *60400000186

10.4.3.3.1 Single Failure Considerations

If one loop of the safeguards chilled water system were to be disabled by a single active failure during an accident scenario involving a safety injection signal, the other loop would remain available to provide cooling to at least one whole train of safeguards equipment. Thus, a loss of one loop will not result in the loss of any safety functions. 60400000030

The Control Room and the Relay Room are cooled by unit coolers from both loops of the safeguards chilled water system. The unit coolers are also electrically train separated. Analysis demonstrates that one train of cooling is sufficient to maintain acceptable area temperatures (References 30 and 31). Therefore, a single failure cannot result in unacceptable temperatures in these areas. Procedures are available to respond in the most extreme scenario of a complete loss of cooling to either of these areas. *60400000186

Malfunctions or failures which directly affect an individual cooler or a group of coolers do not necessarily adversely affect the rest of the components in that same loop. The impact of such failures would remain localized to the areas which contain the specific coolers. Such an example would be the failure of a power panel which feeds multiple unit cooler motors, disabling the ability for those unit coolers to effectively remove heat from a given area. However, this failure would not impact the heat removal capability of other unit coolers whose motors are powered from other panels. As such, malfunctions, failures, or maintenance activities which impact an individual cooler or a group of coolers do not affect the rest of the components within that same train.

If the unit coolers in a given room degrade or malfunction, procedures are available to respond on a room-by-room basis. These actions typically call for the monitoring of area temperatures, reducing unnecessary electrical heat loads if possible, and, if necessary, open doors to the Turbine Building or to other areas which may still have area cooling to allow for natural convective cooling through the doorways. Equipment in the rooms with non-nonfunctional unit coolers can still perform their necessary functions without an immediate need for equipment heat removal. Operating procedures and supporting analyses establish and maintain normal room temperatures limits such that, should an event occur while room cooling is nonfunctional, there is sufficient time to open doors prior to exceeding the air temperature limits for the equipment located within the rooms. These limits include considerations for allowing a potential steam environment in the Turbine Building to subside following a high energy line rupture such that individuals are able transit through the Turbine Building and open doors without exposing themselves or the equipment to a harsh environment (Reference 30).

The governing procedures are structured such that these actions may be employed concurrently for as many rooms as necessary. The procedures also define the conditions under which the equipment within a given area can still be relied upon even with a nonfunctional unit cooler in that area.

*604000000186

10.4.3.3.3 Seismic Adequacy

The safeguard chilled water system is Design Class III which implies that during the original design a specific detailed analysis for dynamic seismic loadings was not performed on the piping or unit cooler support system. However, it has been demonstrated that the safeguards chilled water system will maintain pressure boundary integrity during a seismic event (Reference 71).

Additional margin, normal load plus 50 percent, was built into the system piping supports. The majority of the piping is supported by rod-type hangers which will withstand the vertical seismic loading so that the piping will not fall from its supports. The piping is of a conventional and simple design. There is much previous experience and analysis with similar designs. The piping systems have been designed and erected in accordance with the piping code B31.1.0-1967. The design pressure is less than 150 psi. The normal operating temperature is expected to be less than 60°F. Therefore, the pressure stresses and temperature stresses are significantly below Code allowable stresses.

The unit coolers were purchased with seismic (operational basis earthquake) design and analyses specified. Since original construction, seismic supports have been provided for the unit coolers by Design Change Nos. 78L485 and 82Y230.

The safeguards chilled water system is supported by, and penetrates, Class I structures which are designed for the maximum postulated seismic event at Prairie Island. The Class I structure and the unit cooler support design provide confidence that the safeguards chilled water system will survive a seismic event without damage. The arrangement of the piping supports and the support provided by the unit coolers and wall penetrations do not allow for large piping movements in a seismic event. In general, the pipe routing in the rooms of concern will preclude it from being damaged through striking any adjacent equipment. Additionally, this piping arrangement essentially uncouples the piping from the building induced loads. The seismic inertial loads are minimized by this design.

Thus, a qualitative evaluation of the safeguards chilled water system concludes that the system is adequate for a seismic event. Therefore, engineering judgment provides reasonable assurance that the system would successfully withstand a seismic event.

In addition, an evaluation of system construction concluded that all piping and supports and associated equipment of the safeguards chilled water system, except for the chillers, is seismically adequate for the Prairie Island design basis earthquake to maintain its pressure boundary during and following the earthquake. Mechanical limit stops around the equipment mounting spring isolators for the chillers have been provided by Design Change #97ZH01 to limit the potential for lateral movement of the chillers during the Prairie Island design basis earthquake.

Therefore, based on the design and construction of the safeguards chilled water system piping, it is concluded that this piping would perform successfully during a seismic event.

10.4.3.4 Testing and Inspection

The safeguards chilled water system and its components are tested and inspected in accordance with the Prairie Island Nuclear Generating Plant ASME Section XI Inservice Testing Implementing Program.

10.4.3.5 Instrumentation and Control

Switches are provided in the control room to start and shut down the system remotely. Local switches are provided to operate the various pieces of rotating equipment.

The cross-over valves have local open-close push buttons. These valves close automatically on safety injection. They can only be opened by the local push buttons.

Control logic is provided to ascertain that cooling water is available and a flow path for the chilled water exists before starting the chiller unit.

THIS PAGE IS LEFT INTENTIONALLY BLANK

10.5 EQUIPMENT AND SYSTEM DECONTAMINATION

10.5.1 Design Basis

Activity outside the core could result from fission products from defective fuel elements, fission products from tramp uranium left on the cladding in small quantities during fabrication, products of n - γ or n - p reactions in the water or impurities in the water, and 98120
activated corrosion products. Fission products in the reactor coolant associated with normal plant operation and tramp uranium are generally removed with the coolant or in subsequent flushing of the system to be decontaminated. The products of water activation are not long lived and may be removed by natural decay during reactor cooldown and subsequent flushing procedures. Activated corrosion products are the primary source of the remaining activity.

The corrosion products contain radioisotopes from the reactor coolant which have been adsorbed on or have diffused into the oxide film. The oxide film, essentially magnetite (Fe_3O_4) with oxides of other metals including Cr and Ni, can be removed by chemical means presently used in industry.

Water from the primary coolant system and the spent fuel pit is the primary potential source of contamination outside of the corrosion film of the primary coolant system. The contamination could be spread by various means when access is required. Contact while working on primary system components could result in contamination of the equipment, tools and clothing of the personnel involved in the maintenance. Also, leakage from the system during operation or spillage during maintenance could contaminate the immediate areas and could contribute to the contamination of the equipment, tools, and clothing.

10.5.2 Methods of Decontamination

Surface contaminants which are found on equipment in the primary system and the spent fuel pit that are in contact with the water are removed by conventional techniques of flushing and scrubbing as required. Tools are decontaminated by flushing and scrubbing since the contaminants are generally on the surface only of non-porous materials. Personnel and their clothing are decontaminated according to the standard health physics requirements.

Those areas of the plant which are susceptible to spillage of radioactive fluids are painted with a sealant to facilitate decontamination that may be required. Generally, washing and flushing of the surfaces are sufficient to remove any radioactivity present.

The corrosion films generally are tightly adhering surface contaminants, and must be removed by chemical processes. The removal of these films is generally done with the aid of commercial vendors who provide both services and formulations. Since decontamination experience with reactors is continually being gained, specific procedures may change for each decontamination case. For corrosion films, the APAC (alkaline permanganate-diammonium citrate) treatment, or an organic acid variation of the APAC treatment is considered to be the most effective for removal. 98120

Portable components may be cleaned with a combination of chemical and ultrasonic methods if required.

10.5.3 Decontamination Facilities

Decontamination facilities on site consist of an equipment cleaning area inside containment and in the hot machine shop, a decontamination sink in the hot instrument laboratory as well as a cask decontamination pad located adjacent to the spent fuel storage pool. Fuel handling tools and other tools can be cleaned and decontaminated in the cask decontamination pad. These facilities are shared by Units 1 and 2.

In the cask decontamination pad, the outside surfaces of the shipping casks are decontaminated, as required by using water/detergent solutions and manual scrubbing to the extent required. When the outside of the casks are decontaminated, the casks may be removed with the auxiliary building crane. 98120

In the equipment cleaning areas, located in the hot machine shop and in the hot instrument small laboratories, equipment and tools can be decontaminated by using water, detergent solutions, and manual scrubbing to the extent required.

For personnel, a decontamination shower and washroom are located at Access Control. Personnel decontamination kits with instructions for their use are in the health physics station.

10.6 REFERENCES

1. Letter, L.O. Mayer to the Director of Nuclear Reactor Regulation, April 20, 1981. (18309/0486)

2. P.L. Doan, “Tornado Considerations for Nuclear Power Plant Structures,” Nuclear Safety (11) 4: 296-308, July-August, 1970.

3. Miller, D.R. and Williams, W.A., “Tornado Protection for Spent Fuel Pit”, General Electric Report APED 5696, November 1968.

4. P.L. Doan, “Tornado and Tornado Effect Considerations for Nuclear Plant Structures Including Spent Fuel Storage Pool”.

5. “Behavior of Spent Nuclear Fuel in Water Pool Storage”, BNWL-2256, September 1977.

6. deleted

7. Letter, L. Mayer (NSP) to V. Stello (NRC), “Fire Hazard Analysis Report”, March 11, 1977. (10502/3113)

8. Letter, L. Mayer (NSP) to V. Stello (NRC), “Completion of Fire Protection Review”, July 5, 1977. (10502/3574)

9. Letter, L. Mayer (NSP) to Director of NRR, “Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls, and Quality Assurance”, May 18, 1978. (15748/0785)

10. Letter, L. Mayer (NSP) to Director of NRR, “NRC Staff Evaluation of Fire Protection Program”, January 2, 1979. (15748/1445)

11. Letter, L. Mayer (NSP) to Director of NRR, “NRC Staff Evaluation of Fire Protection Program”, March 9, 1979. (15748/2018)

12. Letter, A. Schwencher (NRC) to L. Mayer (NSP), “Fire Protection Safety Evaluation Report”, September 6, 1979. (505/1405)

13. Letter, L. Mayer (NSP) to Director of NRR, “Nuclear Plant Fire Brigade Requirements”, June 22, 1978. (15748/0844)

14. Letter, L. Mayer (NSP) to Director of NRR, “Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls, and Quality Assurance”, May 2, 1979. (15749/0050)

15. Letter, A. Schwencher (NRC) to L. Mayer (NSP), “Additional Fire Protection Review”, April 21, 1980. (15760/0932)

16. Letter, R. Clark (NRC) to L. Mayer (NSP), “Additional Fire Protection Review”, December 29, 1980. (15761/1078)

17. Letter, D.M. Musolf (NSP) to Director of NRR, “Fire Protection Safe Shutdown Analysis and Compliance with Section III.G and III.O of 10CFR50, Appendix R”, June 9, 1986. (30270/1302)

18. Letter, D M Musolf (NSP) to Director of NRR, “Clarification of Information Provided in Support of Request for Exemptions from the Requirements of 10CFR50, Appendix R, Section III.G”, October 22, 1982. (18312/1621)

19. Letter, D M Musolf (NSP) to Director of NRR, “Information Related to Compliance with Safe Shutdown Requirements of 10CFR50, Appendix R and Request for Exemption from Requirements of 10CFR50, Appendix R, Section III.G.3”, December 6, 1982. (18347/0083)

20. Letter, R Clark (NRC) to D M Musolf (NSP), “Prairie Island Unit Nos. 1 and 2 Fire Protection Request for Exemption from a Requirement of Appendix R to 10 CFR Part 50, Section III.G”, February 2, 1983. (18347/1135)

21. Letter, D M Musolf (NSP) to Director of NRR, “Request for Relief from the Requirements of 10CFR50, Section 50.48(b) for Fire Areas No. 58, 59, 73 and 74”, March 11, 1983. (18347/1643)

22. Letter, R Clark (NRC) to D M Musolf (NSP), “Safety Evaluation Report on Appendix R Exemption Requests”, May 4, 1983. (18349/1242)

23. Letter, D M Musolf (NSP) to Director of NRR, “Clarifying Information in Support of Exemption Request for Fire Areas 58, 59, 73 and 74”, May 16, 1983. (18349/1382)

24. Letter, D M Musolf (NSP) to Director of NRR, “Supplementary Information to Exemption Request for Fire Areas 58, 59, 73 and 74”, September 2, 1983. (18351/0019)

25. (Not Used)

26. Letter, D M Musolf (NSP) to Director of NRR, “Exemption Request to the Requirements of Appendix R to 10 CFR 50”, January 23, 1984. (19896/0442)

27. Letter, D M Musolf (NSP) to Director of NRR, “Information in Support of Exemption Requests Submitted January 23, 1984 and Request for Exemption from the Requirements of Section III.O of Appendix R to 10 CFR Part 50”, April 5, 1984. (19896/1274)

28. Letter, D G Eisenhut (NRC) to D M Musolf (NSP), “Exemption request of January 23, 1984 - Fire Protection Schedular Requirements of 10 CFR 50.48(c) - Prairie Island Nuclear Generating Plant, Units 1 and 2”, April 26, 1984. (19896/1457)

29. Letter, J R Miller (NRC) to D M Musolf (NSP), “Exemption from the Requirements of Appendix R to 10 CFR 50, Section III.G.2 in Fire Areas 1 and 71 and Section III.O”, July 31, 1984. (19897/1354)

30. Calculation No. ENG-ME-847, "HELB Case Specific Inputs & SEA Room Heat Up" 604000000186

31. Calculation No. ENG-ME-849, "Design Basis Accident Room Heat Up Model Case Specific Inputs and Results"

32. (Not Used)

33. Letter, D M Musolf (NSP) to the Director of NRR (NRC), “Response to NRC Generic Letter 87-12, Potential for Loss of Residual Heat Removal While the Reactor Coolant System is Partially Filled”, September 17, 1987. (30408/0958)

34. Letter, D M Musolf (NSP) to the Director of NRR (NRC), “Fuel Rod Consolidation”, September 22, 1987. (30408/1024)

35. Letter, D M Musolf (NSP) to the Director of NRR (NRC), “Response to Generic Letter 88-14, Instrument Air Supply System Problems Affecting Safety-Related Equipment”, February 20, 1989. (1771/0215)

36. (Not Used)

37. Safety Evaluation No. 260, “Spent Fuel Pool Loads - Empty Fuel Handling Tools.” (1861/2140)

38. Generic Licensing Topical Report EDR-1(P)-A, “Ederer Nuclear Safety-Related Extra Safety and Monitoring (X-SAM) Cranes,” October 8, 1982.

39. “Criticality Analysis of the Prairie Island Units 1 & 2 Fresh and Spent Fuel Racks,” Westinghouse Commercial Nuclear Fuel Division, February 1993.

40. (Not Used)

41. Calculation No. ENG-ME-820, “CL Hydraulic Analysis - LOOP, LOCA, and Seismic Response.”

42. Calculation No. ENG-ME-244, Rev. 0, “CC Heat Exchanger TCV Position Range”, November 17, 1985. (3281/2019)

43. Design Change 95CL04, “CC HX TCV Travel Stops to Limit Cooling Water Flow through CC HX’s.” (3271/2245)

44. (Not Used)

45. WCAP 17400-NP, “Prairie Island Units 1 and 2 Spent Fuel Pool Criticality Safety Analysis,” Rev. 0, July, 2011.

46. WCAP-17400-P, Supplement 1, Revision 2, "Prairie Island Units 1 and 2 Spent Fuel Pool Criticality Safety Analysis Supplemental Analysis Including the Storage of IFBA Bearing Fuel," September 2017.

47. NRC letter to NSP, "Prairie Island Nuclear Generating Plant, Units 1 and 2 - Issuance of Amendment Revising Spent Fuel Pool Criticality Technical Specification (CAC NOS. MF7121 and MF7122, EPID L-2015-LLA-0002)," November 30, 2017.

48. “Prairie Island Spent Fuel Pool Dilution Analysis,” February 1997. (3265/1284)

49. Letter, K.C. Midock (Westinghouse) to T.L. Breene (NSP), “Northern States Power Company Prairie Island Units 1 & 2 Criticality Analysis F/A with Instrument Tube Removed”, June 27, 1997.

50. (Not Used)

51. (Not Used) *604000000193

52. (Not Used)

53. (Not Used)

54. Letter, J P Sorenson to NRC, “Supplement 9 to License Amendment Request dated 1/29/97 Amendment to Cooling Water System Emergency Intake Design Bases”, June 30, 1997. (3404/0387)

55. Calculation No. ENG-ME-347, Rev. 1A, Minimum Required Intake Bay Volume.

56. Calculation No. ENG-355, Rev. 1A, Intake Canal Available Water Volume Comparison Analysis. (4471/2885)

57. Service Water System Self Assessment, question AQ-3, October 30, 1995.

58. (Not Used)

59. Letter, R. Clark (NRC) to L. O. Mayer (NSP), “Safety Evaluation Report and Environmental Impact Appraised on Increasing the Spent Fuel Storage Capability”, May 13, 1981. (18309/0818)

60. IEEE Standard 279, “Proposed Criteria for Protection Systems for Nuclear Power Generating Stations,” August 1968.

61. Letter, R. Clark (NRC) to D. M. Musolf (NSP), “Safety Evaluation Report on Spent Fuel Assembly Degradation”, July 11, 1983. (18349/1865)

62. (Not Used)

63. (Not Used)

64. (Not Used) 60400000030

65. (Not Used)

66. (Not Used)

67. (Not Used)

68. (Not Used) 60400000186

69. (Not Used)

70. (Not Used)

71. Safety Evaluation No. 321 Rev. 2, “Safeguards Chilled Water System - Seismic Adequacy.” (3381/1680)

72. Calculation No. ENG-ME-020, Latest Rev., D1/D2 and DDCLP Fuel Oil Storage Capacity.

73. Calculation No. ENG-ME-066, Latest Rev., D5/D6 Fuel Oil Storage Requirements.

74. Calculation No. ENG-ME-485, Evaluation of Prairie Island Spent Fuel Pool Thermal Transients, Rev. 0B.

75. Calculation No. ENG-ME-476, Spent Fuel Pool Thermal Heat Load, Rev. 1.

76. Calculation No. ENG-ME-477, Spent Fuel Pool Time to Boiling, Rev. 2.

77. Calculation No. ENG-ME-541, Rev 1, CC Hydraulic Model Proto Power Calc. 02-002.

78. (Not Used)

79. Generic Letter 96-06, Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions, dated September 30, 1996. [3883-0599]

80. NRC Letter to NMC, Prairie Island, Electric Power Research Institute (EPRI) Topical Report TR-113594, Resolution of Generic Letter 96-06 Waterhammer Issues, Volumes 1 and 2, dated April 24, 2002. [3994-2630]

81. Calculation ENG-ME-517, Determination of Potential Waterhammer Scenarios for Generic Letter 96-06. [4115-0109]

82. Calculation ENG-ME-518, Determination of Waterhammer Loads for Generic Letter 96-06. [4115-0232]

83. NRC Letter to NMC, Prairie Island, Final Closeout of Response to Generic Letter 96-06, dated March 21, 2003. [4071-1631]

84. Calculation PI-M-002, Safeguards Chiller Room Outside Air Duct Evaluation.

85. NEI 99-03, Rev. 1, Control Room Habitability.

86. NMC Response to Generic Letter 2003-01 for Prairie Island, Control Room Habitability.

87. Calculation ENG-ME-374, Addendum 2, Tracer Gas Inleakage Testing of the Control Room, dated Feb. 23, 2005.

88. (Not Used)

*604000000193

89. (Not Used)

90. Operations Manual H39, “Ventilation Filter Testing Program (VFTP).” 60400000186

91. CHAMPS Work Order 9510143, Emergency Intake Line Flow Test.

92. Letter, G. Shibayama (PS & E) “Field Trip Report–Component Cooling System” February 12, 1973 (7202-1781).

93. Letter, D. E. Hanson and Wm. Deutsch “Notes of Field Visit Feb. 6, 7, & 8, 1973” February 14, 1973 (7202-1778).

94. (Not Used)

95. Letter, M D Wadley (NSP) to U.S. Nuclear Regulatory Commission (NRC), “Response to NRC Generic Letter 87-02, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Issue(USI) A-46”, November 20, 1995. (4109/3981)

96. ENG-ME-254, Rev. 0, Safeguards Bay Supply Capacity.

97. Calculation ENG-ME-662, Unit 2 EDG Building Maximum Outside Air Temperature Evaluation.

98. EC 21789 Unit 2 RCP Seal Replacement Modification

99. EC 21790 Unit 1 RCP Seal Replacement Modification

100. Letter, J.P. Sorensen (NSPM) to NRC Document Control Desk, "License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors", dated September 28, 2012

101. Letter, J.E. Lynch (NSPM) to NRC Document Control Desk, "Supplement to License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors - Submittal of Internal Flooding Peer Review Results and Revised Total Plant Risk Values", dated November 8, 2012 *60400000193

102. Letter, J.E. Lynch (NSPM) to NRC Document Control Desk, "Supplement to License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors - Response to Acceptance Review Questions", dated December 18, 2012

103. Letter, J.E. Lynch (NSPM) to NRC Document Control Desk, “Commitment to Submit a Supplement to the PINGP NFPA 805 License Amendment Request”, dated May 3, 2013

104. Letter, J.E. Lynch (NSPM) to NRC Document Control Desk, “NFPA 805 License Amendment Request- Milestone Schedule for Submittal of Supplement” dated October 17, 2013

105. Letter, S. Sharp (NSPM) to NRC Document Control Desk, "Supplement to License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors", dated April 30, 2014

106. Letter, K. Davison (NSPM) to NRC Document Control Desk, "License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors - Response to Request for Additional Information", dated May 28, 2015

107. Letter, K. Davison (NSPM) to NRC Document Control Desk, "License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors - Response to Request for Additional Information - 90-Day Responses", dated June 19, 2015

108. Letter, K. Davison (NSPM) to NRC Document Control Desk, "License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors - Response to Request for Additional Information (Fire Modeling - Second Round)", dated October 6, 2015

109. Letter, K. Davison (NSPM) to NRC Document Control Desk, "License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors - Response to Final Request for Additional Information (PRA - Second Round)", dated October 22, 2015

110. Letter, K. Davison (NSPM) to NRC Document Control Desk, "License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors - Response to Request for Additional Information", dated January 20, 2016

111. Letter, S. Northard (NSPM) to NRC Document Control Desk, "License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors - Response to Request for Additional Information", dated May 24, 2016

112. Letter, S. Northard (NSPM) to NRC Document Control Desk, "License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors - Response to Request for Additional Information", dated August 17, 2016

113. Letter, S. Northard (NSPM) to NRC Document Control Desk, "License Amendment Request to Adopt NFPA 805 Performance-Based Standard for Fire Protection for Light Water Reactors - Response to Request for Additional Information", dated December 14, 2016

*604000000193

114. Letter, S. Northard (NSPM) to NRC Document Control Desk, “License Amendment Request to Adopt NFPA 805 Performance Based Standard for Fire Protection for Light Water Reactors - Response to Request for Additional Information", dated March 6, 2017

115. Letter, Kuntz, Robert, U.S. Nuclear Regulatory Commission, to Northard, Scott D., Northern States Power Company - Minnesota, "Prairie Island Nuclear Generating Plant, Units 1 and 2 - Issuance Of Amendments Re: Transition To NFPA-805 "Performance-Based Standard For Fire Protection For Light Water Reactor Electric Generating Plants", dated August 8, 2017 *604000000193

116. ENG-ME-849, Design Basis Accident Room Heat Up Model Case Specific Inputs and Results. 604000000030

117. Calculation No. ENG-ME-532, Spent Fuel Pool and Reactor Cavity Times to Boiling. 604000000342

THIS PAGE IS LEFT INTENTIONALLY BLANK

TABLE 10.2-1 FUEL HANDLING DATA

New Fuel Storage Pit		
Fuel assemblies storage capacity	74	
Center-to-center spacing of assemblies, in.	21	
Maximum k_{eff} with unborated water	0.95	
Maximum k_{eff} with low density optimum moderation	0.98	
Spent Fuel Storage Pool		
Fuel assemblies storage capacity	1582*	
Number of space accommodations for spent fuel shipping cask	1	
Center-to-center spacing of assemblies, in.	9.5	
Maximum k_{eff} under normal operating conditions	0.95	
Maximum k_{eff} with unborated water	<1.0	
Miscellaneous Details		
Width of fuel transfer canal, ft.	4	
Wall thickness for spent fuel storage pit, ft.	4-6	
Weight of fuel assembly with RCC (dry), lb.	1404	00-286
Capacity of refueling water storage tank, each gal.	298,000	
Quantity of water required for refueling, gal.	275,000	

* With the four storage racks in the southeast corner of pool #1 removed, a total of 1386 storage locations are provided.

TABLE 10.2-2 REACTOR AUXILIARY AND PLANT COOLING SYSTEMS CODE REQUIREMENTS

Component cooling heat exchangers	ASME III* Class C
Component cooling surge tank	ASME III, Class C
Component cooling system piping and valves	USAS*** B31.1
Residual heat exchangers	ASME III, Class C tube side ASME VIII** shell side
Residual heat removal system piping and valves	USAS B31.1
Spent fuel pool filter	ASME III, Class C (121) ASME VIII (122 & 123) 00-279
121 Spent fuel pool heat exchanger	ASME III, Class C tube side ASME VIII, shell side
122 spent fuel pool heat exchanger	ASME III, Class 3 (shell and tube side)
Spent fuel pool demineralizer	ASME III, Class C
Spent fuel pool cooling system piping and valves	USAS B31.1

* ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels

** ASME VIII - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section VIII

*** USAS B31.1 - Code for Pressure Piping, and special nuclear cases where applicable.

TABLE 10.2-3 SPENT FUEL POOL COOLING SYSTEM COMPONENT DATA

Page 1 of 4

Pool Heat Load used in Evaluation of System Capability (Btu/hr)	
Normal (1362 normally discharged fuel assemblies)	16.72×10^6 01227119
Maximum (1362 normally discharged fuel assemblies plus 1 freshly offloaded core of 121 fuel assemblies)	30.54×10^6
121 Spent fuel pool heat exchanger	
Quantity	1*
Type	Shell and U-tube horizontal
Design heat transfer rate, Btu/hr	25.09×10^6
Shell side (component cooling water)	
Design Inlet temperature, °F	95
Design Outlet temperature, °F	121.6
Design flow rate, lb/hr	0.9×10^6
Design pressure, psig	150
Design temperature, °F	200
Material	Carbon steel
Tube side (spent fuel pool water)	
Design Inlet temperature, °F	171.2
Design Outlet temperature, °F	134.4
Design flow rate, lb/hr	0.6506×10^6
Design pressure, psig	150
Design temperature, °F	200
Material	Stainless steel

* Shared by unit 1 and unit 2

TABLE 10.2-3 SPENT FUEL POOL COOLING SYSTEM COMPONENT DATA

122 Spent fuel pool heat exchanger	
Quantity	1*
Type	Shell and U-tube, horizontal
Design heat transfer rate, Btu/hr	25.09×10^6
Shell side (component cooling water)	
Design Inlet temperature, °F	95.0
Design Outlet temperature, °F	124.1°
Design flow rate, lb/hr	0.9×10^6
Design pressure, psig	150
Design temperature, °F	200
Material	Carbon Steel
Tube side (spent fuel pool water)	
Design Inlet temperature, °F	171.2
Design Outlet temperature, °F	138.5
Design flow rate, lb/hr	0.8×10^6
Design pressure, psig	150
Design temperature, °F	200
Material	Stainless Steel
Spent Fuel Pool Pump	
Quantity	2*
Type	Horizontal centrifugal
Design flow rate, gpm	1300
Total developed head, ft H_2O	150
Motor horsepower	60
Design pressure, psig	150
Design temperature, °F	200
Material	Stainless steel

TABLE 10.2-3 SPENT FUEL POOL COOLING SYSTEM COMPONENT DATA

Spent Fuel Pool Filters	
Quantity	3*
Type	Replacement cartridge
Internal design pressure of housing, psig	200 (121), 150 (122 & 123)
Design temperature, °F	250
Design flow rate, gpm	60
Maximum differential pressure across filter element at rated flow (clean cartridge), psi	5
Spent Fuel Pool Demineralizer	
Quantity	1*
Type	Flushable
Design pressure, psig	200
Design temperature, °F	250
Design flow rate, gpm	60
Resin volume, cu. ft.	20
Vessel volume, cu. ft.	27
Spent Fuel Pool Skimmers	
Quantity	2*
Design flow rate (each), gpm	50
Vertical fluctuation range:	
Floating, inch	4
Manual adjustment, feet	2
Spent Fuel Pool Skimmer Strainer	
Quantity	1*
Type	Basket
Design flow rate, gpm	100
Design pressure, psig	50
Design temperature, °F	200
Perforation, inch	1/8

TABLE 10.2-3 SPENT FUEL POOL COOLING SYSTEM COMPONENT DATA

Spent Fuel Pool Skimmer Filter	
Quantity	1*
Type	Replacement cartridge
Internal design pressure, psig	200
Design temperature, °F	250
Design flow rate, gpm	100
Spent Fuel Pool Skimmer Pump	
Quantity	1*
Type	Horizontal centrifugal
Design flow rate, gpm	100
Total developed head, ft H_2O	50
Design pressure, psig	150
Design temperature, °F	200
Material	Stainless steel
Spent Fuel Pool Cooling System Piping and Valves	
Design pressure, psig	150
Design temperature, °F	200
Spent Fuel Pool Skimmer System Piping and Valves	
Design pressure, psig	150
Design temperature, °F	200

* Shared by unit 1 and unit 2

TABLE 10.2-4 FAILURE ANALYSIS OF COMPONENTS

	Components	Malfunction	Comments and Consequences
1.	Component cooling water pumps	Rupture of a pump casing	The casing is designed for 150 psi and 200°F which exceeds maximum operating conditions. Pump is inspectable and protected against missiles. Rupture due to missiles is not considered credible. Each unit is isolable. The second unit can carry the total emergency heat load.
2.	Component cooling water pumps	Pump fails to start	One operating pump supplies sufficient water for emergency cooling.
3.	Component cooling water exchanger	Tube or shell rupture	Rupture is considered improbable because of low operating pressures. Each unit is isolable. The standby unit can carry total emergency heat load.
4.	Residual heat removal pumps	Rupture of a pump casing	The casing and shell are designed for 600 psi and 400°F. The pump is protected from overpressurization by two normally closed valves in the pump suction line and by an open relief line, containing a relief valve, back to the pressurizer relief tank. The pump is inspectable and is located in the auxiliary building protected against credible missiles. Rupture is considered unlikely but in any event the pump can be isolated.
5.	Residual heat removal pump	Pump fails to start	The redundant train of cooling is available to remove decay heat for shutdown cooling and ECCS functions. If the Unit is attempting to cool down, the alternate train will be dedicated to the ECCS safety function. In such a failure, the cooldown would be halted and the Unit would rely on decay heat removal via the steam generators until repairs could be made. 01551325

TABLE 10.2-4 FAILURE ANALYSIS OF COMPONENTS

	Components	Malfunction	Comments and Consequences
6.	Remote operated valves inside containment in the residual heat removal pump suction lines	Valve fails to open in one of the suction lines	One suction path is adequate for plant cooldown, however, the time required to cooldown may increase slightly.
7.	Remote operated valves inside containment on the residual heat removal pump discharge line	Valve fails to open	Injection of Residual Heat Removal System discharge through the safety injection nozzles in response to a LOCA is classified as an emergency condition and is assumed to occur only once during reactor lifetime. When the Residual Heat Removal System is placed into operation for cooldown from 350°F, pump discharge pressure instrumentation would show pump shutoff head indicating no flow if the normal loop return valve is closed. The low head safety injection line valves may be opened and utilized to direct flow through the nozzles provided a reactor coolant pump is in operation. The most extreme condition on the nozzles in this case is when a minimum of water temperature of 290°F contacts the nozzles at a maximum temperature of 350°F. Due to the low temperature of the nozzles, the small change in temperature and the classification of the occurrences, no thermal stress analysis is necessary.
8.	Residual heat exchanger	Tube or shell rupture	Rupture is considered unlikely, but in any event the faulty heat exchanger may be isolated.
9.	Spent fuel pool pumps	Rupture of a pump casing	The casing and shell are designed for 150 psi and 200°F which exceeds maximum operating conditions. The pump is inspectable and is located in the auxiliary building protected against credible accidents. Rupture is considered unlikely; however, pump can be isolated.

TABLE 10.2-4 FAILURE ANALYSIS OF COMPONENTS

Components	Malfunction	Comments and Consequences
10. Spent fuel pool pumps	Pump stops running and cannot be re-started	Pool temperature does not exceed 200°F. See Section 10.2.2.3 for details
11. Spent fuel pool pump	Suction strainer plugs	There is sufficient time to stop the pumps and clean the strainer before the spent fuel pool temperature becomes too high.
12. Spent fuel pool skimmer pump	Pump stops running and cannot be restarted	Spent fuel assemblies continue to be cooled by spent fuel pool pump. Surface of pool may become slightly murky possibly decreasing visual observations until pump is restored to service. Spent fuel pool water is clarified by passing spent fuel pool water through spent fuel pool demineralizer.

TABLE 10.2-5 CHEMICAL AND VOLUME CONTROL SYSTEM CODE REQUIREMENTS

Regenerative heat exchanger	ASME III*, Class C
Letdown heat exchanger	ASME III, Class C ASME VIII, shell side
Mixed bed demineralizers	ASME III, Class C
Reactor coolant filter	ASME III, Class C
Volume control tank	ASME III, Class C
Seal water heat exchanger	ASME III, Class C, tube side ASME VIII, shell side
Excess letdown heat exchanger	ASME III, Class C, tube side ASME VIII, shell side
Chemical mixing tank	No code stamp
Deborating demineralizers	ASME III, Class C
Cation bed demineralizer	ASME III, Class C
Seal water injection filters	ASME III, Class C
Holdup tanks	API*** - 620
Boric acid filter	ASME III, Class C
Evaporator condensate demineralizers	ASME III, Class C
Concentrates filter	ASME III, Class C

* ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

*** American Petroleum Institute Code.

TABLE 10.2-5 CHEMICAL AND VOLUME CONTROL SYSTEM CODE REQUIREMENTS

Evaporator feed ion exchanger	ASME III, Class C
Ion exchanger filter	ASME III, Class C
Condensate filter	ASME III, Class C
Chg Pmp Pulse Dampener	ASME VIII
Chg Pmp suction Stabilizer	ASME III, Class C
Piping and valves	USAS B31.1**

86412 86003

** USAS B31.1 - Code for Pressure Piping and special nuclear cases where applicable.

TABLE 10.2-6 PRINCIPAL COMPONENT DATA SUMMARY

	Quantity[1]	**Heat Transfer Btu/hr**	**Letdown Flow lb/hr**	**Letdown ΔT °F**	**Design Pressure psig**	**Design Temperature °F**
Heat Exchangers					Shell/tube	Shell/tube
Regenerative	1	5.46x10^6	19,760	254.5	2485/2735	650/650
Letdown	1	10.2x10^6	19,760	166.4	150/600	200/400
Seal water	1	1.19x10^6	79,940	16	150/150	250/200
Excess letdown	1	4.6x10^6	12,350	349	150/2485	200/650

	Quantity[1]	**Type**	**Nominal Capacity Each gpm**	**Head ft**	**Design Pressure psig**	**Design Temperature °F**
Pumps						
Charging	3	Pos. displ.	60.5	2385psi	3000	200
Boric acid transfer	2	Centrifugal	40	235	150	250
Holdup tank recirc.	1*	Centrifugal	500	100	150	200
Reactor makeup water	4**	Centrifugal	80	192	150	125
Monitor tank	2*	Centrifugal	100	150	150	200
Concentrates holding tank transfer	2*	Centrifugal	40	150	150	200
Gas stripper feed	3*	Canned and Centrifugal	15	250	150	200

01257699

TABLE 10.2-6 PRINCIPAL COMPONENT DATA SUMMARY

Page 2 of 2

	Quantity[1]	Type	Volume, Each Gal.	Design Pressure psig	Design Temperature °F
Tanks					
Volume Control	1	Vertical	200 ft^3	75Int/15Ext	200
Boric acid	3*	Vertical	5000	Atmos.	250
Chemical mixing	1	Vertical	5.0	150	200
Batching	1*	Jacket	800	Atmos.	250
Holdup	3*	Vertical	8800 ft^3	14	200
Reactor makeup water	4**	Vertical	46000	Atmos.	125
Concentrates holding	1*	Vertical	2000	Atmos.	250
Monitor	3*	Vertical	10,000	Atmos.	150
Chg Pump Pulse Dampener	3	Horizontal	5.0	2735	200
Chg Pump Suct. Stabilizer	3	Vertical	5.0	150	200

	Quantity[1]	Type	Resin Volume ft^3	Flow gpm	Design Pressure psig	Design Temperature °F
Demineralizers						
Mixed bed	2	Flushable	30	80	200	250
Cation bed	1	Flushable	12	40	200	250
Evaporator feed ion exchanger	4*	Flushable	20	15	200	250
Evaporating condensate	2*	Fixed	20	40	200	250
Deborating	2	Fixed	30	40	200	250

[1] Quantity per unit unless otherwise specified shared or capable of being shared by Unit 1 and Unit 2; items not marked are duplicated for each unit.

* Share Component Plant Total #

** Two per unit

TABLE 10.2-7 CHEMICAL AND VOLUME CONTROL SYSTEM PERFORMANCE REQUIREMENTS*

Original Plant design life, years	40	
Seal water supply flow rate, normal, gpm	16	
Seal water return flow rate, normal, gpm	5	
Normal letdown flow rate, gpm	40	
High flow letdown (purification) flow rate, gpm	80	
Normal total charging pump flow, gpm	46	
Normal charging line flow, gpm	30	
Maximum rate of boration with one boric acid transfer pump and one charging pump, ppm/min (EOL)	6.4	64 pcm**/min
Equivalent cooldown rate to above rate of boration, °F/min	1.5	
Maximum rate of boron dilution at refueling (two charging pumps), ppm/min	4.9	49 pcm**/min
Two-pump rate of boration (at EOL), using refueling water, ppm/min	6.0	60 pcm**/min
Equivalent cooldown rate to above rate of boration, °F/min	1.4	
Design temperature of reactor coolant entering system at full power, °F	544.5	
Design temperature of coolant return to Reactor Coolant System at full power, °F	487.6	
Normal coolant discharge temperature to holdup tanks, °F	127.0	
Amount of 12% boric acid solution required (per unit) to meet cold shutdown requirements shortly after full power operating, approximate gallons (including consideration for one stuck rod)	3150***	

60400000185

* All volumetric flow rates in gpm are based on 127°F and 15 psig

** 1 pcm = 10^{-5} $\Delta k/k$

*** 3150 gallons is a bounding value. Each cycle's core design may have a lower required volume.

60400000335

TABLE 10.2-8 MALFUNCTION ANALYSIS OF CHEMICAL AND VOLUME CONTROL SYSTEM

	Component	Failure	Comments and Considerations
1)	Letdown line	Rupture in the line inside the reactor containment	The remote air-operated valves located near the main coolant loop are closed on low pressurizer level to prevent supplementary loss of coolant through the letdown line rupture. The containment isolation valve in the letdown line outside the reactor containment and also the orifice block valves are automatically closed by the containment isolation signal initiated by the concurrent loss-of-coolant accident. The closure of the isolation valve outside the reactor containment prevents any leakage of the reactor containment atmosphere to the outside atmosphere.
2)	Charging line	See above	The check valve located near the main coolant loop will prevent supplementary loss of coolant through the line rupture. The remote operated control valve with its bypass line check can also be used to isolate the reactor coolant system from the rupture. The check valve located at the boundary of the reactor containment would prevent any leakage of the reactor containment atmosphere outside the reactor containment. Should the check valve leak, any leakage would be collected in the closed system outside of containment which serves as a secondary containment boundary.

00043

TABLE 10.2-8 MALFUNCTION ANALYSIS OF CHEMICAL AND VOLUME CONTROL SYSTEM

	Component	Failure	Comments and Considerations
3)	Seal water	See above	The motor-operated isolation valves return line located inside and outside of the containment are manually closed or are automatically closed by the containment isolation signal initiated by the concurrent loss-of-coolant accident. The closure of the inside valve would normally isolate the rupture from the outside atmosphere. Should the inside valve fail or the rupture be located between the inside valve and the containment wall, the outside valve would prevent any leakage of the reactor containment atmosphere outside the reactor containment.

00043

TABLE 10.2-9 RESIDUAL HEAT REMOVAL SYSTEM COMPONENT DATA
Page 1 of 2

Reactor coolant temperature at startup of residual heat removal, °F	350
Time to cool reactor coolant system from 350°F to 140°F, hr (all equipment operational)	20
Decay heat generation at 20 hrs after shutdown condition Btu/hr	32.94×10^4
H_3B0_3 concentration in refueling water storage tanks, ppm boron	2600-3500 01-091
Residual heat removal pumps	
Quantity (per unit)	2
Type	Vertical centrifugal
Design flow rate (each), gpm	2000
Total developed head, ft H_2O	280
Motor horsepower, hp	200
Material	SS
Design pressure, psig	600
Design temperature, °F	400
Residual heat removal pump room sump pumps	
Quantity (per unit)	2
Type	Self-priming sump pump
Capacity, gpm	60
Head, ft	60
Motor horsepower	3.5
Material (wetted surface)	316 stainless steel

TABLE 10.2-9 RESIDUAL HEAT REMOVAL SYSTEM COMPONENT DATA

Residual Heat Exchangers

Quantity (per unit)	2
Type	Shell and U-tube vertical
Design heat transfer, Btu/hr	26.0×10^6
Shell side (component cooling water)	
Design Inlet temperature, °F	95
Design Outlet temperature, °F	116.1
Design flow rate, lb/hr	1.25×10^6
Design pressure, psig	150
Design temperature, °F	350
Material	Carbon steel
Tube side (reactor coolant)	
Design Inlet temperature, °F	160
Design Outlet temperature, °F	133.5
Design flow rate, lb/hr	1.0×10^6
Design pressure, psig	600
Design temperature, °F	400
Material	Stainless Steel

TABLE 10.2-10 REACTOR MAKEUP WATER DEOXYGENATION SYSTEM COMPONENT DATA

Degasifier	
Number	1
Design Capacity	80 gpm
Design Pressure	full vacuum/150 psig
Design Temperature	35-150°F
Design Code	ASME Sect. VIII, Division I
Transfer Pumps	
Design Capacity	80 gpm
Design Temperature	120°F
Vacuum Pumps	
Design Capacity	26.5 SCFM @ .60″ Hg A.

01400506

TABLE 10.3-1 SAMPLING SYSTEM CODE REQUIREMENTS

Sample heat exchanger	ASME III*, Class C, tube side ASME VIII, shell side
Piping and valves	ANSI B31.1**

* ASME III - American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Nuclear Vessels.

** ANSI B31.1 - Code for Pressure Piping and special nuclear cases where applicable.

TABLE 10.3-2 SAMPLING SYSTEM COMPONENTS

Sample Heat Exchanger

General

Number	10 (both units)
Type	Shell and coiled-tube
Design heat transfer rate (duty for 652.7°F saturated steam to 127°F liquid), each Btu/hr	1.05×10^5

98120

Shell

Design pressure, psig	150
Design temperature, °F	200
Component cooling water flow, gpm	6.0
Pressure loss at 6.0 gpm, psi	10
Operating cooling water temperature, in (maximum), °F	95
Operating cooling water temperature, out (maximum), °F	130
Material	Carbon Steel

Tubes

Design pressure, psig	2500
Design temperature, °F	680
Sample flow, normal, each, lb/hr	200
Maximum pressure loss	40 psi
Operating sample temperature, in (maximum), °F	653
Operating sample temperature, out (maximum), °F	125
Material	Austenitic stainless steel

TABLE 10.3-2 SAMPLING SYSTEM COMPONENTS

Sample Cylinders	
Number, total	8
Volume, 4 supplied, cc	75
Volume, 4 supplied, cc	500
Design pressure, psig	1800
Design temperature, °F	Amb
Manual Pressure Reducing Valves	
Normal operating temperature, °F	120-130
Design pressure, psig	6000
Body design temperature, °F	Amb
Piping	
Design pressure, psig	2500
Design temperature, °F	650

TABLE 10.3-3 MALFUNCTION ANALYSIS OF SAMPLING SYSTEM

Sample Chains	Malfunction	Comments and Consequences	
Pressurizer steam space sample, pressurizer liquid space sample, hot leg sample, or steam generator blowdown sample.	Remote operated sampling valve inside reactor containment fails to close. (Inside containment isolation valve)	Remotely operated outside containment isolation valve closes on containment isolation signal.	01-056
Any of the above sample chains.	Sample line break inside containment.	Remotely operated containment isolation valves close on containment isolation signal.	01-056
Any of the above sample chains.	Sample line break outside containment.	Remotely operated containment isolation valves close on containment isolation signal.	01-056

TABLE 10.4-1 COOLING WATER REQUIREMENTS FOR SINGLE UNIT OPERATION IN GPM

Note: These are nominal flow rates, not the output of a calculation.

	Mode 1, Power Operation or Mode 2, Startup	Mode 3, Hot Standby	Normal Cooldown	Slow Cooldown
Component Cooling Heat Exchangers	4,500	4,500	9,000	4,500
Fan Coil Units	3,600	3,600	3,600	3,600
Diesel Generator	- -	- -	- -	- -
Auxiliary Feedwater Pump	- -	- -	- -	- -
Air Compressor	100	50	50	50
Control Room Air Conditioning	280	280	280	280
Administration Building Air Conditioning	280	280	280	280
Cooling Water Pump Cooling	20	20	20	20
Feedwater Pump Oil Coolers	100	100	100	100
Filter Water, Strainer Backwash and Screen Backwash	250	250	250	250
Steam Generator Blowdown Heat Exchanger	100*	- -	- -	- -
Miscellaneous Equipment Ventilation	1,160	810	810	810
Turbine:				
Oil Coolers	1,290	520	520	520
Hydrogen Coolers	4,095	4,095	4,095	4,095
Hydrogen Seal Oil Coolers	150	150	150	150
Bus Duct Coolers	110	- -	- -	- -
Exciter Air Coolers	220	220	220	220
Total Flow Required (GPM)	16,255	14,875	19,375	14,875

604000000062

* Only used when SGB Heat Exchanger 11(21) is in operation.

TABLE 10.4-2 COMPONENT COOLING SYSTEM COMPONENT DATA

Component Cooling Pumps	
Quantity (per unit)	2
Type	Centrifugal
Design flow rate (each), gpm	4000
Total developed head, ft H_2O	175
Motor horsepower, hp	250
Casing material	ASTM A216 Grade WCB
Design pressure, psig	150
Design temperature, °F	200
Component Cooling Heat Exchangers	
Quantity (per unit)	2
Type	Straight Tube, Horizontal 00079
Design heat transfer, Btu/hr.	29×10^6
Shell side (component cooling water)	
Design Inlet Temp., °F	109.5
Design Outlet Temp., °F	95
Design flow rate, lb/hr	2×10^6
Design temperature, °F	200
Design pressure, psig	150
Material	Carbon Steel
Tube side (cooling water)	
Design Inlet temperature, °F	85
Design Outlet temperature, °F	97.9
Design flow rate, lb/hr	2.25×10^6
Design temperature, °F	200
Design pressure, psig	150
Material	ASTM A249 TP 304

TABLE 10.4-2 COMPONENT COOLING SYSTEM COMPONENT DATA

Component Cooling Surge Tank	
Quantity (per unit)	1
Volume, gal.	2000
Normal water volume, gal.	1000
Design pressure (internal), psig	150
Design pressure (external), psig	Atmospheric
Material	ASTM A-515 Grade 70 Pressure Vessel Quality
Component Cooling System Piping and Valves	
Design pressure, psig	150
Design temperature, °F	250

TABLE 10.4-2a COMPONENT COOLING SYSTEM, NOMINAL MODE FLOW RATES AND DUTY (Note 1) 01291437 01320893

UNIT 1 OR UNIT 2

	Start-up		Mode 1, Power Operation		Mode 2, Startup		Mode 3, Hot Standby		Mode 4, Hot Shutdown		Mode 5, Cold Shutdown	
	GPM	**BTU/HR**	**GPM**	**BTU/HR**	**GPM**	**BTU/HR**	**GPM**	**BTU/HR**	**GPM**	**BTU/HR**	**GPM**	**BTU/HR**
1. Letdown HX	690	10.2x10^{6}	225	3.3x10^{6}	225	3.3x10^{6}	690	10.2x10^{6}	225	3.3x10^{6}	- -	- -
2. Excess Letdown HX	235	4.6x10^{6}	- -	- -	235*	4.6x10^{6}*	235*	4.6x10^{6}	235	4.6x10^{6}	- -	- -
3. Seal Water HX	95	1.19x10^{6}	95	1.19x10^{6}	95	1.19x10^{6}	95	1.19x10^{6}	95	1.19x10^{6}	- -	- -
4. Spent Fuel Pit HX	1800	7.89x10^{6}	1800	7.89x10^{6}	1800	7.89x10^{6}	1800 [A]	7.89x10^{6} [A]	1800 [B]	7.89x10^{6} [B]	1800 [B]	7.89x10^{6} [B]
5. RHR HX	- -	- -	- -	- -	- -	- -	- -	- -	2500	26x10^{6}	2500	26x10^{6}
6. RHR Pumps	30	- -	30	- -	30	- -	30	- -	30	0.5x10^{6}	30	- -
7. Safety Injection Pumps	50	- -	50	- -	50	- -	50	- -	50	- -	50	0.5x10^{6}
8. Reactor Coolant Pumps	400	2.4x10^{6}	400	2.4x10^{6}	400	2.4x10^{6}	400	2.4x10^{6}	200	1.2x10^{6}	- -	- -

01344967

TABLE 10.4-2a COMPONENT COOLING SYSTEM, NOMINAL MODE FLOW RATES AND DUTY (Note 1) 01291437 01320893

UNIT 1 OR UNIT 2

	Start-up		Mode 1, Power Operation		Mode 2, Startup		Mode 3, Hot Standby		Mode 4, Hot Shutdown		Mode 5, Cold Shutdown		
	GPM	**BTU/HR**	**GPM**	**BTU/HR**	**GPM**	**BTU/HR**	**GPM**	**BTU/HR**	**GPM**	**BTU/HR**	**GPM**	**BTU/HR**	
9. Waste Gas Comp	75	1.15x10^{6}	75	1.15x10^{6}	75	1.15x10^{6}	75	1.15x10^{6}	75	1.15x10^{6}	75	1.15x10^{6}	
10. Sampling HX	205	1.05x10^{6}	205	1.05x10^{6}	205	1.05x10^{6}	205	1.05x10^{6}	205	1.05x10^{6}	- -	- -	
11. Containment Spray Pumps	20	- -	20	- -	20	- -	20	- -	20	- -	20	- -	
Totals													
Design:													
Duty	3600	2.848x10^{7}	2900	1.698x10^{7}	3135	2.158x10^{7}	3600	2.848x10^{7}	5435	4.688x10^{7}	4475	3.554x10^{7}	01344967
Pumps Avail.	2	2	2	2	2	2	2	2	2	2	2	2	
Mandatory:													
Duty	3600	2.848x10^{7}	2900	1.698x10^{7}	2900	1.698x10^{7}	3365	2.848x10^{7}	5435	4.688x10^{7}	4475	3.554x10^{7}	01344967
Pumps Avail.	1	1	1	1	1	1	1	1	1	1	1	1	

LEGEND

* Not Mandatory

A. Start to transfer to Unit 2

B. Available on Unit 2

1. Assuming no more than one unit undergoing cooldown.
2. Assuming only one Unit under DBA, the other Unit in Mode 2, Startup.
3. The Flow Rates and Heat Removal Rates presented in this Table are nominal and not intended to be inputs into the safety analysis. 01291437

TABLE 10.4-2b COMPONENT COOLING SYSTEM, NOMINAL DBA MODE FLOW RATES AND DUTY (Note 2 & 3)

Page 1 of 2

01344967 01320893 01320893

	UNIT 1						UNIT 2	
	DBA-Immediate		DBA-Interim		DBA-Long Term		Mode 2, Startup	
	GPM	BTU/HR	GPM	BTU/HR	GPM	BTU/HR	GPM	BTU/HR
1. Letdown HX	- -	- -	- -	- -	- -	- -	225	3.3×10^{6}
2. Excess Letdown HX	- -	- -	- -	- -	- -	- -	235*	4.6×10^{6} *
3. Seal Water HX	- -	- -	- -	- -	- -	- -	95	1.19×10^{6}
4. Spent Fuel Pit HX	- -	- -	- -	- -	- -	- -	1800	7.89×10^{6}
5. RHR HX	- -	- -	2500	26×10^{6}	2500	26×10^{6}	- -	- -
6. RHR Pumps	30	0.5×10^{6}	30	0.5×10^{6}	30	0.5×10^{6}	30	- -
7. Safety Injection Pumps	50	0.5×10^{6}	50	0.5×10^{6}	50	0.5×10^{6}	50	- -
8. Reactor Coolant Pumps	- -	- -	- -	- -	- -	- -	400	2.4×10^{6}
9. Waste Gas Comp	- -	- -	- -	- -	- -	- -	75	1.15×10^{6} *
10. Sampling HX	- -	- -	- -	- -	- -	- -	205	1.05×10^{6}

01344967

TABLE 10.4-2b COMPONENT COOLING SYSTEM, NOMINAL DBA MODE FLOW RATES AND DUTY (Note 2 & 3) 01320893

		UNIT 1						UNIT 2		
		DBA-Immediate		DBA-Interim		DBA-Long Term		Mode 2, Startup		01344967
		GPM	BTU/HR	GPM	BTU/HR	GPM	BTU/HR	GPM	BTU/HR	
11. Containment Spray Pumps		20	$0.4x10^6$	20	$0.4x10^6$	20	$0.4x10^6$	20	$0.4x10^6$	01320893
Design:	Duty	100	$1.400x10^6$	2600	$2.740x10^7$	2600	$2.740x10^7$	3135	$2.198x10^7$	01344967
	Pumps	2	2	2	2	2	2	2	2	
Mandatory:	Duty	100	$1.400x10^6$	2600	$2.740x10^7$	2600	$2.740x10^7$	2825	$1.623x10^7$	01344967
	Pumps	1	1	1	1	1	1	1	1	

LEGEND

* Not Mandatory

A. Start to transfer to Unit 2

B. Available on Unit 2

1. Assuming no more than one unit undergoing cooldown.
2. Assuming only one Unit under DBA, the other Unit in Mode 2, Startup.
3. The Flow Rates and Heat Removal Rates presented in this Table are nominal and not intended to be inputs into the safety analysis. 01291437

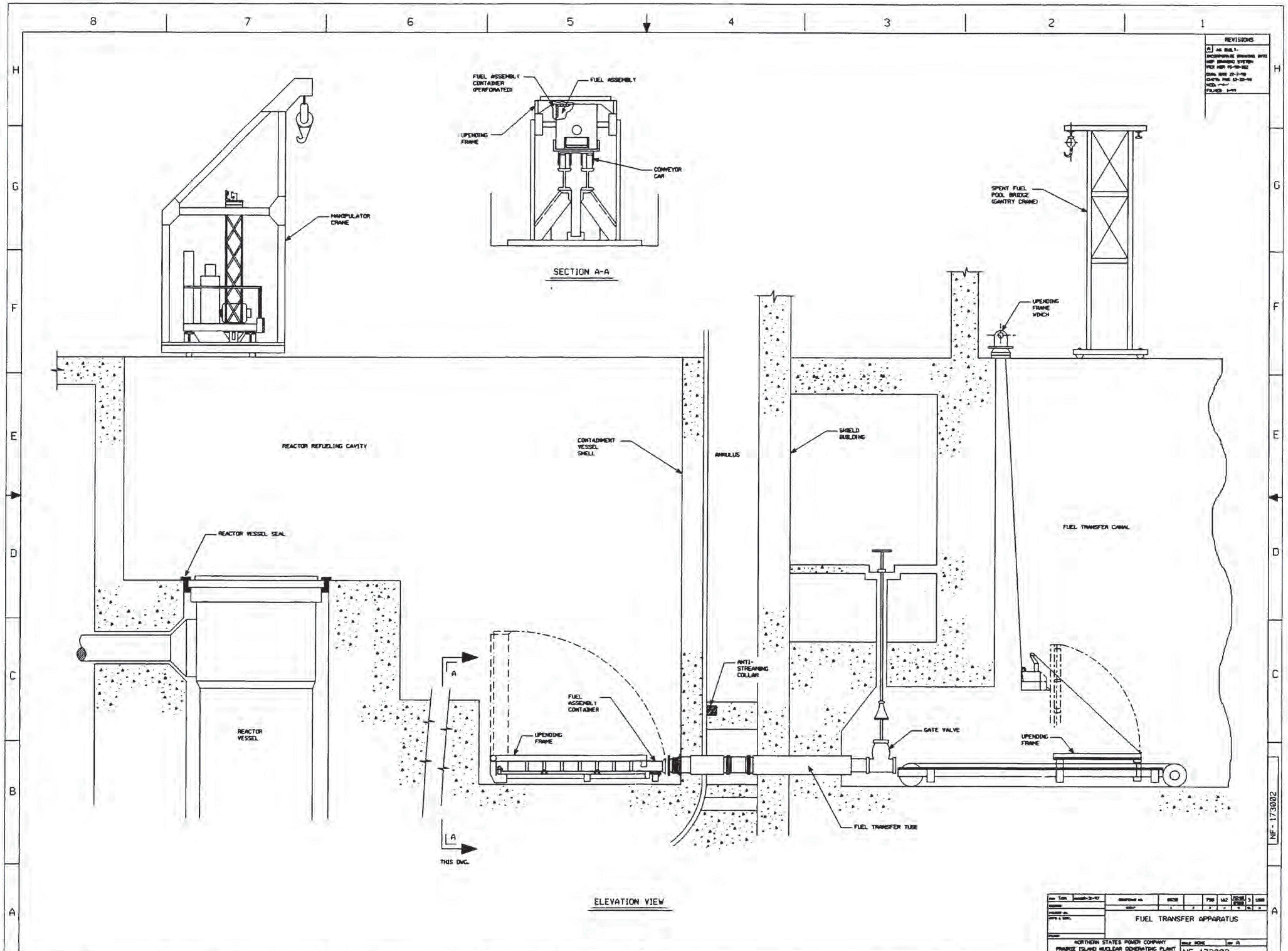
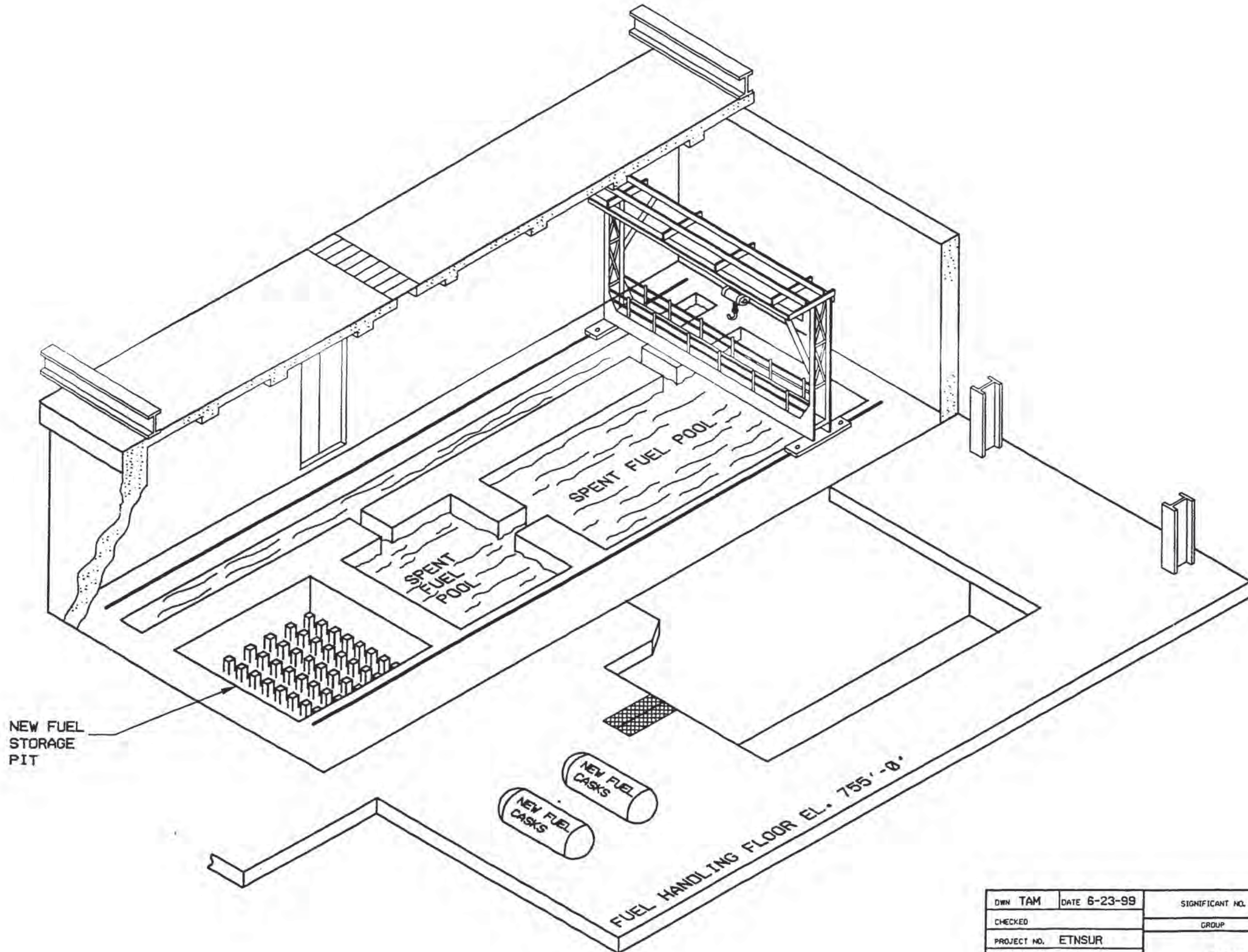
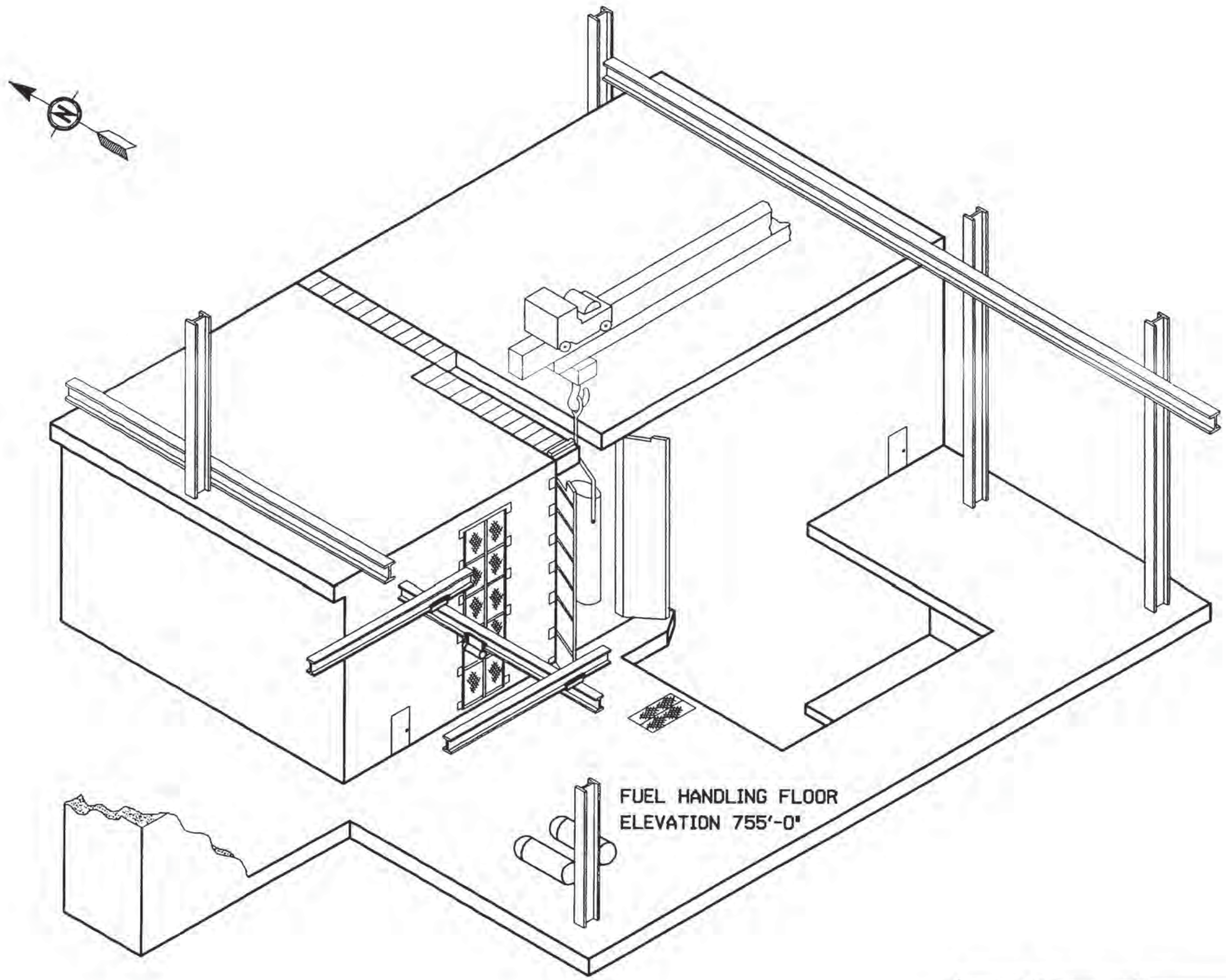


FIGURE 10.2-1 REV. 20



REVISIONS

DWN TAM	DATE 6-23-99	SIGNIFICANT NO.	
CHECKED		GROUP	1 2 3 4 5 CL 6
PROJECT NO. ETNSUR		SPENT FUEL POOL ENCLOSURE INTERNAL	
APP'D & CERT.			
CAD FILE U10202.DGN			
NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA		SCALE NONE	
		FIGURE 10.2-2	REV. 18



REVISIONS

DWN TAM	DATE 6-23-99	SIGNIFICANT NO.						
CHECKED		GROUP	1	2	3	4	5	CL 6
PROJECT NO. ETNSUR								
APP'D & CERT.								
CAD FILE17300302.DGN								

SPENT FUEL POOL ENCLOSURE
EXTERNAL

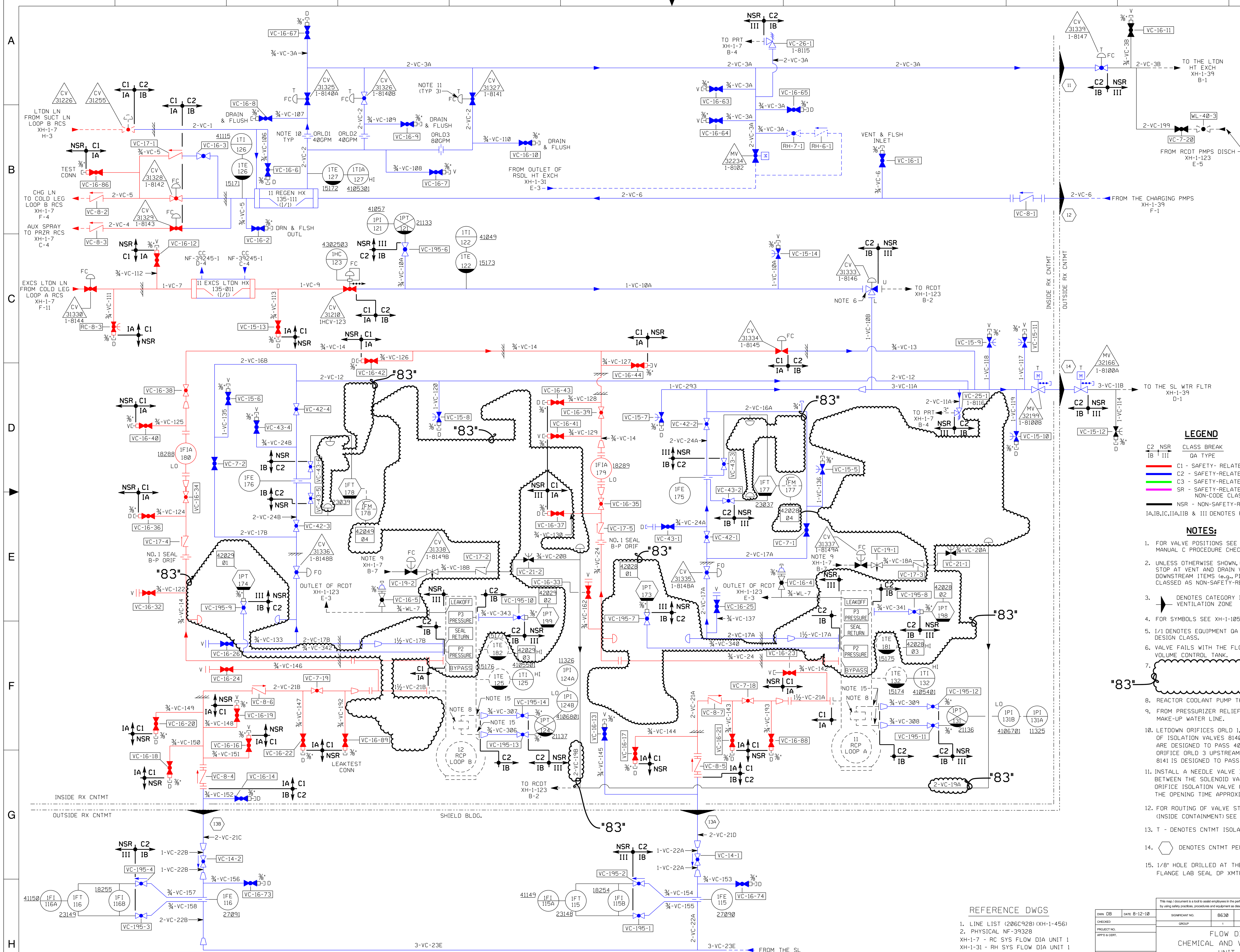
NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA

SCALE NONE

FIGURE 10.2-3 REV. 18

FIGURE 10.2-4 REV. 34

CAD FILE: U10204.DGN



REVISIONS

81 AS BUILT-
CAP CHANGED TO VENTED CAPS ON VALVES. (VC-16-4 & VC-16-5)
PER DRR PI-15-028
DWN: MEA 2-17-15
CHK'D: MJN 2-18-15
MOD#: EC-25282
APP'D: CMR 2-18-15

82 AS BUILT-
VALVES CHANGED FROM NC TO NO. (VC-16-4 & VC-16-5)
PER DRR PI-15-029
DWN: MEA 3-10-15
CHK'D: RWC 3-16-15
MOD#: EC-25283
APP'D: KJW 3-16-15

83 ISSUED FOR CONSTRUCTION
REMOVED STANDPIPPES & EXISTING XMTRS IPT-173, IPT-174, IPT-175, IPT-176 & ASSOC DEVICES & PIPING, ADDED NEW XMTRS IPT-173, IPT-174, IPT-198, IPT-199 ASSOC DEVICES & PIPING, REMOVED SEAL LINE 2 DEVICES & PIPING. DELETED NOTE 7.
DWN: JMB 3-11-14
CHK'D: FJH 3-11-14
MOD#: EC-21790
REVIEWED: RW 3-11-14
PE CERT:
T.A. MAHER
3-11-14 PE# 51207
APP'D: TAM 3-11-14

ISSUED FOR CONSTRUCTION
INCORP: PLANNER COMMENTS, REDESIGNATED PREVIOUSLY OMITTED LINES 2VC-19A & 2VC-19B.
DWN: JMB 7-28-14
CHK'D: FJH 9-16-14
MOD#: EC-21790
REVIEWED: RWA 9-16-14
PE CERT:
PE#
APP'D:

AS BUILT-
INCORPORATED A/E's REV. 83 PER DRR PI-15-005 CERTIFIED REV. 83, TRANSFERRED TO RECORD TRACING.
DWN: MEA 4-17-15
CHK'D: RSA 6-1-15
MOD#: EC-21790
APP'D: KJW 6-1-15

LEGEND

C2 NSR / IB III — CLASS BREAK / QA TYPE

- C1 - SAFETY- RELATED; ISI CLASS 1
- C2 - SAFETY-RELATED; ISI CLASS 2
- C3 - SAFETY-RELATED; ISI CLASS 3
- SR - SAFETY-RELATED FLUID BOUNDARY; NON-CODE CLASS
- NSR - NON-SAFETY-RELATED

IA,IB,IC,IIA,IIB & III DENOTES PIPING QA TYPES.

NOTES:

1. FOR VALVE POSITIONS SEE OPS MANUAL C PROCEDURE CHECKLIST.
2. UNLESS OTHERWISE SHOWN, CLASS BOUNDARIES STOP AT VENT AND DRAIN VALVES WITH DOWNSTREAM ITEMS (e.g., PIPE, CAPS, ETC.) CLASSED AS NON-SAFETY-RELATED.
3. DENOTES CATEGORY I VENTILATION ZONE
4. FOR SYMBOLS SEE XH-1-105, NF-39214.
5. I/1 DENOTES EQUIPMENT QA TYPE/ DESIGN CLASS.
6. VALVE FAILS WITH THE FLOW TO VOLUME CONTROL TANK.
7. "83"
8. REACTOR COOLANT PUMP THERMAL BARRIER.
9. FROM PRESSURIZER RELIEF TANK, REACTOR MAKE-UP WATER LINE.
10. LETDOWN ORIFICES ORLD 1, ORLD 2 UPSTREAM OF ISOLATION VALVES 8140A, 8140B RESPECTIVELY ARE DESIGNED TO PASS 40 GPM AND THIRD ORIFICE ORLD 3 UPSTREAM OF ISOLATION VALVE 8141 IS DESIGNED TO PASS 80 GPM.
11. INSTALL A NEEDLE VALVE IN THE AIR LINE BETWEEN THE SOLENOID VALVE AND THE ORIFICE ISOLATION VALVE OPERATOR, MAKING THE OPENING TIME APPROXIMATELY 10 SECONDS.
12. FOR ROUTING OF VALVE STEM LEAKOFF (INSIDE CONTAINMENT) SEE NF-39250
13. T - DENOTES CNTMT ISOLATION TRIP SIGNAL
14. DENOTES CNTMT PENETRATION NUMBER
15. 1/8" HOLE DRILLED AT THERMAL BARRIER FLANGE LAB SEAL DP XMTR TAPS.

REFERENCE DWGS

1. LINE LIST (206C928)(XH-1-456)
2. PHYSICAL NF-39328

XH-1-7 - RC SYS FLOW DIA UNIT 1
XH-1-31 - RH SYS FLOW DIA UNIT 1
XH-1-39 - VC SYS FLOW DIA UNIT 1
XH-1-123 - WL SYS FLOW DIA UNIT 1 & 2
NF-39245-1 - CC SYS FLOW DIA UNIT 1

DWN DB	DATE 8-12-10	SIGNIFICANT NO.	8630			1	M430 / 9071	1	4320
CHECKED		GROUP	1	2	3	4	5	CL	6
PROJECT NO.									
APP'D & CERT.									
FILMED									

FLOW DIAGRAM
CHEMICAL AND VOLUME CONTROL
UNIT 1

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING, MINNESOTA

SCALE NONE — REV 83

XH-1-38

$$USERNAME$$
$$$$$$SYTIME$$$$$$$$$$$$SYDATE$$$$$$
$$$$$$$$$DESIGNFIL$$$$$$$$$

XH-1-38.DGN NSP GENERATION CAD

XH-1-38

01516979

FIGURE 10.2-5 **REV. 34**

CAD FILE: U10205.DGN

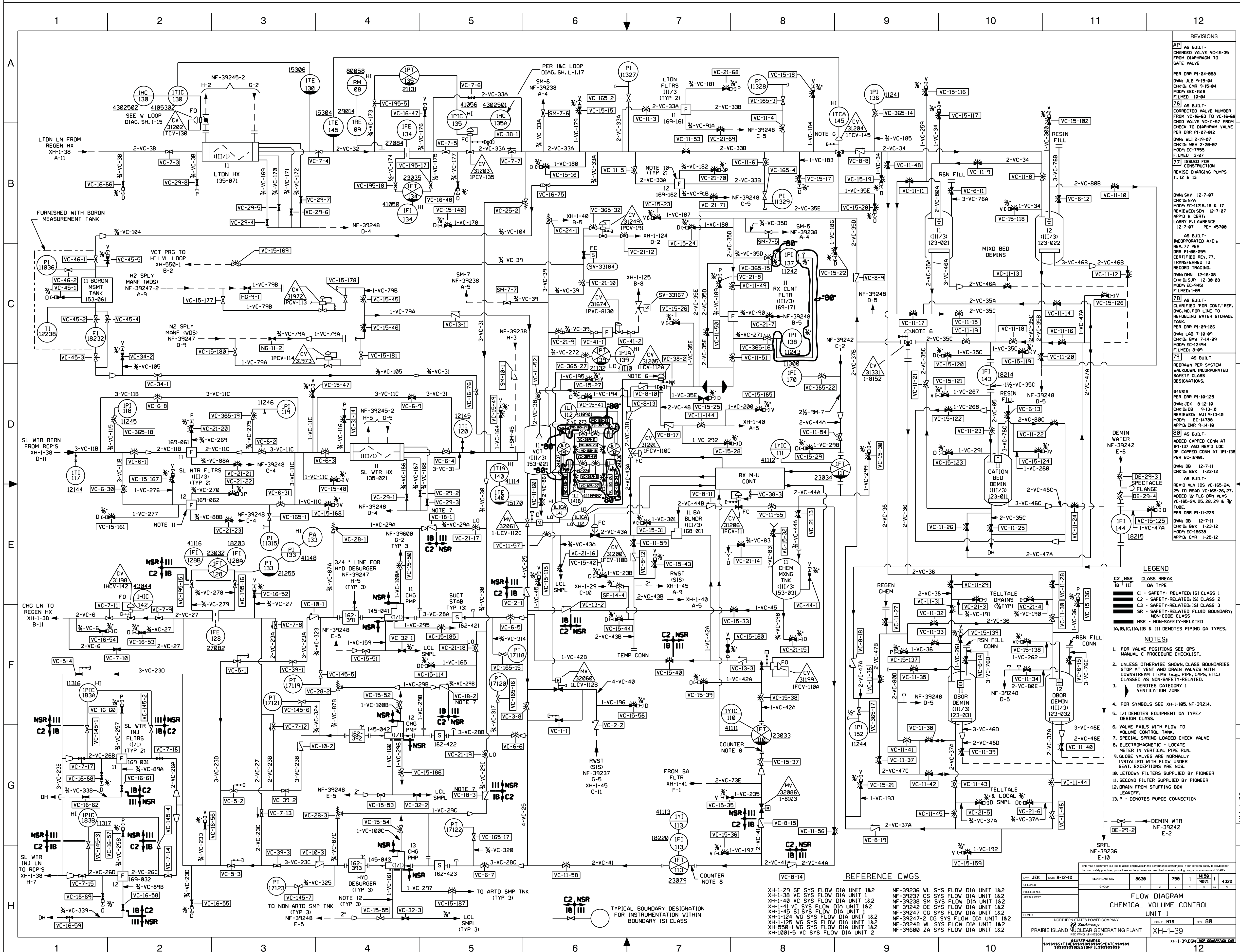
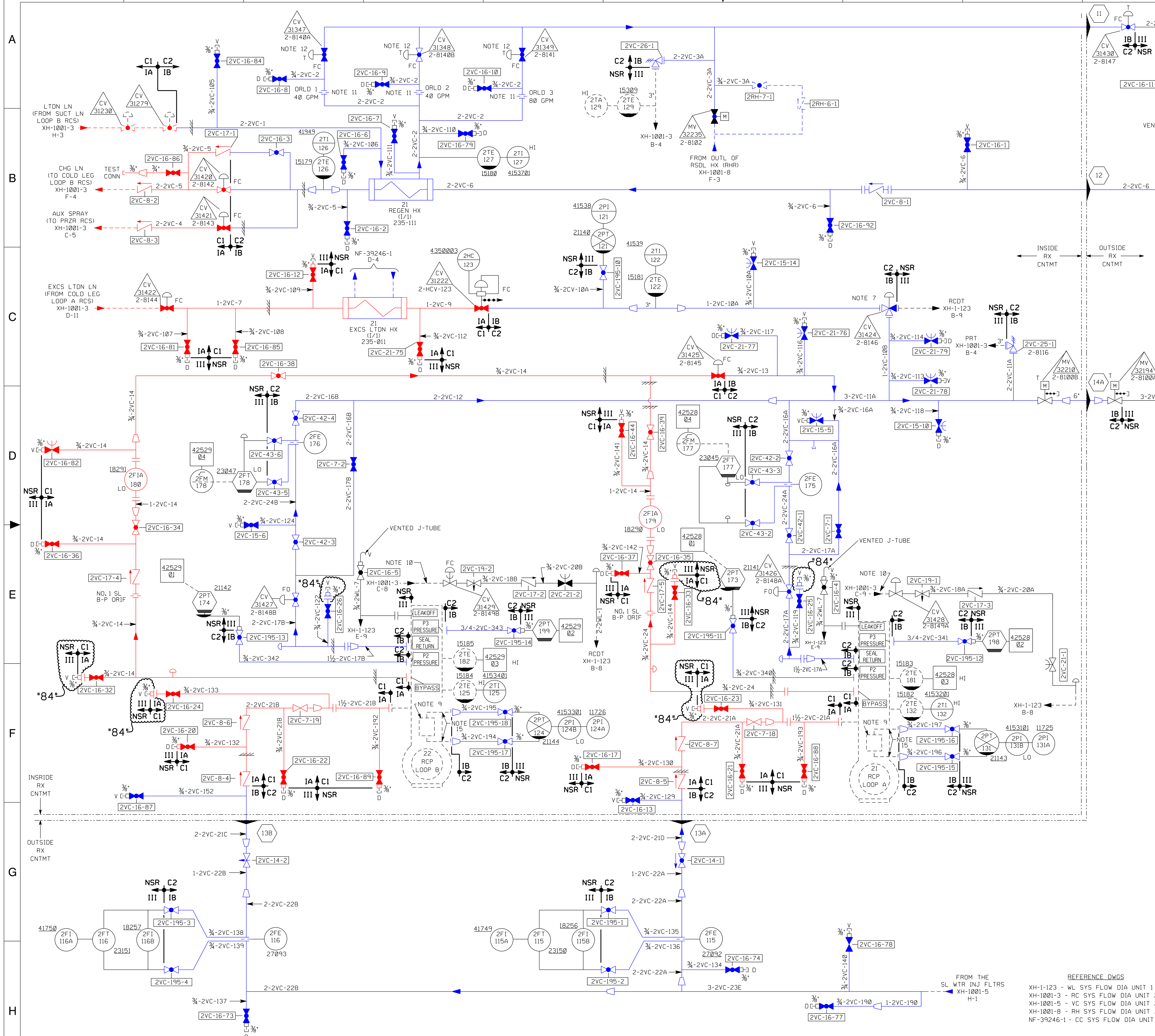


FIGURE 10.2-6 REV. 32

CAD FILE: U10206.DGN

01352784



LEGEND

C2 NSR / IB III — CLASS BREAK / QA TYPE

- C1 - SAFETY- RELATED; ISI CLASS 1
- C2 - SAFETY-RELATED; ISI CLASS 2
- C3 - SAFETY-RELATED; ISI CLASS 3
- SR - SAFETY-RELATED FLUID BOUNDARY; NON-CODE CLASS
- NSR - NON-SAFETY-RELATED

IA,IB,IC,IIA,IIB & III DENOTES PIPING QA TYPES.

NOTES:

1. FOR VALVE POSITIONS SEE OPS MANUAL C PROCEDURE CHECKLIST.
2. UNLESS OTHERWISE SHOWN, CLASS BOUNDARIES STOP AT VENT AND DRAIN VALVES WITH DOWNSTREAM ITEMS (e.g., PIPE, CAPS, ETC.) CLASSED AS NON-SAFETY-RELATED.
3. DENOTES CATEGORY I VENTILATION ZONE
4. FOR SYMBOLS SEE XH-1-105, NF-39214.
5. I/1 DENOTES EQUIPMENT QA TYPE/ DESIGN CLASS.
6. T - DENOTES CNTMT ISOLATION TRIP SIGNAL
7. VALVE FAILS WITH FLOW TO VOLUME CONTROL TANK.
8.
9. REACTOR COOLANT PUMP THERMAL BARRIER.
10. FROM PRESSURIZER RELIEF TANK MAKEUP WATER LINE.
11. LETDOWN ORIFICES ORLD1, ORLD2 UPSTREAM OF ISOLATION VALVES 8140A, 8140B RESPECTIVELY ARE DESIGNED TO PASS 40 GPM AND THE THIRD ORIFICE ORLD3 UPSTREAM OF ISOLATION VALVE 8141 IS DESIGNED TO PASS 80 GPM.
12. INSTALL A NEEDLE VALVE IN THE AIR LINE BETWEEN THE SOLENOID VALVE AND THE ORIFICE ISOLATION VALVE OPERATOR MAKING THE OPENING TIME APPROXIMATELY 10 SECONDS.
13. FOR ROUTING OF VALVE STEM LEAKOFFS (INSIDE CONTAINMENT) SEE DWG NF-39250.
14. - DENOTES CNTMT PENETRATION SYMBOL
15. ¼" HOLE DRILLED AT THERMAL BARRIER FLANGE FOR LAB SEAL DP XMTR TAPS.

REFERENCE DWGS

XH-1-123 - WL SYS FLOW DIA UNIT 1 & 2
XH-1001-3 - RC SYS FLOW DIA UNIT 2
XH-1001-5 - VC SYS FLOW DIA UNIT 2
XH-1001-8 - RH SYS FLOW DIA UNIT 2
NF-39246-1 - CC SYS FLOW DIA UNIT 2

REVISIONS

S AS BUILT- CHANGED VALVE NUMBER FROM 2VC-16-23 TO 2VC-16-22.
PER DRR PI-98-89
DWN: JMM 9-14-98
CHK'D: PAS 9-17-98
MOD#:
FILMED 9-98

T AS BUILT- ADD FLANGE IN NO. 2 SEAL LEAKOFF PIPING OF 21 AND 22 RCP TO 2VC-8-4 AND 2VC-8-5.
PER DRR PI-00-27
DWN: BMS 3-31-00
CHK'D: CMR 5/3/00
MOD#:
FILMED 5/00

U AS BUILT- REMOVE FLANGES ON VALVES 2VC-8-4 AND 2VC-8-5
PER DRR PI-05-092
DWN: VLS 05/24/05
CHK'D: CMR 05/24/05
MOD#: 01VC01
FILMED 06/05

76 AS BUILT- UPDATE WITH STANDARD BORDER FOR CONSISTENCY WITH DRAWING CONTINUATION COORDINATES.
PER DRR PI-09-209
DWN: DB 1-26-10
CHK'D: JEK 1-27-10
MOD#: EC-14781
APP'D: CMR 2-12-10

77 AS BUILT REDRAWN PER SYSTEM WALKDOWN, INCORPORATED SAFETY CLASS DESIGNATIONS.
04NS15
PER DRR PI-10-125
DWN: JEK 8-18-10
CHK'D: DB 9-13-10
REVIEWED: WJI 9-13-10
MOD#: EC-14788
APP'D: CMR 9-14-10

78 AS BUILT- REMOVED "LO" REF AT VALVE 2RH-7-1 LOC A-7.
PER DRR PI-11-204
DWN: DB 11-3-11
CHK'D: RSA 11-7-11
MOD#: EC-18873
APP'D: CMR 11-14-11

79 AS BUILT- ADDED FLANGE TO LINE NO 1½-2VC-21B LOC F-3.
PER DRR PI-12-162
DWN: KJF 8-16-12
CHK'D: WEH 8-20-12
MOD#: EC-19005
APP'D: CMR 8-21-12

80 AS BUILT- REPLACED NEEDLE VALVE 2VC-14-1 WITH GLOBE VLV INSTALLED WITH FLOW OVER SEAT.
PER DRR PI-13-142
DWN: JEK 9-12-13
CHK'D: BWK 9-17-13
MOD#: EC-21096
APP'D: CMR 9-17-13

81 AS BUILT- CORRECTED VLV NUMBER MV-31424 TO CV-31424 @ LOC C-8.
PER DRR PI-13-233
DWN: DB 12-10-13
CHK'D: RLM 12-11-13
MOD#: EC-22940
APP'D: CMR 12-11-13

82 AS BUILT- REMOVED STANDPIPES & EXIST. XMTRS 2PT-173, 2PT-174, 2FT-175, 2FT-176 & ASSOCIATED DEVICES & PIPING. ADDED NEW XMTRS 2PT-173, 2PT-174, 2PT-198 & 2PT-199 & ASSOCIATED DEVICES & PIPING. REMOVED SEAL LINE 2 DEVICES & PIPING. DELETED NOTE 8.
PER DRR PI-14-051
DWN: LAB 3-20-14
CHK'D: JKR 3-24-14
MOD#: EC-21789
APP'D: CMR 3-25-14

83 AS BUILT- VALVES 2VC-16-4 & -5 NORMALLY CLOSED CHANGED TO NORMALLY OPEN. CAPPED VENT CHANGED TO VENTED J-TUBE.
PER DRR PI-15-037
DWN: MEA 3-16-15
CHK'D: BWK 3-17-15
MOD#: EC-25364
APP'D: KJW 3-17-15

84 AS BUILT- ADDED ¾" PIPE × ⅜" TUBE ADAPTER & ⅜" CAP TO FLANGE ON ROOT VALVES 2VC-16-23,24,25,26,32&33 AND SAFETY CLASS FLAGS FOR CLASS ONE VALVES.
PER DRR PI-17-140
DWN: JEK 10-2-17
CHK'D: RSA 10-18-17
MOD#: 6MODWM022220
APP'D: DB 10-18-17

XH-1001-4

DWN JEK	DATE 8-18-10	SIGNIFICANT NO.	8630		200 750	2	M430 9071	1	4320
CHECKED		GROUP	1	2	3	4	5	CL	6
PROJECT NO.									
APP'D & CERT.									
FILMED									

FLOW DIAGRAM
CHEMICAL AND VOLUME CONTROL
UNIT 2

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING, MINNESOTA

SCALE NONE REV 84
XH-1001-4

$$USERNAME$$
$$$$$$SYTIME$$$$$$$$$$$SYDATE$$$$$$
$$$$$$$$$DESIGNFIL$$$$$$$$$

XH-1001-4.DGN NSP GENERATION CAD

60300001331

FIGURE 10.2-7 REV. 35

CAD FILE: U10207.DGN

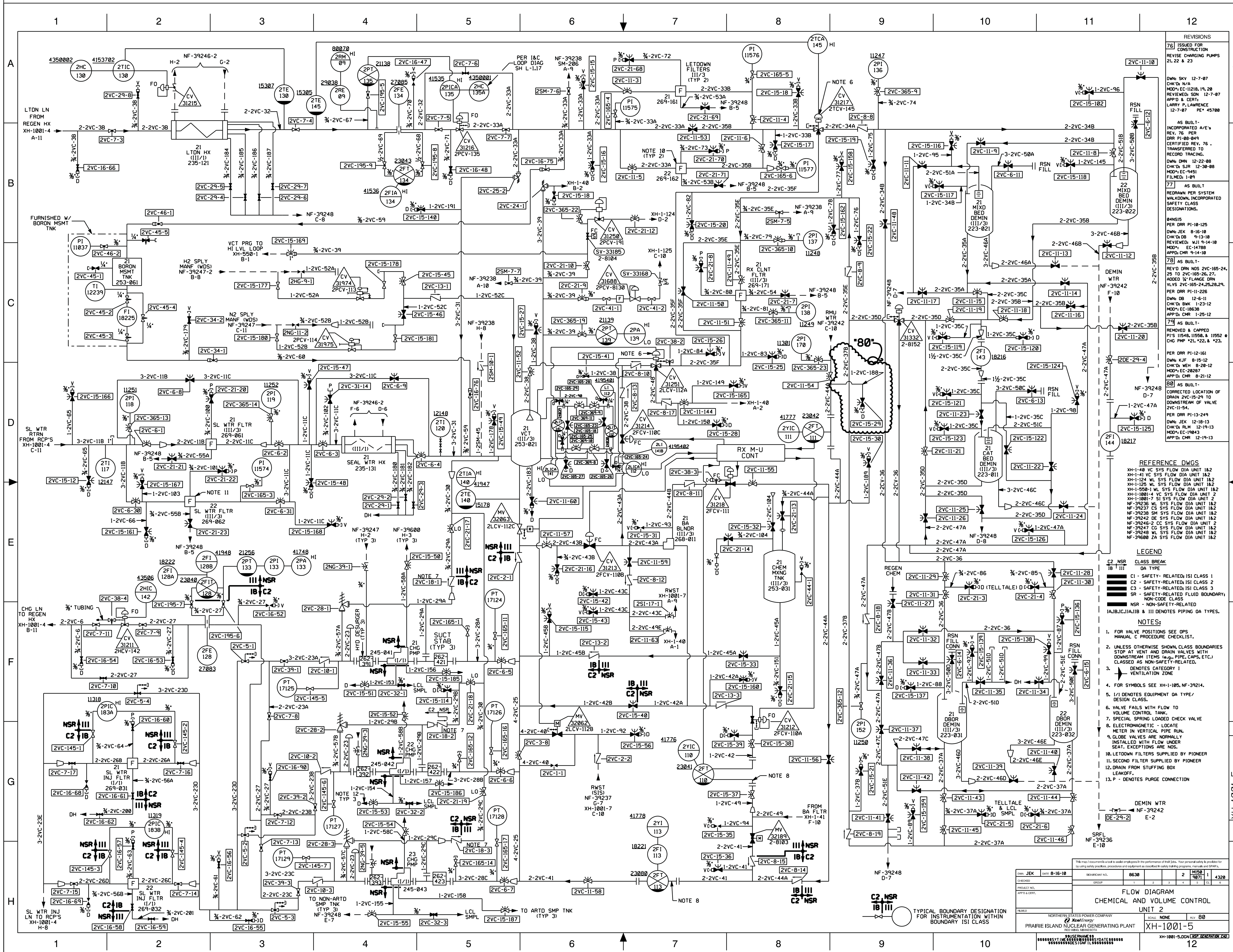


FIGURE 10.2-8 REV. 33

0142908 8

CAD FILE: U10208.DGN

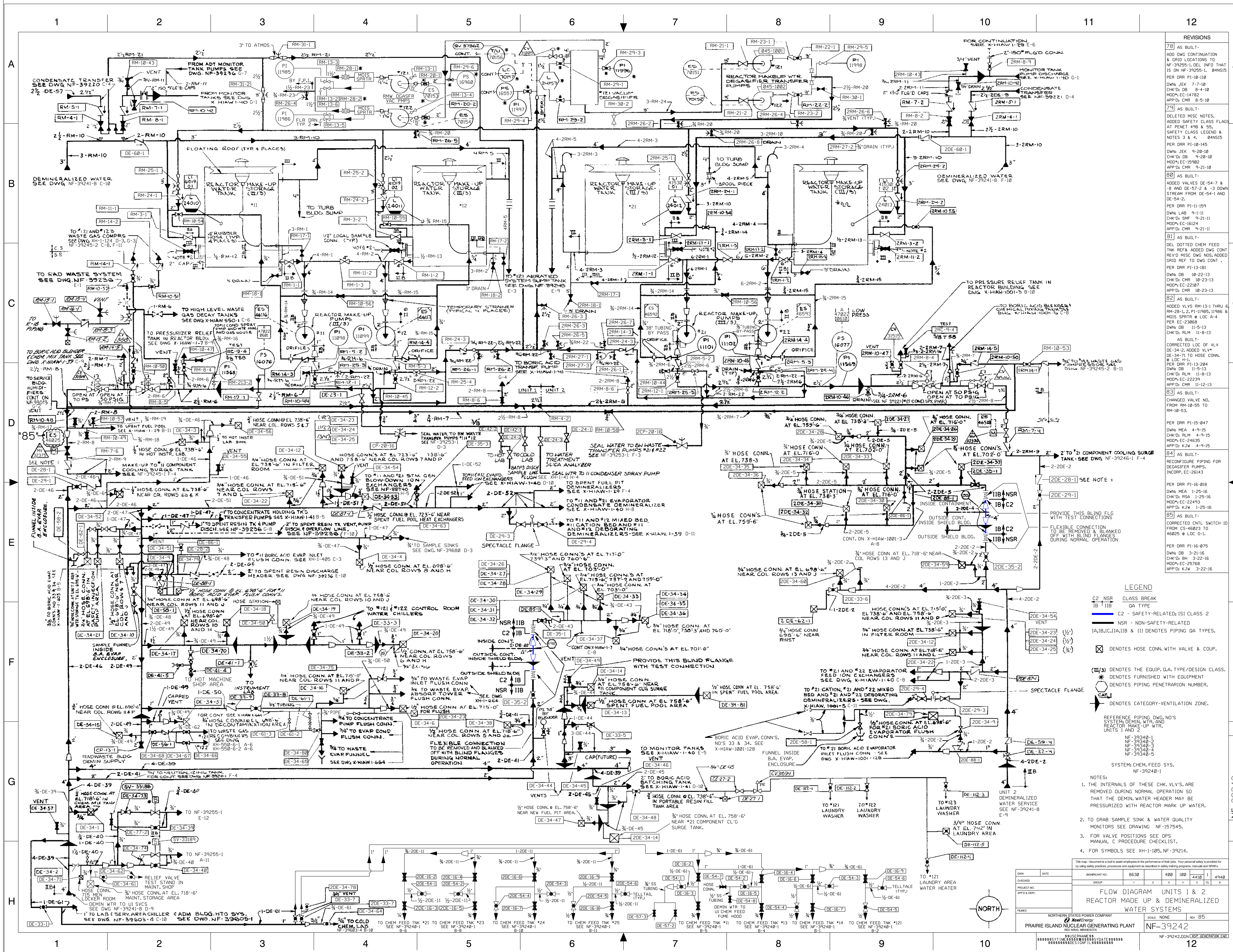


FIGURE 10.2-9 REV. 34

01516979

CAD FILE: U10209.DGN

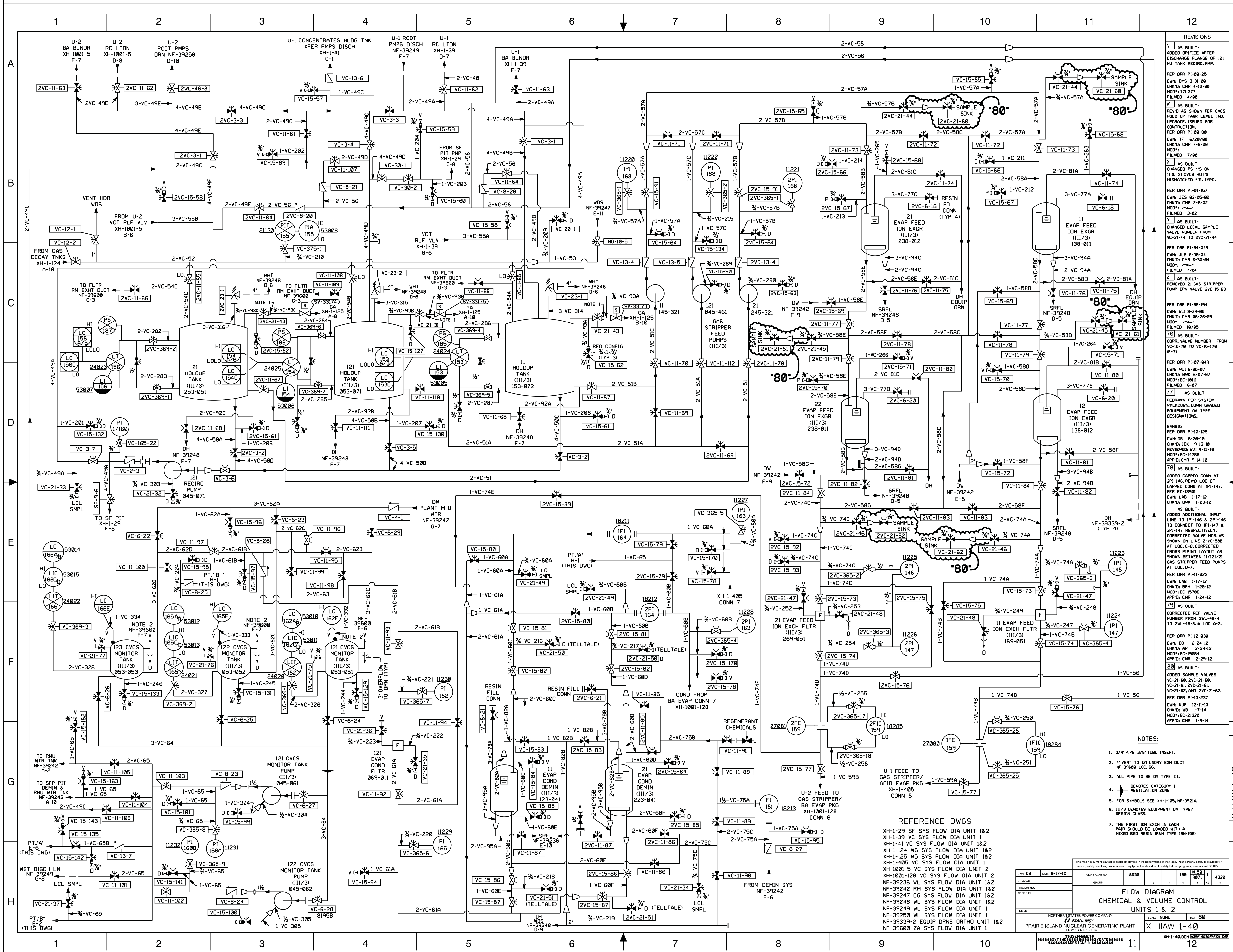


FIGURE 10.2-10A REV. 33

CAD FILE: U10210A.DGN

01429088

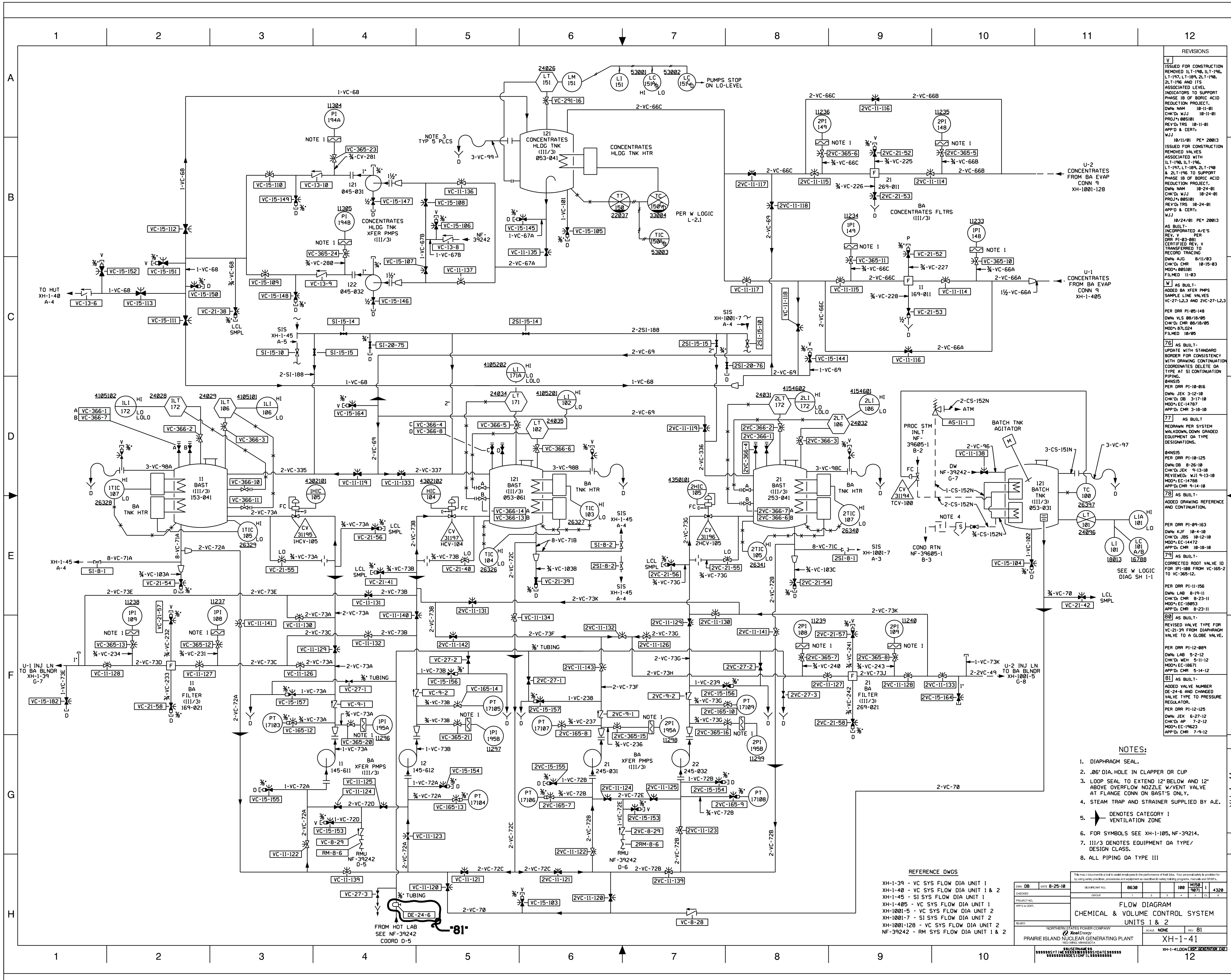


FIGURE 10.2-10B REV. 32

01352784

CAD FILE: U10210B.DGN

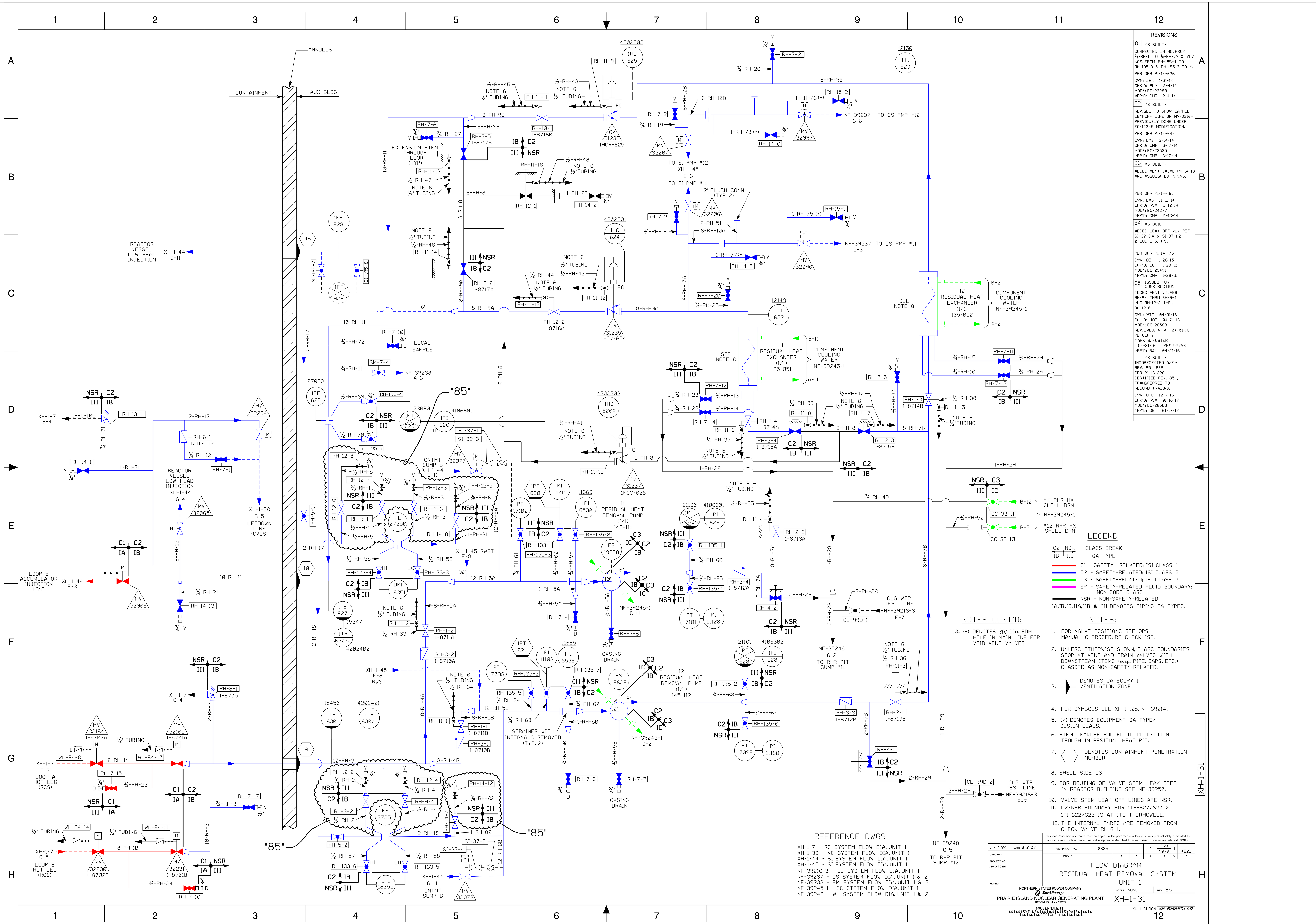
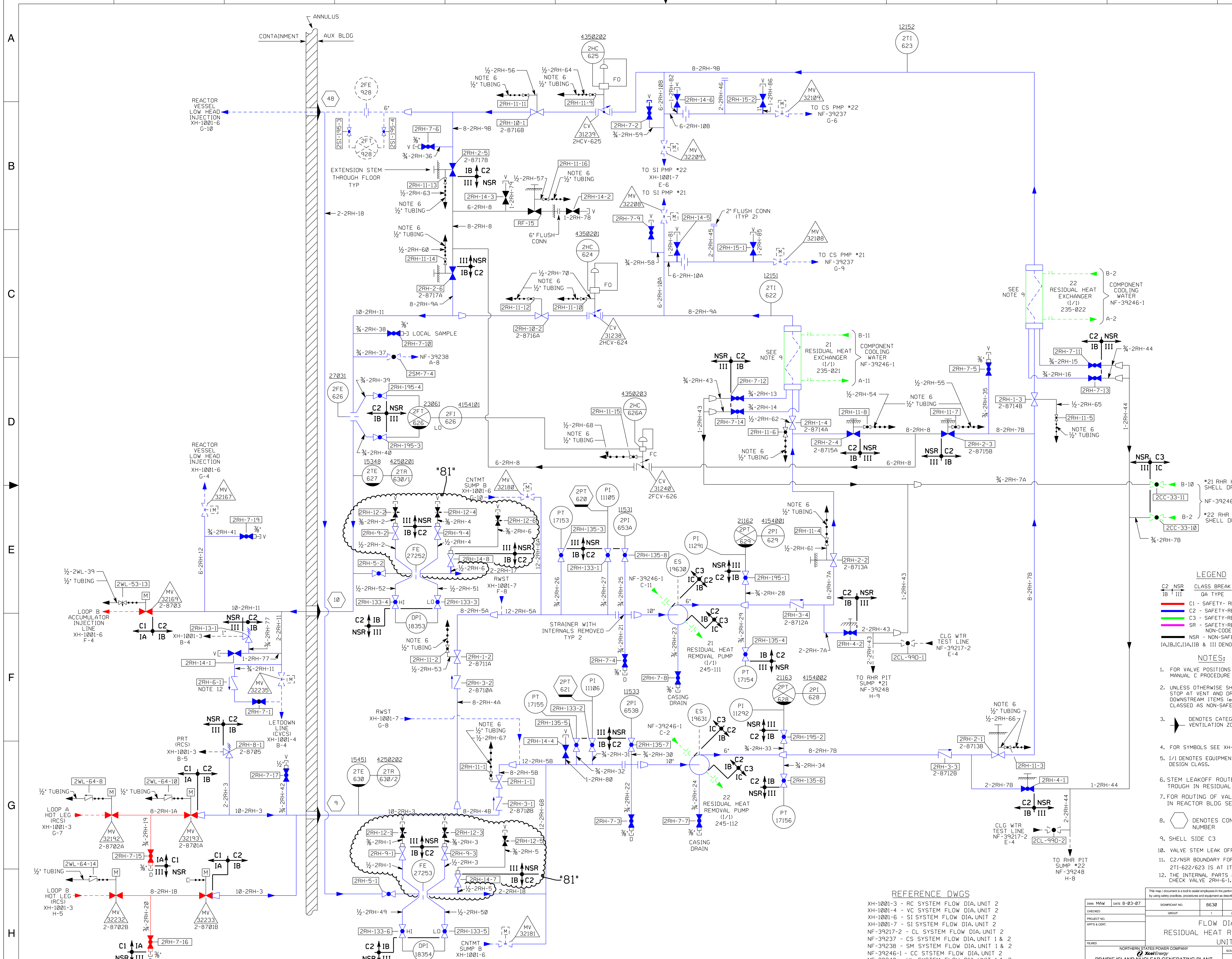


FIGURE 10.2-11 REV. 35

60300001331

CAD FILE: U10211.DGN



REVISIONS

77 AS BUILT-
REMOVE QA DESIGNATION AT VALVE 2SM-7-4.
04NS15
PER DRR PI-09-202
DWN: JEK 10-7-09
CHK'D: DB 10-8-09
MOD#: EC-14556
APP'D: CMR 11-9-09

78 AS BUILT
REDRAWN PER SYSTEM WALKDOWN, INCORPORATED SAFETY CLASS DESIGNATIONS.
04NS15
PER DRR PI-09-209
DWN: MAW 8-03-07
CHK'D: JEK 12-10-09
REVIEWED: WJI 12-10-09
MOD#: EC-14781
FILMED: 1-10

79 ISSUED FOR CONSTRUCTION
ADDED VENT VALVES 2RH-15-1, 2RH-15-2 AND 2RH-14-1 THRU 2RH-14-8 & RELIEF VALVE 2RH-13-1.
DWN: RPS
CHK'D: CDZ 4-12-10
MOD#: EC-13483
REVIEWED: CDH 4-12-10
PE CERT:
A.V. SETLUR
4-12-10 PE# 21678
APP'D: SP 4-12-10
AS BUILT-
INCORPORATED A/E's REV. "79" PER DRR PI-10-069 CERTIFIED REV. "79", TRANSFERRED TO RECORD TRACING.
DWN: LAB 7-19-10
CHK'D: RSA 8-4-10
MOD#: EC-13483
APP'D: CMR 8-4-10

80 AS BUILT-
REV'D VLV SYMBOL FOR VLV 2WL-53-13 FROM A CHECK TO NEEDLE VLV @ LOC E-1.
PER DRR PI-12-219
DWN: DB 3-13-13
CHK'D: AP 3-20-13
MOD#: EC-20975
APP'D: CMR 3-20-13

81 ISSUED FOR CONSTRUCTION
ADDED VENT VALVES 2RH-9-1 THRU 2RH-9-4 AND 2RH-12-1 THRU 2RH-12-6
DWN: WTT 10-9-15
CHK'D: WLS 10-9-15
MOD#: EC-25955
REVIEWED: WFW 10-9-15
PE CERT:
PE#
APP'D: BTL 10-9-15
AS BUILT-
INCORPORATED A/E's REV. 81 PER DRR PI-16-016 CERTIFIED REV. 81, TRANSFERRED TO RECORD TRACING.
DWN: MEA 1-20-16
CHK'D: RSA 1-21-16
MOD#: EC-25955
APP'D: KJW 1-21-16

LEGEND

C2 NSR / IB III — CLASS BREAK / QA TYPE

- C1 - SAFETY- RELATED; ISI CLASS 1
- C2 - SAFETY-RELATED; ISI CLASS 2
- C3 - SAFETY-RELATED; ISI CLASS 3
- SR - SAFETY-RELATED FLUID BOUNDARY; NON-CODE CLASS
- NSR - NON-SAFETY-RELATED

IA,IB,IC,IIA,IIB & III DENOTES PIPING QA TYPES.

NOTES:

1. FOR VALVE POSITIONS SEE OPS MANUAL C PROCEDURE CHECKLIST.
2. UNLESS OTHERWISE SHOWN, CLASS BOUNDARIES STOP AT VENT AND DRAIN VALVES WITH DOWNSTREAM ITEMS (e.g., PIPE, CAPS, ETC.) CLASSED AS NON-SAFETY-RELATED.
3. DENOTES CATEGORY I VENTILATION ZONE
4. FOR SYMBOLS SEE XH-1-105, NF-39214.
5. I/1 DENOTES EQUIPMENT QA TYPE/ DESIGN CLASS.
6. STEM LEAKOFF ROUTED TO COLLECTION TROUGH IN RESIDUAL HEAT PIT.
7. FOR ROUTING OF VALVE STEM LEAK OFFS IN REACTOR BLDG SEE DWG NF-39250.
8. DENOTES CONTAINMENT PENETRATION NUMBER
9. SHELL SIDE C3
10. VALVE STEM LEAK OFF LINES ARE NSR.
11. C2/NSR BOUNDARY FOR 2TE-627/630 & 2TI-622/623 IS AT ITS THERMOWELL.
12. THE INTERNAL PARTS ARE REMOVED FROM CHECK VALVE 2RH-6-1.

REFERENCE DWGS

XH-1001-3 - RC SYSTEM FLOW DIA. UNIT 2
XH-1001-4 - VC SYSTEM FLOW DIA. UNIT 2
XH-1001-6 - SI SYSTEM FLOW DIA. UNIT 2
XH-1001-7 - SI SYSTEM FLOW DIA. UNIT 2
NF-39217-2 - CL SYSTEM FLOW DIA. UNIT 2
NF-39237 - CS SYSTEM FLOW DIA. UNIT 1 & 2
NF-39238 - SM SYSTEM FLOW DIA. UNIT 1 & 2
NF-39246-1 - CC STSTEM FLOW DIA. UNIT 2
NF-39248 - WL SYSTEM FLOW DIA. UNIT 1 & 2

SIGNIFICANT NO.	8630			2	J104 / 9070	1	4822
GROUP	1	2	3	4	5	CL	6

DWN MAW DATE 8-03-07
CHECKED
PROJECT NO.
APP'D & CERT.
FILMED

FLOW DIAGRAM
RESIDUAL HEAT REMOVAL SYSTEM
UNIT 2

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING, MINNESOTA

SCALE NONE REV 81

XH-1001-8

$$USERNAME$$
$$$$$$SYTIME$$$$$$$$$$$$SYDATE$$$$$$
$$$$$$$$$DESIGNFIL$$$$$$$$$

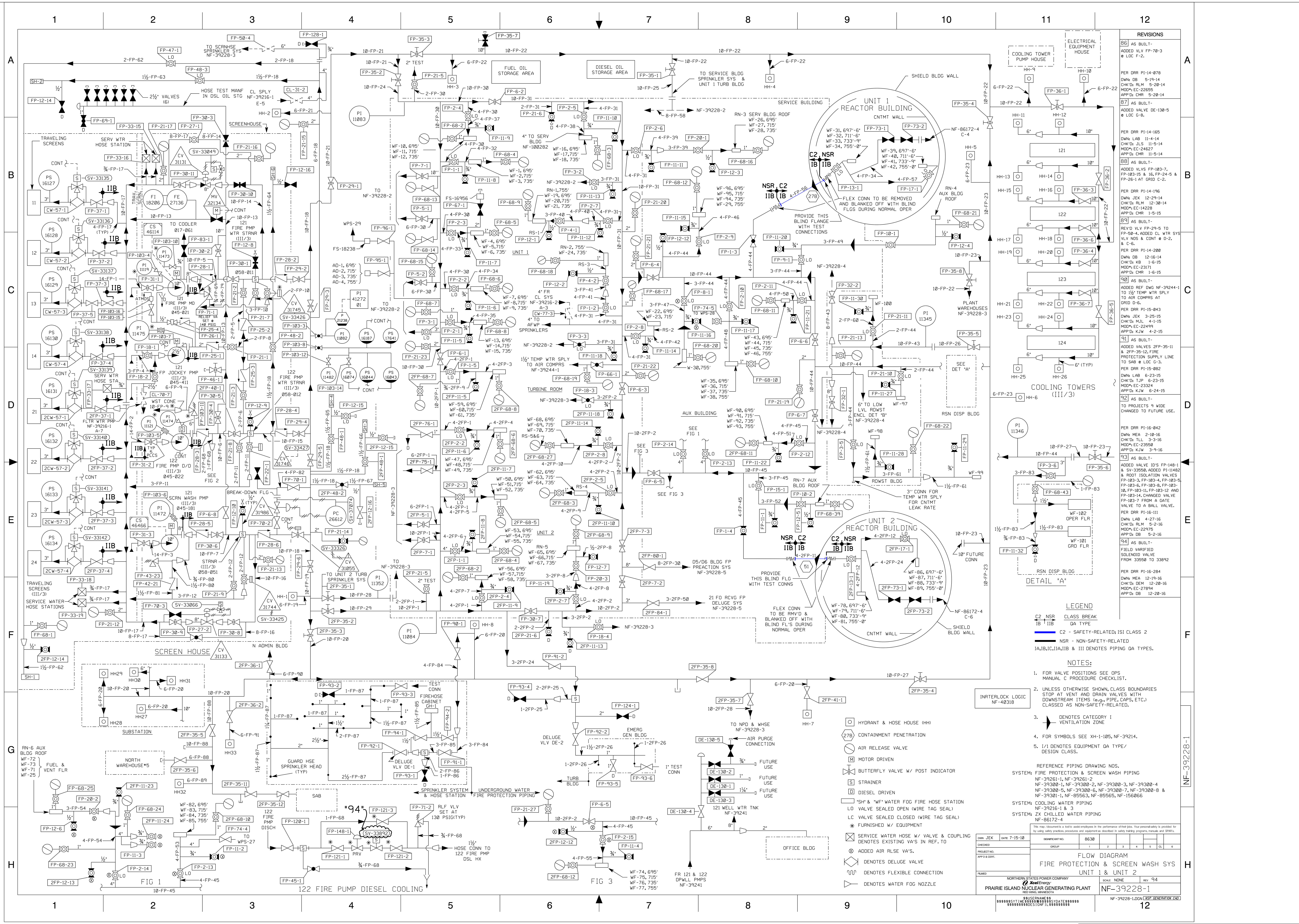
XH-1001-8.DGN NSRP GENERATION CAD

XH-1001-8

01516979

FIGURE 10.2-12 REV. 34

CAD FILE: U10212.DGN



60300000133 1

FIGURE 10.3-1 REV. 35

CAD FILE: U10301.DGN

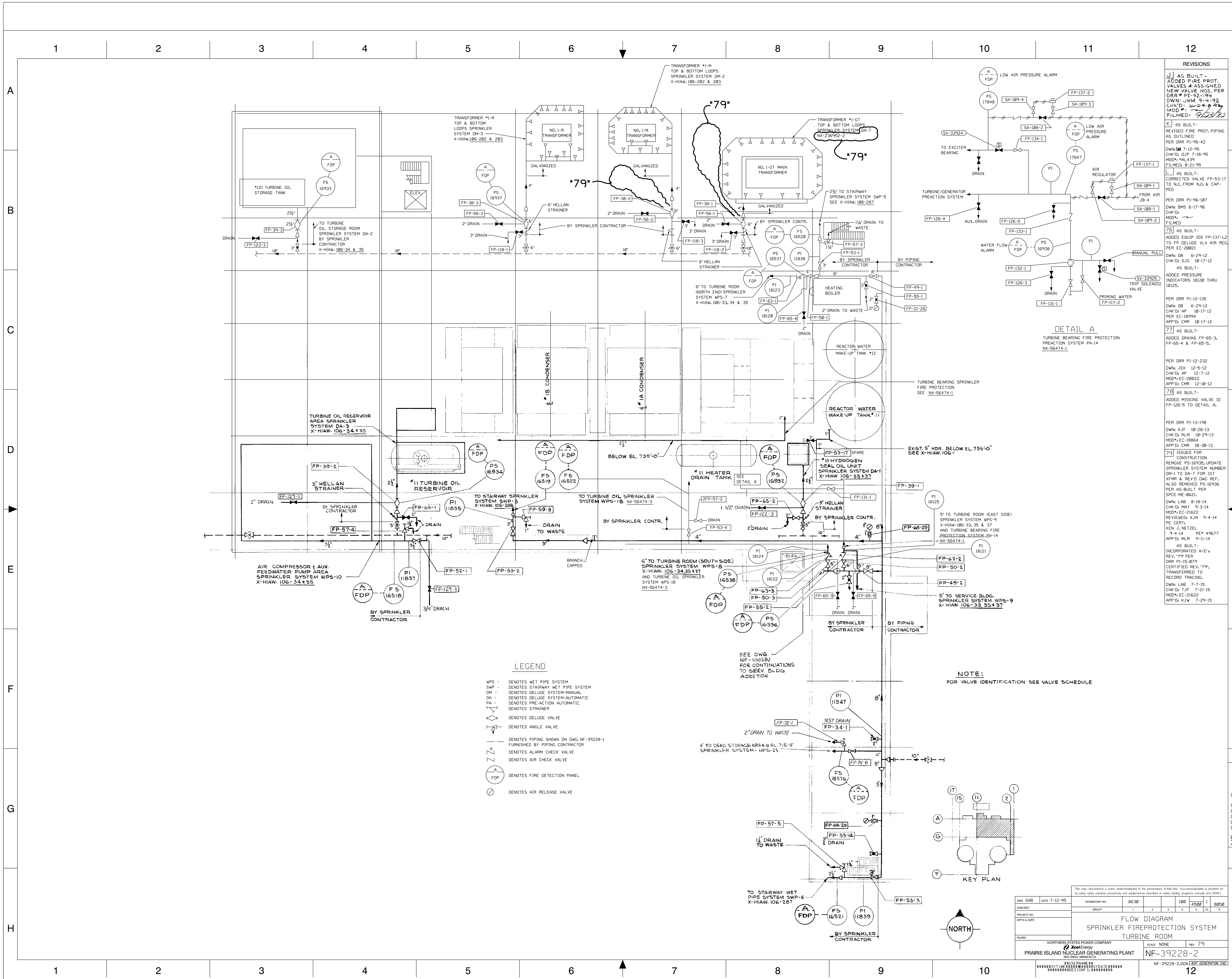


FIGURE 10.3-2 REV. 34

CAD FILE: U10302.DGN

01516979

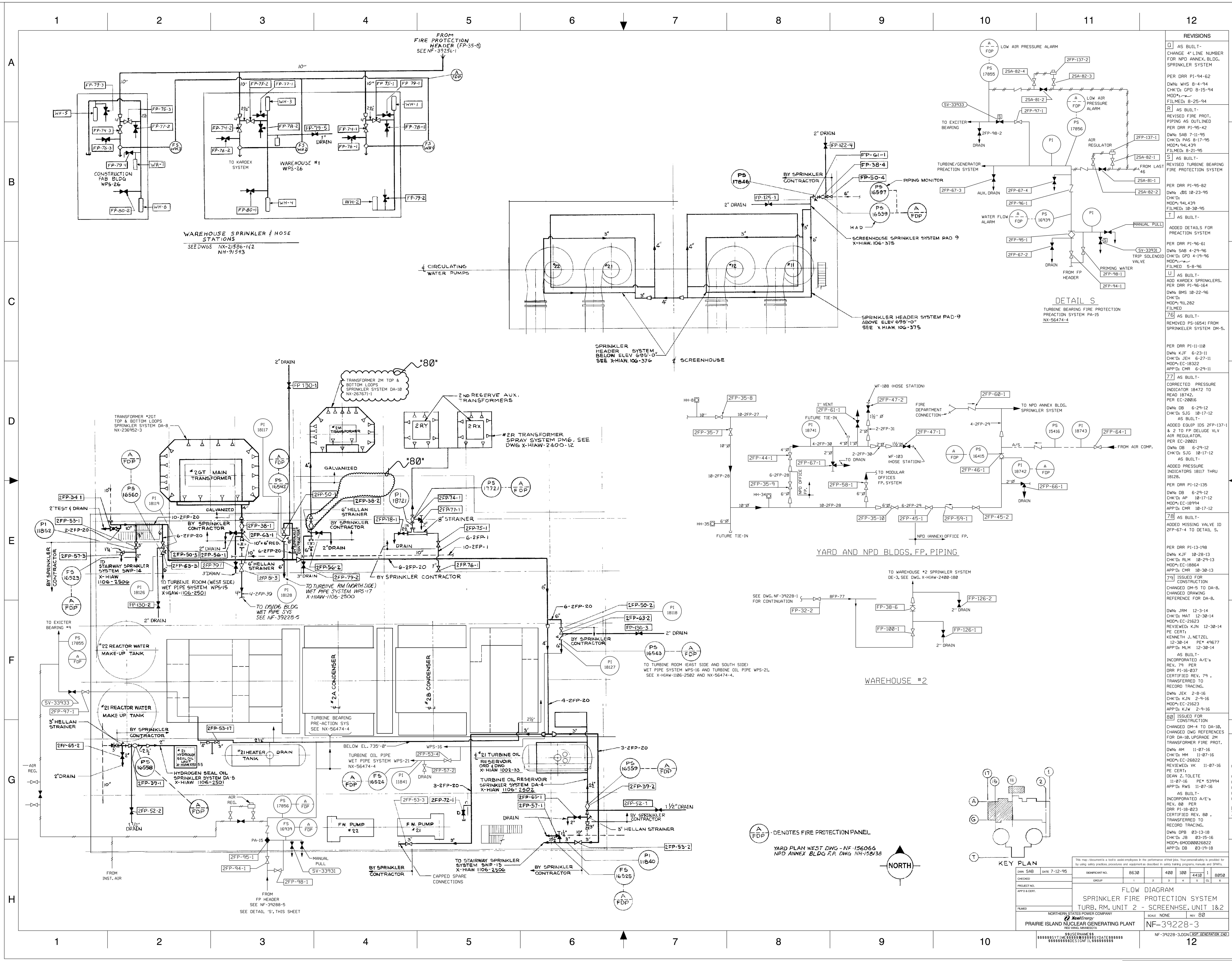


FIGURE 10.3-3 REV. 35

60300000133 1

CAD FILE: U10303.DGN

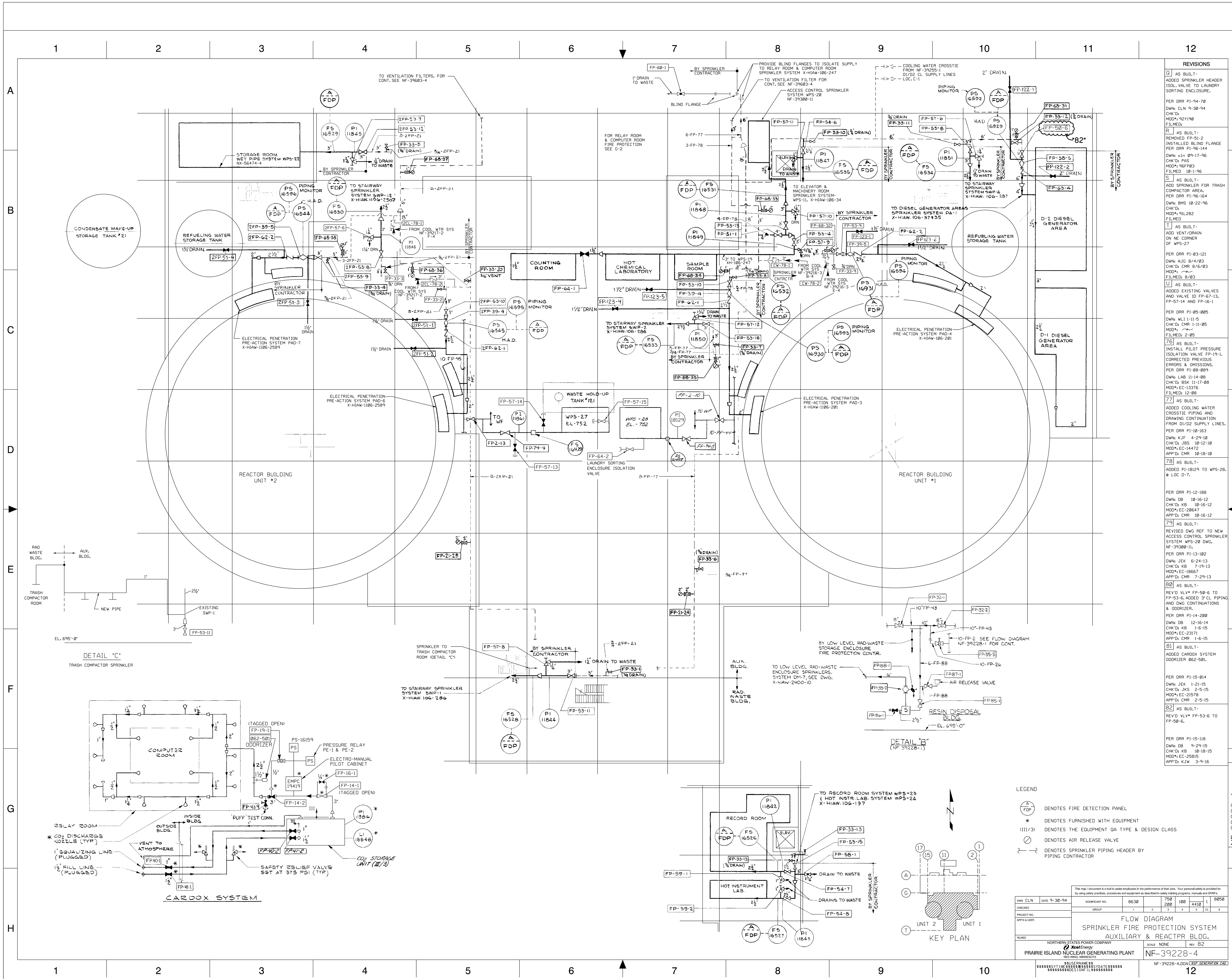


FIGURE 10.3-4 REV. 34

01516979

CAD FILE: U10304.DGN

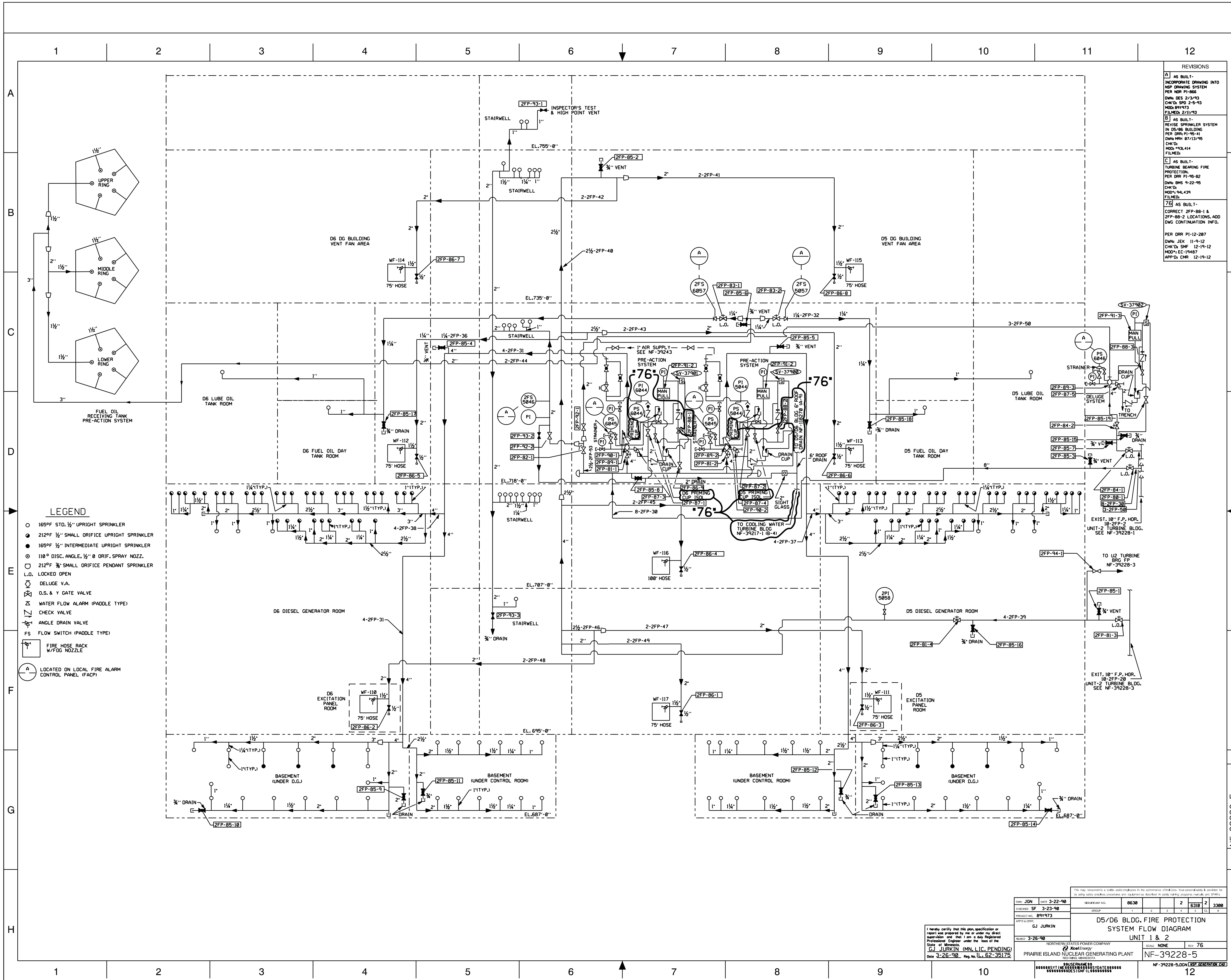


FIGURE 10.3-5 REV. 33

CAD FILE: U10305.DGN

01429088

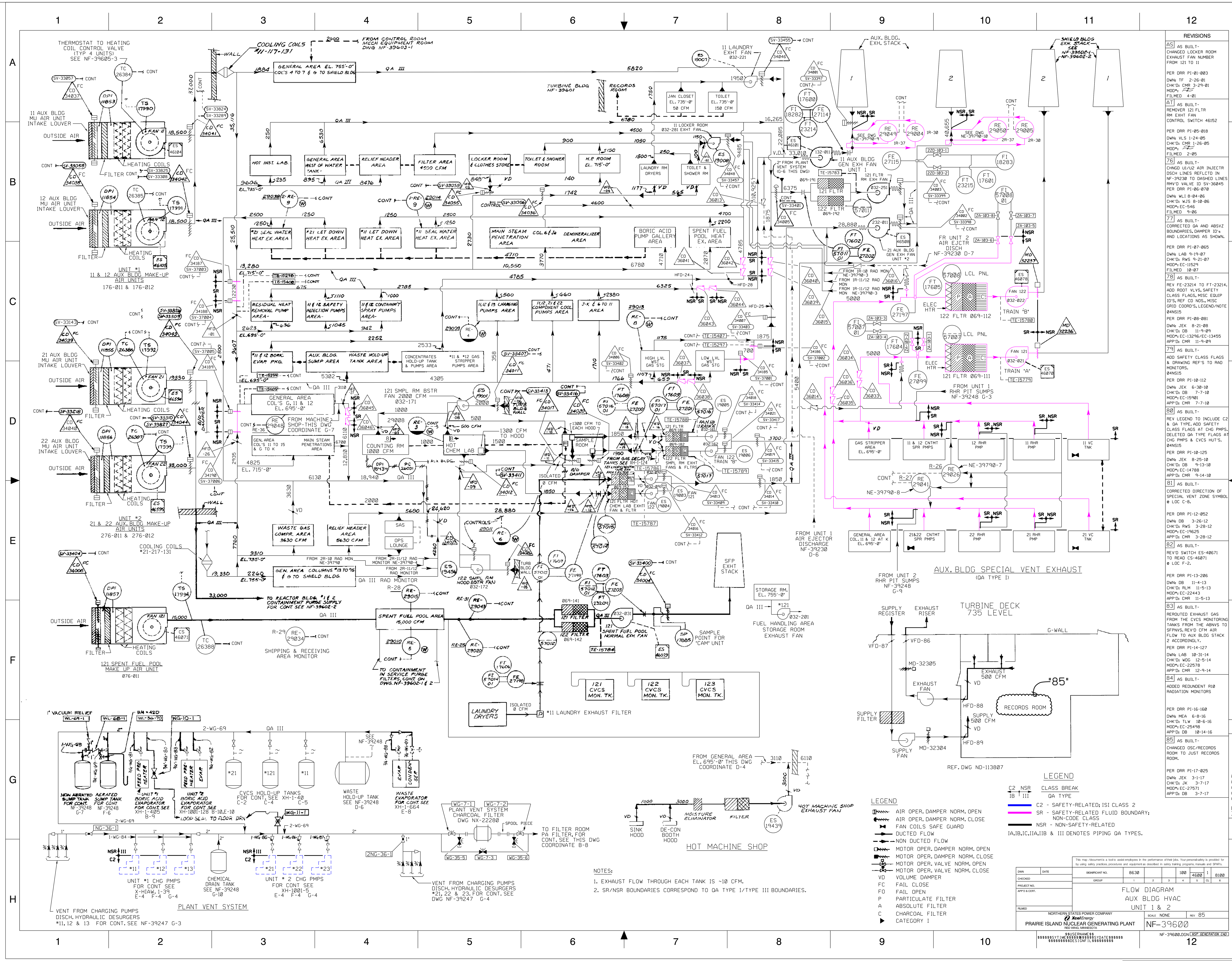


FIGURE 10.3-6 REV. 35

60300001331

CAD FILE: U10306.DGN

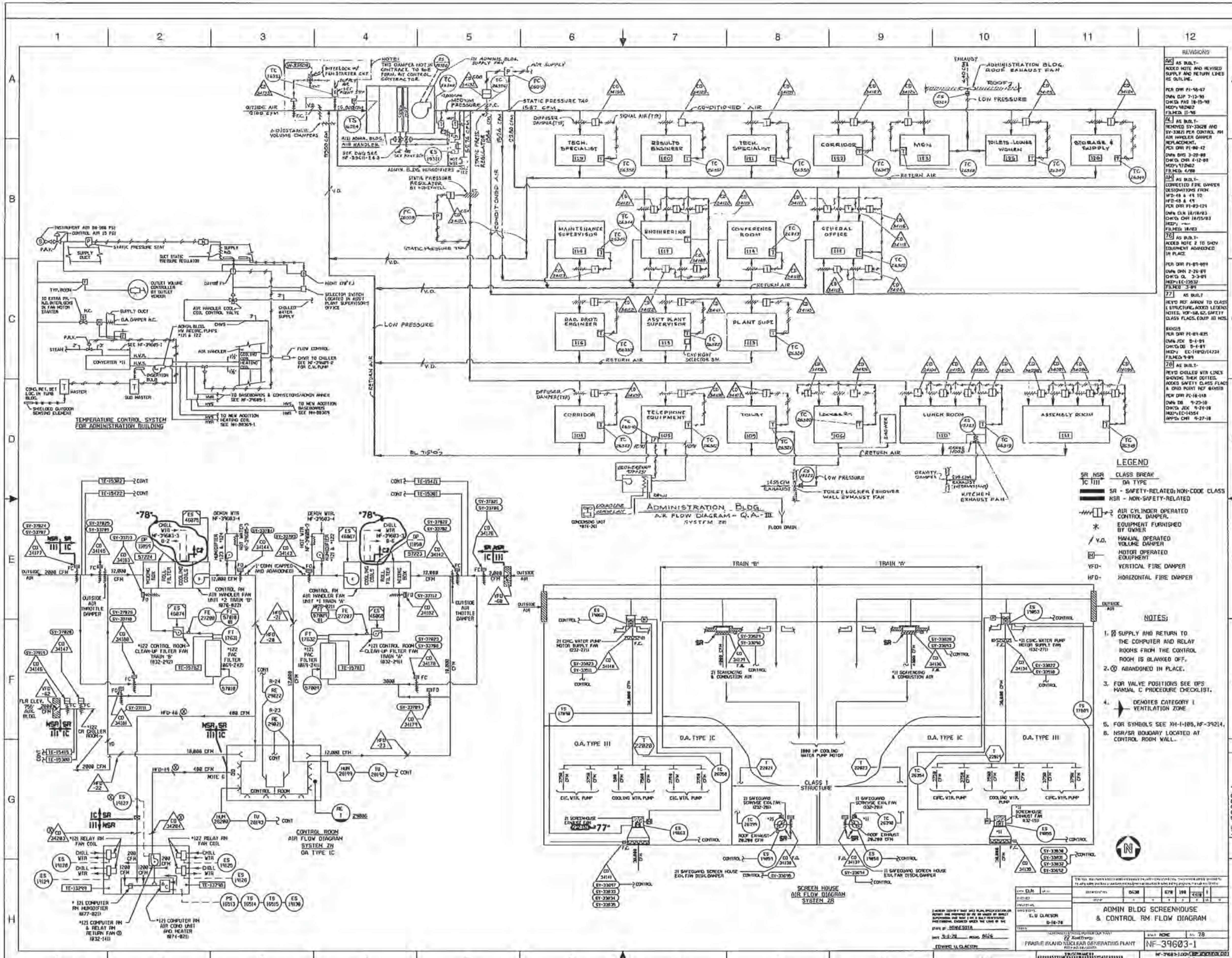


FIGURE 10.3-7 REV. 32

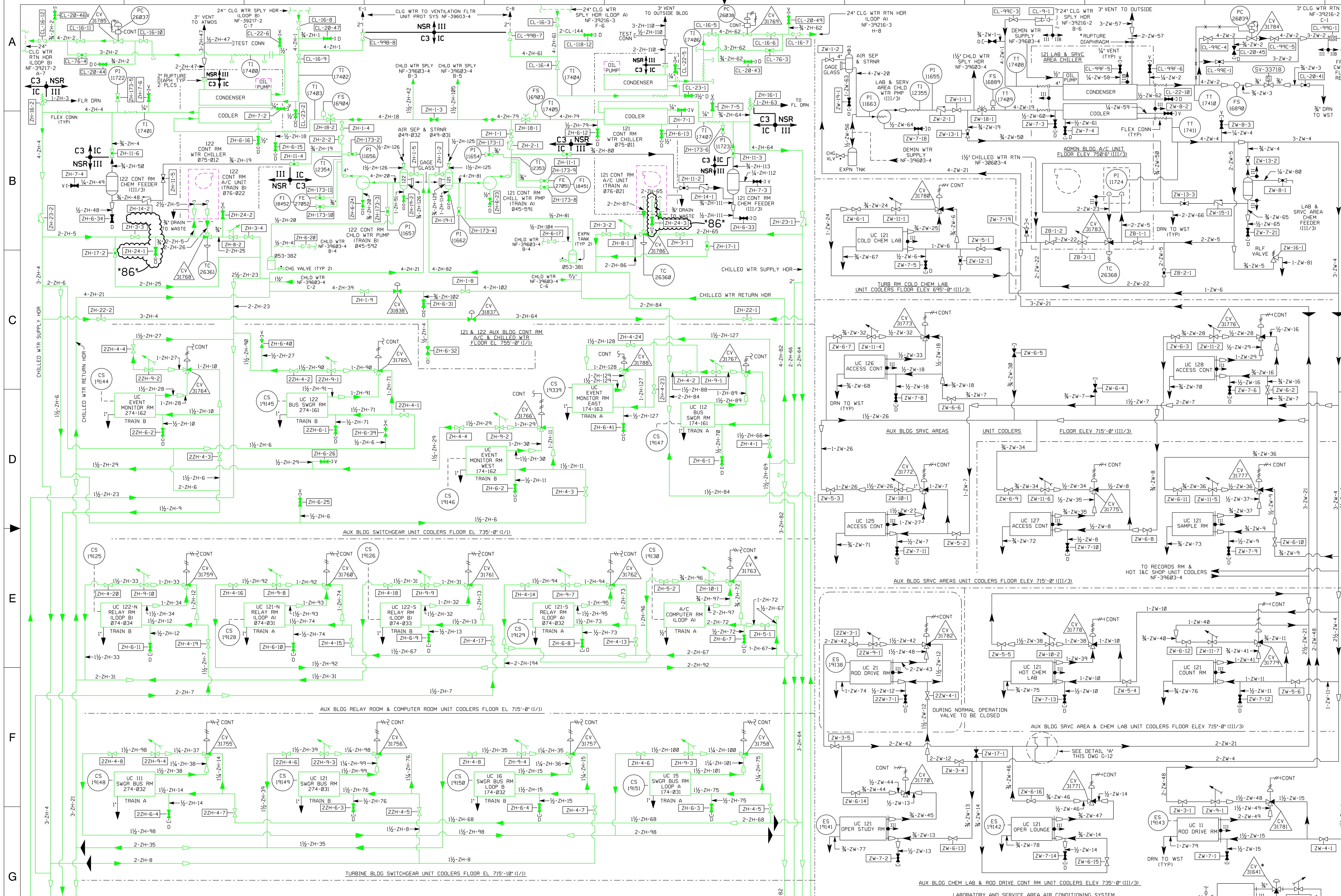
CAD FILE: UI0307.DGN

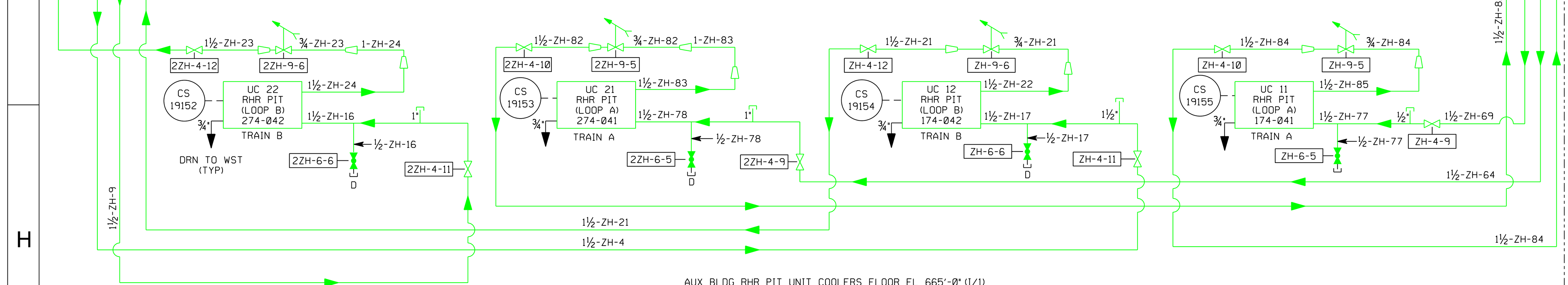
01352784

60300001331

FIGURE 10.3-8 REV. 35

CAD FILE: U10308.DGN





NOTES:

1. FOR VALVE POSITIONS SEE OPS MANUAL C PROCEDURE CHECKLIST.
2. UNLESS OTHERWISE SHOWN, CLASS BOUNDARIES STOP AT VENT AND DRAIN VALVES WITH DOWNSTREAM ITEMS (e.g., PIPE, CAPS, ETC.) CLASSED AS NON-SAFETY-RELATED.
3. DENOTES CATEGORY I VENTILATION ZONE
4. FOR SYMBOLS SEE XH-1-105, NF-39214.
5. I/1 DENOTES EQUIPMENT QA TYPE/ DESIGN CLASS.
6. * DENOTES FURNISHED WITH EQUIPMENT.
7. DRN LINE ON UC IS NSR.

LEGEND

C3 NSR / IC III — CLASS BREAK / QA TYPE

- C1 - SAFETY- RELATED; ISI CLASS 1
- C2 - SAFETY-RELATED; ISI CLASS 2
- C3 - SAFETY-RELATED; ISI CLASS 3
- SR - SAFETY-RELATED FLUID BOUNDARY; NON-CODE CLASS
- NSR - NON-SAFETY-RELATED

IA,IB,IC,IIA,IIB & III DENOTES PIPING QA TYPES.

C3 NSR / IC III — TYPICAL BOUNDARY DESIGNATION FOR INSTRUMENTATION WITHIN BOUNDARY ISI CLASS

DETAIL "A"

REVISIONS

76 AS BUILT- UPDATE WITH STANDARD BORDER FOR CONSISTENCY WITH DRAWING CONTINUATION COORDINATES PER DRR PI-10-048
DWN: DB 5-5-10
CHK'D: JEK 5-11-10
MOD#: EC-14552
APP'D: CMR 5-12-10

77 AS BUILT ZH PORTION REDRAWN PER SYS WALKDOWN, INCORP SAFETY CLASS FLAGS NOTES AND LEGEND.
04NS15
PER DRR PI-10-148
DWN: DB 9-21-10
CHK'D: JEK 9-23-10
REVIEWED: WJI 9-24-10
MOD#: EC-14554
APP'D: CMR 9-27-10

78 AS BUILT- ADDED DRAWING CONT. AND COORDINATES FOR DRAIN LINES FROM 121 & 122 C.R. AIR CONDITIONING UNITS. PER DRR PI-09-163
DWN: KJF 10-4-10
CHK'D: JBS 10-12-10
MOD#: EC-14472
APP'D: CMR 10-18-10

79 AS BUILT- REV'D LINE NO ¾-ZH-61 TO READ 2-CL-144.
04NS15
PER DRR PI-10-182
DWN: DB 11-18-10
CHK'D: JEK 11-24-10
MOD#: EC-17064
APP'D: CMR 11-29-10

80 AS BUILT- REMOVED PIPE & CAP AT VALVE ID ZH-6-34 TO REFLECT PLANT CONFIG. PER EC-17777.
DWN: KJF 10-4-11
CHK'D: MGC 10-10-11
AS BUILT- CHG'D TEMP INDICATOR ID FROM TI-12355 TO TI-12353 @ DWG COORD B-5 & FROM TI-12353 TO 12355 @ A-8
PER DRR PI-10-200
DWN: KJF 9-30-11
CHK'D: WEH 10-3-11
MOD#: EC-16866
APP'D: CMR 10-11-11

81 AS BUILT- RENAMED U/C ½" POTABLE WTR FOR HUMIDIFIER TO READ SAS & CAPPED ¼" TAP OFF OF SAS U/C LOC G-12
PER DRR PI-13-096
DWN: DB 6-12-13
CHK'D: GTL 6-17-13
MOD#: EC-20439
APP'D: CMR 6-17-13

82 AS BUILT- REVISED DWG TO REFLECT 121 & 122 CONT RM AIR HANDLER DRAIN PATH REMOVAL @ LOC B-2 & B-6.
PER DRR PI-13-236
DWN: KJF 12-10-13
CHK'D: CMR 12-11-13
MOD#: EC-22967
APP'D: CMR 12-11-13

83 AS BUILT- VALVE ZH-6-23 & PIPE NSR CHANGED TO C3-SAFETY-RELATED; ISI CLASS 3. @ LOC B-5
PER DRR PI-15-026
DWN: MEA 2-26-15
CHK'D: JDF 3-6-15
MOD#: EC-23559
APP'D: KJW 3-6-15

84 AS BUILT- CORRECT EQUIPMENT NUMBER /LABEL ON 121 & 122 CONT RM A/C UNITS, (TRAIN A & B).
PER DRR PI-16-220
DWN: DPB 10-18-16
CHK'D: RM 10-18-16
MOD#: EC-20108
APP'D: DB 10-19-16

85 AS BUILT- VALVE CL-20-45 WAS GLOBE VALVE TO GATE VALVE.
PER DRR PI-17-069
DWN: MEA 4-5-17
CHK'D: RLM 4-6-17
MOD#: EC-17647
APP'D: DB 4-6-17

86 AS BUILT- ADDED VALVE ZH-24-3 TO VENT A/C UNIT 045-1011 CHG. CONFIG OF ZH-24-1 FROM VENT TO DRAIN
PER DRR PI-17-108
DWN: MEA 6-7-17
CHK'D: WJS 6-7-17
MOD#: EC-15942
APP'D: DB 6-7-17

NF-39603-3

DWN DB	DATE 9-21-10	SIGNIFICANT NO.	8630			100	1300	1	1180
CHECKED		GROUP	1	2	3	4	5	CL	6
PROJECT NO.									
APP'D & CERT.									
FILMED									

FLOW DIAGRAM LAB & SERV AREA
A/C & CHLD WTR SFGD SYS
UNIT 1 & 2

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING, MINNESOTA

SCALE NONE REV 86

NF-39603-3

$$USERNAME$$
$$$$$$SYTIME$$$$$$$$$$$$SYDATE$$$$$$
$$$$$$$$$DESIGNFIL$$$$$$$$$

NF-39603-3.DGN NSP GENERATION CAD

60300001331

FIGURE 10.3-9 REV. 35

CAD FILE: U10309.DGN

FIGURE 10.3-10 REV. 35

60300001331

CAD FILE: U10310.DGN

FIGURE 10.3-11 REV. 35

60300001331

CAD FILE: U10311.DGN

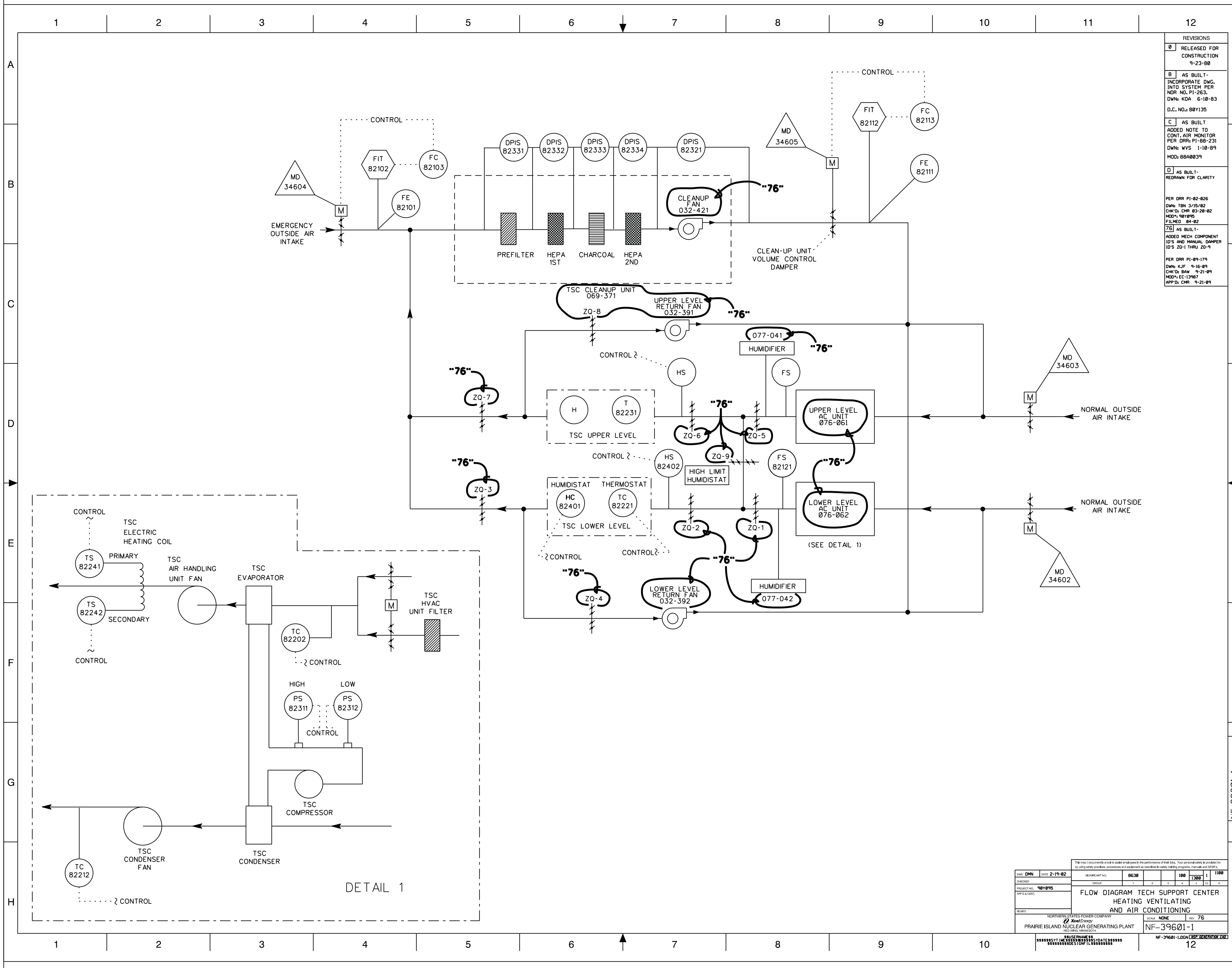


FIGURE 10.3-12 REV. 32

CAD FILE: U10312.DGN

01352784

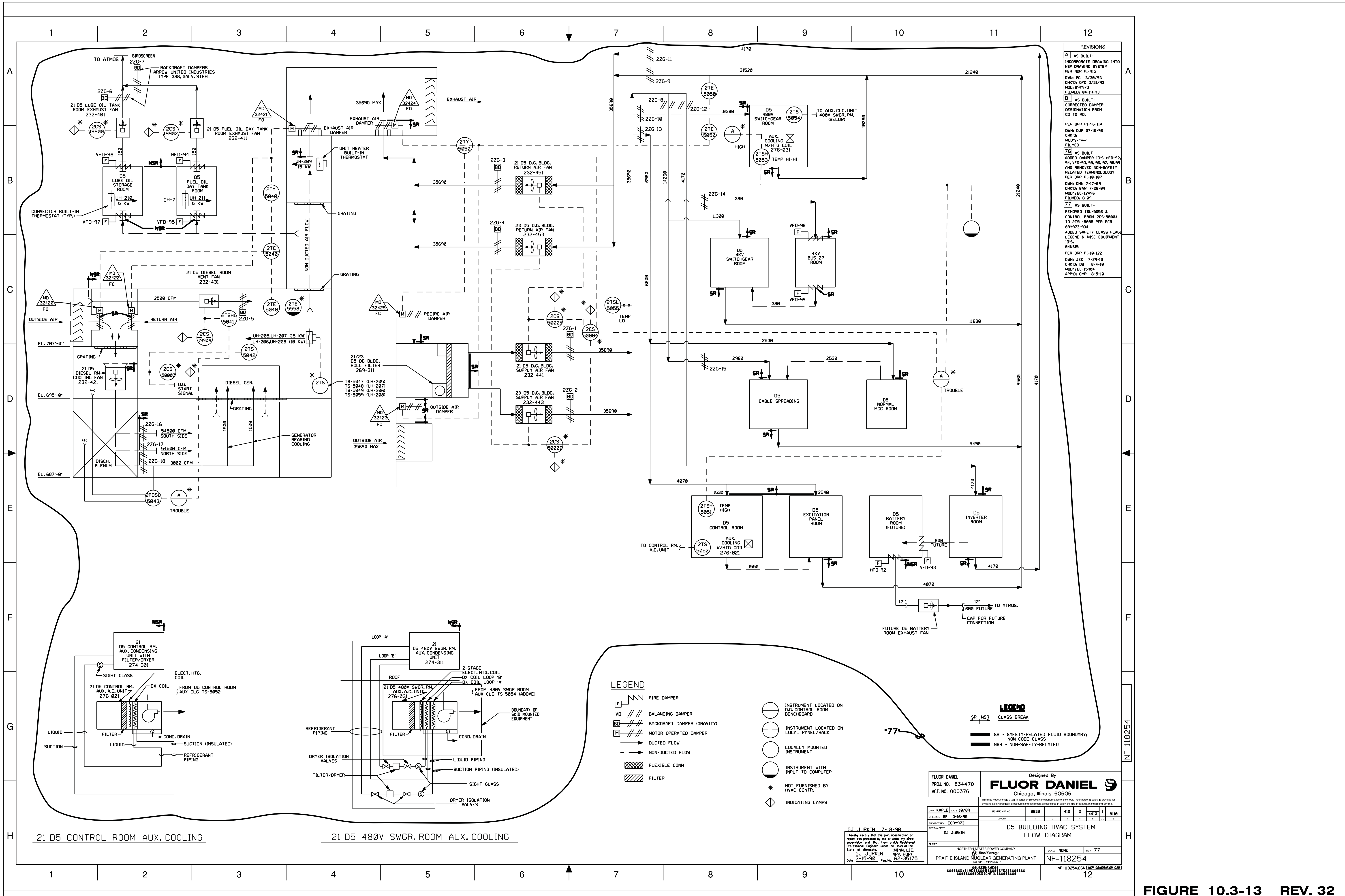


FIGURE 10.3-13 REV. 32

CAD FILE: U10313.DGN

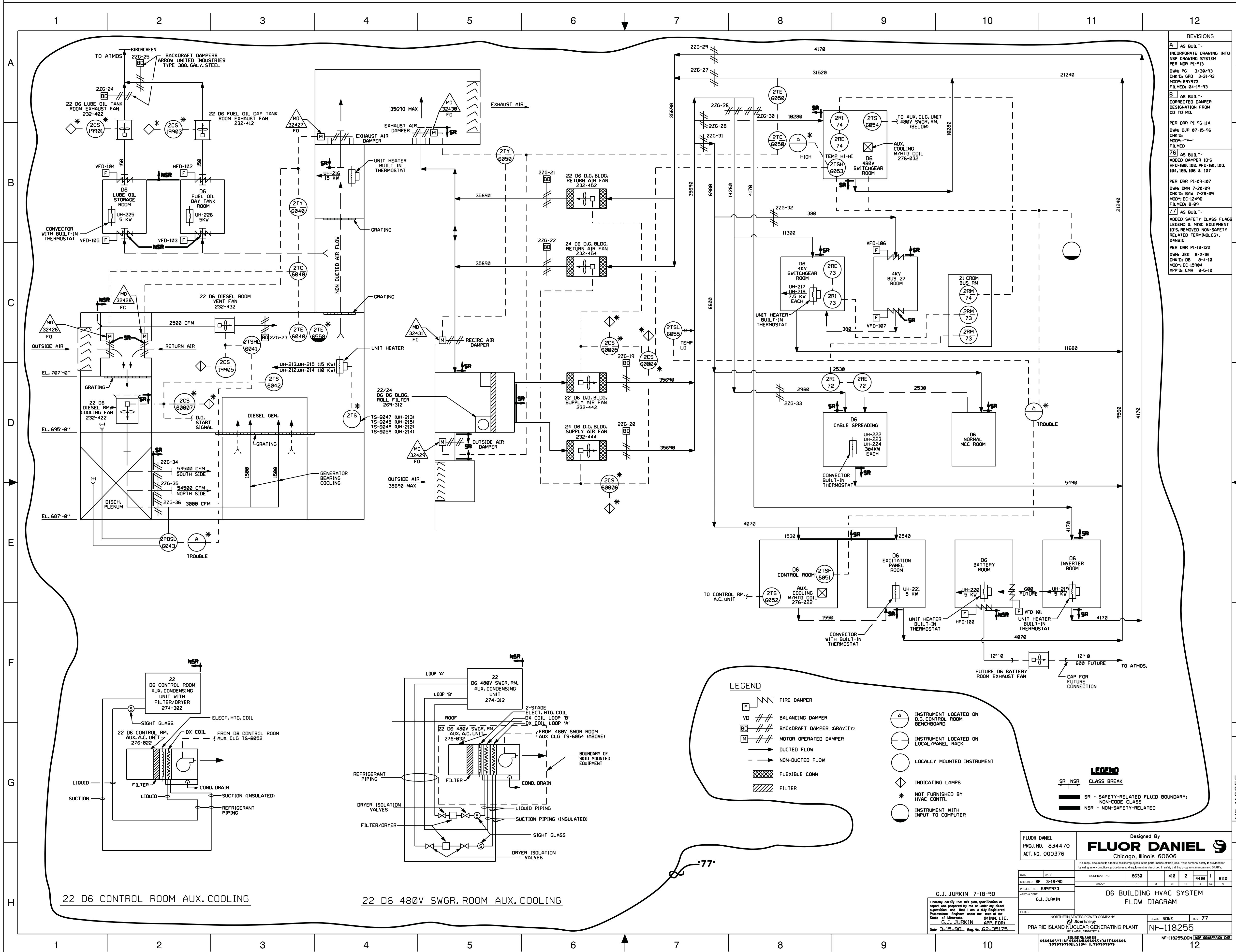


FIGURE 10.3-14 REV. 32

01352784

CAD FILE: U10314.DGN

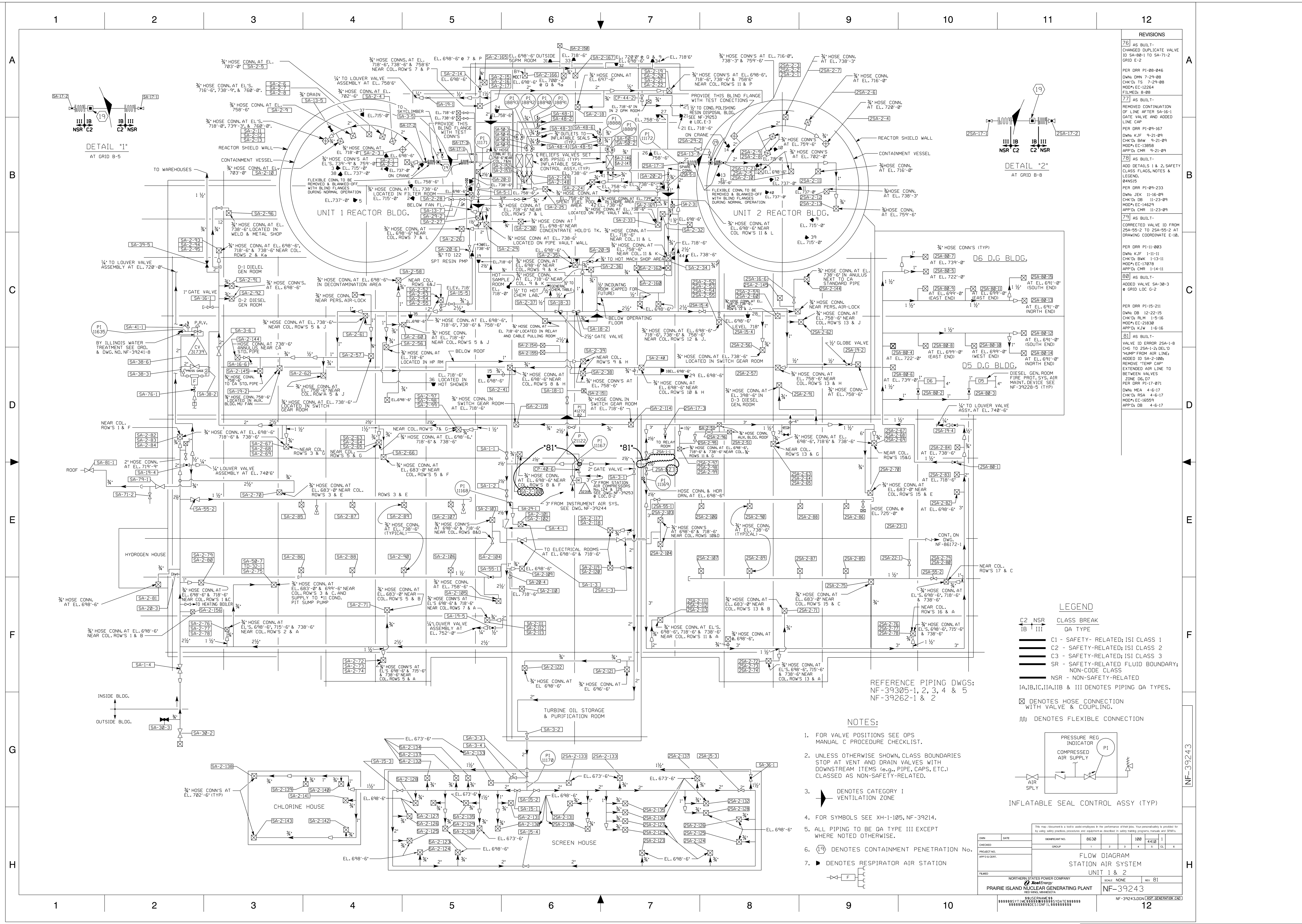


FIGURE 10.3-15 REV. 35

60300001331

CAD FILE: U10315.DGN

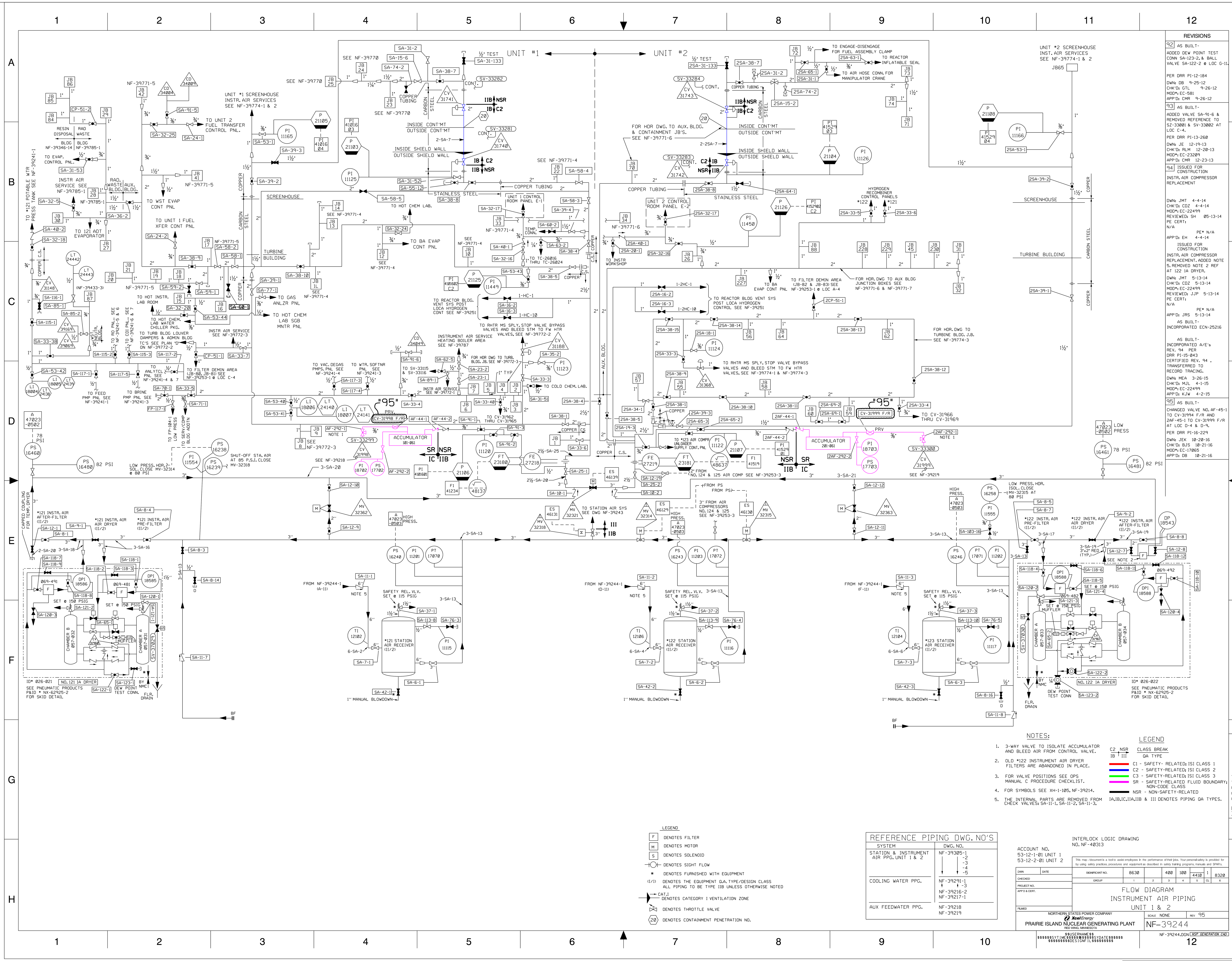
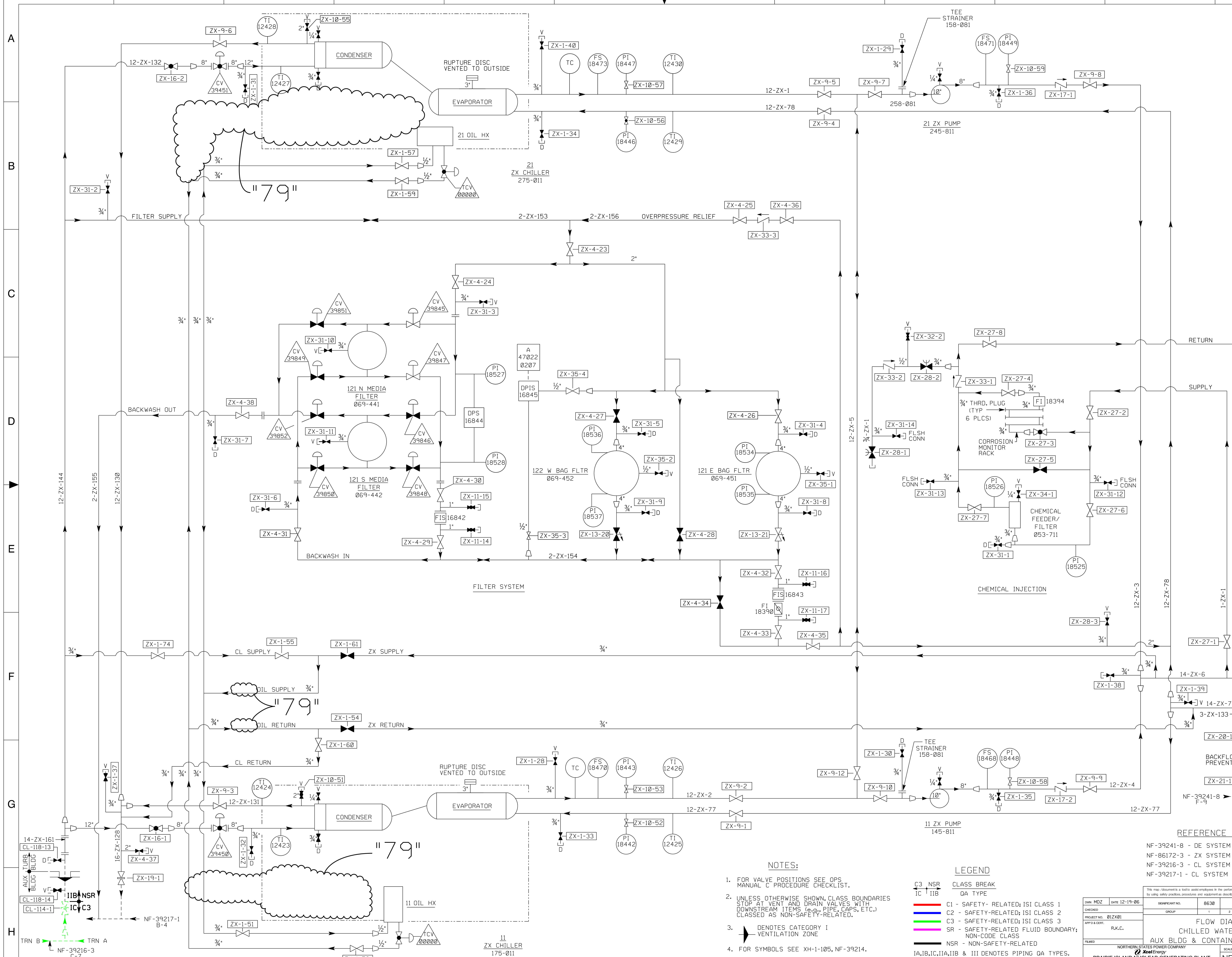


FIGURE 10.3-16 REV. 35

CAD FILE: U10316.DGN

60300001331



NOTES:

1. FOR VALVE POSITIONS SEE OPS. MANUAL C PROCEDURE CHECKLIST.
2. UNLESS OTHERWISE SHOWN, CLASS BOUNDARIES STOP AT VENT AND DRAIN VALVES WITH DOWNSTREAM ITEMS (e.g., PIPE, CAPS, ETC.) CLASSED AS NON-SAFETY-RELATED.
3. DENOTES CATEGORY I VENTILATION ZONE
4. FOR SYMBOLS SEE XH-1-105, NF-39214.

LEGEND

C3 NSR / IC IIB — CLASS BREAK / QA TYPE

- C1 - SAFETY-RELATED; ISI CLASS 1
- C2 - SAFETY-RELATED; ISI CLASS 2
- C3 - SAFETY-RELATED; ISI CLASS 3
- SR - SAFETY-RELATED FLUID BOUNDARY; NON-CODE CLASS
- NSR - NON-SAFETY-RELATED

IA,IB,IC,IIA,IIB & III DENOTES PIPING QA TYPES.

REFERENCE DWGS

- NF-39241-8 - DE SYSTEM FLOW DIA. UNIT 1 & 2
- NF-86172-3 - ZX SYSTEM FLOW DIA. UNIT 1 & 2
- NF-39216-3 - CL SYSTEM FLOW DIA. UNIT 1
- NF-39217-1 - CL SYSTEM FLOW DIA. UNIT 2

REVISIONS

AG	AS BUILT. DRAWING REVISED AND REDRAWN FOR CLARITY. PER DRR PI-04-002. DWN: DB 3-13-03. CHK'D: R.K.C. 6-9-03. MOD.#: 01ZX01. RELOC. 3" DEMIN LINE. REVERSED FLOW ARROWS AS SHOWN. DWN: DB 6-9-03. CHK'D: R.K.C. 6-9-03. MOD#: 01ZX01. ADDED EQUIPMENT NO. TO STRAINERS. ADDED LINE# 14-ZX-161. MOD#: 01ZX01. DWN: DB 9-14-03. CHK'D: R.K.C. 11-21-03. FILMED 2-04
76	AS BUILT- REV'D TO CORRECT FOR CONTINUATION REFERENCE DRAWING NO.'s. PER DRR PI-09-104. DWN: LAB 7-9-09. CHK'D: BAW 7-14-09. MOD#: EC-11686. FILMED: 8-09
77	AS BUILT. REDRAWN PER SYSTEM WALKDOWN. INCORPORATED SAFETY CLASS DESIGNATIONS. 04NS15. PER DRR PI-10-087. DWN: JEK 5-4-10. CHK'D: DB 5-12-10. REVIEWED: WJI 5-12-10. MOD#: EC-14553. APP'D: CMR 5-12-10
78	AS BUILT- CORRECTED 11 PURGE UNIT EVAPORATOR VENT VALVE FROM ZX-1-41 TO ZX-1-28. PER DRR PI-11-193. DWN: LAB 10-13-11. CHK'D: RWS 10-18-11. MOD#: EC-18734. APP'D: CMR 10-19-11
79	AS BUILT- REMOVAL OF PIPING AND EQUIPMENT. PER DRR PI-16-115. DWN: MEA 3-15-16. CHK'D: TEO 4-25-16. MOD#: EC-24952. APP'D: DB 4-29-16

FLOW DIAGRAM
CHILLED WATER SYSTEM
AUX BLDG & CONTAINMENT UNITS 1 & 2

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING, MINNESOTA

DWN MDZ DATE 12-19-06 · PROJECT NO. 01ZX01 · R.K.C. · SCALE NONE · REV 79

NF-86172-1

60300000331

FIGURE 10.3-17 REV. 35

CAD FILE: U10317.DGN

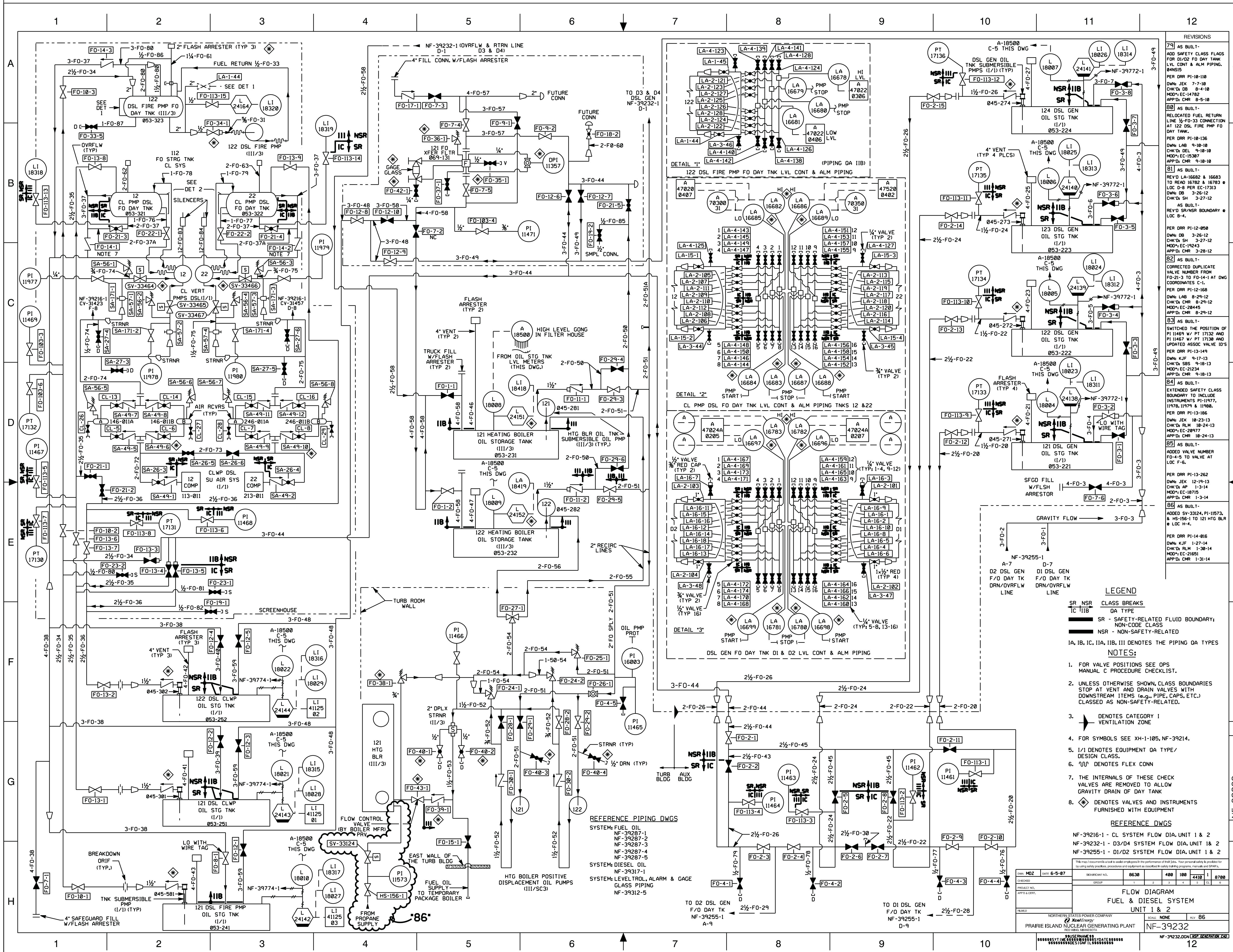
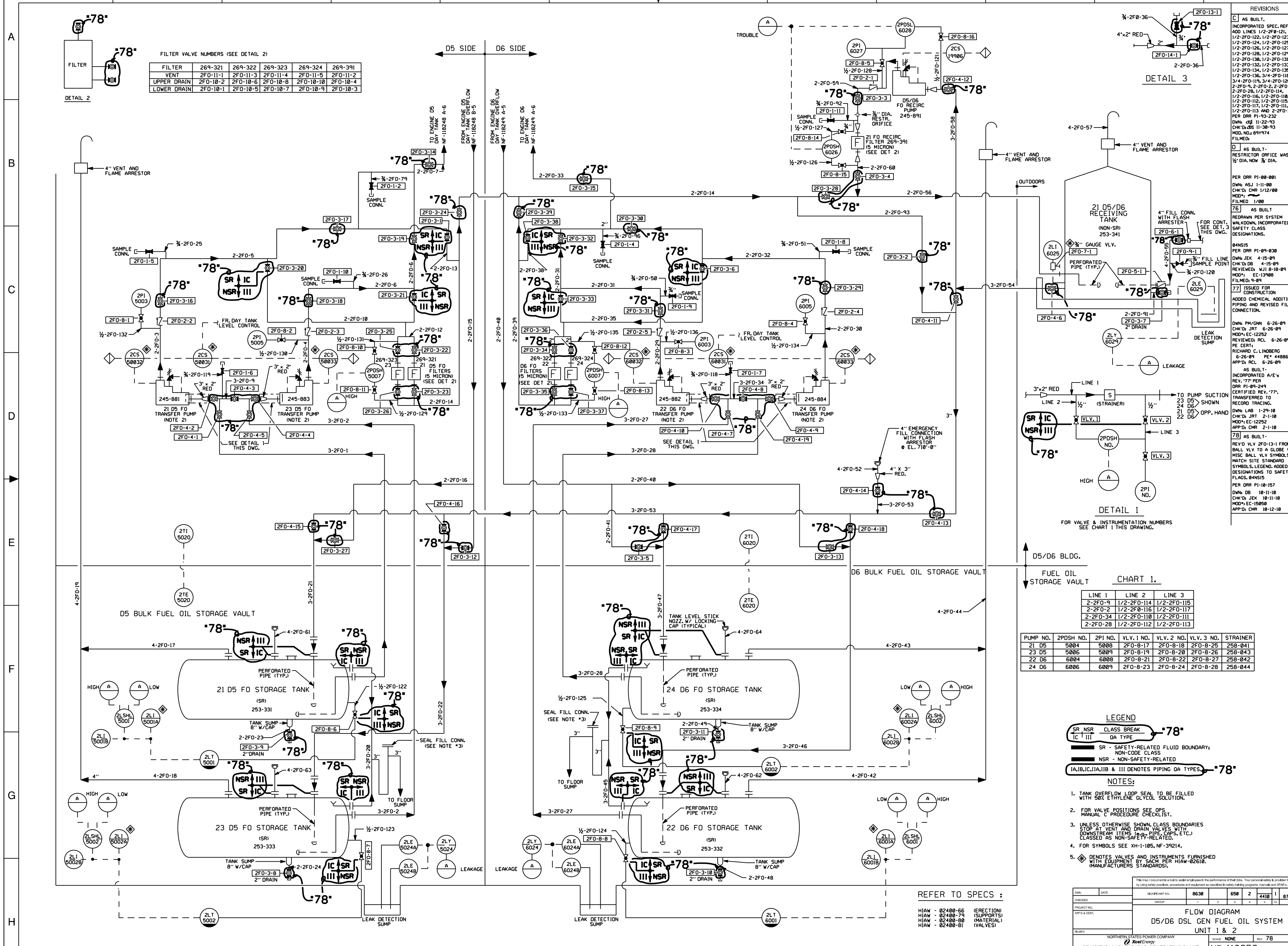


FIGURE 10.3-18 REV. 33

CAD FILE: U10318.DGN



FILTER VALVE NUMBERS (SEE DETAIL 2)

FILTER	269-321	269-322	269-323	269-324	269-391
VENT	2FO-11-1	2FO-11-3	2FO-11-4	2FO-11-5	2FO-11-2
UPPER DRAIN	2FO-10-2	2FO-10-6	2FO-10-8	2FO-10-10	2FO-10-4
LOWER DRAIN	2FO-10-1	2FO-10-5	2FO-10-7	2FO-10-9	2FO-10-3

CHART 1.

LINE 1	LINE 2	LINE 3
2-2FO-9	1/2-2FO-114	1/2-2FO-115
2-2FO-2	1/2-2FO-116	1/2-2FO-117
2-2FO-34	1/2-2FO-110	1/2-2FO-111
2-2FO-28	1/2-2FO-112	1/2-2FO-113

PUMP NO.	2PDSH NO.	2PI NO.	VLV. 1 NO.	VLV. 2 NO.	VLV. 3 NO.	STRAINER
21 D5	5004	5008	2FO-8-17	2FO-8-18	2FO-8-25	258-041
23 D5	5006	5009	2FO-8-19	2FO-8-20	2FO-8-26	258-043
22 D6	6004	6008	2FO-8-21	2FO-8-22	2FO-8-27	258-042
24 D6	6006	6009	2FO-8-23	2FO-8-24	2FO-8-28	258-044

LEGEND

SR NSR IC III CLASS BREAK / QA TYPE "78"

SR - SAFETY-RELATED FLUID BOUNDARY; NON-CODE CLASS

NSR - NON-SAFETY-RELATED

IA,IB,IC,IIA,IIB & III DENOTES PIPING QA TYPES. "78"

NOTES:

1. TANK OVERFLOW LOOP SEAL TO BE FILLED WITH 50% ETHYLENE GLYCOL SOLUTION.
2. FOR VALVE POSITIONS SEE OPS MANUAL C PROCEDURE CHECKLIST.
3. UNLESS OTHERWISE SHOWN, CLASS BOUNDARIES STOP AT VENT AND DRAIN VALVES WITH DOWNSTREAM ITEMS (e.g., PIPE, CAPS, ETC.) CLASSED AS NON-SAFETY-RELATED.
4. FOR SYMBOLS SEE XH-1-105, NF-39214.
5. ◈ DENOTES VALVES AND INSTRUMENTS FURNISHED WITH EQUIPMENT BY SACM PER HIAW-02610. (MANUFACTURERS STANDARDS).

REFER TO SPECS :

HIAW - 02400-66 (ERECTION)
HIAW - 02400-79 (SUPPORTS)
HIAW - 02400-80 (MATERIAL)
HIAW - 02400-81 (VALVES)

DWN DATE CHECKED PROJECT NO. APP'D & CERT. FILMED

SIGNIFICANT NO. 8630 650 2 4410 1 8720
GROUP 1 2 3 4 5 CL 6

FLOW DIAGRAM
D5/D6 DSL GEN FUEL OIL SYSTEM
UNIT 1 & 2

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING, MINNESOTA

SCALE NONE REV 78

NF-118252

NF-118252.DGN NSP GENERATION CAD

01352784

FIGURE 10.3-19 REV. 32

CAD FILE: U10319.DGN

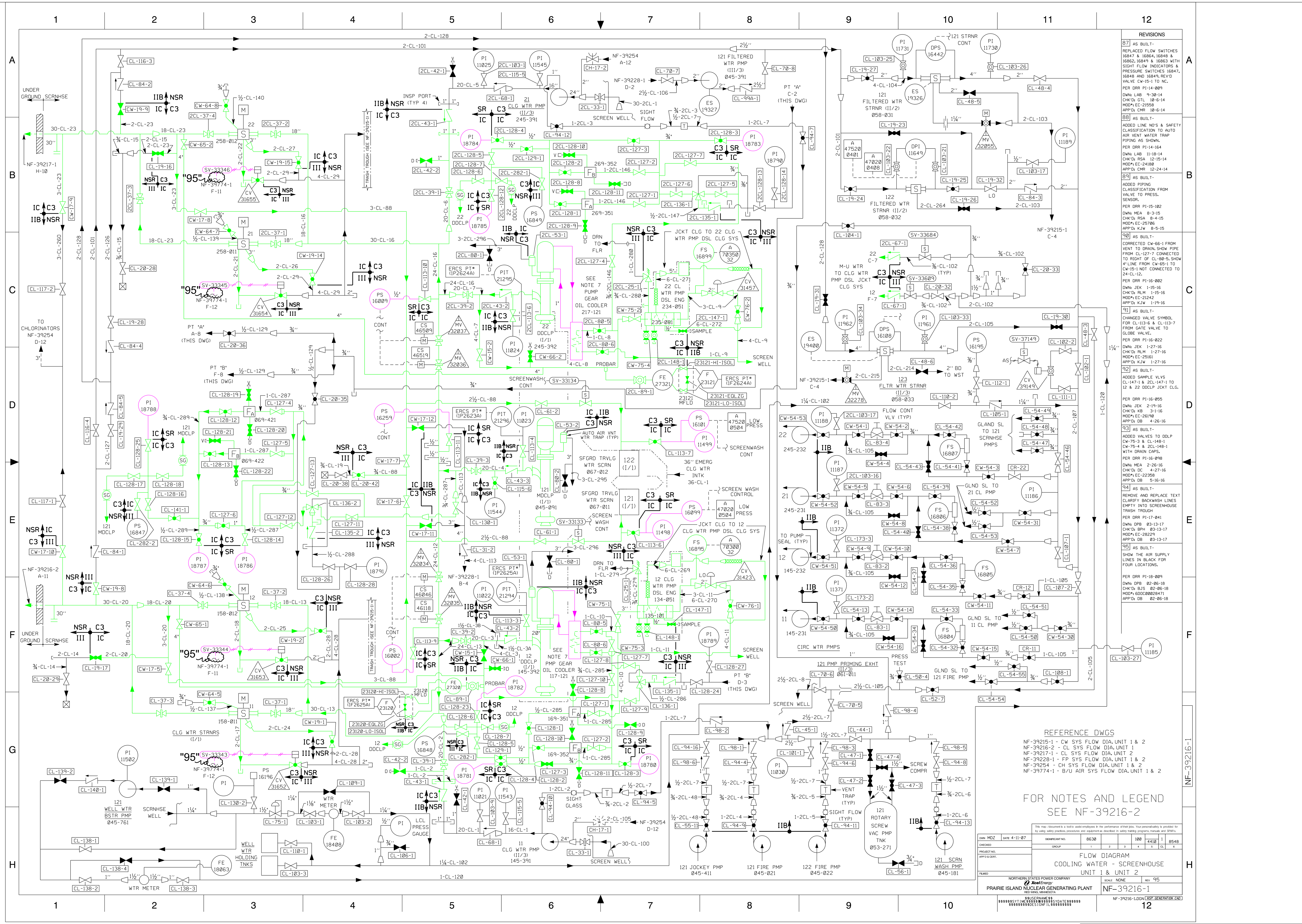
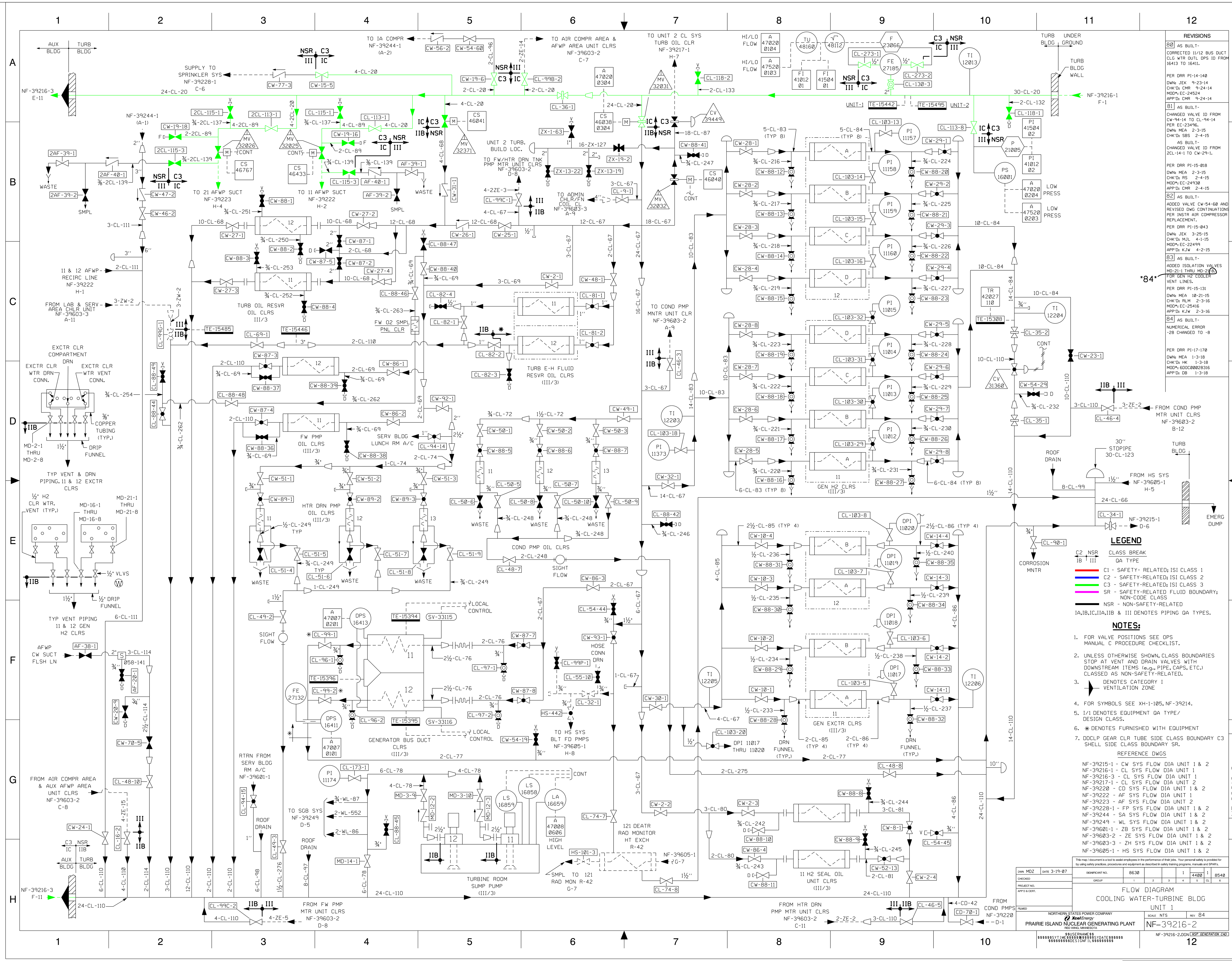


FIGURE 10.4-1A REV. 35

CAD FILE: U10401A.DGN

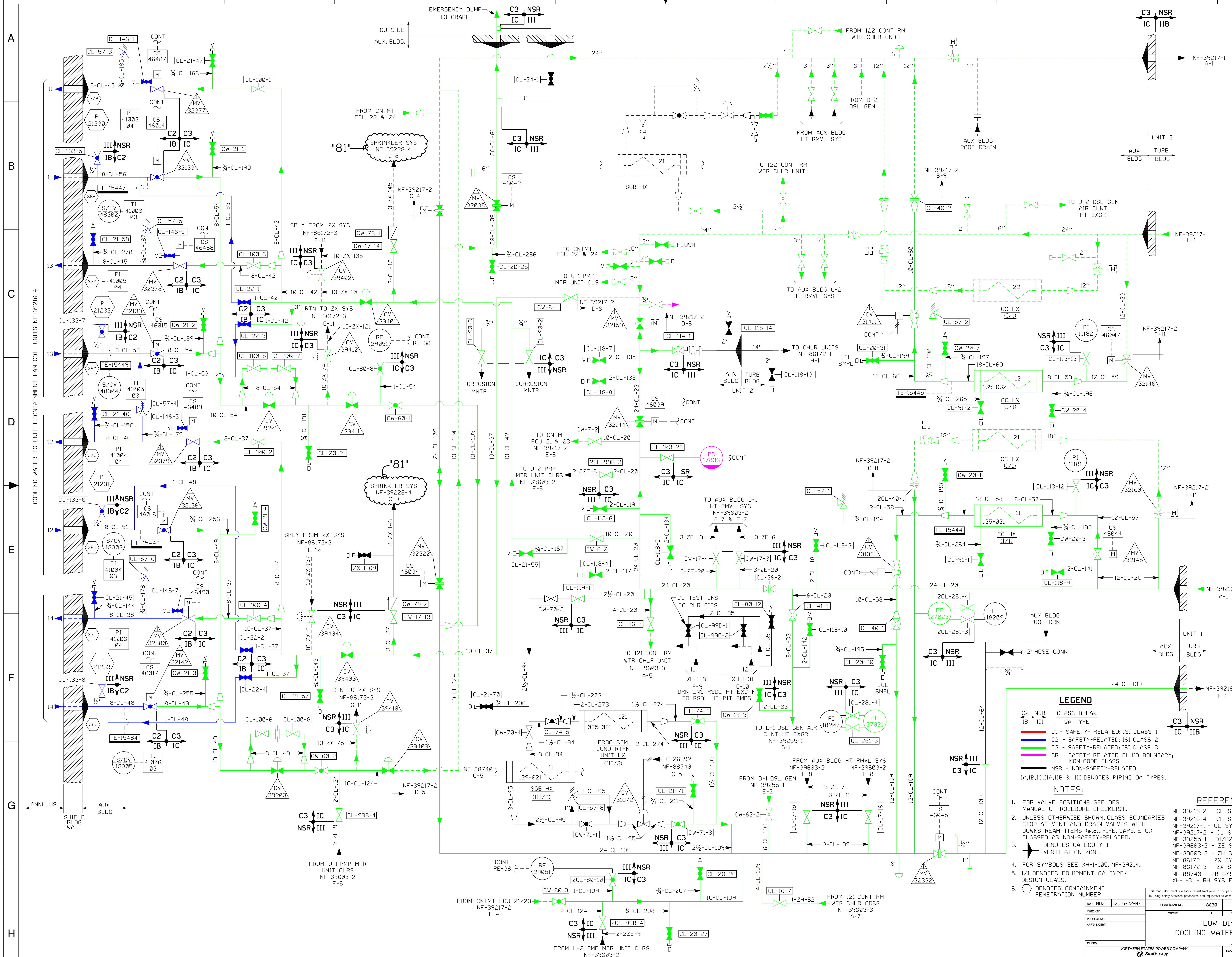
60300001331



60300001331

FIGURE 10.4-1B REV. 35

CAD FILE: U10401B.DGN



REVISIONS

76	AS BUILT- ADDED VENT VALVES CL-146-1, CL-146-3, CL,146-5, CL-146-7. PER DRR PI-09-208 DWN: DMN 10-27-09 CHK'D: BWK 10-28-09 MOD#: EC-691 APP'D: CMR 10-28-09
77	AS BUILT REDRAWN PER SYSTEM WALKDOWN, INCORPORATED SAFETY CLASS DESIGNATIONS. 04NS15 PER DRR PI-10-048 DWN: DB 4-13-10 CHK'D: JEK 5-11-10 REVIEWED: WJI 5-11-10 MOD#: EC-14552 APP'D: CMR 5-11-10
78	AS BUILT- ADDED DRAIN LINE & DWG. CONT. & COORDINATES FOR 121 AIR HANDLER EQUIPMENT. PER DRR PI-09-163 DWN: KJF 8-16-10 CHK'D: JBS 10-12-10 MOD#: EC-14472 APP'D: CMR 10-18-10
79	AS BUILT- CORRECTED VALVE ID FROM CW-40-1 TO CL-40-1. PER DRR PI-12-134 DWN: JEK 6-29-12 CHK'D: SBS 7-11-12 MOD#: EC-18147 APP'D: CMR 7-16-12
80	AS BUILT- REVISED DWG TO REFLECT CONT RM AIR HANDLER DRAIN PATH REMOVAL. PER DRR PI-13-236 DWN: KJF 12-10-13 CHK'D: CMR 12-11-13 MOD#: EC-22967 APP'D: CMR 12-11-13
81	AS BUILT- ADDED DWG CONT REF @ LOC E-4, B-4. PER DRR PI-14-200 DWN: DB 12-18-14 CHK'D: KB 1-6-15 MOD#: EC-23171 APP'D: CMR 1-6-15

LEGEND

C2 NSR / IB III — CLASS BREAK / QA TYPE

- C1 - SAFETY- RELATED; ISI CLASS 1
- C2 - SAFETY-RELATED; ISI CLASS 2
- C3 - SAFETY-RELATED; ISI CLASS 3
- SR - SAFETY-RELATED FLUID BOUNDARY; NON-CODE CLASS
- NSR - NON-SAFETY-RELATED

IA,IB,IC,IIA,IIB & III DENOTES PIPING QA TYPES.

NOTES:

1. FOR VALVE POSITIONS SEE OPS MANUAL C PROCEDURE CHECKLIST.
2. UNLESS OTHERWISE SHOWN, CLASS BOUNDARIES STOP AT VENT AND DRAIN VALVES WITH DOWNSTREAM ITEMS (e.g., PIPE, CAPS, ETC.) CLASSED AS NON-SAFETY-RELATED.
3. DENOTES CATEGORY I VENTILATION ZONE
4. FOR SYMBOLS SEE XH-1-105, NF-39214.
5. I/1 DENOTES EQUIPMENT QA TYPE/ DESIGN CLASS.
6. DENOTES CONTAINMENT PENETRATION NUMBER

REFERENCE DWGS

NF-39216-2 - CL SYS FLOW DIA. UNIT 1
NF-39216-4 - CL SYS FLOW DIA. UNIT 1
NF-39217-1 - CL SYS FLOW DIA. UNIT 2
NF-39217-2 - CL SYS FLOW DIA. UNIT 2
NF-39255-1 - D1/D2 SYS FLOW DIA. UNIT 1/2
NF-39603-2 - ZE SYS FLOW DIA. UNIT 1/2
NF-39603-3 - ZH SYS FLOW DIA. UNIT 1/2
NF-86172-1 - ZX SYS FLOW DIA. UNIT 2
NF-86172-3 - ZX SYS FLOW DIA. UNIT 1/2
NF-88740 - SB SYS FLOW DIA. UNIT 1
XH-1-31 - RH SYS FLOW DIA. UNIT 1

DWN MDZ	DATE 5-22-07	SIGNIFICANT NO.	8630			1 4410	1 8540
CHECKED		GROUP	1	2	3	4 5	CL 6

PROJECT NO.
APP'D & CERT.
FILMED

FLOW DIAGRAM
COOLING WATER - AUX BLDG
UNIT 1

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING, MINNESOTA

SCALE NONE REV 81

NF-NF-39216-3

NF-39216-3.DGN NSP GENERATION CAD

$$USERNAME$$
$$$$$$SYTIME$$$$$$$$$$$$SYDATE$$$$$$
$$$$$$$$$DESIGNFIL$$$$$$$$$

01516979

FIGURE 10.4-1C REV. 34

CAD FILE: U10401C.DGN

FIGURE 10.4-1D REV. 35

CAD FILE: U10401D.DGN

60300001331

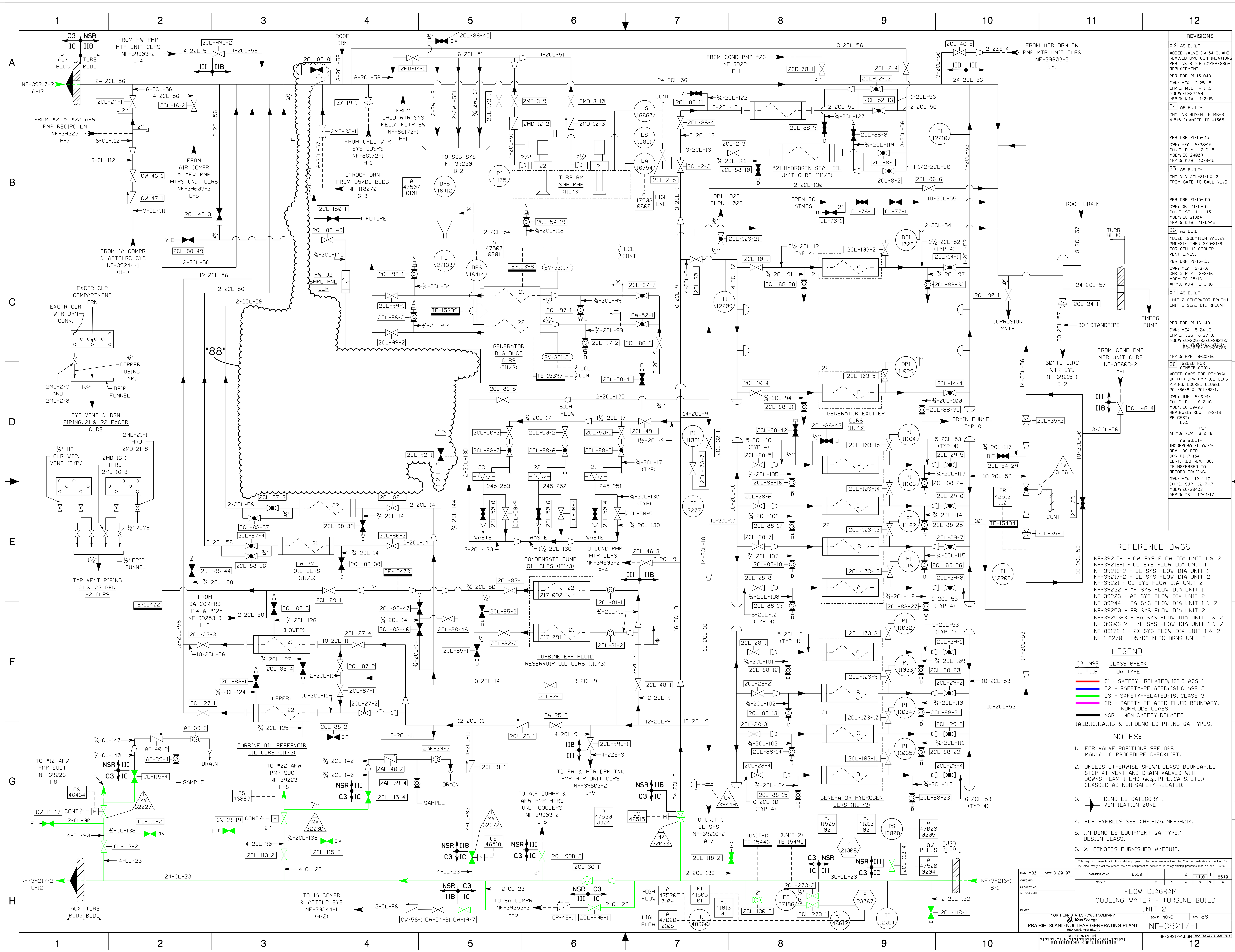


FIGURE 10.4-2A REV. 35

60300001331

CAD FILE: U10402A.DGN

FIGURE 10.4-2B REV. 34

CAD FILE: U10402B.DGN

01516979

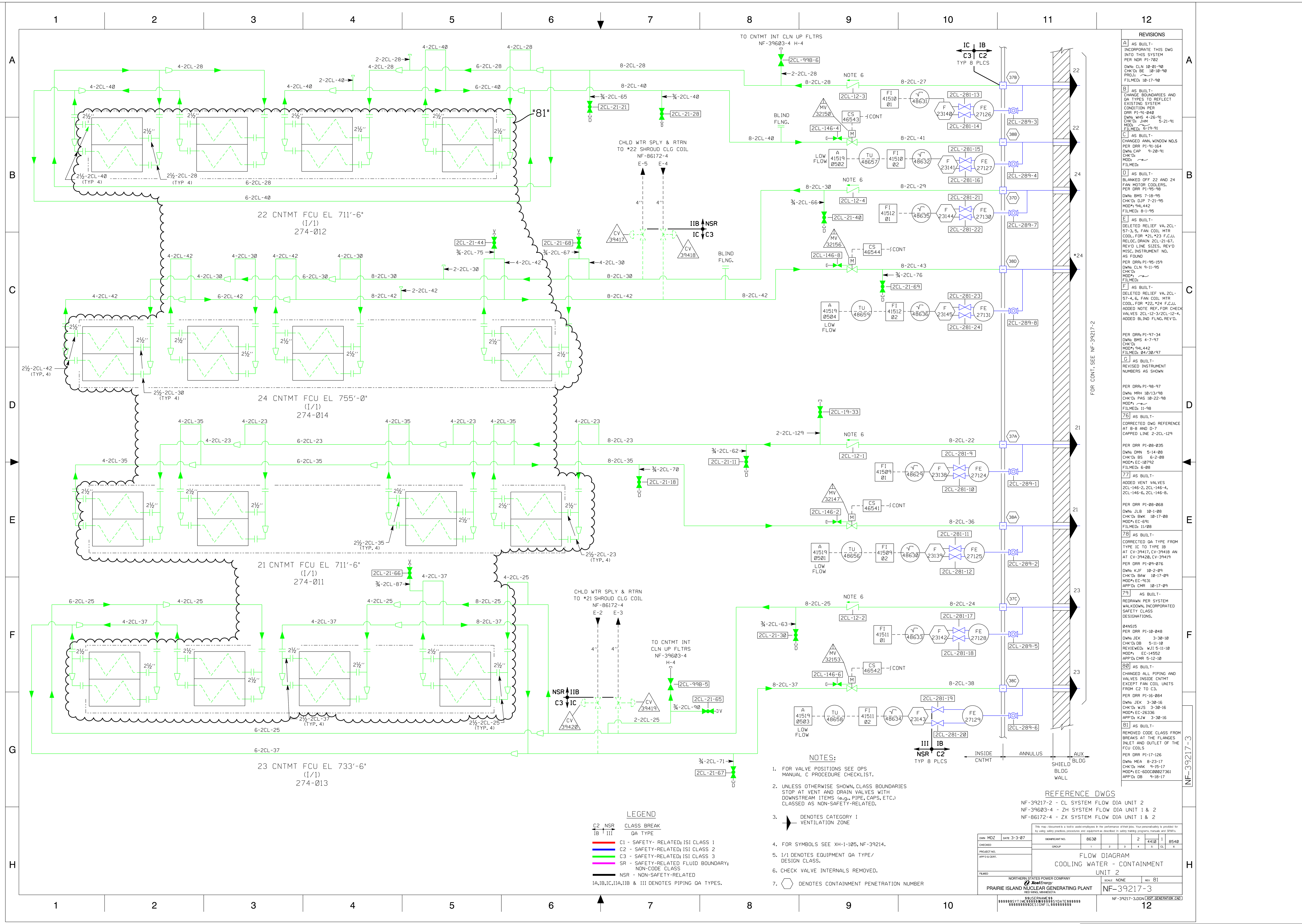


FIGURE 10.4-2C REV. 35

CAD FILE: U10402C.DGN

60300001331

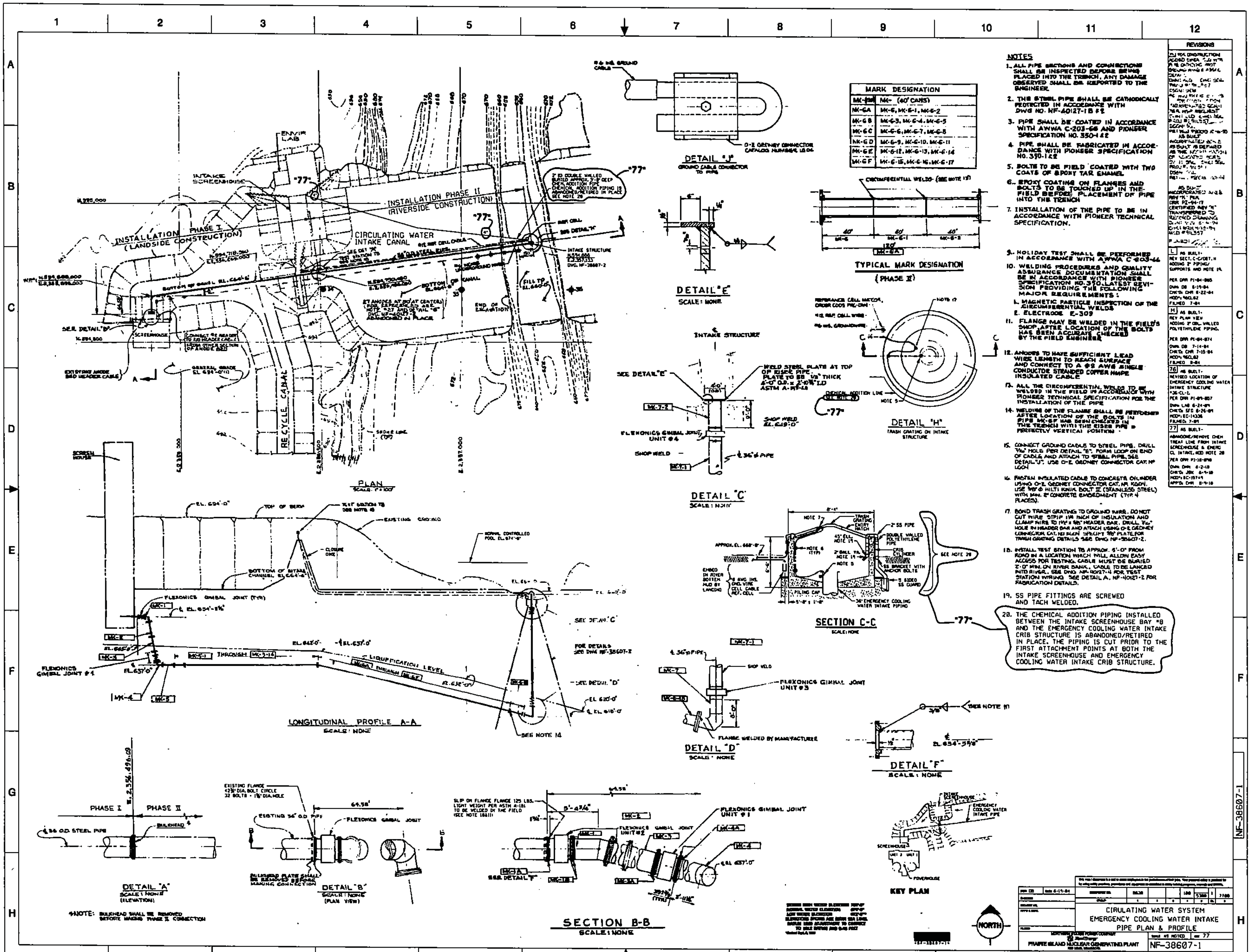


FIGURE 10.4-3A REV. 31

01248495

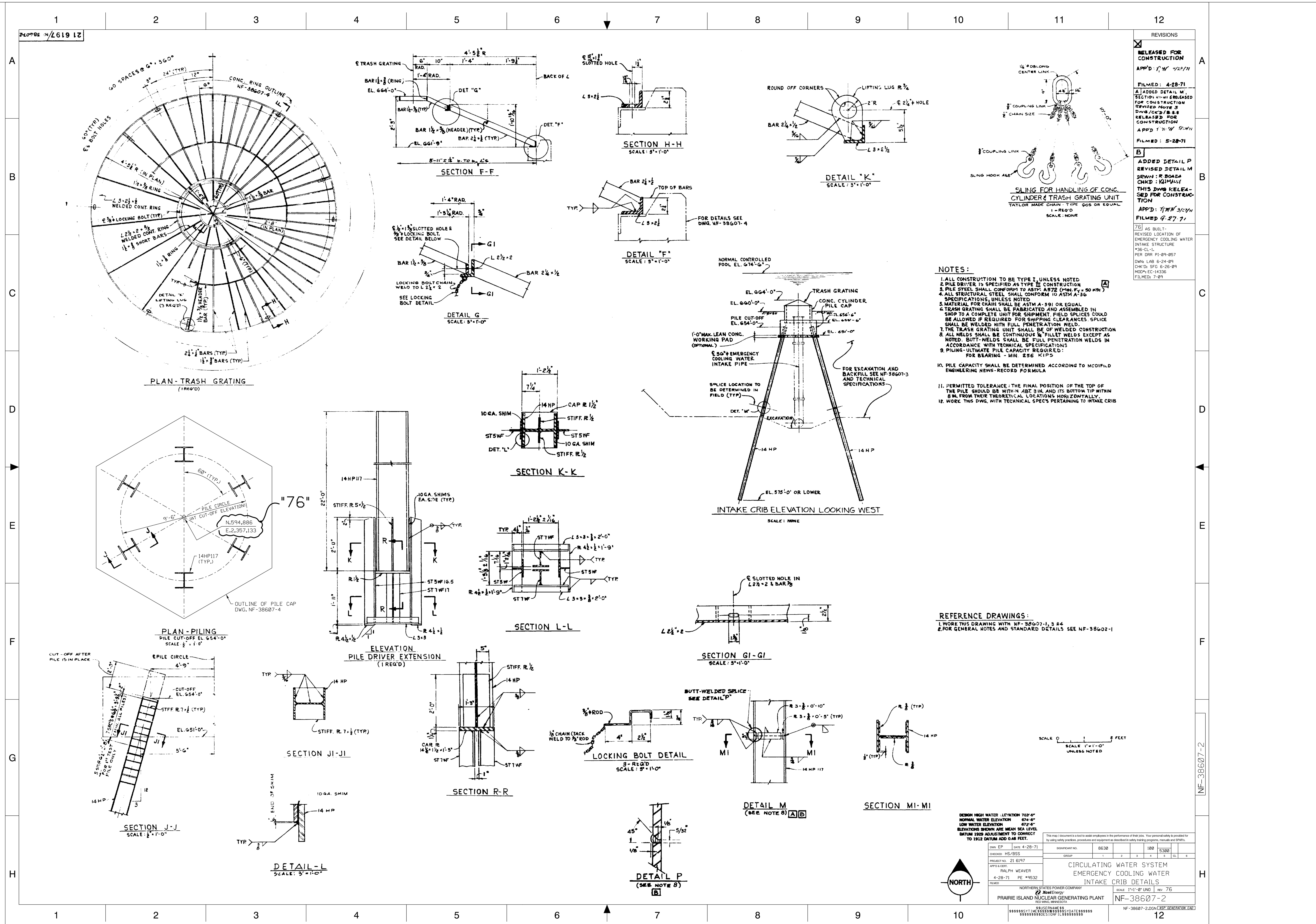


FIGURE 10.4-3B REV. 35

CAD FILE: U10403B.DGN

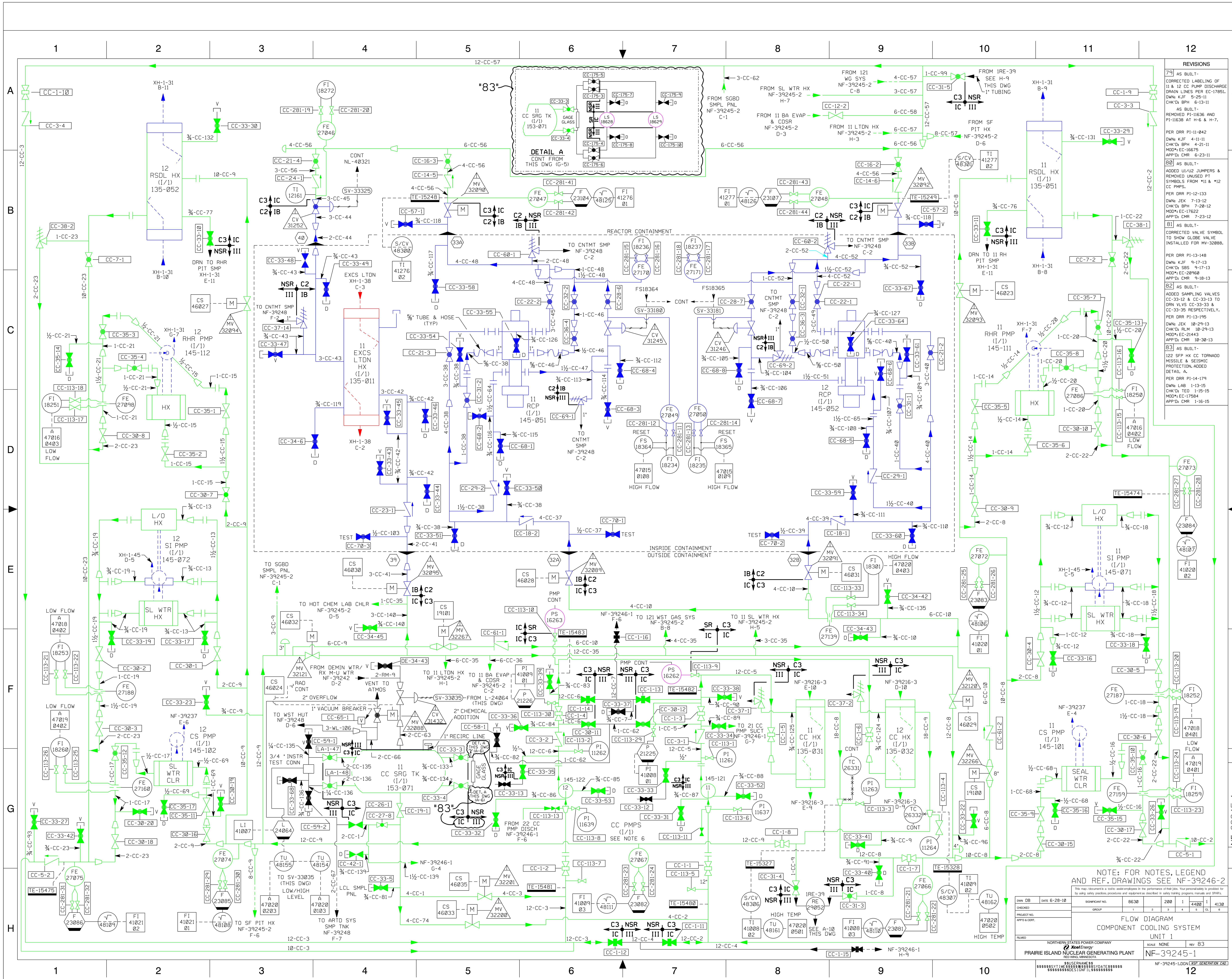


FIGURE 10.4-4A REV. 34

01516979

CAD FILE: U10404A.DGN

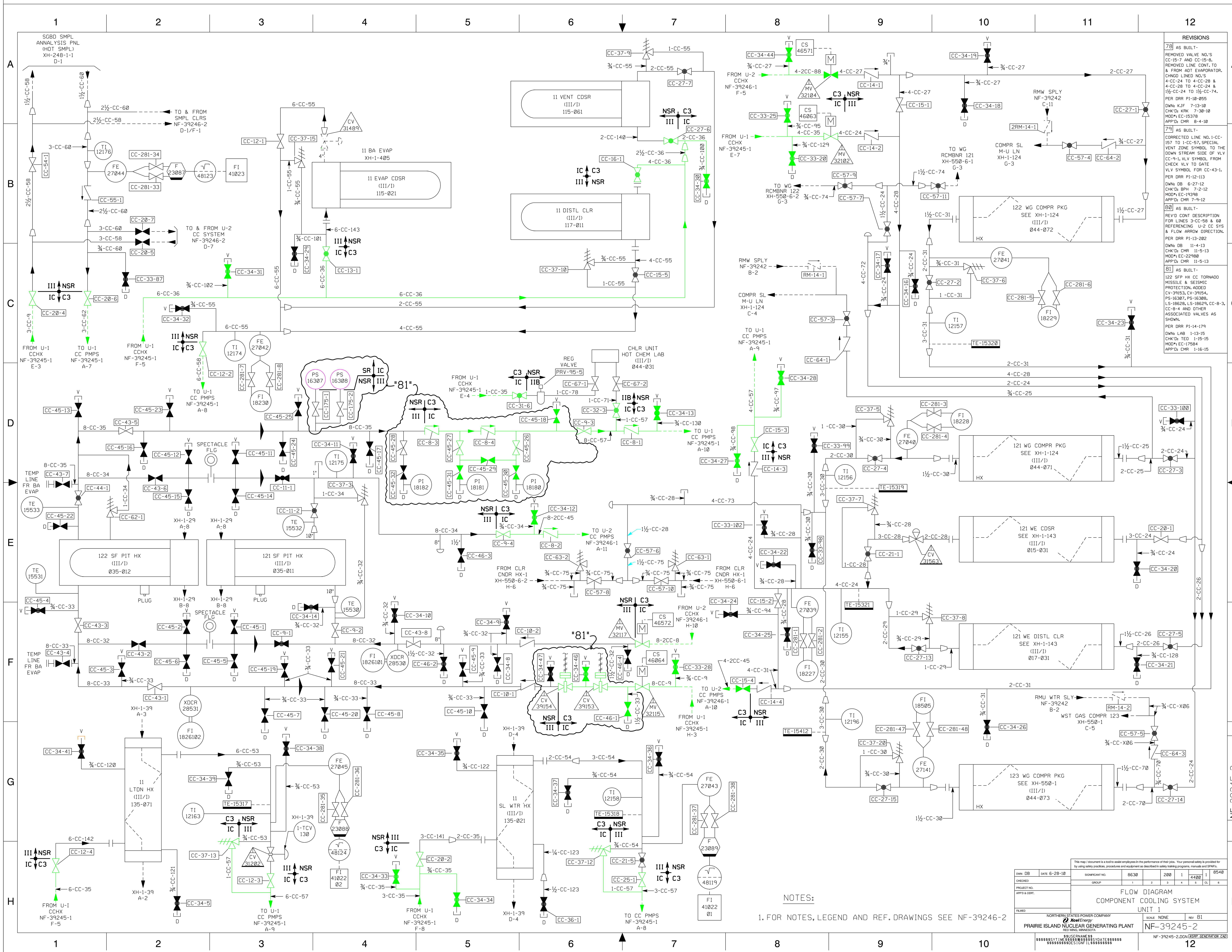


FIGURE 10.4-4B REV. 34

CAD FILE: U10404B.DGN

01516979

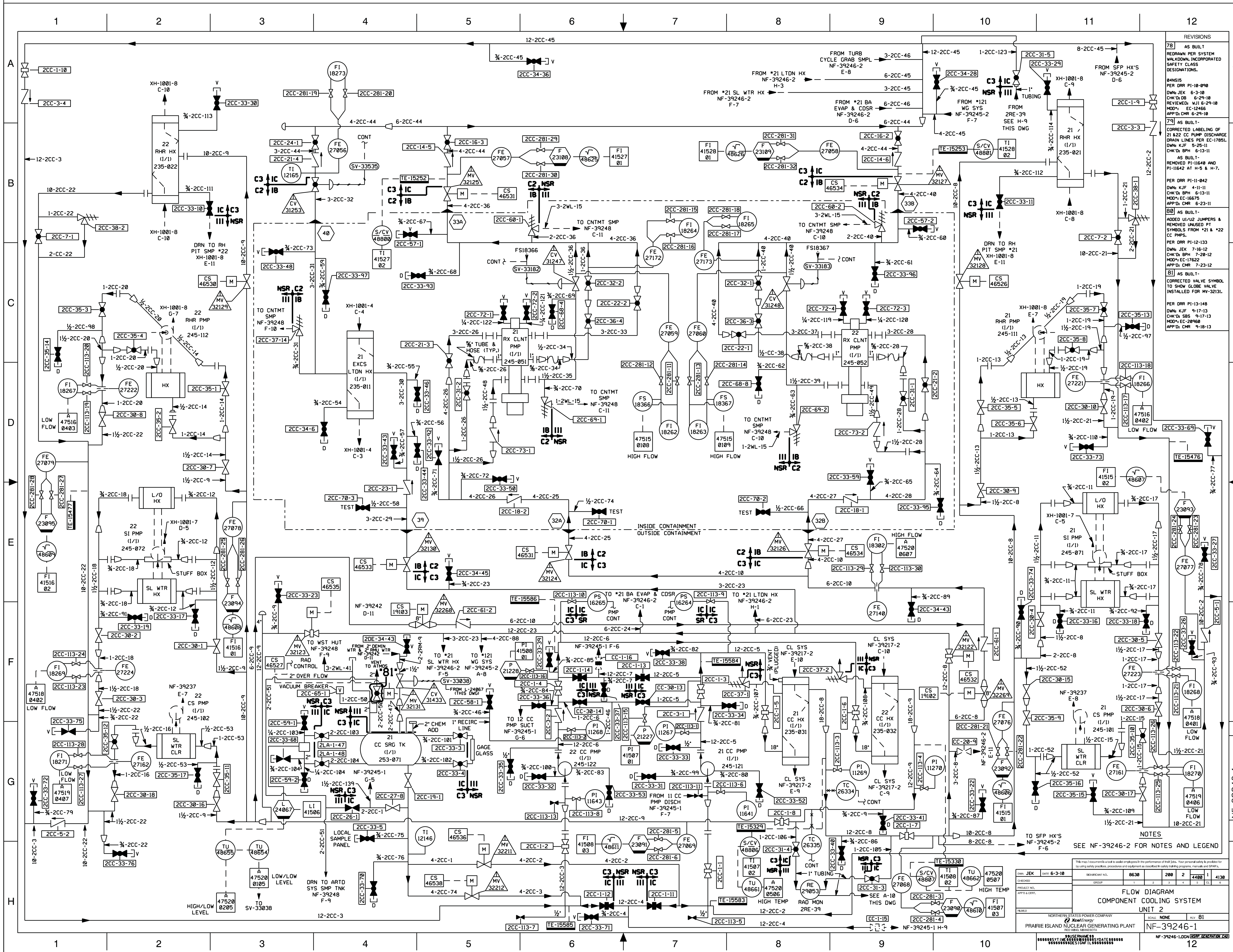


FIGURE 10.4-5A REV. 33

01429088

CAD FILE: U10405A.DGN

01429088

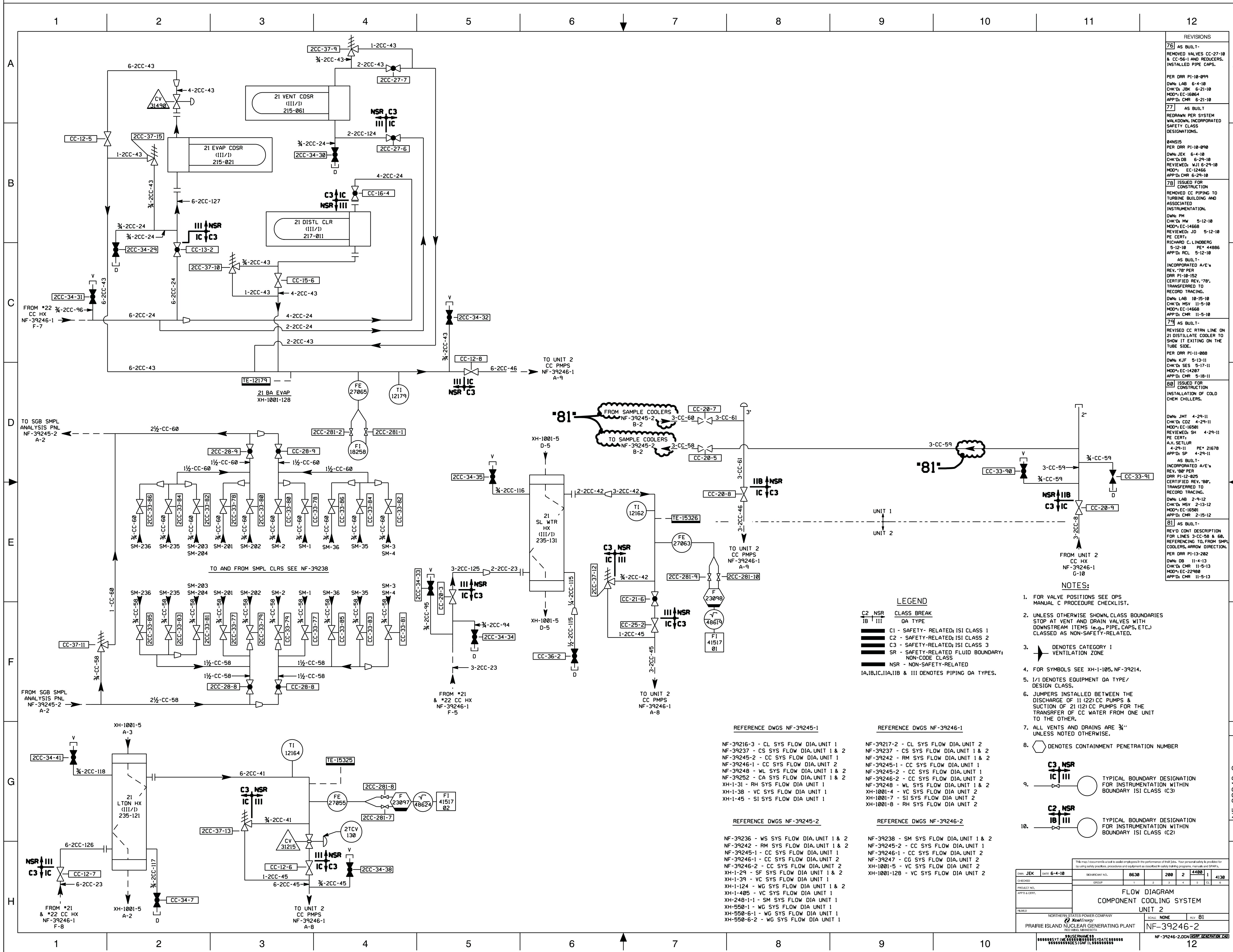


FIGURE 10.4-5B REV. 33

CAD FILE: U10405B.DGN

SECTION 11

PLANT POWER CONVERSION SYSTEM

TABLE OF CONTENTS

Page

TABLE OF CONTENTS [Continued]

Page

TABLE OF CONTENTS [Continued]

LIST OF TABLES

TABLE OF CONTENTS [Continued]

LIST OF FIGURES

TABLE OF CONTENTS [Continued]

LIST OF FIGURES [Continued]

THIS PAGE IS LEFT INTENTIONALLY BLANK

SECTION 11 POWER PLANT CONVERSION SYSTEM

11.1 SUMMARY DESCRIPTION

The Steam and Power Conversion Systems of Units 1 and 2 are identical except as noted.

11.1.1 Performance Description

The steam and power conversion system consists of a closed, regenerative cycle in which steam from the main turbine is condensed and returned to the steam generators as heated feedwater.

The turbine-generator system consists of components of conventional design, designed for use in large central power stations. The equipment is arranged to provide high thermal efficiency with no sacrifice in safety. The component design parameters are given in Table 11.1-1.

The Main Steam and Feedwater Systems are designed to remove heat from the reactor coolant in the two steam generators, producing steam for use in the turbine-generator. The Main Steam System can receive and dispose of the total heat existent or produced in the Reactor Coolant System following a turbine-generator trip at full load.

Two auxiliary feedwater pumps, one turbine-driven and one electric-driven are provided for each unit to ensure that adequate feedwater is supplied to the steam generators for heat removal under all circumstances, including loss of power and normal heat sink. Feedwater flow can be maintained until power is restored or reactor decay heat removal can be accomplished by other systems. The Auxiliary Feedwater System is designed as a Class I system, and is described in Section 11.9.

11.1.2 Load Change Capability

The plant can accommodate step load changes of 10% or ramp load changes of 5% per minute without reactor trip as described in USAR Sections 4 and 7. The Reactor Coolant System will accept a complete loss of load from full power with reactor trip. In addition, both units are designed to accept a step decrease of 40.0% of nominal full load with the combined operation of the Reactor Rod Control System and the Steam Dump System.

04--024

11.1.3 Functional Limits

The system incorporates backup means (power operated relief valves and code safety valves) for heat removal under any loss of normal heat sink (i.e., main-steam stop valves trip, condenser isolation, loss of circulating water flow) to accommodate reactor shutdown heat rejection requirements.

11.1.4 Secondary Functions

The Steam and Power Conversion System also provides steam for driving the turbine-driven auxiliary feedwater pump and for turbine gland steam, reheater steam, condenser and water box steam-jet air ejectors, hogging ejectors, waste evaporator, boric acid evaporator packages and building heating.

11.1.5 Codes and Classifications

The pressure boundary components comply with the codes given in Table 11.1-2.

11.1.6 Schematic Flow Diagrams

The Main, Auxiliary Steam and Steam Dump, Condensate, Feedwater, Bleed Steam and Heater Vents, Feedwater Heater, Moisture Separator and Reheater Drains, Air Removal, Turbine Building Traps and Drains, Feedwater Pump Injection and Gland Seal Piping, Circulating Water, and Condensate Polishing Flow Diagrams are given in Figures 11.1-1 through 11.1-20, respectively.

11.1.7 Single Failure Analysis

A single failure analysis has been made for all active components of the system which have an emergency function. The analysis, which is presented in Table 11.1-3, shows that the failure or malfunction of any single active component will not reduce the capability of the system to perform its emergency function.

11.1.8 Shielding

No radiation shielding is required for the components of the Steam and Power Conversion System. Continuous access to the components of this system is possible during normal conditions, except for the components located inside the containment.

11.2 TURBINE-GENERATOR SYSTEM

11.2.1 Design Basis

The turbine is designed to produce a maximum calculated gross rating of 591,988 KW when operating with inlet steam conditions of 702 psia and 503.4°F, exhausting at 1.6 in. Hg absolute, zero percent makeup, and with five stages of feedwater heating in service. The expected throttle flow at 591,988 KW is 7,370,720 lb/hr of steam. See Figures 11.2-1 through 11.2-5 for various turbine/condenser/reheat heat balance gross loads.

The hydrogen inner-cooled generator is designed to produce rated 730,000 KVA at 1800 RPM and 60 psig hydrogen gas pressure. 604000000062

11.2.2 Description

The turbine is a three-element, tandem-compound, four-flow exhaust, 1800 rpm unit that has moisture separation and reheating between the HP and LP elements. The a-c generator and rotating rectifier exciter are direct-connected to the turbine shaft. The turbine consists of one double-flow HP element in tandem with two double-flow LP elements. Four combination moisture-separator reheater assemblies are located alongside the turbine.

The turbine oil system is of a conventional design. It consists of three parts: a) a high pressure oil system, b) a lubrication system, and c) an Electro-Hydraulic (E/H) control system. The E/H control system is completely separate from the other two parts. Lube oil is also used to seal the generator glands to prevent hydrogen leakage from the machine. The fluid used for E/H control system is a fire resistant synthetic oil. The maximum available steam temperature is not capable of initiating a fire in the E/H oil system.

The turbine oil system supplies all of the oil required for the emergency trip and lubrication system during normal operation. A turbine lube oil purification and filtration system purifies the lube oil for the turbine.

A gland steam condenser maintains a pressure slightly below atmospheric in the Turbine Gland Leakoff System. Sealing steam and air leakage along the shaft at each turbine gland is fed to this condenser, thus preventing any leakage of steam into the turbine room. Two motor-driven exhausters are mounted on the gland condenser to remove noncondensable gases, as shown in Figure 11.1-11.

The turbine has low speed, motor-driven spindle turning gear equipment which is side mounted on the outboard bearing of the low-pressure turbine nearest the generator.

11.2.3 Performance Analysis

11.2.3.1 Turbine Controls

High-pressure steam enters the turbine through two turbine stop valves and four governing valves. One turbine main steam stop and two main steam governing valves form a single assembly which is anchored above the turbine room floor line. An electro-hydraulic (E-H) actuator controls each turbine stop valve so that it is either in the wide-open or closed position. One of the control signals for this actuator comes from the mechanical-hydraulic overspeed trip portion of the Electro-Hydraulic Control System. The safety function of these turbine stop valves is to shut off the flow of steam to the turbine in the event the unit overspeeds beyond the setting of the overspeed trip. These valves are also tripped when the other protective devices function. The main steam governing valves are positioned by an electrical signal from the main governor portion of the Electro-Hydraulic Control System.

Additionally, there are Reheat Steam Stop Valves (at the outlet of each reheater) and reheat steam intercept valves (in each reheat steam line just ahead of the low pressure turbine inlet). These reheat stop and intercept valves limit the reheated steam flow available to the low pressure turbine.

The Electro-Hydraulic Turbine Control System combines triple modular redundant controller with a high-pressure fire-resistant fluid supply system which is independent of the lubricating oil. The design features and response characteristics of the E-H control system increase the reliability and availability of the power plant.

The Electro-Hydraulic Control System includes the following features:

a. Governor valve controller

b. Load limit controller

c. Overspeed Protection Controller

d. Load Controller

e. Operator’s touch screens on the control room control panel

f. High-pressure hydraulic fluid pumping unit

g. Turbine protective devices, including function limit trips, automatic load reference runback upon receipt of the OTΔT and OPΔT signal, and extraction line non-return valves closing signal.

In the steam admission system, each steam path has two valves in series which are controlled by the high pressure E-H oil system. Loss of hydraulic fluid pressure or power supply causes closure of the steam valves.

The auto-stop oil is dumped to drain, directly and indirectly via the interface valve, when any one of the protective trip devices is actuated. Independent reactor trip signals will actuate the EH controller trip logic to dump ET, OPC, and auto-stop oil to drain.

Automatic turbine load reference runback is initiated as described in Section 7.2.

11.2.3.2 Turbine Overspeed Control

Turbine overspeed, upon loss of electrical load, is prevented by the rapid cut-off of steam admission to the high pressure turbine, and to the low pressure turbine. Main steam admission to the high pressure turbine is controlled by a series array of main steam stop and governor valves; and reheat steam admission to the low pressure turbine is controlled by a series array of reheat steam stop and reheat steam intercept valves. All these valves are held open against strong spring pressure by high-pressure hydraulic fluid.

Should loss of electrical load occur, the turbine will tend to accelerate, and the E-H control automatically switches from load follow to speed follow and calls for the maintaining of a turbine synchronous speed of 1800 rpm such that the main E-H governor calls for modulated closing of the main steam governor valves.

(Should the loss of load be from maximum calculated load to zero load, the E-H overspeed protection controller alone limits turbine speed to a maximum of 108% of synchronous speed.)

Overspeed control is accomplished by trip-valve release of hydraulic fluid pressure. Redundant shaft-speed sensors and trip-valving systems assure a highly reliable prevention of turbine overspeed and prevention of resultant turbine missiles.

The Electro-Hydraulic Control System contains turbine shaft speed probes. At 103% of rated shaft speed the E-H controller releases actuating hydraulic fluid pressure to close the main steam governor and the reheat steam intercept valves, which cut off both high pressure and low pressure turbine steam admission.

(Should this trip be from maximum calculated load to zero load, the 103% E-H overspeed trip function alone limits the turbine speed to a maximum of 111% of synchronous speed.)

In addition to the two protective functions already described, the turbines are provided with three emergency overspeed trip functions which are activated at less than 111% of rated shaft speed.

The first of these emergency overspeed trip functions is the conventional back-up control consisting of an overspeed trip valve and mechanical overspeed mechanism which consists of a spring-loaded eccentric weight mounted in the end of the turbine shaft. At 110% of rated speed, centrifugal force moves the weight outward to mechanically actuate the overspeed trip valve which dumps auto-stop oil pressure and in turn releases the actuating hydraulic fluid pressure to close the main steam stop valves, the main steam governor valves, the reheat steam stop valves, and the reheat steam intercept valves. The supply steam pressure and the spring force act to hold the stop valves closed.

Upon loss of the actuating hydraulic fluid pressure, an air pilot valve closes the extraction non-return valves to heaters No. 14 and 15. Baffles in feedwater heaters No. 11, 12, and 13 minimize flashback of water in these heaters.

The secondary emergency overspeed control is provided by the Electro-Hydraulic Control system if the turbine speed exceeds 108% of rated speed by 10 rpm. At this point ET, OPC, and AST solenoids are actuated to dump the auto-stop oil which in turn dumps the actuating hydraulic fluid pressure to ensure closing of the main steam stop valves, the main steam governor valves, the reheat steam stop valves and the reheat steam intercept valves.

The third emergency overspeed control is provided by the Electro-Hydraulic Control system if the turbine speed exceeds 109% of rated speed. At this point the independent Protech system actuates the ET and OPC solenoids to dump ET oil header pressure, thereby depressurizing the AST header via the interface valve which in turn dumps the actuating hydraulic fluid pressure to ensure closing of the main steam stop valves, the main steam governor valves, the reheat steam stop valves and the reheat steam intercept valves. The Protech also provides trip input to the main EH controller to actuate the ET, OPC, and AST solenoids.

The reheat steam stop valves and reheat steam intercept valves stop the steam flow to the low pressure turbine, such that assuming a single failure of one reheat steam intercept valve, the 111% overspeed trip point limits turbine shaft speed to less than the 120% of synchronous speed which was used as a design basis for the turbine-generator.

Thus a 100% maximum calculated load rejection (with no in-plant load) cannot result in destructively excess overspeed.

The overspeed trip function is tested periodically. The turbine valves function to control and protect the main turbine. They must be capable of moving freely in response to control and protection signals. In an effort to develop a reasonable basis for frequency of turbine valve testing, a probabilistic study of turbine valve failure mechanisms was undertaken by the Westinghouse Owners Group. This work was reported in WCAP-11525: “Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency” (Reference 7). This study concluded that the Prairie Island turbine valves could be tested at a reduced frequency not exceeding one year while not exceeding NRC guidance for acceptable turbine missile ejection probability. A change to the Prairie Island Technical Specifications allowing the interval between turbine valve tests to be up to, but not exceeding one year, was approved by NRC SER dated February 7, 1989. (Reference 8). IT.S. has subsequently relocated these requirements to the TRM.

In accordance with the program plan for tracking turbine valve failure rates, the Westinghouse Owners Group performed evaluations and updates of turbine stop and control valve failure rates. The evaluation process used the most recent study results to set the requirements for turbine valve testing. 604000000392

The turbine valve failure rates through January 1998 were reevaluated in March 1999 (reference 13) in accordance with the program plan established in WCAP 11525. This reevaluation resulted in conservative missile ejection probabilities relative to previous studies. WCAP-16054 was commissioned to re-check WCAP-11525. WCAP 16054 confirmed WCAP-11525 with the inclusion of recent valve failure data and increasing the valve exercise surveillance interval to 12 months. The total probability continues to be maintained at less than $1x10^{-5}$. 604000000392

11.2.3.3 Variables Limit Functions

Trips, automatic control actions and alarms will be initiated by deviations of system variables within the Steam and Power Conversion System. The more significant malfunctions or faults which cause trips, or automatic actions in the Steam and Power Conversion System are listed below.

Turbine Trips

a. Generator electrical faults

b. Low condenser vacuum

c. Thrust bearing failure

d. Low turbine bearing lubricating oil pressure

e. Turbine overspeed

f. Reactor trip

g. Manual trip

h. Loss of both main feedwater pumps

i. Loss of E/H system internal power

j. Low auto-stop oil pressure

k. Steam generator High-High level.

l. MSIV closure initiated turbine trip

m. AMSAC actuation

11.3 MAIN CONDENSER SYSTEM

11.3.1 Condenser

The condenser is the double-flow, dual-pressure, single-pass vertically divided surface type with fabricated steel water boxes at both ends. The hotwell has sufficient storage for three minutes operation at maximum throttle flow with an equal free volume for surge protection.

There are two air coolers built integral with each condenser shell, located in the center of each tube bundle, extending from face to face of the tube sheets. The coolers are subdivided by the main support plates.

The “direct steam flow” type tube bundle in each shell is arranged so that steam will enter at the top, outboard and inboard sides, and bottom where it flows through the tubes until reaches a common area at the center of the tube nest before entering the air coolers.

The arrangement of the tubes in the tube bundle allows the steam to effectively feed to all the tubes. This tube arrangement creates decreasing cross-sectional area, and as the volume of steam is decreased by being condensed as it penetrates the depth of the tube bank, a brisk velocity is maintained at all times, assuring maximum condensation at maximum efficiency.

In its passage through the tube bundle most of the steam is condensed and when the flow reaches the air cooler there remains only a mixture of air, non-condensible vapor and water vapor.

The air and non-condensible vapors are cascaded from the outlet end to the inlet end of each condenser. This is accomplished by having each section of the condenser arranged so that the air and non-condensible vapors from preceding sections will be forced to pass over cooler tubes in every section of each condenser.

In passing through the air coolers, the air and non-condensible vapors are cooled and a large part of the water vapor is condensed. This reduces the partial vapor pressure of the mixture which is analogous to shrinking what was originally a large volume of rarefied air into a small volume of dense air. In this state it is drawn into the air removal equipment where it is compressed to atmospheric pressure with a minimum expenditure of energy.

Each condenser is divided into two sections by means of separate water boxes. This construction for practical purposes may be considered as two condensers placed side by side, having a common steam inlet and condensate outlet, but with separate air-vapor outlets. This construction also makes it possible to open the water boxes on one section of the condenser to clean and inspect the tubes while there is vacuum on the condenser and the turbine is operating.

11.3.2 Main Condenser Air Removal System

The steam-jet air ejector maintains a vacuum in the condenser. This ejector has three first-stage elements and three second-stage elements mounted on the shells of the intermediate and after-condensers. Only two of the three stages are required during normal operation. During startup, a separate hogging ejector is used to evacuate the condenser. The ejectors are supplied with steam from the main steam line, as shown in Figures 11.1-1,-2,-11, or from the plant heating boiler. They are used in parallel with the second stage of the steam jet air ejectors which are also started at the same time. After a vacuum of 20″ to 25″ Hg. has been established, the first stage jets of the air ejector are started automatically. Operation of the first and second stages of the air ejector will lower the turbine condenser steam space to its operating vacuum. The hogging ejectors are removed from service by closing, first, the suction valves, and second, closing their steam supply valves.

The discharge of the hogging ejectors is not monitored for radioactivity because this parameter can be measured by the radiation monitor in the discharge of the normal steam jet air ejector which discharges to the Auxiliary Building Ventilation System.

11.3.3 Condenser Spray System

The condenser spray system, as shown in Figures 11.1-3, -4, consists of a pump, filters, strainers, and spray nozzles. The system is designed to eliminate stratification which causes vacuum problems during unit startup. When steam dump and other steam sources enter the condenser, the steam in the process of going to a low pressure condition goes to a superheated condition. Since the superheated steam has a higher specific volume the steam rises to the top of the condenser. To prevent this steam from reaching the top of the condenser, the condenser spray system blankets the condenser with a water spray below the feed water heater level. 01-003

Hydrazine is injected into the condenser spray system to start the O_2 scavenging sooner in the condensate and feed water cycle. This will help reduce the dissolved O_2 in the condensate pump suction. In this way the quantity of iron oxides produced in the condenser and carried to the steam generators is reduced.

11.4 STEAM SAFETY, RELIEF AND DUMP SYSTEMS

11.4.1 Design Basis

If the condenser heat sink is not available during a turbine trip, excess steam generated as a result of Reactor Coolant System sensible heat and core decay heat is discharged to the atmosphere.

There are five 6-in. by 10-in. code safety valves located on each of the two 30-in. main steam lines outside the reactor containment and upstream of the main steam isolation and non-return valves. Discharge from these safety valves is carried to the atmosphere through individual vents. The total relieving capacity of all 10 valves is 7,745,470 lb/hr at 1194 psig. The five safety valves on each main steam line are set to relieve at 1077, 1093, 1110, 1120, and 1131 psig. The main steam safety valve Technical Specification originally required lift setpoints to be within ± 1% of the specified setpoint. The Specification was difficult to meet when test instrument error and repeatability were considered. A License Amendment Request justified increasing the as-found setpoint tolerance to ± 3%, provided the setpoint was returned to ± 1% following testing. License Amendments 123 and 116 approving the request were issued May 21, 1996.

In addition, one 5-in. power-operated relief valve is provided in each main steam line which is capable of releasing the sensible and core decay heat to the atmosphere. These valves are automatically controlled by pressure or may be manually operated from the main control board and have a total capability of ten per cent of the maximum calculated steam flow (405,000 lb/hr each at 1100 psia). Discharge from each power relief valve is carried to the atmosphere through an individual vent stack. In addition, the power-operated relief valves may be used to release the steam generated during reactor physics testing, operator license training, plant cooldown, and Mode 2, Startup, if the condenser is not available. Two steam dump systems, the condenser steam dump system and the atmospheric steam dump system, are available to remove energy for the steam generators downstream of the mainsteam isolation and non- return valves. The condenser steam dump system taps off one main steam line (downstream of the 20″ bypass/equalizing line connecting the two lines) with a 16″ then to 12″ line. From the 12-in. line two valves are installed in parallel (one 8-in. and one 4-in.). These valves discharge through a 16-in. pipe into the condenser through a perforated diffuser. The 8-in. valve has a capacity of 590,000 lb/hr, at an inlet pressure of 722 psia. The 4-in. valve has a capacity of 200,000 lb/hr. However, the 4-inch valve receives no automatic control signals and can only be operated by manipulating it locally, intended to be used only if the 8-inch valve is out of service (i.e., unavailable for cooldown). Therefore, the effective capacity is only that of the 8-inch valve, at least 7.0% of full load steam flow.

01183316
01183316

The atmospheric dump system provides two atmospheric dump valves on each steam generator main steam line. Each 8-in. valve is capable of dumping 590,000 lb/hr at an inlet pressure of 721 psia. Total capacity of all four atmospheric dump valves is at least 28.6% of full load steam flow. Two valves were installed to limit the maximum steam flow from one valve stuck open to 890,000 lb/hr at 1100 psia. A potential hazard in the form of an uncontrolled plant cooldown is thus eliminated. Manual isolation valves are provided at each control valve. 01183316

11.4.2 Description

The relief, safety and steam dump system is shown in Figures 11.1-1 and 11.1- 2.

The atmospheric dump valves and the condenser dump valve are controlled by a servoloop. Either a Tavg error signal or a main steam pressure error signal may be selected as the loop error signal. The Tavg error signal is used for normal at power operation. Under this condition, the loop provides the capability for rejecting a minimum 40.0% of nominal full load without reactor trip. 01183316

During a normal orderly shutdown of the turbine generator leading to plant cooldown, the operator may select pressure control for more accurate maintenance of no-load conditions using the steam dump valves to release steam generated by the residual heat. Plant cooldown, programmed to minimize thermal transients and based on residual heat release, is effected by a gradual manual adjustment of this pressure setpoint or by controlling the valve position in “Manual” until the cooldown process is completed or transferred to the Residual Heat Removal System.

During start-up, Mode 2, Startup, or physics testing, the steam dump valves are remotely controlled from the main control board.

The automatic condenser steam dump valve is prevented from opening on loss of condenser vacuum; it is also blocked on trip of both circulating water pumps that supply water to the Unit.

11.4.3 Performance Analysis

The condenser and atmospheric Steam Dump System has been included to increase the transient capability of the plant to provide a means for an orderly reactor power reduction in the event the load is suddenly decreased. The time for a return to full power operation is therefore minimized. The minimum dump capacity is equal to 35.6% of full load steam flow. Dump is initiated by a large rapid load change. Steam Dump Control is described in section 7.2.2.3. 01183316

Table 4.1-8 lists the number of these type transients expected during the plant lifetime.

If the condenser heat sink is not available during a turbine trip, excess steam, generated as a result of Reactor Coolant System sensible and core decay heat, is discharged to the atmosphere.

The amount of steam that will be dumped to atmosphere during load reduction is as follows:

Load Reduction of 10%	no steam released
Load Reduction of 20%	no steam released
Load Reduction of 30%	7000 lbs.
Load Reduction of 40%	30,000 lbs.
Load Reduction of 50%	75,000 lbs.

Based on a 50% load loss and the subsequent release of 75,000 lbs. of steam, the total radioactivity release to atmosphere would be 1.4 curies of I-131 equivalent. Using the yearly average X/Q, the site boundary thyroid inhalation dose associated with this release would be less than 0.5 mrem. This value additionally assumes that the secondary system radioactivity level is at 0.1 μCi/gm and only 10% of the activity contained in the steam generator secondary side is available for dispersion to atmosphere. The analysis neglected any plate-out or condensation effects on the release plume.

The requirement for monitoring the secondary coolant water chemistry is specified in the PINGP Chemistry Procedures. 01193402

If the control valves should fail to dump steam, the result is a loss-of-load transient. If they operate to dump steam inadvertently, the result would be a load increase equivalent to a small steam break. In either case, the Reactor Control and Protection System precludes unsafe operation. These protection systems are provided to trip the reactor in the event of a sustained load mismatch between the reactor and turbine.

Continuous radioactive monitoring of the secondary loops of the steam generators is provided by the Steam Generator Blowdown System Liquid Sample Monitor and the Condenser Air Ejector Gas Monitor as discussed in Sections 7.5.2.13 and 7.5.2.6.

Once there is an indication of tube leakage in a steam generator, the affected unit's steam generators will be sampled and actual release documentation will be based on the known isotopic inventory and ODCM requirements. Isotopic analyses will quantify activity of the individual nuclides and total nuclide activity. Partitioning Factors will be applied to the steam generator bulk water particulate and iodine concentrations, to adjust activity results for a steam release, based on the differences in the volatility of individual isotopes. Radiation monitors will provide confirmation that no change in the system activity has taken place during the release.

Normal turbine overspeed protection and the steam generator safety valves provide protection for these systems completely independent of any steam dump valve operation.

In the event of failure of one feedwater pump, the feedwater pump remaining in service will carry approximately 65% of full load feedwater flow. If both main feedwater pumps fail, the turbine and the reactor will be tripped, and the auxiliary feedwater pumps start automatically.

Pressure relief is required at the system design pressure of 1085 psig. The first safety valve is set to relieve at 1077 psig. Additional safety valves are set at pressures up to 1131 psig, as allowed by the ASME Code. In addition to the safety valves, one power-operated relief valve is installed for each steam generator which can be manually operated from the control room. The power-operated relief valves are set to open at a pressure slightly below that of the main steam safety valves.

The original Westinghouse sizing criteria for the code safety valves was a flow rate equal to the original maximum calculated steam generation rate. 01183316

11.5 CIRCULATING WATER SYSTEM

11.5.1 Design Basis

The circulating water system provides the heat sink for the generating plant. Excess heat from the steam leaving the turbine is transferred to circulating water flowing through the condenser tubes. Based on seasonal limitations heat is transferred to the environment either by the use of the cooling towers, discharge to the river, or a combination of cooling towers and river discharge. Operating restrictions are governed by National Pollutant Discharge Elimination System (NPDES).

During startup and shutdown of the steam plant, the Circulating Water System removes the heat of steam dumped to the condenser at low power.

The Circulating Water System is designed to supply 294,000 gpm to each Unit in normal operation. Each Unit has two condenser circulating water pumps, each rated at 147,000 gpm at a TDH of 45 ft. The system is designed for condenser heat rejection of 3.88×10^9 BTU/hr from each Unit with a temperature rise across the condensers of 27°F. Total plant heat rejection by the Circulating Water System is 8.09×10^9 BTU/hr.

01-009

The Circulating Water System also supplies the water for the Cooling Water System and Fire Protection System. Water flows from the Intake Bay into the Plant Screenhouse. The Cooling Water pumps draw water from the screenhouse, pump it through the system and discharge to the warm circulating water leaving the condensers. Thus, the Circulating Water System indirectly cools the plant auxiliary equipment. The Intake Bay is required to remain intact during and after a design basis seismic event. The Intake Bay is classified as a Class I* structure. Refer to Section 12.2 for more discussion on classification of structures and components. Refer to Section 10.4 for more discussion on the cooling water system response to a seismic event.

The circulating water system flow diagrams are shown in Figures 11.1-16 and 17. The general plan of the system external to the plant is shown in Figure 11.1-18. 01-009

11.5.2 Description

Circulating water for the generating plant is taken from the Mississippi River and directed to the plant site by the intake canal. The quantity of river water which may be appropriated for use in the Circulating Water System is specified in Water Appropriations Permit #69-072 (issued by the Minnesota Department of Natural Resources). 01-015

Circulating water flows through the intake screenhouse to the intake canal and into the Screenhouse. Trash racks and traveling water screens located in the intake screenhouse collect fish, fish larvae and debris from the intake stream and return these organisms to the river to prevent them from entering plant systems.

Two circulating water pumps for each unit individually pump circulating water through one side of each condenser for the associated unit. As the circulating water passes through the condenser tubes, it absorbs the heat of vaporization from the low pressure turbine exhaust system.

The heated circulating water leaving the condenser is directed to the discharge basin through 102-in. concrete piping. From the discharge basin the water is directed to the river or to the cooling towers (see Section 11.6). From the cooling tower, the water flows through the cooling tower return canal to the distribution basin.

A recycle canal is provided to recycle circulating water from the distribution basin back to the intake canal. Recycle control gates between the distribution basin and the recycle canal control the recycle flow rate. Guide walls and submerged mixing blocks are located in the intake canal to mix the warm recycle and cool river water to prevent large temperature differences between the four circulating water pumps. Water returned to the river is dispersed through pipes into the main body.

The exterior circulating water system is operated to NPDES Permit MN0004006.

11.5.3 Performance Analysis

The design of the circulating water system allows for a variety of operating conditions that are governed by power levels and NPDES Permit requirements. In the open cycle mode the cooling towers are not used and the system acts as a once through design. In the closed cycle mode the cooling towers are in operation and there is limited return flow to the river. Depending on cooling requirements the system may be operated with cooling towers on line in addition to substantial blowdown to the river.

System discharge to the river, blowdown, is measured in cubic feet per second (CFS) 01-015
and is restricted by environmental impact considerations. The system can be operated
with complete reliance on the cooling towers and a nominal (150 cfs) blowdown, as a
once through system with maximum allowed blowdown, or at any desired blowdown
rate in between in order to meet environmental impact based restrictions. Operations
that exceed NPDES permit limits are reported to the appropriate state officials in 01-015
accordance with the NPDES permit.

Limitations are placed on the discharge flow rates by the NPDES permit April through June.

During other periods of the year the intake flow rate may vary to provide maximum plant efficiency provided the thermal criteria of the NPDES permit are not exceeded.

11.6 COOLING TOWER SYSTEM

11.6.1 Design Basis

The cooling tower system is designed to dissipate to the atmosphere the heat rejected to the cooling water system and the entire circulating water flow passing through the condensers.

11.6.2 Description

The cooling tower system is comprised of four towers, fans, water distribution headers and basins as shown in Figure 11.1-17. Each tower has one cooling tower pump. Each tower is made up of 12 cells grouped together (a bank).

The cooling tower pumps intake water from the discharge basin and discharge into individual distribution pipes to the top of the cooling towers. The pumps are vertical, dry pit pumps mounted so that the casing will be flooded with the water in the discharge basin at normal level. The pump motors are mounted on, and supported by, the pump. The intakes to the pumps are submerged to prevent the intake of air from any cause.

Spray nozzles at the top of the cooling towers break-up the water stream into small streams which drop by gravity through a maze of “fill” to a basin at the base of the towers. Fans draw air up through the streams of water and the heat of the water is carried into the atmosphere by the airstream. From the cold water basin at the bottom of the towers, the water flows through the cooling tower return canal to the distribution basin.

THIS PAGE IS LEFT INTENTIONALLY BLANK

11.7 MAIN STEAM SYSTEM

11.7.1 Design Basis

The Main Steam System is designed to remove heat from the reactor coolant in the two steam generators, producing steam for use in the turbine generator. The system can receive and dispose of the total heat existent or produced in the Reactor Coolant System following a turbine generator trip at full load.

The steam and feedwater lines from the steam generators to their respective isolation valves are Class I. A failure either of the main steam or feedwater lines, or malfunction of a valve installed therein, will not impair the reliability of the Auxiliary Feedwater System, render inoperative any engineered safety feature, initiate a loss-of-coolant condition, or cause failure of any other steam or feedwater line.

11.7.2 Description

Steam from each of the two steam generators supplies the turbine, where the steam expands through the double-flow, high-pressure turbine, and then flows through moisture separator reheaters to two, double-flow, low-pressure turbines, all in tandem. Five stages of extraction are provided, two from the high-pressure turbine (one of which is the exhaust) and three stages from the low-pressure turbines. The feedwater heaters for the lowest three stages are located in the condenser neck. All feedwater heaters are horizontal, halfsize units (two strings), including those for the lowest two extraction stage points, which are of the duplex type. The feedwater string is the closed type with deaeration accomplished in the condenser.

The four reheaters drain to the No. 5 high-pressure heaters. The No. 5 heaters drain to the No. 4 feedwater heaters. The No. 4 heaters and the moisture separators drain to the heater drain tank. The heater drain pumps take suction from the drain tank and discharge to the feedwater pump suction. Drains from the three lower pressure heaters cascade to the condenser.

The Main Steam System conducts steam in a 30-in. pipe from each of the two steam generators within the reactor containment through a swing-disc type isolation valve and a swing-disc type non-return valve to the turbine stop and control valves. The isolation and non-return valves are located outside of the containment. The two lines are cross-connected by a 20-in. equalizing line downstream of the isolation valves. The design pressure of the system is 1085 psig at 600°F. A steam flow nozzle is provided in the line from each steam generator upstream of the isolation and non-return valves, to meter steam flow from each steam generator and to limit the rate of steam release in the event of a main steam line break. Steam flow signals are used by the Automatic Feedwater Flow Control System as discussed in Section 7.

The steam for the turbine-driven auxiliary feedwater pump is obtained from both main steam lines, upstream of the main steam isolation valves, as shown in Figures 11.1-1 and 11.1-2.

Main steam for the turbine gland steam supply control valve, the air ejectors, the reheater section of the four moisture separator reheaters, and the priming ejector, is obtained from branches on the main steam lines ahead of the turbine stop valves.

Steam from five extraction points in the turbine casings is piped to the shells of the two parallel strings of feedwater heaters. The first point of extraction originates at the high-pressure turbine casing and supplies steam to the shell of the No. 5 high-pressure feedwater heater. The second point of extraction originates in the high- pressure turbine exhaust piping ahead of the moisture separators, and supplies steam to the No. 4 low-pressure feedwater heater. The third, fourth, and fifth point extractions all originate at the low-pressure turbine casings and supply steam to the No. 3, No. 2, and No. 1 low-pressure feedwater heaters, respectively, as shown in Figures 11.1-7 and 11.1-8.

To prevent turbine overspeed from backflow of flashed condensate from the heaters after a turbine trip, non-return valves are provided in the extraction lines to heaters No. 4 and 5. The non-return valves are air-cylinder operated valves which are closed automatically upon a signal from the turbine trip circuit and on high level in the feedwater heater.

11.7.3 Performance Analysis

The main steam line isolation and check valve assemblies have been modified by changing valve disc material to 410 stainless steel and by adding a rupture disc assembly to the isolation valve air-cylinder actuator. An extensive design analysis has shown that disc, linkage and valve body will perform as required for the entire range of valve closure incidents.

In both the check and the isolation valve, the disc has been designed to withstand the maximum energy impact from closure. Separate valve models were made for the analysis of isolation valve and check valve. In order to determine the flow parameters of the fluid passing through the valve, a blowdown computer program was used. The relevant equations required to determine the angular acceleration, angular velocity and angular position of the valve disc are incorporated into the program. Valve flow coefficients were employed to calculate the frictional pressure drop across the valve at the various angular positions of the disc. Using appropriately conservative conditions, the highest closure energy calculated was 1.252×10^6 in.-lb.

However, an additional margin was arbitrarily added to the closure energy (raising it to 1.35×10^6 in.lb.) for design.

Details of the closure energy analysis are presented in a topical report PI0- 02-03 (Reference 15) titled: “Analysis Report - Maximum Energy of Disc Impact - Main Steam Check and Isolation Valves for Kewaunee Unit 1,” submitted to the Regulatory Staff on Kewaunee Docket 50-305. Because the main steam isolation and check valves for the Prairie Island and Kewaunee plants are identical, a jointly sponsored program was undertaken by Northern States Power Company and Wisconsin Public Service Corporation to determine disc closure energies. Due to the locations of postulated breaks relative to the valves, the Kewaunee plant has the highest disc closure energies. Therefore, in the analysis, the Kewaunee values were used; and the report, PI0-02-03 (Reference 15), not only applies to Prairie Island but also gives a margin of safety. Due to changes in the full power operating characteristics the MS check and isolation valve disc impact energies were updated in 09Q4836-CAL-002 (Reference 11); however, the Hot-Zero Power condition disc impact energies for the check and isolation valves of PI0-02-03 (Reference 15) remains applicable.

A finite element model of the disc linkage and valve body was developed and an elastic plastic analysis was made to determine deformations. The elastic plastic design of the valve allows for permanent deformation of the disc upon spurious valve closure at full load steam flow conditions. A detailed presentation of the stress analysis was presented in a topical report PI0- 01-06 (Reference 9) titled: “Analysis Report - Structural Analysis of Main Steam Check and Isolation Valves for Prairie Island Unit 1.” An updated structural analysis of the main steam check and isolation valves is presented in 09Q4836-CAL-003 (Reference 10).

The non-return valves prevent reverse flow of steam. If a steam line ruptures between a non-return valve and a steam generator, the affected steam generator will blow down. The non-return valve in the line eliminates blowdown from the other steam generator. The steam break incident is analyzed in Section 14.5.

11.7.4 Inspection and Testing

The main steam line valves can be tested at regular intervals.

The main steam isolation valves serve to limit an excessive reactor coolant system cooldown rate and resultant reactivity insertion following a main steam break incident. Their ability to close upon signal within a specified time interval is verified each refueling outage or when work has been performed on the valves. See Technical Specification Surveillance Requirement 3.7.2.2. 60400000344

THIS PAGE IS LEFT INTENTIONALLY BLANK

11.8 CONDENSATE POLISHING SYSTEM

11.8.1 Design Basis

The condensate polishing system is typically used during unit start-up and is designed to remove suspended and dissolved impurities from the condensate so that the secondary water chemistry is maintained within specified limits. The system is designed to accommodate a maximum condenser tube leak of 0.5 gpm. The system was originally sized to process approximately 10,000 gpm of condensate. The peak flow capacity of the system is 11,000 gpm.

The system is designed with 50% redundant capacity to provide for continuous operation when portions of the system are shutdown for maintenance or repair.

The system also provides storage, handling and processing of waste solids with interfaces to the ultimate means of disposal via the plant waste solidification system, portable onsite solidification equipment, offsite solidification or offsite landfill.

The system is provided with a process air supply which is designed with sufficient excess capacity to supplement the plant station air system. Chemistry sampling and monitoring is provided to ensure proper system operation. Shielding is provided for the protection of plant personnel. The design of the shielding is based on the maximum primary-to-secondary leakage allowed by the Technical Specifications.

11.8.2 Description

The condensate polishing system (Figures 11.1-19 through 11.1-20) consists of the following subsystems:

a. filter/demineralizer

b. backwash and flush water

c. spent resin disposal

d. backwash air supply

e. resin disposal building sump

All system functions are controlled locally. System malfunctions are alarmed locally and in the control room.

11.8.2.1 Filter/Demineralizer System

The filter/demineralizer (F/D) system is shown in detail in Figure 11.1-20 and consists of three 50%-capacity, precoat-type F/D vessels per unit arranged in parallel in the condensate pump discharge header. Each F/D vessel is rated at 5500 gpm and 30 psi max ΔP across the filter elements. During normal operation two vessels are online while the third is in backwash, precoat, shutdown or standby.

One full-capacity bypass is provided for all three F/D vessels. The bypass valve is automatically actuated by F/D differential pressure to maintain a maximum total system ΔP of 45 psid. Full capacity manual bypass is provided in parallel with the automatic bypass.

A holding pump is provided for each vessel to retain the precoat on the filter elements. The holding pump maintains a 750 gpm flow through the F/D vessel and is automatically actuated on low F/D vessel effluent flow.

Backwash air and water are supplied to each vessel for the purpose of dislodging precoat from the filters by pressurizing and then rapidly depressurizing the vessel. Separate precoating equipment is provided for each F/D train. The vessels are individually precoated via cross-ties to the precoat equipment.

Adequate shielding is provided in the vicinity of the F/D vessels to allow personnel access through the area during design basis primary-to-secondary leakage conditions.

11.8.2.2 Backwash and Flush Water System

Backwash and flush water is stored in the backwash water storage tank (BWST) which is manually supplied from the condensate storage tank (CST). A cross- tie is provided so that the BWST for one unit may be supplied from the CST of the other unit. Backwash waste water and resin from the F/D vessels dumps by gravity to the backwash waste receiving tank (BWRT). The slurry is then transferred to the resin disposal building (RDB). After dewatering via clamshell filters, the spent resin is diverted to the spent resin disposal system, and the backwash waste water is filtered and directed to the turbine building sump. The backwash waste water may be directed to the BWST should circumstances warrant. Each Unit's BWST and BWRT have capacity for two backwashes. Cross-ties are provided such that the dewatering equipment for each unit is interchangeable with the other unit.

11.8.2.3 Spent Resin Disposal System

Dewatered, spent resin from backwash system operations of both units is transferred, via the drain diverters and spent resin disposal chutes, to the spent resin transfer tank (SRXT) in the resin disposal building, or to barrels or to other containers, depending on ultimate disposal. Flush water is also supplied to the SRXT for disposal and/or processing of spent resins.

Flush water or resin slurry in the SRXT can then be pumped under manual control to one of the following places for further processing and/or disposal:

a. Atcor waste metering tank for solidification via the plant waste solidification system in the radwaste building

b. Normally-closed, blind-flanged line in the resin disposal building for transfer to truck or portable solidification equipment

c. backwash system for further reprocessing

d. recirculation line to SRXT

11.8.2.4 Backwash Air Supply System

Compressed air for resin backwashing operations is supplied from the Compressed Air System. The Compressed Air System is discussed in Section 10.3.10. 01284959

11.8.2.5 Resin Disposal Building Sump System

The resin disposal building sump system consists of two sumps, each equipped with a redundant set of sump pumps.

Sump “A” handles the RDB floor drains and may be discharged to either the miscellaneous drains collection tank or the waste holdup tanks.

Sump “B” handles the truck loading enclosure floor drains and discharges to the aerated drains sump tank.

11.8.3 Performance Evaluation

The condensate polishing system is designed to maintain the EPRI PWR Secondary Water Chemistry Guidelines (Reference 1). During normal power operation, sampling of steam generator blowdown, condensate and feedwater is performed in accordance with these guidelines per plant chemistry procedures.

System high conductivity is annunciated at local control panels and actuate the system trouble alarms in the main control room.

The volume of spent powdered resin throughput from the plant is conservatively estimated at 3525 cubic feet annually for both units. Almost all of the spent powdered resin contains negligible radioactivity and can be safely disposed of by landfill burial.

The annual volume of radioactive spent powdered resin depends on the amount of primary-to-secondary leakage. In general, the annual volume of radioactive spent powdered resin is extremely small and has sufficiently low activity to be disposed of as low level waste in accordance with applicable federal regulations.

11.9 CONDENSATE, FEEDWATER AND AUXILIARY FEEDWATER SYSTEMS

11.9.1 Design Basis

11.9.1.1 Condensate and Feedwater Systems

The Condensate and Feedwater System design is based on removing condensate from the hotwell of the condenser and supplying heated feedwater to the steam generators at all load conditions.

There are three multi-stage, vertical, pit-type, centrifugal condensate pumps with vertical motor drives. Each pump is half capacity with the turbine operating at the maximum calculated rating.

Two half-capacity, high speed, centrifugal, vertically-split case, motor-driven main feedwater pumps increase the pressure of the condensate for delivery through one stage of feedwater heating and the feedwater regulating valves to the steam generators.

The main feedwater pumps are single-stage, horizontal, centrifugal pumps with barrel casings. Each feedwater pump is rated at 8600 gpm and 2100 ft. TDH. Shaft sealing is accomplished by a pressure breakdown style arrangement cooled with seal water injection. Bearing lubrication for the motor, the pump, and its step-up gear is accomplished by an integral Lubrication Oil System mounted on the pump base. Normal circulation of the lubrication oil is by shaft-driven pump. The Lubricating Oil System includes a reservoir, a cooler, and an ac motor-driven back-up oil pump. Feedwater pump bearing temperatures are available on ERCS. The feedwater pumps are started and stopped from the main control board. A minimum flow control system is provided to ensure 925 gpm flow during low system flow conditions.

Should there be a loss of suction pressure, an automatic bypass around the low-pressure feedwater heaters ensures sufficient suction pressure at the feedwater pumps.

11.9.1.2 Auxiliary Feedwater System

The Auxiliary Feedwater System supplies feedwater following interruption of the main feedwater supply. Feedwater must be provided for the removal of residual heat from the core by heat exchange in the steam generators if the main feedwater pumps cease to operate for any reason.

The Auxiliary Feedwater System delivers feedwater from the condensate storage tank (or from the cooling water system) to the main feedwater piping at a location near the steam generator inlet. The system consists of the auxiliary feedwater pumps, associated valves and piping, and control systems. The entire system is redundant.

The Auxiliary Feedwater System provides three essential functions during abnormal conditions:

a. prevents thermal cycle of the steam generator tube sheet upon loss of main feedwater pump;

b. removes residual heat from the reactor coolant system until the RCS temperature drops below 300-350°F and the RHR system is capable of providing the necessary heat sink;

c. maintains a head of water in the steam generator following a loss of coolant accident.

The feedwater flow rate required to prevent thermal cycling of the tube sheet and for removing residual heat is the same and is about 160 gpm (historical) per Unit (or 80 gpm per steam generator). A 200-gpm flow is therefore sufficient to fulfill all the 01491637
three functions stated above. However, since the Auxiliary Feedwater System is a safety features system, an additional 200-gpm pump is provided as a backup for the first for each Unit. 200 gpm is the design sizing of the AFW Pumps and not a minimum flow requirement.

In other 2-loop plants (R.E. Ginna, Point Beach, etc.) prior to Prairie Island, the inventory of secondary side water in the steam generator versus secondary side water level was such that the pump size required to prevent thermal cycling was larger than the pump size required for removing the residual heat in the core (almost twice as big).

As a result of this difference in capacity requirement between the two functions, these plants used the turbine driven pump to meet the larger capacity since it was not a safeguards requirement and therefore did not require redundancy. Smaller motor driven pumps are used for the safeguards requirements of removing fission product decay heat so as not to unnecessarily increase the diesel-generator size. The recent designs use a large steam generator with a different dimensional configuration. This reduces the pump size required to prevent thermal cycling, such duty being about the same as for removing residual heat, 160 gpm (historical) per unit or 80 gpm per steam generator. 160 gpm (historical) minimum flow rate is based on normal SG water levels 01491637
at the time of the event (Reference 2). [Only one steam generator is required to remove all decay heat in the core.]

11.9.2 Description

11.9.2.1 Condensate and Feedwater Systems

Condensate is taken from the condenser hotwell by the condensate pumps and pumped through the filter/demineralizer system or its bypass line, the air ejector condensers, gland steam condenser, and low-pressure heaters to the suction of the feedwater pumps. The feedwater pumps then send feedwater through the high-pressure heaters to each steam generator. The condensate and feedwater systems flow diagrams are shown in Figures 11.1-3 to 11.1-6.

The two main feedwater pumps operate in series with the condensate and the heater drain pumps, discharging through check valves and motor-operated gate valves into the No. 5 heaters. The feedwater flows through the two parallel, high-pressure feedwater heaters and flows into a common header. Two 16-in. lines containing the feedwater control stations feed the two steam generators from the header.

Bypass valves together with shutoff valves at the inlets and outlets of the feedwater heaters are provided to permit heaters to be taken out of service.

The steam generator feedwater control system indicates, records and controls the water level in each of the two steam generators.

Reactor trip is actuated by low-low steam generator water level. These trips are discussed in further detail in Section 7.

The main feedwater control valves are closed when any one of the following conditions occurs:

Abnormally high steam generator level

Safety injection signal

Reactor trip in coincidence with low Tavg

Any safety injection signal will isolate the main feedwater lines by closing all control valves (main and bypass valves) and tripping the main feedwater pumps, which causes the discharge valves to close.

One manual control station is provided for each feedwater valve. This unit consists of auto/manual transfer capability and analog output control. When in automatic, flow is adjusted as necessary to maintain narrow range steam generator level at its set point, which is programmed as a function of load.

The reheater and moisture separator are housed in one pressure vessel. Reheaters are provided with drain tanks and level controls. The moisture separators are also provided with level control, while feedwater heater No. 15 is equipped with a duplex level control. All the low-pressure feedwater heaters, No. 11, 12, and 13, are located in the condenser neck. Feedwater heaters No. 11 & 12 are combined into one shell (duplex) with bolted-head construction. Feedwater heater No. 11 is provided with a separate Feedwater Heater Drain Cooler (No. 11). Drain from moisture separator and Feedwater heater No. 14 are drained directly to the Heater Drain Tank, as shown in Figures 11.1-9, 10.

The level controllers operate the emergency drain dump valves which dump the various drains directly to the condenser in case of abnormally high level. Three half-capacity, vertical, centrifugal heater drain pumps are provided for pumping the heater drainage into the condensate line ahead of the feedwater pumps. The pumps are started and stopped from the main control board. Tank level is controlled by variable-speed pump drives. An emergency dump valve to the condenser is sized to pass all condensate from Feedwater Heater No. 14.

11.9.2.2 Auxiliary Feedwater System

The Auxiliary Feedwater System is the most reliable system for decay heat removal following any reactor shutdown. Full flow capability is reached within a maximum response time of one minute when the pump drives are automatically energized from an open-valve standby status, when the normal coolant source is available. As discussed below, response time to other scenarios such as seismic events and tornadoes may take longer if there is a need to realign pump suction to the backup coolant source. Redundancy of flow paths, valving, pumps, and redundancy and diversity of coolant sources, and pump energy sources assures a high degree of system reliability.

The Auxiliary Feedwater System consists of one steam turbine-driven pump and one motor-driven pump per operating unit, with each capable of delivering coolant to either or both steam generators of the same operating unit. Check valves are provided to prevent a rupture in either pump’s discharge from negating the other pump’s effectiveness. Welded construction is used where possible throughout the Auxiliary Feedwater System piping, valves, and equipment to minimize the possibility of leakage. The Auxiliary Feedwater System is shown on the Main Steam System and Feedwater System flow diagrams, Figures 11.1-1, 11.1-2, 11.1-5 and 11.1-6. Pump characteristic curves are shown on Figure 11.9-1.

There is no interconnection between the two turbine-driven pumps, and there is no sharing of the Auxiliary Feedwater System components by the two operating units during normal operations. However, a cross-connection between the discharge lines of the motor-driven pumps is provided to achieve greater flexibility during operational emergencies. By incorporating two valves in this cross-connection, the Auxiliary Feedwater System has the capability to take an active or passive failure and still fulfill its functional requirements.

The turbine-driven auxiliary feedwater pumps operate independent of all plant AC power sources and are supplied steam from both main steam lines of their associated operating unit. The two steam lines join together downstream of motor-operated isolation valves (one per line) to supply steam to the turbine through a single air-operated, fail open, steam admission valve.

The air-operated steam admission valve has two safety related functions:

1) Open: To allow passage of steam to start the associated turbine-driven auxiliary feedwater pump.

2) Close: Tripping the pump on low turbine-driven auxiliary feedwater pump suction or discharge pressure.

The steam admission valve safety related air pressure boundary is from the safety related check valve to the air-operated steam admission valve actuator. The instrument air system supplies air to the steam admission valve air pressure boundary. The air supply to the steam admission valve is controlled by a three-way DC powered solenoid. The air-operated steam admission valve opens automatically on a turbine-driven auxiliary feedwater pump start signal. Additionally, the turbine-driven auxiliary feedwater pump may also be started locally using a 3-way manual valve to locally bleed air pressure from the steam admission valve air pressure boundary.

Failure of control power to the three-way DC powered solenoid valve causes the air pressure boundary to be vented, which results in the steam admission control valve to open, starting the associated pump. On failure of the instrument air system, the accumulator is capable of maintaining sufficient air pressure for the steam admission valve. The steam admission valve will remain closed until accumulator pressure is lost or an automatic start signal is received. In the case of loss of instrument air, the most likely start signal will be from Low-Low Steam Generator Water Level.

The motor-driven auxiliary feedwater pumps are fed by separate safeguard buses, one each per operating unit, and are included in the load restoration sequencing onto the emergency buses. Motor-operated valves are not stripped from the emergency buses. A failure in the automatic circuitry will not affect the capability to manually initiate auxiliary feedwater from the control room.

Instrumentation and logic circuits for starting both the motor- and turbine-driven pumps meet the single failure criterion (except for AMSAC) for actuation and are capable of being tested at power.

Instrumentation power supplies are from the site's four vital 120 VAC buses, each supplied by an inverter connected to the associated 480 VAC emergency bus and 125 VDC power system. Motor-driven pump breaker controls are powered by the respective train of the 125 VDC system. Control power for the turbine-driven pumps' steam admission control valves is also supplied from the Safeguards 125 VDC battery systems.

The following signals automatically start the pump motors and open the steam admission control valve to the turbine-driven pumps:

a. Low-low water level in either steam generator.

b. Trip of both main feedwater pumps (bypassed during startup and shutdown operation).

c. Safety injection.

d. Loss of both 4.16 KV normal buses (turbine-driven pump only).

e. AMSAC actuation.

In addition, the motor-driven pumps and the turbine-driven pumps can be manually started locally or remotely.

Each auxiliary feedwater pump has a pressure switch on its suction and on its discharge piping. If a low pressure setpoint is reached on either switch, the pump will trip either by closing the air-operated steam admission control valve on the turbine-driven auxiliary feedwater pumps, or by opening the motor breaker on the motor-driven auxiliary feedwater pumps. The low discharge pressure trip protects the pump from damage due to runout. The low suction pressure trip prevents damage to the pump from loss of suction. In either case, the pump will be protected so it can be restarted once the cause of low pressure is corrected.

On 11 and 22 Turbine-Driven Auxiliary Feedwater Pumps, the low discharge pressure trip is blocked when in AUTO and the Reactor Trip Breakers are closed (RTA for relay contact for 11 TD AFW pump and RTB relay contact for 22 TD AFW pump). This circuit ensures that following the completion of the AMSAC initiation of Auxiliary Feedwater during an ATWS transient, the TD AFW pump will continue to run.

During reactor operation, all pumps are on standby, and the isolation valves and pump suction and discharge valving are open. Start of an auxiliary feedwater pump causes the steam generator blowdown flow control valves in the associated operating unit to auto close.

Auxiliary feedwater system coolant sources are redundant and diverse. The normal source is by gravity feed from the three cross-connected 150,000 gallon condensate storage tanks. The safety related (backup) water supply is provided by the Design Class I Cooling Water System. If an external event such as a tornado or seismic event were to cause flow disruption from the condensate storage tanks, the auxiliary feedwater pumps would likely trip on low suction pressure. Piping connecting the three condensate storage tanks has been evaluated against failure under seismic loads. 01427085

An auxiliary feedwater reliability study [Ref. 14] was performed after the Three Mile Island accident and in response to NUREG-0611. This study determined steam generator dryout times with no auxiliary feedwater flow available. For a loss of normal feedwater event, the dryout time is approximately 30 minutes. For a loss of offsite power event, the dryout time is approximately 60 minutes. (Additional reliability study information follows near the end of this section.) Additional analysis (NSP-07-33, Reference 5) has determined that additional time is available for reinitiating of A.F. flow based on the effect on the primary system for a loss of offsite power due to an external event.

PINGP has standing operating procedures for realigning the auxiliary feedwater pump suction from the condensate storage tanks to the Cooling Water System and for flow restoration after a low suction/low discharge pressure auxiliary feedwater pump trip. These procedures have been time-validated and can be accomplished within the SG dryout time frames listed above.

In the normal cooldown procedure, after programmed reactor shutdown or trip, steam generator levels may be maintained by control of the feedwater flow control valves. If the Main Feedwater System is inoperable or its flow is too great, steam generator levels are controlled by local or remote manual operation of the auxiliary feedwater flow control valves for the turbine- and motor-driven pumps.

When reactor containment isolation is initiated, the normally-open auxiliary feedwater containment isolation valves receive an “open” signal.

Following blowdown in the loss-of-coolant accident, the Auxiliary Feedwater System maintains a positive pressure differential from the secondary side to the primary side of the steam generators, providing a barrier to prevent possible fission product escape to the Main Steam System.

The SI actuation circuits which initiate auxiliary feedwater addition are safety grade, separated and trained. The SI actuation contacts which trip the normal feedwater pumps off are also safety grade, using additional relays to maintain separation even though both pumps are tripped off by both Train A and Train B SI signals. In addition, either Train A or Train B SI Signal causes closure of the parallel flow control valves downstream of the feedwater pumps. The SI signal causes closure of the containment isolation valves downstream of the normal feedwater flow control valves through the containment isolation signals.

A cycle timer control circuit automatically runs the auxiliary motor-driven lube oil pump on each auxiliary feedwater pump for approximately 10 minutes twice per week. The minimum requirement is 5 minutes once per week. If the proper lube oil pressure is not reached following the lube oil pump start, an alarm is sounded in the control room. This ensures that sufficient auxiliary feedwater pump oil film for pump start is maintained at all times. Thus, the auxiliary motor-driven lube oil pump is not required for auxiliary feedwater pumps starting.

The bearing oil coolers are cooled by recirculation flow from the discharge of the auxiliary feedwater pumps back to the condensate storage tanks. Oil cooling is thus available whenever the pump is running.

As a result of the Three Mile Island accident, reliability of the auxiliary feedwater system received additional attention. The NRC issued Generic Letter 81-14, "Seismic Qualification of AFW Systems". Several responses to the NRC were made from which the NRC concluded in a letter dated June 16, 1983 that, following a number of minor modifications, the auxiliary feedwater system had sufficient capability to withstand a safe shutdown earthquake and accomplish its safety function.

Generic Issue No. 124, "Auxiliary Feedwater System Reliability" was also identified as a result of the Three Mile Island accident. The Prairie Island Auxiliary Feedwater System was determined to be in the low reliability range based on an NRC reliability analysis reported in NUREG-0611. As a result of Generic Issue No. 124, Northern States Power Company performed a probabilistic risk assessment study on the auxiliary feedwater and supporting systems, Prairie Island Units 1 and 2 Auxiliary Feedwater System Reliability Study [Ref 14]. Based on the NSP study, and an NRC staff audit of plant variables affecting the Auxiliary Feedwater system, Generic Issue No. 124 was closed out by an NRC Safety Evaluation Report transmitted by letter dated November 26, 1986.

The following is a list of actions that were taken as a result of the NSP study and remaining NRC concerns expressed in the NRC Safety Evaluation to close out Generic Issue 124.

a. Lube Oil Cooling - AFW pump discharge recirculation flow was rerouted to supply cooling water for pump lube oil coolers. This action removed the AFW dependency on cooling water for lube oil cooling.

b. Manual Control of TDAFW Pump - A three way solenoid valve has been added to the air supply line to the TDAFW pump steam inlet supply control valve. This valve allows the pump to be run manually by locally opening the control valve by venting diaphragm air. A procedure has been written for manual auxiliary feedwater pump operations. All operations crews have been trained in use of the procedures.

c. Eliminate Auto Open Signal to MV-32041 & MV-32042 - The auto open signal to the "Condensate Emergency Supply Valve," MV-32041 (Unit 1) and MV-32042 (Unit 2), has been removed.

d. Drain Valves from AFW Steam Lines to the Main Condenser - All drain valves from the AFW steam lines to the main condenser have been blocked open using safeguards hold cards.

e. Proceduralize Bypass of Control/Actuation Faults - The subject procedures have been written as subsections of the Auxiliary Feedwater System procedure.

f. AFW System Valve Integrity - Check valve integrity is assured by monitoring the temperature of AFW discharge lines during each shift.

g. Trip/Throttle Leakoff - Both the high and low pressure leakoff for the TDAFW pump trip/throttle valves have been rerouted to discharge into the turbine exhaust lines. This modification was completed to eliminate the potentially for creating a steam environment in the auxiliary feedwater pump room during operation of the turbine-driven auxiliary feedwater pump.

h. Condensate Header Valve C-41-1 - Condensate header valve C-41-1 was installed during plant construction to facilitate isolation and testing of systems. This valve was not used after plant startup and represented a potential for loss of AFW pump suction supply, it was removed from service and replaced by a spoolpiece.

i. Actions Taken to Eliminate Final NRC Concerns:

    1. Administratively locked open the condensate storage tank isolation valves to ensure AFW pumps suction supply.

    2. A step ladder is located in each AFW pump room to aid operators in manipulating overhead AFW valves in emergency situations.

    3. Installed additional emergency lighting in the area of the TDAFW pumps.

    4. Work toward maintaining similarity between Unit 1 and Unit 2 AFW surveillance and maintenance procedures.

11.9.3 Performance Analysis

The Auxiliary Feedwater System serves as a backup system for supplying feedwater to the secondary side of the steam generators at times when the feedwater system is not available, thereby maintaining the heat sink capabilities of the steam generator. As an Engineered Safeguards System, the Auxiliary Feedwater System is directly relied upon to prevent core damage and system overpressurization in the event of transients such as a loss of normal feedwater or a secondary system pipe rupture, and to provide a means for plant cooldown following any plant transient.

Following a reactor trip, decay heat is dissipated by evaporating water in the steam generators and venting the generated steam either to the condensers through the steam dump or to the atmosphere through the atmospheric steam dump valves, steam generator safety valves or the power-operated relief valves. Steam generator water inventory must be maintained at a level sufficient to ensure adequate heat transfer and continuation of the decay heat removal process. The water level is maintained under these circumstances by the Auxiliary Feedwater System which delivers an emergency water supply to the steam generators. The Auxiliary Feedwater System must be capable of functioning for extended periods, allowing time either to restore normal feedwater flow or to proceed with an orderly cooldown of the plant to the reactor coolant temperature where the Residual Heat Removal System can assume the burden of decay heat removal. The Auxiliary Feedwater System flow and the emergency water supply capacity must be sufficient to remove core decay heat, reactor coolant pump heat, and sensible heat during the plant cooldown. The Auxiliary Feedwater System can also be used to maintain the steam generator water levels above the tubes following a LOCA. In the latter function, the water head in the steam generators serves as a barrier to prevent leakage of fission products from the Reactor Coolant System into the secondary plant.

The reactor plant conditions which impose performance requirements on the design of the Auxiliary Feedwater System are as follows for the Prairie Island plants.

Loss of Main Feedwater Transient
- Loss of main feedwater with offsite power available (*)
- Loss of main feedwater without offsite power available (*)

Secondary Pipe Ruptures
- Feedline rupture
- Steamline rupture (*)

Loss of All AC Power (station blackout)

Loss of coolant Accident (LOCA) (*)

Cooldown

a. Loss of Main Feedwater Transients

The design loss of main feedwater transients are those caused by:

– Interruptions of the Main Feedwater System flow (LONF) due to a malfunction in the feedwater or condensate system

– Loss of offsite power (LOOP) with the consequential shutdown of the system pumps, auxiliaries, and controls

---

(*) Impose safety related performance requirements

Loss of main feedwater (LONF) transients are characterized by a rapid reduction in steam generator water levels which results in a reactor trip, a turbine trip, and auxiliary feedwater actuation by the protection system logic. Following reactor trip from high power, the power quickly falls to decay heat levels. The water levels continue to decrease, progressively uncovering the steam generator tubes as decay heat is transferred and discharged in the form of steam either through the steam dump valves (to the condenser or atmosphere) or through the steam generator safety or power-operated relief valves to the atmosphere. The reactor coolant temperature increases as the residual heat in excess of that dissipated through the steam generators is absorbed. With increased temperature, the volume of reactor coolant expands and begins filling the pressurizer. Without the addition of sufficient auxiliary feedwater, further expansion will result in water being discharged through the pressurizer safety and relief valves. If the temperature rise and the resulting volumetric expansion of the primary coolant are permitted to continue, then (1) pressurizer safety valve capacities may be exceeded causing overpressurization of the Reactor Coolant System and/or (2) the continuing loss of fluid from the primary coolant system may result in core uncovering, loss of natural circulation, and core damage. If such a situation were ever to occur, the Emergency Core Cooling System would be ineffectual because the primary coolant system pressure exceeds the shutoff head of the safety injection pumps, the nitrogen over-pressure in the accumulator tanks, and the design pressure of the Residual Heat Removal Loop. Hence, the timely introduction of sufficient auxiliary feedwater is necessary to arrest the decrease in the steam generator water levels, to reverse the rise in reactor coolant temperature, to prevent the pressurizer from filling to a water solid condition, and eventually to establish stable hot standby conditions. Subsequently, a decision may be made to proceed with plant cooldown if the problem cannot be satisfactorily corrected.

The LOOP transient differs from a simple loss of main feedwater in that emergency power sources must be relied upon to operate vital equipment. The loss of power to the electric driven condenser circulating water pumps results in a loss of condenser vacuum and condenser dump valves. Hence, steam formed by decay heat is relieved through the atmospheric steam dump valves, steam generator safety valves or the power-operated relief valves. The calculated transient would be similar for both the loss of main feedwater and the LOOP, except that reactor coolant pump heat input is not a consideration in the LOOP transient following loss of power to the reactor coolant pump bus.

The LONF transient serves as the basis for the minimum flow required for the smallest capacity single auxiliary feedwater pump for the Prairie Island plants due to the additional heat from Reactor Coolant Pump operation. The pump is sized so that any single pump will provide sufficient flow against the steam generator safety valve set pressure (with accumulation) to prevent water relief from the pressurizer. For decay heat removal using the safety valve(s), actual accumulation is a function of the steam flow rate required for the decay heat load and if the decay heat load is being removed by one or both Steam Generators.

b. Secondary System Pipe Ruptures

The feedwater line rupture accident not only results in the loss of feedwater flow to the steam generators but also results in the complete blowdown of one steam generator within a short time if the rupture should occur downstream of the last nonreturn valve in the main or auxiliary feedwater piping to an individual steam generator. Another significant result of a feedline rupture may be the spilling of auxiliary feedwater out the break as a consequence of the fact that the auxiliary feedwater branch line may be connected to the main feedwater line in the region of the postulated break. Such situations can result in the spilling of a disproportionately large fraction of the total auxiliary feedwater flow because the system preferentially pumps water to the lowest pressure region in the faulted loop rather than to the effective steam generator which is at a relatively high pressure. The system design must allow for terminating, limiting, or minimizing that fraction of auxiliary feedwater flow which is delivered to a faulted loop or spilled through a break in order to ensure that sufficient flow will be delivered to the remaining effective steam generator. The concerns are similar for the main feedwater line rupture as those explained for the loss of main feedwater transients.

Main steamline rupture accident conditions are characterized initially by plant cooldown and, for breaks inside containment, by increasing containment pressure and temperature. Auxiliary feedwater is not needed during the early phase of the transient but flow to the faulted loop will contribute to the release of mass and energy to containment. Thus, steamline rupture conditions establish the upper limit on auxiliary feedwater flow delivered to a faulted loop. Eventually, however, the Reactor Coolant System will heat up again and auxiliary feedwater flow will be required to be delivered to the unfaulted loop, but at somewhat lower rates than for the loss of feedwater transients described previously. Provisions must be made in the design of the Auxiliary Feedwater System to allow limitation, control, or termination of the auxiliary feedwater flow to the faulted loop as necessary in order to prevent containment overpressurization following a steamline break inside containment, and to ensure the minimum flow to the remaining unfaulted loops.

c. Loss of All AC Power

The loss of all AC power is postulated as resulting from accident conditions wherein not only onsite and offsite AC power is lost but also AC emergency power is lost as an assumed common mode failure.

Battery power for operation of protection circuits is assumed available. The impact on the Auxiliary Feedwater System is the necessity for providing both an auxiliary feedwater pump power and control source which are not dependent on AC power and which are capable of maintaining the plant in Mode 3, Hot Standby until AC power is restored.

d. Loss-of-Coolant Accident (LOCA)

The loss of coolant accidents do not impose on the auxiliary feedwater system any flow requirements in addition to those required by the other accidents addressed in this response. The following description of the small LOCA is provided here for the sake of completeness to explain the role of the auxiliary feedwater system in this transient.

Small LOCA's are characterized by relatively slow rates of decrease in reactor coolant system pressure and liquid volume. The principal contribution from the Auxiliary Feedwater System following such small LOCAs is basically the same as the system's function during Mode 3, Hot Standby or following spurious safety injection signal which trips the reactor. Maintaining a water level inventory in the secondary side of the steam generators provides a heat sink for removing decay heat and establishes the capability for providing a buoyancy head for natural circulation. The auxiliary feedwater system may be utilized to assist in a system cooldown and depressurization following a small LOCA while bringing the reactor to Mode 5, Cold Shutdown.

e. Cooldown

The cooldown function performed by the Auxiliary Feedwater System is a partial one since the reactor coolant system is reduced from normal zero load temperatures to a hot leg temperature of approximately 350°F. The latter is the maximum temperature recommended for placing the Residual Heat Removal System (RHRS) into service. The RHR system completes the cooldown to Mode 5, Cold Shutdown conditions.

Cooldown may be required following expected transients, following an accident such as a main feedline break, or during a normal cooldown prior to refueling or performing reactor plant maintenance. If the reactor is tripped following extended operation at rated power level, the AFWS is capable of delivering sufficient AFW to remove decay heat and reactor coolant pump (RCP) heat following reactor trip while maintaining the steam generator (SG) water level. Following transients or accidents, the recommended cooldown rate is consistent with expected needs and at the same time does not impose additional requirements on the capacities of the auxiliary feedwater pumps, considering a single failure. In any event, the process consists of being able to dissipate plant sensible heat in addition to the decay heat produced by the reactor core.

Table 11.9-1 summarizes the criteria which are the general design bases for each event. Specific assumptions used in the analyses to verify that the design bases are met are discussed below.

The primary function of the Auxiliary Feedwater System is to provide sufficient heat removal capability for heatup accidents following reactor trip to remove the decay heat generated by the core and prevent system overpressurization. Other plant protection systems are designed to meet short term or pre-trip fuel failure criteria. The effects of excessive coolant shrinkage are bounded by the analysis of the rupture of a main steam pipe transient. The maximum flow requirements determined by other bases are incorporated into this analysis, resulting in no additional flow requirements.

Analyses have been performed for the limiting transients which define the AFWS performance requirements. Specifically, they include:

– Loss of Main Feedwater (LONF)

– Rupture of a Main Feedwater Pipe

– Rupture of a Main Steam Pipe Inside Containment

The analyses described below are for determining the performance requirements of the AFWS; for example, sizing of the AFW Pumps. The description below, the criteria in Table 11.9-1, and the inputs and assumptions in Table 11.9-2 may be different than those used for the accident and transient analyses described in Section 14. In addition, the accidents and transients evaluated for AFW sizing may be different than those analyzed in Section 14. For example, the rupture of Main Feedwater Line (cannot be isolated from the associated SG) is evaluated for AFW sizing, but is not an analyzed accident in Section 14. That is, the Main Feedwater Line Break is not a design basis accident for Prairie Island.

In addition to the above analyses, calculations have been performed specifically for the Prairie Island plants to determine the plant cooldown flow (storage capacity) requirements. The Loss of All AC Power is evaluated via a comparison to the transient results of a LOOP, assuming an available auxiliary pump having a diverse (non-AC) power supply. The LOCA analysis, as discussed in Item (d) above, incorporates the system flow requirements as defined by other transients, and therefore is not performed for the purpose of specifying AFWS flow requirements. Each of the analyses listed above are explained in further detail below.

Loss of Main Feedwater (LONF)

A loss of feedwater (LONF) transient assuming a single auxiliary feedwater pump delivering flow to both steam generators was evaluated to show that this event does not result in filling the pressurizer, that the peak RCS pressure remains below the criterion for Condition II transients and that no fuel failures occur (refer to Table 11.9-1). As previously discussed, for determining AFW flow requirements, maintaining off-site power is more conservative than losing off-site power. Table 11.9-2 summarizes the assumptions used in this analysis. The transient analysis begins at the time of the loss of main feedwater. The analysis assumes that the plant is initially operating at the power shown on the table, a very conservative assumption in defining decay heat and stored energy in the RCS. The reactor is assumed to be tripped on low-low steam generator level. Steam generator level at the time of reactor trip was assumed to be 0% NRS for additional conservatism; to that, allowance for level uncertainty was also accounted for. The analysis shows that there is a considerable margin with respect to filling the pressurizer.

This analysis establishes the capacity of the smallest single pump and also establishes train association of equipment so that this analysis remains valid assuming the most limiting single failure.

Rupture of Main Feedwater Pipe

The double ended rupture of a main feedwater pipe inside of containment is analyzed for determining AFW performance requirements (Reference 3). Table 11.9-2 summarizes the assumptions used in the analyses. Reactor trip is assumed to occur as a result of a safety injection signal based on high containment pressure. This is a conservative time assumption which increases the stored heat prior to reactor trip and minimizes the ability of the steam generator to remove heat from the RCS following reactor trip due to a conservatively small total steam generator inventory. As in the loss of normal feedwater analysis, the initial power rating was assumed to be 1683 MWt. The analysis allows for 180 gpm auxiliary feedwater delivered to the intact loop within 10 minutes of the reactor trip (10 minutes for operator action to reroute flow paths and to start the auxiliary feedwater pumps). The criteria listed in Table 11.9-1 are met.

The outside of containment main feedwater line break and subsequent blowdown of a steam generator is precluded by the closing of the check valve inside containment. However, the Turbine Building or Auxiliary Building would experience the break flow from the feedwater pump discharge. The reactor coolant system would experience an event which would be similar to the loss of normal feedwater transient.

This analysis establishes the capacity requirements for a single pump, establishes requirements for layout to preclude indefinite loss of auxiliary feedwater to the postulated break, and establishes train association requirements for equipment so that the AFWS can deliver the minimum flow required in 10 minutes following operator actions assuming the worst single failure. Primary system heat removal due to blowdown is included in our analytical code model and is correctly simulated during the feedline rupture analysis.

Rupture of a Main Steam Pipe Inside Containment

Because the steamline break transient is a cooldown, the AFWS is not needed to remove heat in the short term. Furthermore, addition of excessive auxiliary feedwater to the faulted steam generator will affect the peak containment pressure following a steamline break inside containment. This transient is performed for several break sizes. Auxiliary feedwater is assumed to be initiated at the time of the break, independent of system actuation signals to provide the most conservative analysis with respect to containment pressure.

Table 11.9-2 summarizes the assumptions used in this analysis. The criteria stated in Table 11.9-1 are met.

This transient establishes auxiliary feedwater flow rate to a single faulted steam generator assuming one pump operational and establishes layout requirements so that the flow requirements may be met considering the worst single failure. Primary system heat removal due to blowdown is included in our analytical code model and is correctly simulated during the steamline rupture analysis.

Plant Cooldown

Maximum and minimum flow requirements from the previously discussed transients meet the flow requirements of plant cooldown. This operation, however, defines the basis for tankage size, based on the required cooldown duration, maximum decay heat input and maximum stored heat in the system. As previously discussed above the auxiliary feedwater system partially cools the system to the point where the RHRS may complete the cooldown, i.e., 350°F in the RCS. Table 11.9-2 shows the assumptions used to determine the cooldown heat capacity of the auxiliary feedwater system.

The cooldown is assumed to commence at the maximum rated power, and maximum trip delays and decay heat source terms are assumed when the reactor is tripped. Primary metal, primary water, secondary system metal and secondary system water are all included in the stored heat to be removed by the AFWS. See Table 11.9-3 for the items constituting the sensible heat stored in the NSSS.

This operation is analyzed to establish minimum tank size requirements for auxiliary feedwater fluid source which are normally aligned. This analysis is documented in Reference 6.

11.9.4 Inspection and Testing

11.9.4.1 Auxiliary Feedwater System

The auxiliary feedwater pumps can be periodically operated to verify their operability, as discussed in Section 11.9.1.

Proper functioning of the steam admission valve and subsequent starting of the steam-driven pump demonstrates the integrity of the system. Verification of correct operation can be made both from instrumentation within the main control room and direct visual observation of the pump.

The actions required to provide a head of water in the steam generator after a loss of coolant accident are exactly the operations required to fill a tank with fluid using a pump.

The test for the auxiliary feedwater system is to confirm the operability of the pumps, valves, and flow paths. The operability of the Auxiliary Feedwater System will be proven by starting any one of the pumps and demonstrating that steam generator water level is controlled using auxiliary feedwater during startup operations. Testing requirements are specified in Prairie Island Technical Specifications. If these operate, the ability of the system to maintain a water level in the steam generators is confirmed.

The Auxiliary Feedwater System is operated during reactor shutdown until the reactor conditions permit use of the Residual Heat Removal System. The active components (valves, pumps and pump drives, lube-oil pumps) of the system can be tested at any other time.

NRC IE Bulletin 85-01 presented a concern over the operability of a steam driven auxiliary feedwater pump due to steam binding (Generic Issue 89). Steam binding incidents have been observed as a result of back leakage through check valves from steam generators to the auxiliary feedwater pump casing. To alleviate concerns over auxiliary feedwater pump steam binding, Prairie Island has implemented procedures to monitor the temperature of pump discharge piping each shift. Procedures have also been implemented to recognize steam binding and for restoring the Auxiliary Feed System to operable status.

11.9.4.2 Wall Thickness Monitoring of High-Energy Piping

An Erosion/Corrosion program or Flow-Accelerated Corrosion program as referred to by EPRI to survey high-energy pipe wall thickness was begun at Prairie Island in 1983 and expanded following a feedwater pump suction line rupture event at the Surry plant in December 1986.

The Prairie Island program incorporates guidelines from NRC Bulletin 87-01 (Reference 4), NRC Generic Letter 89-08 (Reference 12), and EPRI NSAC-202L to evaluate piping components susceptible to erosion/corrosion.

Sample size and inspection frequency are adjusted based on engineering review of the operating conditions, previous inspection results, experience gained, and results of an analytical program.

Non-Destructive Examination (NDE) methods such as: Ultrasonic Testing (UT) or Radiography Testing (RT) are used to determine pipe wall thickness for run/repair/replace decision.

Run/repair/replace decisions are made by the plant system engineers following evaluation of the inspection data.

11.10 REFERENCES

1. EPRI PWR Secondary Water Chemistry Guidelines

2. "Westinghouse Letter PIW-N-50, Auxiliary Feedwater System," dated Sept. 4, 1968. [Film Loc. 7497-No Blip]

3. NSP NAD-98006, "Analysis of a Feedwater Line Break for Prairie Island," dated September 1998. [NAD Files]

4. NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," July 9, 1987. (1400/0304)

5. NSP-07-33, "Loss of Offsite Power with Delayed AFW Analysis Results" 01477171

6. Calculation ENG-ME-443, latest Rev, Condensate Storage Tank Sizing

7. WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency", June, 1987. (1729/0009)

8. Letter, D C DiIanni (NRC) to D M Musolf (NSP) "Amendment Nos. 86 and 79 to Facility Operating Licenses Nos. DPR-42 and DPR-60: Turbine Valve Test Frequency Reduction (TACS Nos. 66867 and 66868)", February 7, 1989. (1664/2491)

9. PI0-01-06, Analysis Report - Structural Analysis of Main Steam Check and Isolation Valves for Prairie Island Unit 1, September 14, 1973 (7346/515)

10. 09Q4836-CAL-003, Updated Structural Analysis of Main Steam Check and Isolation Valves

11. 09Q4836-CAL-002, Updated Disc Impact Analysis of Main Steam Check and Isolation Valves

12. NRC Generic Letter 89-08, "Erosion/Corrosion–Induced Pipe Wall Thinning," May 2, 1989. (1771/0376)

13. Westinghouse Owners Group Report, "Update and Evaluation of BB-95/96 Turbine Valve Failure Data Base," March 1999 (Westinghouse Letter WOG-TVTF-99-007, March 24, 1999) (see PI copy of WCAP 11525).

14. NSPNAD-8606, Auxiliary Feedwater System Reliability Study, Rev. 0, April 1986, [Location: Library Manual and film at 1270-645].

15. PI0-02-03, Analysis Report Maximum Energy of Disc Impact Main Steam Check and Isolation Valves for Kewaunee Unit 1, dated December 23, 2009.

THIS PAGE IS LEFT INTENTIONALLY BLANK

TABLE 11.1-1 STEAM AND POWER CONVERSION SYSTEM COMPONENT DESIGN PARAMETERS
(Page 1 of 3)

Turbine–Generator	
Turbine	Three element, tandem–compound four-flow exhaust
Turbine Capacity KW	
Maximum guaranteed	583,722 (Unit 1); 575,642 (Unit 2) (Note 1)
Maximum calculated	591,988
Generator Rating (Kva)	730,000
Turbine Speed (rpm)	1800
Condensers	
Type	Double flow, single pass deaerating
Number	2
Steam Load, Lb./hr.	4,111,711
BTU Rejected per hour (total condenser “A” & “B”)	3,873,616,764
Absolute Pressure, Ins. Hg.	Cond. A - 1.82 Cond. B - 1.28
Percent Cleanliness	85
Circulating Water Temperature, °F	60
Circulating Water Quantity, gpm	294,000
Water Velocity, fps	8.49
Friction in Water Circuit, ft.	35.7
Guaranteed 0_2 Content, CC/liter	0.003

604000000062

Notes:

(1) For various turbine / condenser / reheat heat balance gross loads see Figures 11.2-1 through 11.2-5.

TABLE 11.1-1 STEAM AND POWER CONVERSION SYSTEM COMPONENT DESIGN PARAMETERS
(Page 2 of 3)

Condensate Pumps	
Type	Multi-stage, vertical, pit-type, centrifugal
Number	3
Design Capacity (each–gpm)	5250
Motor Type	Vertical
Motor Rating (hp)	1750
Feedwater Pumps	
Type	High speed, vertically split single stage, double suction centrifugal
Number	2
Design Capacity (each–gpm)	8600
Motor Type	Horizontal
Motor Rating (hp)	5000
Heater Drain Pump	
Type	Multi–stage, vertical, can-type centrifugal
Number	3
Design Capacity (each–gpm)	2800
Motor Type	Vertical
Motor Rating (hp)	500

TABLE 11.1-1 STEAM AND POWER CONVERSION SYSTEM COMPONENT DESIGN PARAMETERS

(Page 3 of 3)

Emergency Feedwater Source	Three 150,000 gallon condensate storage tanks. Alternate supply from the cooling water system.
Auxiliary Feedwater Pumps	2 total. One steam turbine-driven pump and one electric motor-driven pump.
Design Capacity (gpm)	200 (turbine driven) 200 (motor driven)

TABLE 11.1-2 STEAM AND POWER CONVERSION SYSTEM CODE REQUIREMENTS

System Pressure Vessels	ASME VIII*
Steam Generator Vessel	See USAR Table 4.1-11
System Valves, Fittings and Piping	USAS B31.1, 1967**

01-010

* American Society of Mechanical Engineers, Boiler and Pressure Vessel Code. Section VIII. (The Code version applicable to that which was in effect at the date of placement of order for each individual component).

** Code for Pressure Piping. 01-010

TABLE 11.1-3 STEAM AND POWER CONVERSION SYSTEM SINGLE FAILURE ANALYSIS

Component or System	Malfunction	Comments and Consequences
Auxiliary Feedwater System	Auxiliary feedwater pump fails to start (following loss of main feedwater)	One full-capacity steam driven pump and one full-capacity motor-driven auxiliary feedwater pumps are provided. Hence either of the two auxiliary feedwater pumps provide the required flow of feedwater.
Steam Line Isolation System	Failure of steam line isolation valve to close (following a main steam line rupture)	Each steam line contains an isolation valve and a non-return valve in series. Hence a failure of an isolation (or non-return) valve will not permit the blowdown of more than one steam generator regardless of the steam line rupture location.
Bypass and Atmospheric Steam Dump System	Steam dump valve sticks open (following operation of the system resulting from a turbine trip)	This steam dump system comprises one steam bypass valve and four atmospheric dump valves. One valve will only pass 12% of the maximum calculated steam flow and there is no hazard in the form of an uncontrolled plant cool down if a steam dump valve sticks open. 99057

TABLE 11.9-1
CRITERIA FOR AUXILIARY FEEDWATER SYSTEM DESIGN BASIS CONDITIONS[3]

Condition or Transient	Classification[1]	Criteria[1]	Additional Design Criteria
Loss of Main Feedwater	Condition II	Peak RCS pressure not to exceed design pressure. No consequential fuel failures	Pressurizer does not fill with 1 single motor driven aux. feed pump feeding 2 SGs. 05-002
Loss of Offsite Power (LOOP)	Condition II	(same as LMFW)	Pressurizer does not fill with 1 single motor driven aux. feed pump feeding 2 SGs. 05-002
Feedline Rupture	Condition IV	10CFR100 dose limits. Containment design pressure not exceeded	Core does not uncover
Steamline Rupture	Condition IV	10CFR100 dose limits. Containment design pressure not exceeded	
Loss of all A/C Power	N/A	Note[2]	Same as LOOP assuming turbine driven pump
Loss of Coolant	Condition III	10CFR100 dose limits 10CFR50 PCT limits	
	Condition IV	10CFR100 dose limits 10CFR50 PCT limits	
Cooldown	N/A		100°F/hr 547°F to 350 OF

[1] Ref: ANSI N18.2

[2] Note: Although this Transient establishes the basis for AFW pump powered by a diverse power source, this is not evaluated relative to typical criteria since multiple failures must be assumed to postulate this transient

[3] Note: These criteria and conditions/transients were used for determining the performance capabilities for AFW and may be different than those used to analyze design basis accidents and transients in Section 14.

TABLE 11.9-2
SUMMARY OF ASSUMPTIONS USED IN AFWS MINIMUM FLOW EVALUATION

Input	**Loss of Normal Feedwater or Loss of Off Site Power**	**Cooldown**	**Main Feedwater Line Break (Not isolated from SG)**	**Main Steam Line Break (Containment)**
Initial Reactor Power (%)	1683 MWt	1683 MWt	1683 MWt	Most limiting as determined in the analysis
Time Delay from event to Rx Trip	15 seconds after Lo-Lo SG Level signal	N/A	Time for containment pressure to reach 4 psig + time delay for rod insertion	Time for containment pressure to reach 4 psig + time delay for rod insertion.
AFWS Actuation Signal	Lo-Lo SG Level	N/A	SI	SI
Time Delay for AFWS flow (after initiating signal)	60 seconds	N/A	10 minutes	None (for containment pressure response)
Initial SG liquid level	55% Narrow Range Level	Nominal	Nominal	Greater than maximum operational band
# of SGs which receive AFW flow	2	2	1 *	1 *
AFW Temperature	100°F	100°F	100°F	100°F
AFW flow rate	190 gpm	Variable (as necessary for plant cooldown)	180 gpm	AFW flow is initially maximized for core and containment pressure analyses. Minimum AFW flow is variable and corresponds to the flow rate used for decay heat removal.

01183316

TABLE 11.9-2
SUMMARY OF ASSUMPTIONS USED IN AFWS MINIMUM FLOW EVALUATION
(Page 2 of 2)

Input	Loss of Normal Feedwater or Loss of Off Site Power	Cooldown	Main Feedwater Line Break (Not isolated from SG)	Main Steam Line Break (Containment)
MFW Purge Volume/Temp.	Included in Computer Model	N/A	Included in Computer Model	Included in Computer Model
Operator Action	N/A (immediately)	Control Cooldown Rate	Start Pump and Realign AFW flow path within 10 minutes	Start Pump and Realign AFW flow path within 10 minutes
RCP Status**	Running for LONF/ secured for LOOP	Secured	Running	Running
Sensible Heat	See Cooldown	Table 11.9-3	See Cooldown	See Cooldown
Decay Heat	ANS 5.1-1979 + 2 Sigma	Reference 6	120% of ANS 5.1-1971	120% of ANS 5.1-1971 or ANS 5.1-1979 + 2 Sigma
Time at standby/time to cooldown to RHR	See Cooldown	2 hours/6 hours	See Cooldown	See Cooldown

* Initially the faulted SG receives the AFW flow. Following the system flow path realignment, the intact SG receives the AFW flow.

** Availability of RCPs is a function of whether or not off-site power is available. For each transient, it is determined if it is worse to maintain off-site power or loss off-site power.

TABLE 11.9-3 SUMMARY OF SENSIBLE HEAT SOURCES

Primary Water Sources (initially at rated power temperature and inventory)

- RCS fluid
- Pressurizer fluid (liquid and vapor)

Primary Metal Sources (initially at rated power temperature)

- Reactor coolant piping, pumps and reactor vessel
- Pressurizer
- Steam generator tube metal and tube sheet
- Steam generator metal below tube sheet
- Reactor vessel internals

Secondary Water Sources (initially at rated power temperature and inventory)

- Steam generator fluid (liquid and vapor)
- Main feedwater purge fluid between steam generator and AFWS piping.

Secondary Metal Sources (initially at rated power temperature)

- All steam generator metal above tube sheet, excluding tubes.

THIS PAGE IS LEFT INTENTIONALLY BLANK

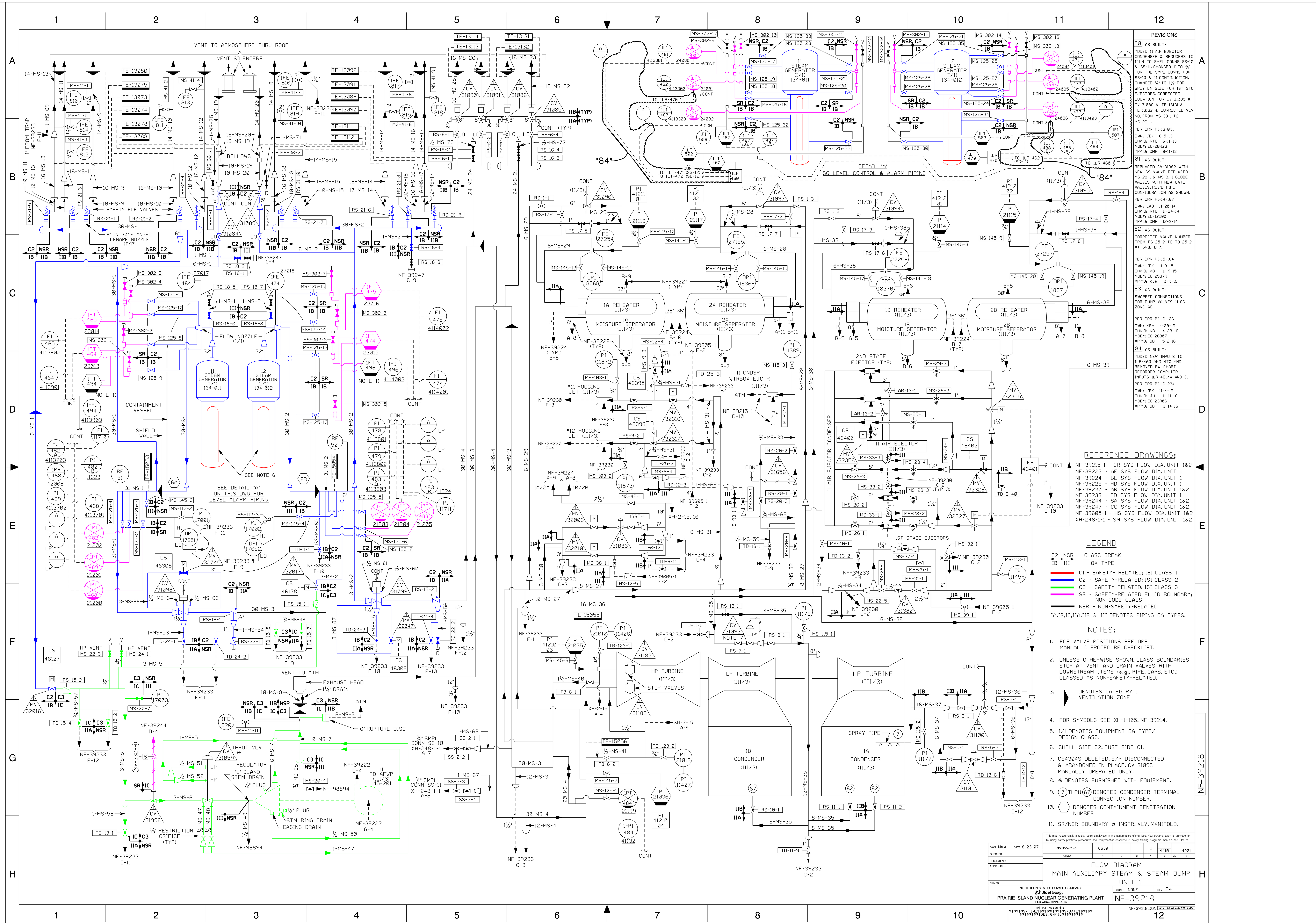
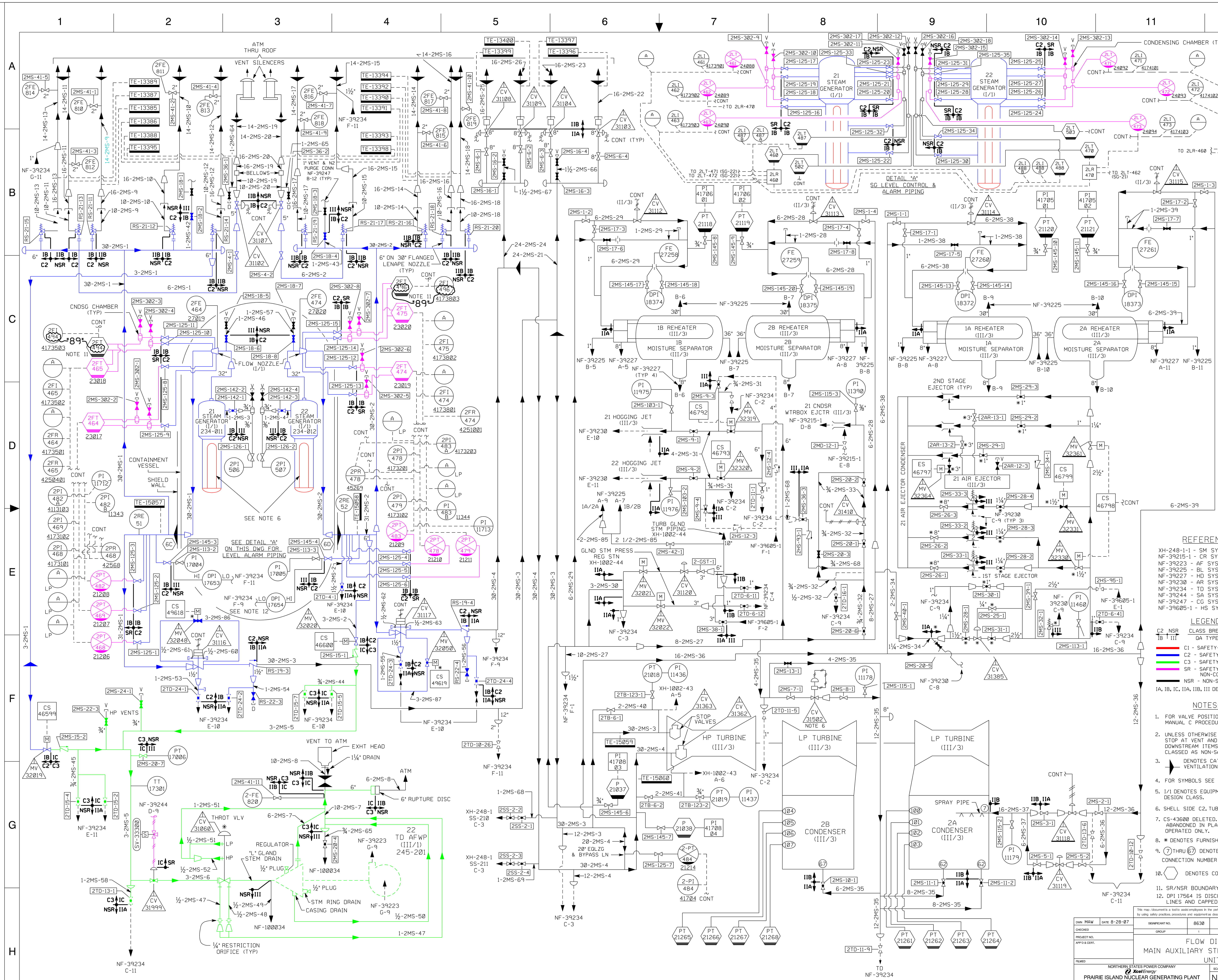


FIGURE 11.1-1 REV. 35

CAD FILE: U11101.DGN

60300000 1331



REVISIONS

84 AS BUILT-
RELOCATED CHECK VALVE 2HS-93-1 AND SHOWED SOLID AND MOVED ¾" x 1" REDUCER UPSTREAM OF 2MS-36-3.
PER DRR PI-12-062
DWN: JEK 4-3-12
CHK'D: SMF 4-10-12
MOD#: EC-17978
APP'D: CMR 4-11-12

85 AS BUILT-
ADDED 21 AIR EJECTOR CONDENSER.
PER DRR PI-13-091
DWN: JEK 6-5-13
CHK'D: RTC 6-11-13
MOD#: EC-20923
APP'D: CMR 6-11-13

86 AS BUILT-
RELOCATED REDUCERS TO SHOW VLVS 2MS-31-1, 2MS-28-1 & CV-31385 & ASSOCIATED PIPING AS 1½"
PER DRR PI-13-171
DWN: JEK 10-10-13
CHK'D: RTC 10-18-13
MOD#: EC-12200
APP'D: CMR 10-28-13

87 AS BUILT-
ADDED VLV 2MS-142-1 THRU 4, 2MS-126-1,2, 2PI-506,7 PI & SC BRK PER EC 16812
DWN: DB 4-15-14
CHK'D: RWR 4-16-14
AS BUILT-
ADD SECONDARY SIDE INSTR &VLVS 2MS-125-32 THRU 35, 2MS-302-17,18. RELOC TIE-IN FOR 2LT487 & 488.
PER DRR PI-14-062
DWN: DB 4-15-14
CHK'D: RWR 4-16-14
MOD#: EC-16808
APP'D: CMR 4-16-14

88 AS BUILT-
ADDED NEW INPUTS TO 2LR-460 AND 470 AND REMOVED FW CHART RECORDER COMPUTER INPUTS 2LR-461/A AND C.
PER DRR PI-15-170
DWN: JEK 11-20-15
CHK'D: JLH 12-9-15
MOD#: EC-23905
APP'D: KJW 12-18-15

89 AS BUILT-
CORRECTED LABELING FOR 2FT-494 TO 496, 2FI-494 TO 496, 2FT-496 TO 494 AND 2FI-496 TO 494.
PER DRR PI-17-169
DWN: JEK 12-14-17
CHK'D: RLM 12-14-17
MOD#: 6DOCEDI23544
APP'D: DB 12-14-17

REFERENCE DWGS

XH-248-1-1 - SM SYS FLOW DIA. UNIT 1&2
NF-39215-1 - CR SYS FLOW DIA. UNIT 1&2
NF-39223 - AF SYS FLOW DIA. UNIT 2
NF-39225 - BL SYS FLOW DIA. UNIT 2
NF-39227 - HD SYS FLOW DIA. UNIT 2
NF-39230 - AR SYS FLOW DIA. UNIT 1&2
NF-39234 - TD SYS FLOW DIA. UNIT 2
NF-39244 - SA SYS FLOW DIA. UNIT 1&2
NF-39247 - CG SYS FLOW DIA. UNIT 1&2
NF-39605-1 - HS SYS FLOW DIA. UNIT 1&2

LEGEND

C2 NSR / IB III — CLASS BREAK / QA TYPE

C1 - SAFETY- RELATED; ISI CLASS 1
C2 - SAFETY-RELATED; ISI CLASS 2
C3 - SAFETY-RELATED; ISI CLASS 3
SR - SAFETY-RELATED FLUID BOUNDARY; NON-CODE CLASS
NSR - NON-SAFETY-RELATED

IA, IB, IC, IIA, IIB, III DENOTES PIPING QA TYPES.

NOTES:

1. FOR VALVE POSITIONS SEE OPS MANUAL C PROCEDURE CHECKLIST.
2. UNLESS OTHERWISE SHOWN, CLASS BOUNDARIES STOP AT VENT AND DRAIN VALVES WITH DOWNSTREAM ITEMS (e.g., PIPE, CAPS, ETC.) CLASSED AS NON-SAFETY-RELATED.
3. DENOTES CATEGORY I VENTILATION ZONE
4. FOR SYMBOLS SEE XH-1-105, NF-39214.
5. I/1 DENOTES EQUIPMENT QA TYPE/ DESIGN CLASS.
6. SHELL SIDE C2, TUBE SIDE C1.
7. CS-43600 DELETED. E/P DISCONNECTED & ABANDONED IN PLACE. CV-31502 MANUALLY OPERATED ONLY.
8. ✳ DENOTES FURNISHED WITH EQUIPMENT
9. 7 THRU 67 DENOTES CONDENSER TERMINAL CONNECTION NUMBER
10. DENOTES CONT PENETRATION NUMBER
11. SR/NSR BOUNDARY @ INSTR. VLV. MANIFOLD.
12. DPI 17564 IS DISCONNECTED FROM GAGE LINES AND CAPPED.

SIGNIFICANT NO.	8630			1	4410		4221
GROUP	1	2	3	4	5	CL	6

DWN MAW DATE 8-28-07
CHECKED
PROJECT NO.
APP'D & CERT.
FILMED

FLOW DIAGRAM
MAIN AUXILIARY STEAM & STEAM DUMP
UNIT 2

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING, MINNESOTA

SCALE NONE REV 89

NF-39219

$$USERNAME$$
$$$$$$SYTIME$$$$$$$$$$$$SYDATE$$$$$$
$$$$$$$$$DESIGNFIL$$$$$$$$$

NF-39219.DGN NSP GENERATION CAD

NF-39219

60300001331

FIGURE 11.1-2 REV. 35

CAD FILE: U11102.DGN

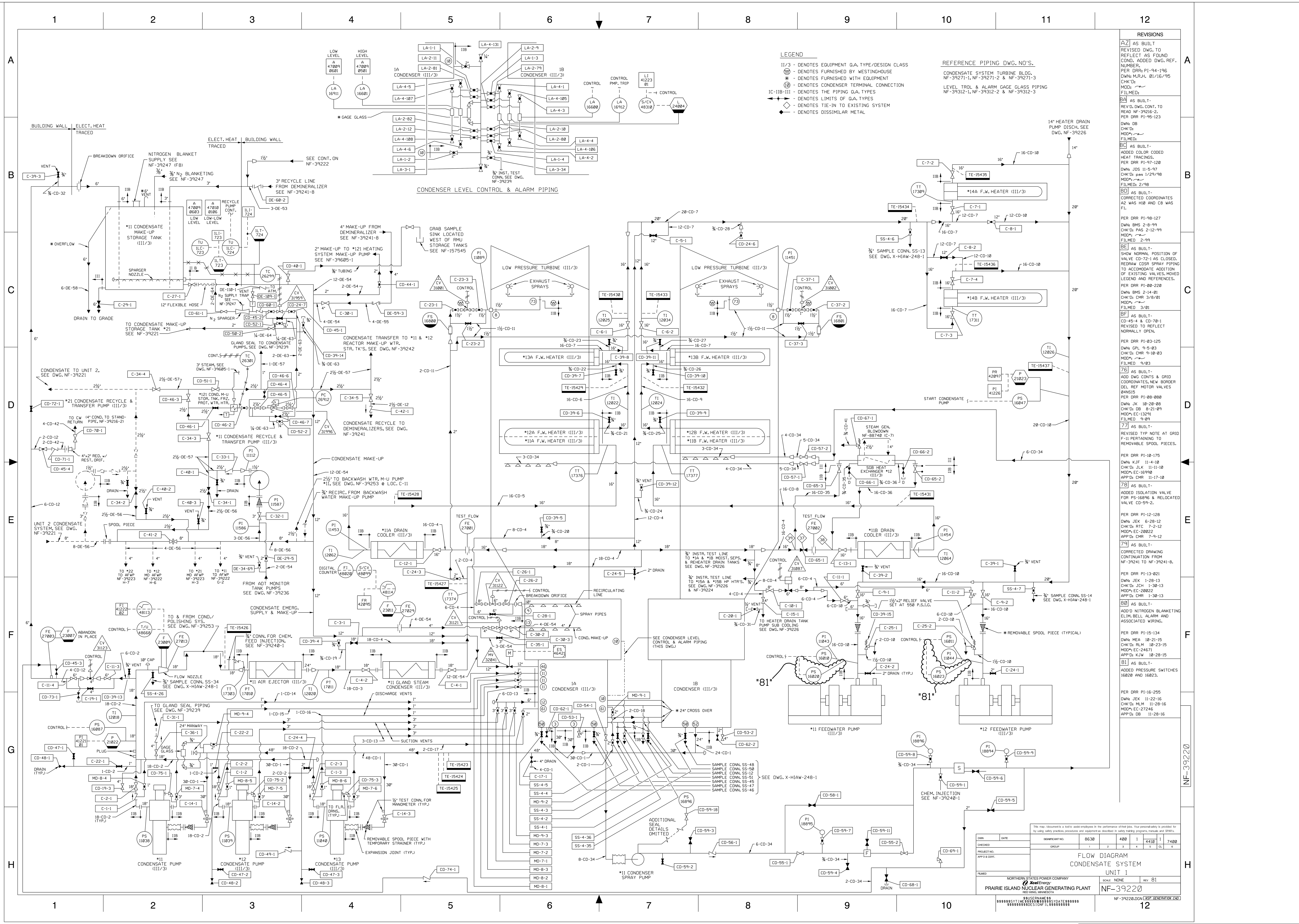


FIGURE 11.1-3 REV. 35

CAD FILE: U11103.DGN

60300001331

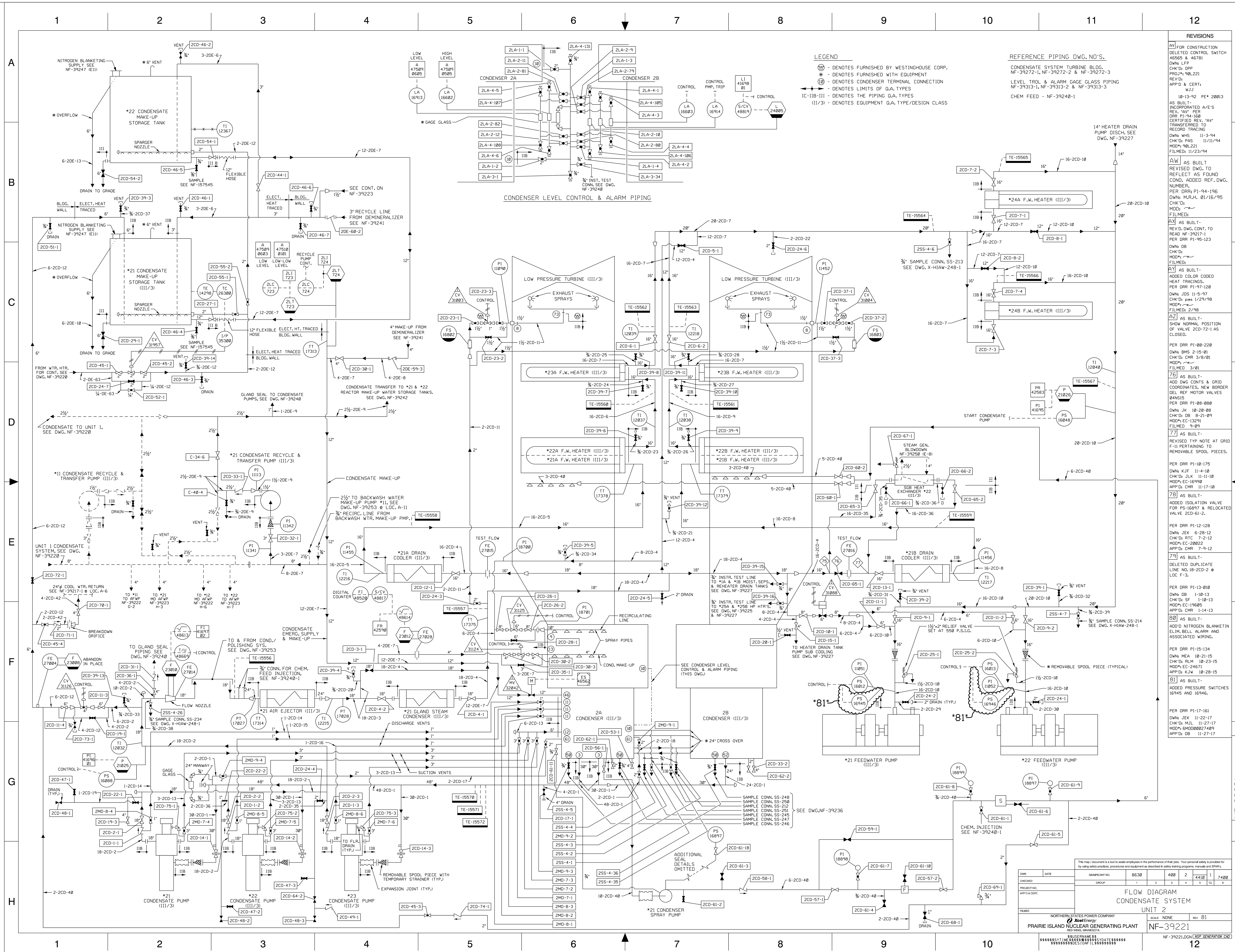


FIGURE 11.1-4 REV. 35

60300001331

CAD FILE: U111Ø4.DGN

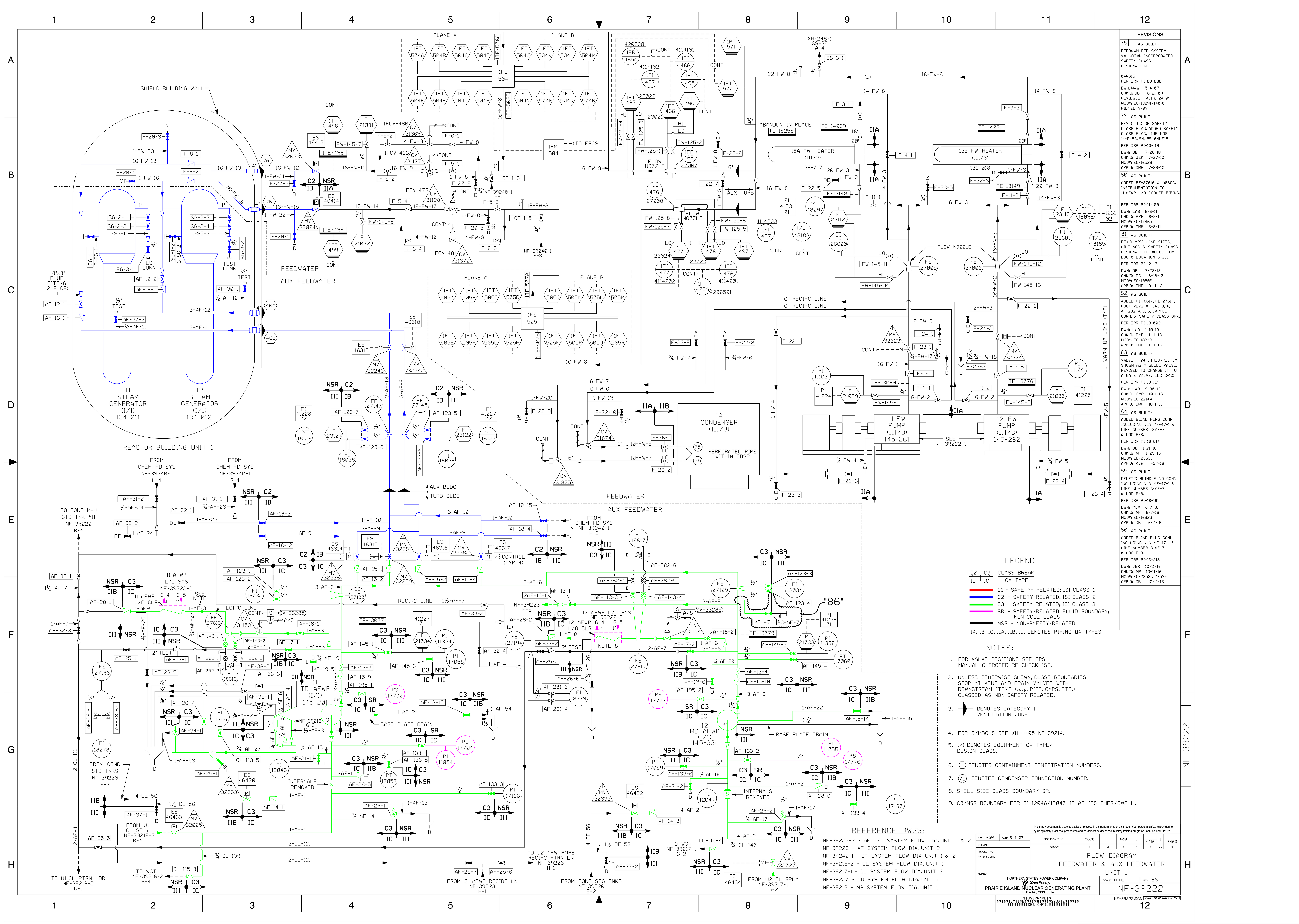


FIGURE 11.1-5 REV. 35

603000001331

CAD FILE: U11105.DGN

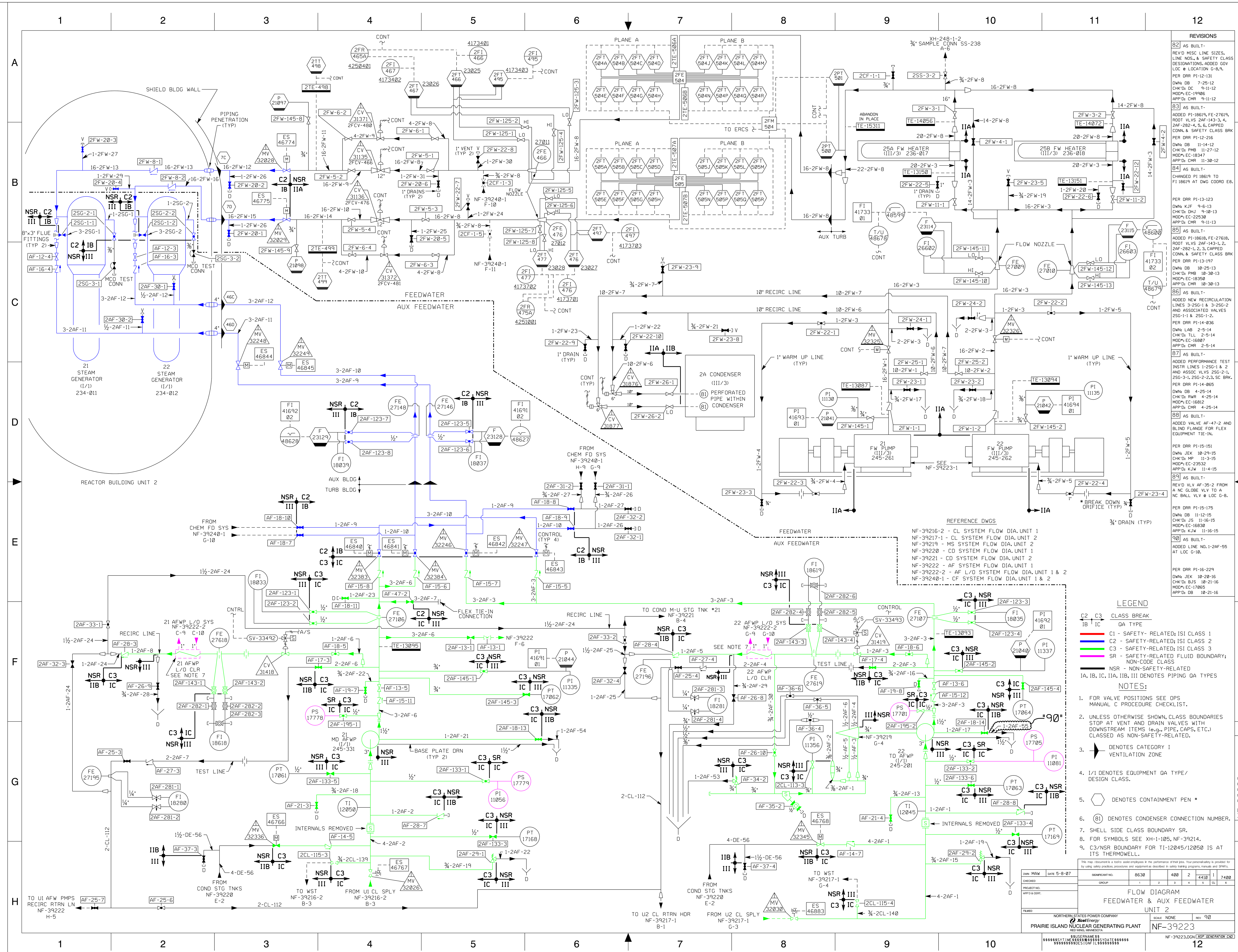


FIGURE 11.1-6 REV. 35

60300001331

CAD FILE: U11106.DGN

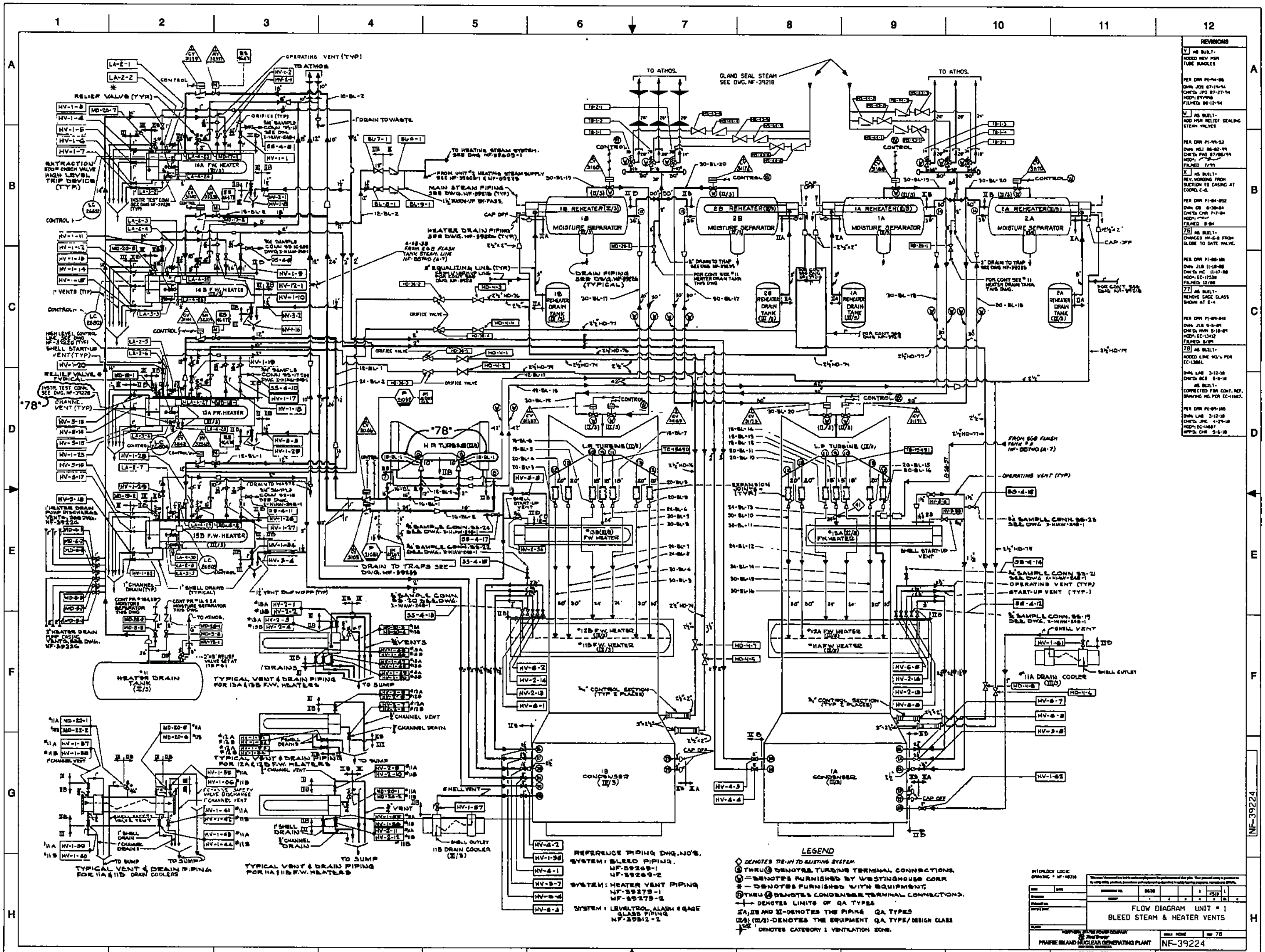


FIGURE 11.1-7 REV. 31

01248495

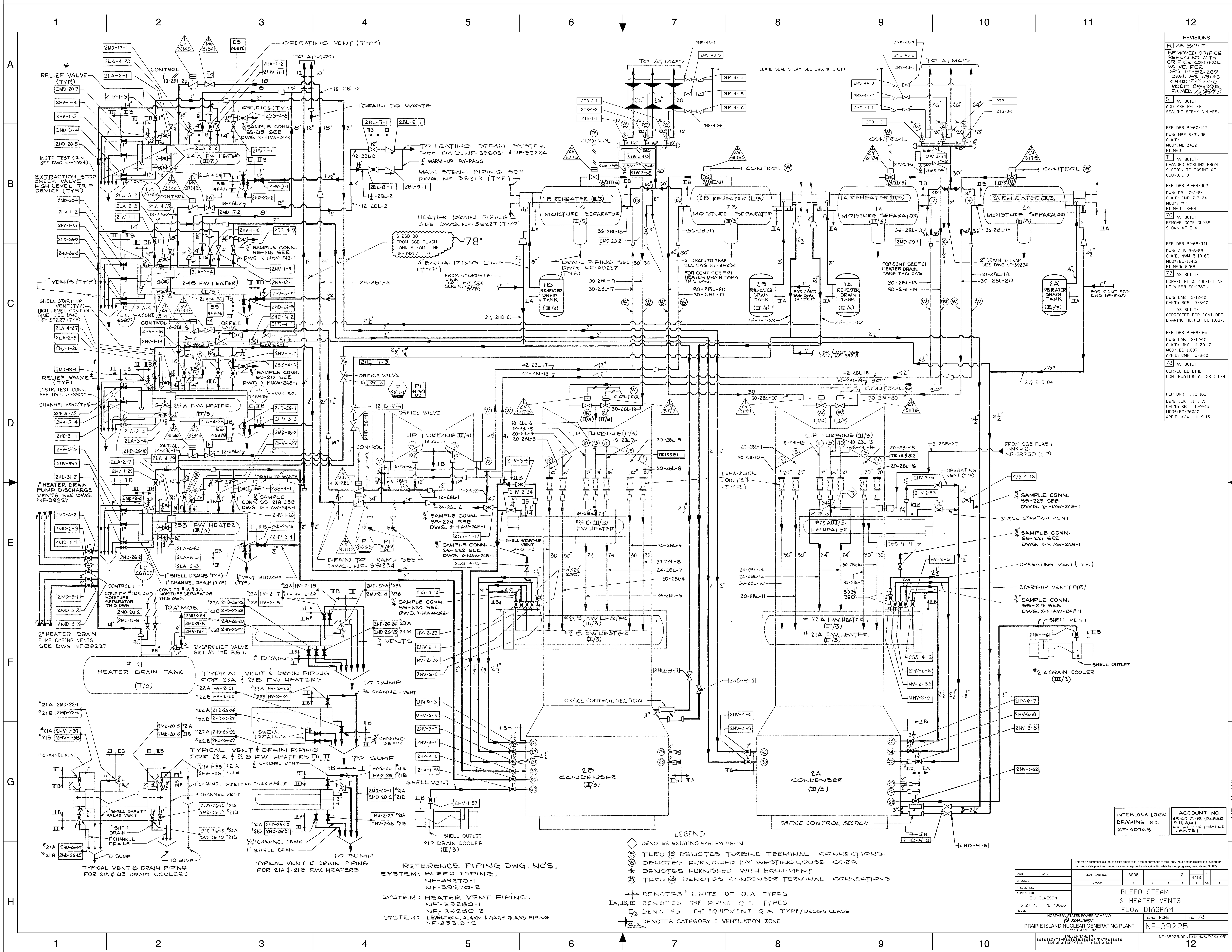


FIGURE 11.1-8 REV. 34

01516979

CAD FILE: U11108.DGN

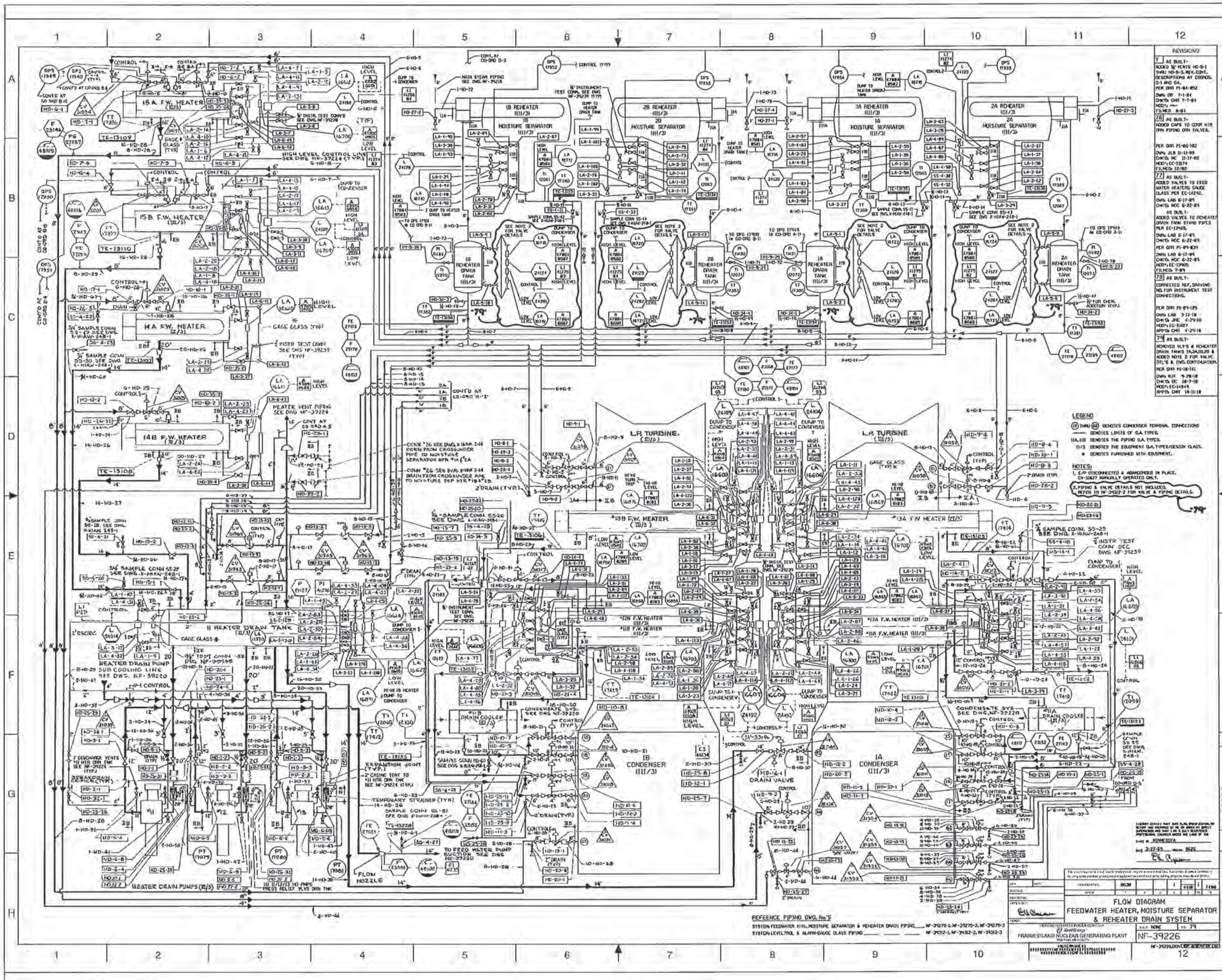
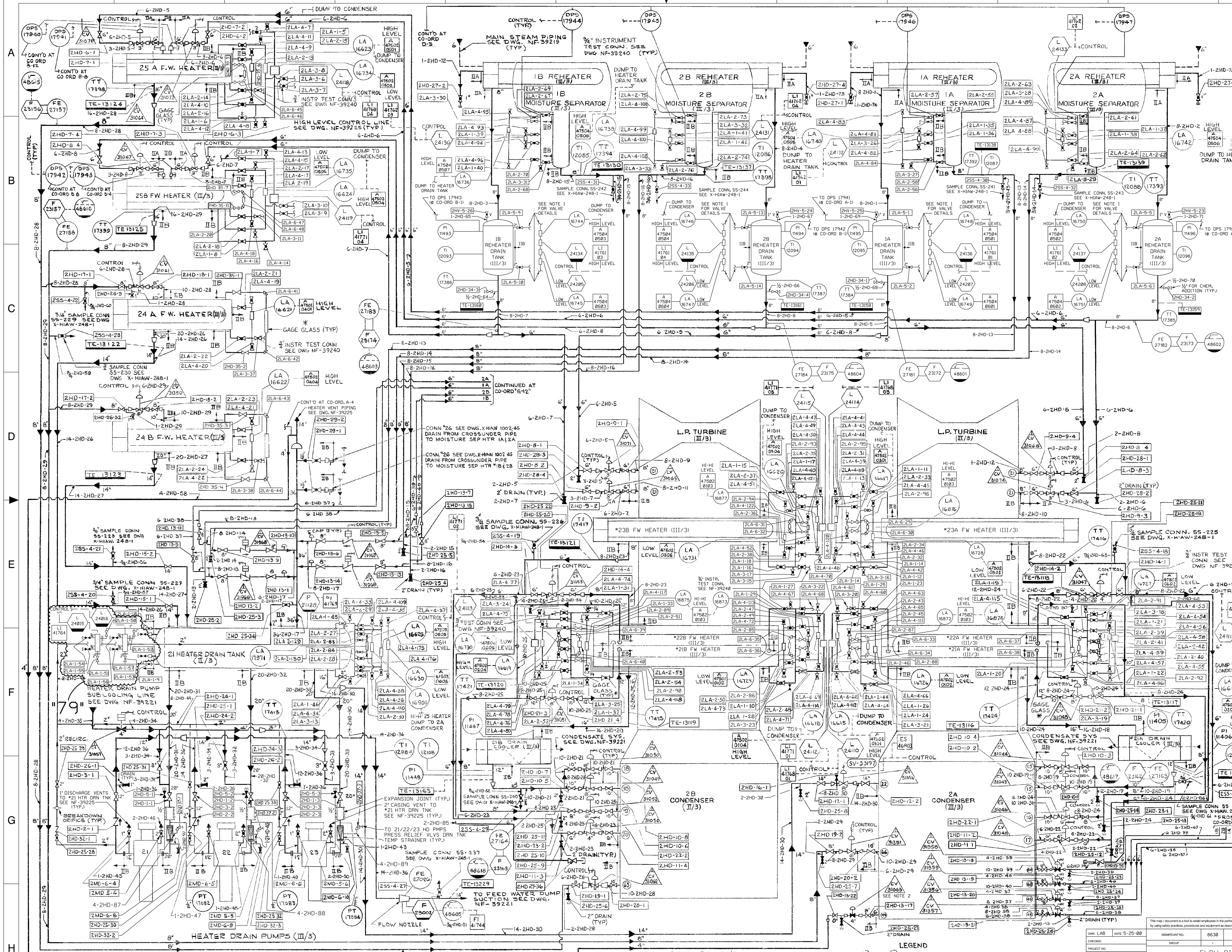


FIGURE 11.1-9 REV. 32

CAD FILE: U11109.DGN

01352784



NOTES.
1) PIPING & VALVE DETAILS NOT INCLUDED. REFER TO NF-39313-2 FOR VALVE & PIPING DETAILS.
2) E/P DISCONNECTED & ABANDONED IN PLACE CV-31063 MANUALLY OPERATED ONLY

REFERENCE PIPING DWG No'S

SYSTEM FEEDWATER HEATER, MOISTURE SEPARATOR & REHEATER DRAIN PIPING
NF-39276-1, NF-39276-2 & NF-39276-3

SYSTEM LEVELTROL, ALARM & GAGE GLASS PIPING.
NF-39313-1, NF-39313-2 & NF-39313-3

LEGEND
(15) THRU (66) DENOTES CONDENSER TERMINAL CONN'S.
←|→ DENOTES LIMITS OF Q A TYPES
IIA & IIB DENOTES THE PIPING Q A TYPES
(II/3) DENOTES THE EQUIPMENT Q A TYPE/DESIGN CLASS.
* DENOTES FURNISHED W/EQUIPMENT

DWN LAB	DATE 5-25-00	SIGNIFICANT NO.	8630			2	4410	1	7400
CHECKED		GROUP	1	2	3	4	5	CL	6
PROJECT NO.									
APP'D & CERT.									
FILMED									

FLOW DIAGRAM
FEEDWATER HEATER, MOISTURE SEPARATOR & REHEATER DRAIN SYSTEM - UNIT 2

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING, MINNESOTA

SCALE NONE
REV 79
NF-39227

$$USERNAME$$
$$$$$$SYTIME$$$$$$$$$$$$SYDATE$$$$$$
$$$$$$$$$DESIGNFIL$$$$$$$$$

NF-39227.DGN NSP GENERATION CAD

NF-39227

60300000I33I

FIGURE 11.1-10 REV. 35

CAD FILE: U11110.DGN

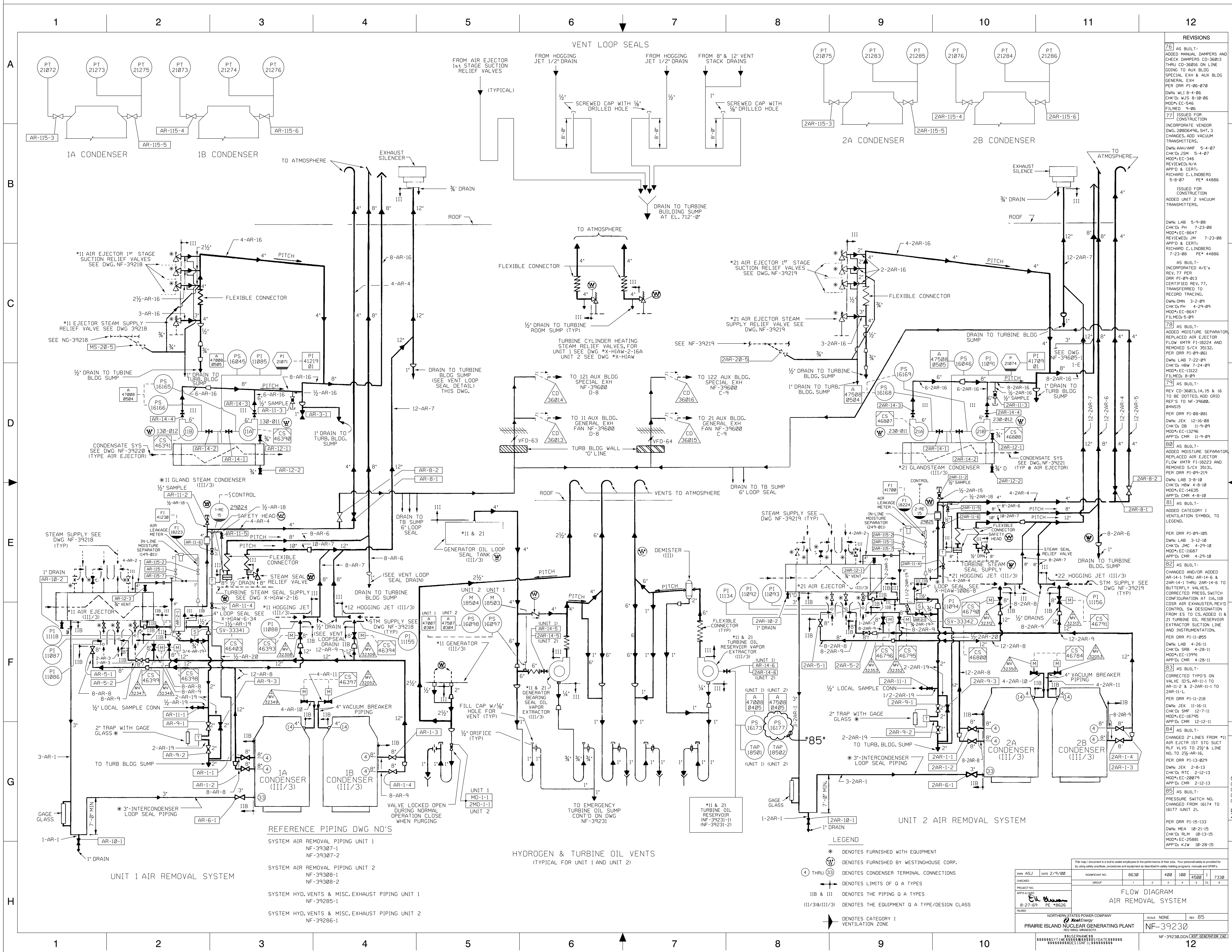
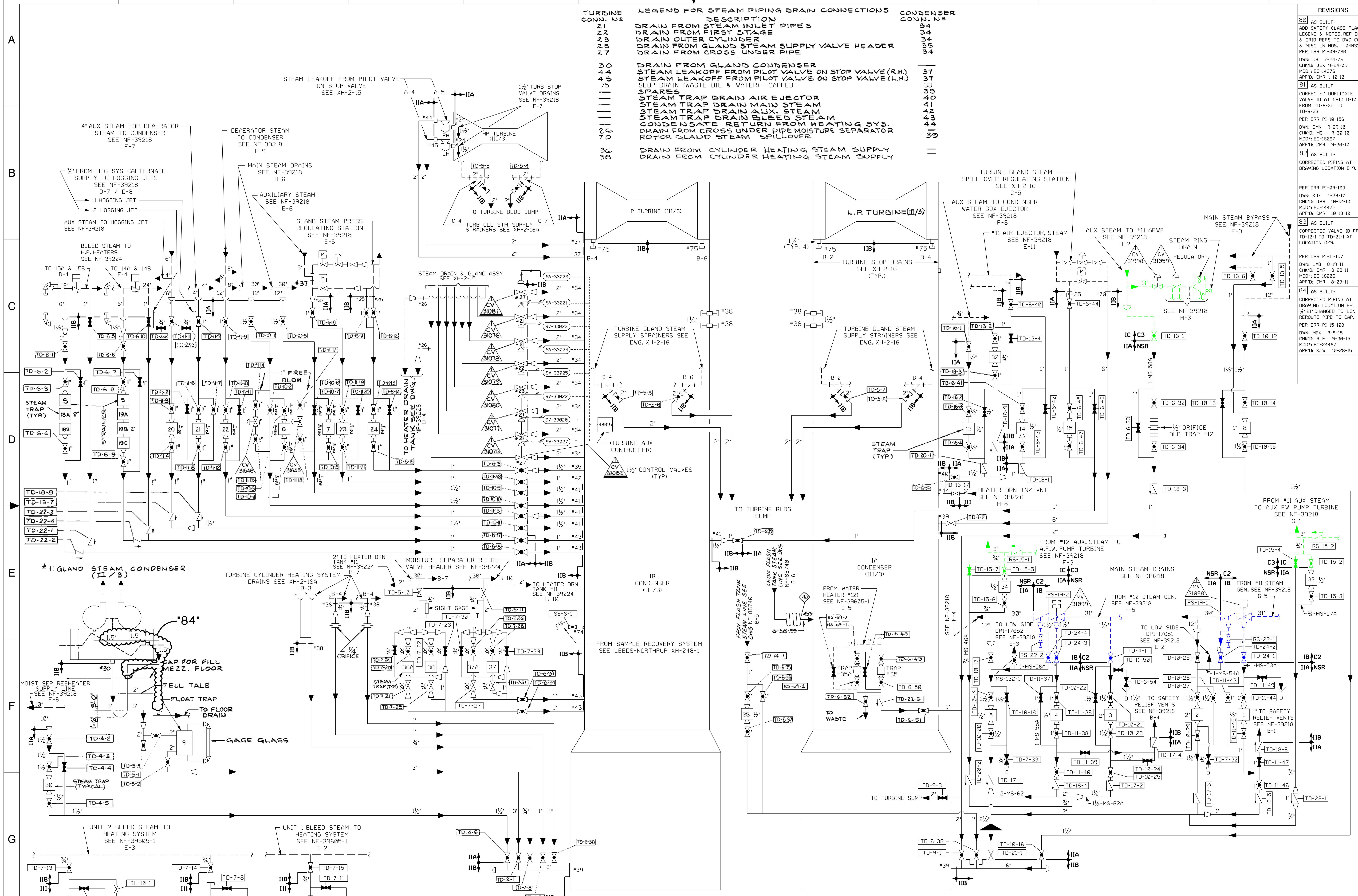


FIGURE 11.1-11 REV. 34

01516979

CAD FILE: U11111.DGN



REFERENCE DWGS:

- NF-39218 MS STM SYS FLOW DIA UNIT 1
- NF-39224 BLD STM & HTR VNTS SYS FLOW DIA U1
- NF-39226 FW HTR, MOIS SEP & RHTR DRNS SYS FLOW DIA U1
- NF-39605-1 HTG STM SYS FLOW DIA UNIT 1 &2
- NF-88740 SGB SYS FLOW DIA UNIT 1 &2
- XH-2-15 STM DRN & GLAND SYS FLOW DIA U1
- XH-2-16 STM DRN & GLAND SYS FLOW DIA U1
- XH-2-16A STM DRN & GLAND SYS FLOW DIA U1
- XH-248-1 HOT LAB GRAB SMPL PNL, SURVEY PNL FLOW DIA U1

NOTES:

1. FOR VALVE POSITIONS SEE OPS MANUAL C PROCEDURE CHECKLIST.
2. UNLESS OTHERWISE SHOWN, CLASS BOUNDARIES STOP AT VENT AND DRAIN VALVES WITH DOWNSTREAM ITEMS (e.g., PIPE, CAPS, ETC.) CLASSED AS NON-SAFETY-RELATED.
3. DENOTES CATEGORY I VENTILATION ZONE
4. FOR SYMBOLS SEE XH-1-105, NF-39214.
5. I/1 DENOTES EQUIPMENT QA TYPE/ DESIGN CLASS.
6. 25 DENOTES STEAM TRAP
7. DENOTES TIE-IN TO EXISTING SYSTEM

LEGEND

C2 NSR / IB III — CLASS BREAK / QA TYPE

- C1 - SAFETY- RELATED; ISI CLASS 1
- C2 - SAFETY-RELATED; ISI CLASS 2
- C3 - SAFETY-RELATED; ISI CLASS 3
- SR - SAFETY-RELATED FLUID BOUNDARY; NON-CODE CLASS
- NSR - NON-SAFETY-RELATED

IA,IB,IC,IIA,IIB & III DENOTES PIPING QA TYPES.

DWN	DATE	SIGNIFICANT NO.	8630			100	4410	1	5343
CHECKED		GROUP	1	2	3	4	5	CL	6
PROJECT NO.									
APP'D & CERT.									
FILMED									

FLOW DIAGRAM
TURBINE BUILDING TRAPS AND DRAINS
UNIT 1

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING, MINNESOTA

SCALE NONE REV 84

NF-39233

$$USERNAME$$
$$$$$$SYTIME$$$$$$$$$$$$SYDATE$$$$$$
$$$$$$$$$DESIGNFIL$$$$$$$$$

NF-39233.DGN NSP GENERATION CAD

FIGURE 11.1-12 REV. 34

01516979

CAD FILE: U11112.DGN

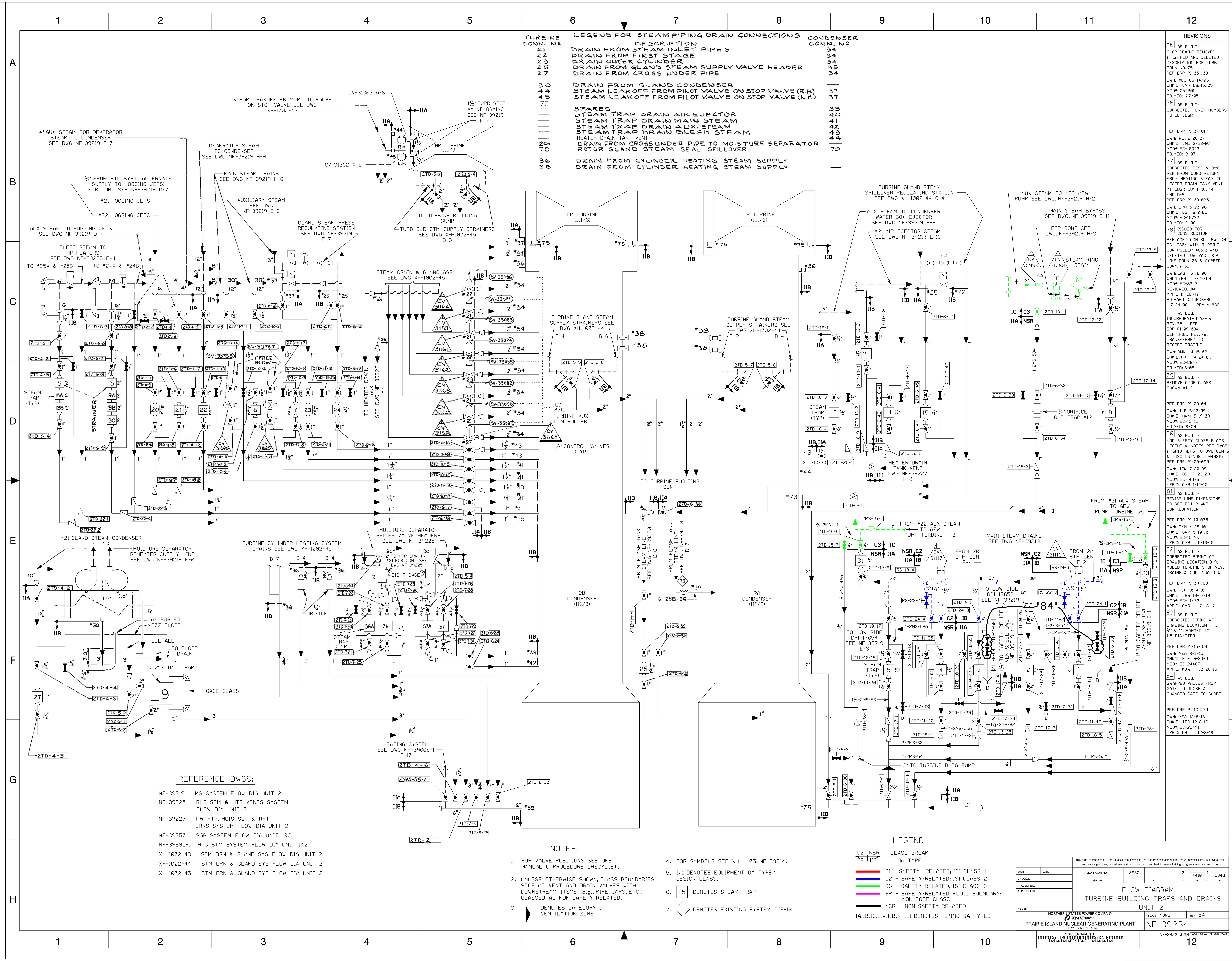


FIGURE 11.1-13 REV. 35

60300000001331

CAD FILE: U11113.DGN

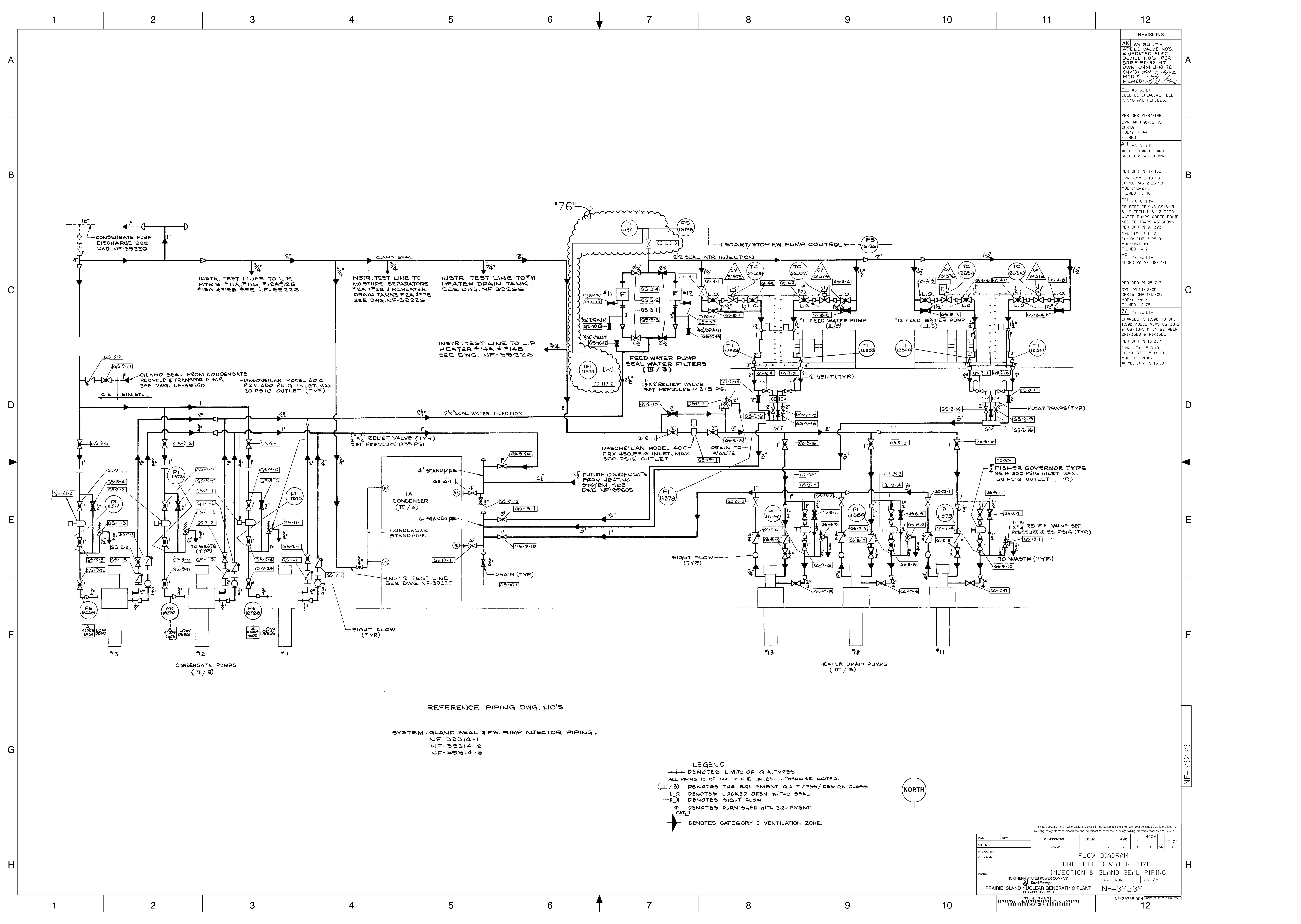
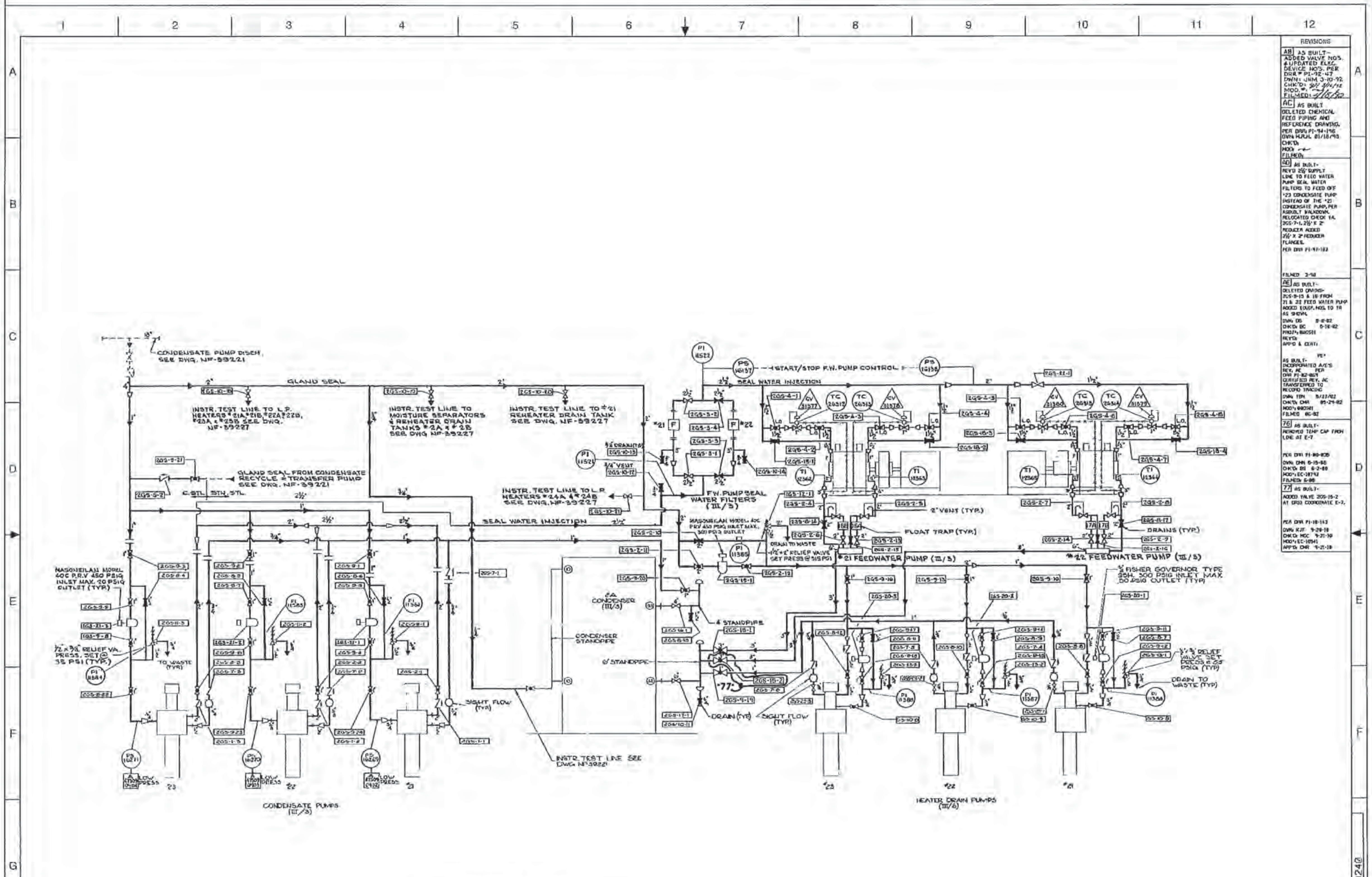


FIGURE 11.1-14 REV. 35

60300001331

CAD FILE: U11114.DGN



REFERENCE PIPING DWG. NO'S.

SYSTEM: GLAND SEAL & F.W. PUMP INJECTOR PIPING
NF-39315-1
NF-39315-2
NF-39315-3

LEGEND:
- DENOTES LIMITS OF Q.A. TYPES
- ALL PIPING TO BE Q.A. TYPE III UNLESS OTHERWISE NOTED.
- (III/3) DENOTES THE EQUIPMENT Q.A. TYPES/DESIGN CLASS
- L.O. DENOTES LOCKED OPEN W/ TAG SEAL
- DENOTES SIGHT FLOW
- DENOTES FURNISHED W/ EQUIPMENT
- CAT. I DENOTES CATEGORY I VENTILATION ZONE.

UNIT 2 FEED WATER PUMP INJECTION AND GLAND SEAL PIPING

NORTHERN STATES POWER COMPANY
Xcel Energy
PRAIRIE ISLAND NUCLEAR GENERATING PLANT

NF-39240

01352784

FIGURE 11.1-15 REV. 32

CAD FILE: U11115.DGN

FIGURE 11.1-16 REV. 35

CAD FILE: U11116.DGN

60300000 1331

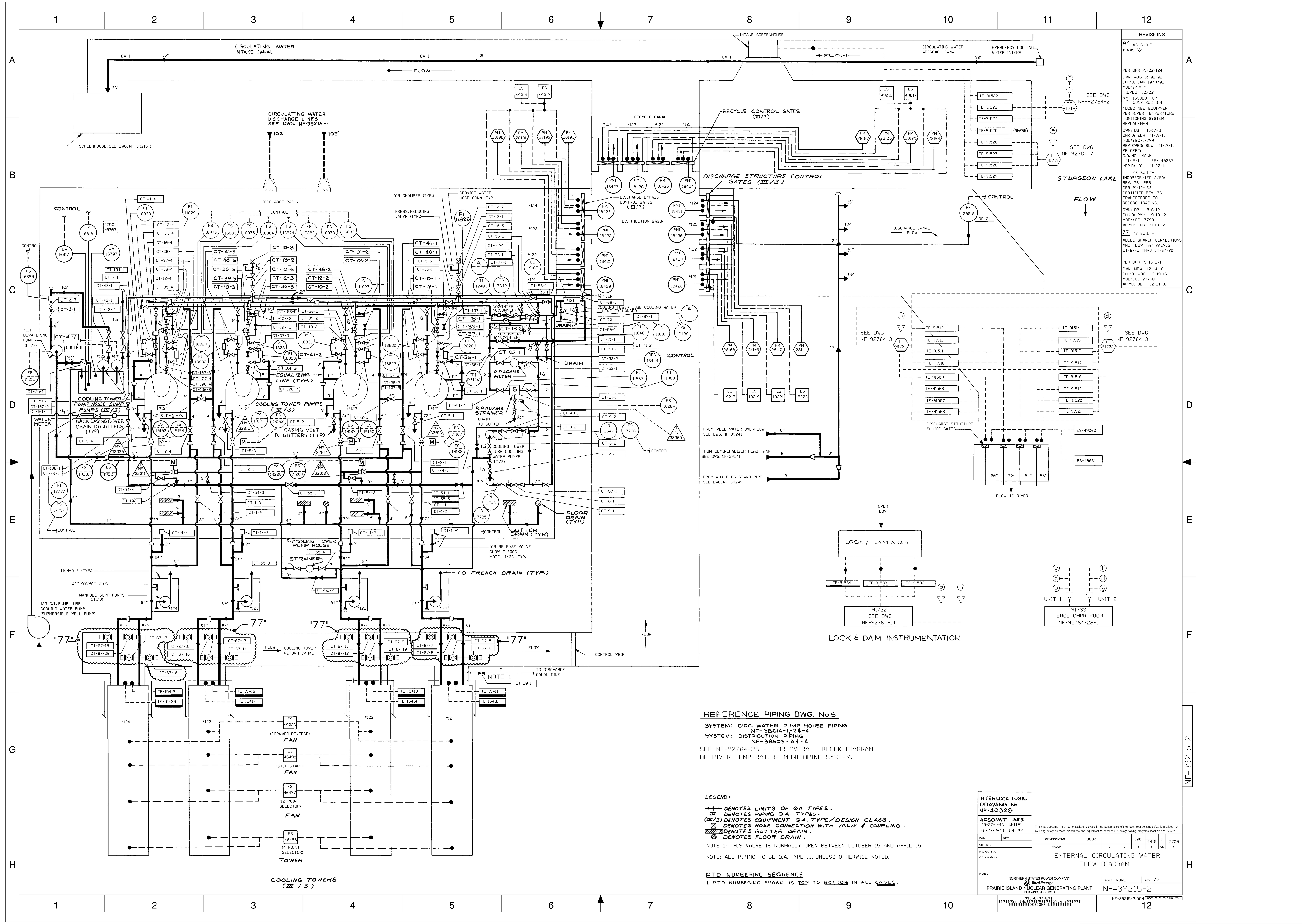


FIGURE 11.1-17 REV. 35

60300001331

CAD FILE: U11117.DGN

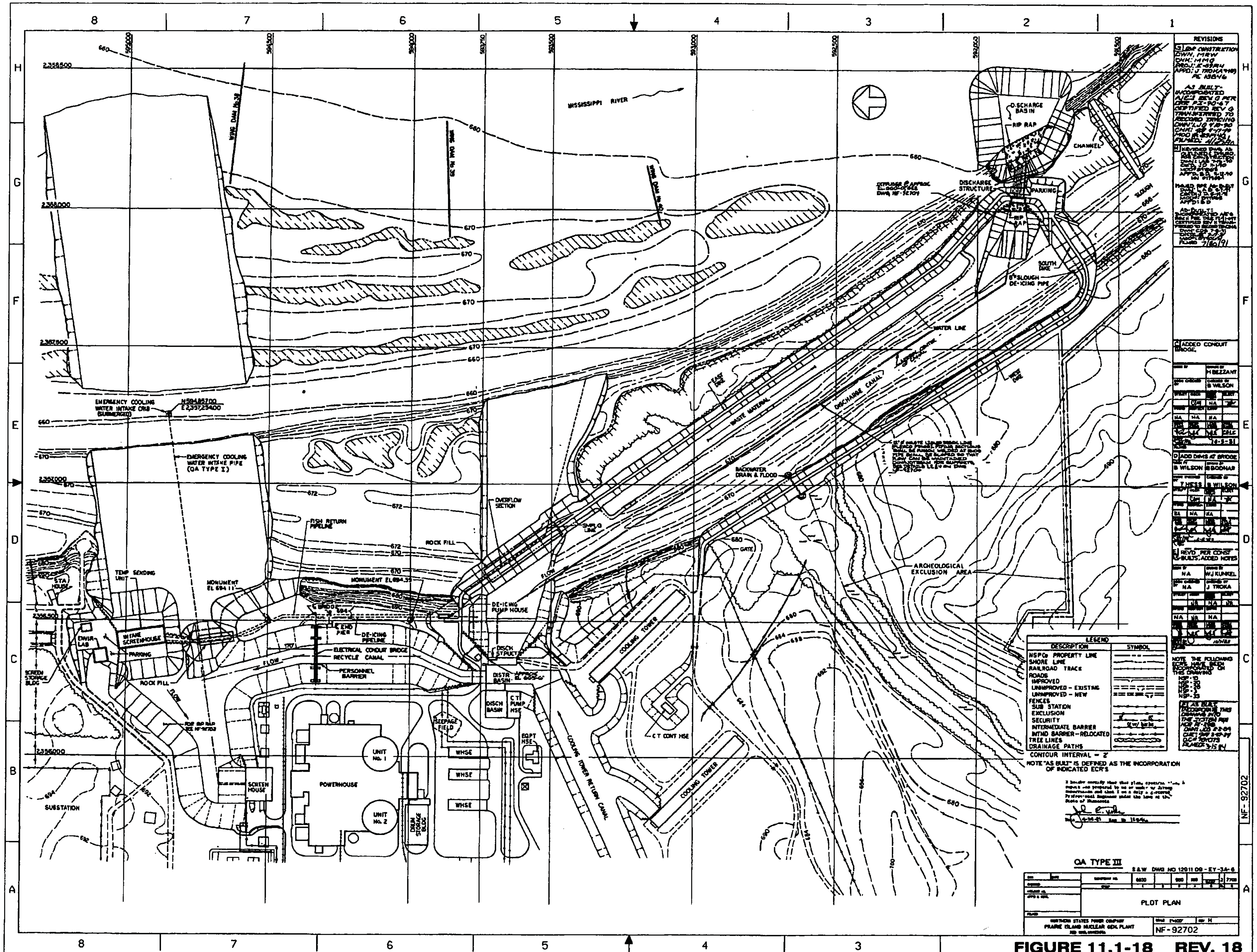
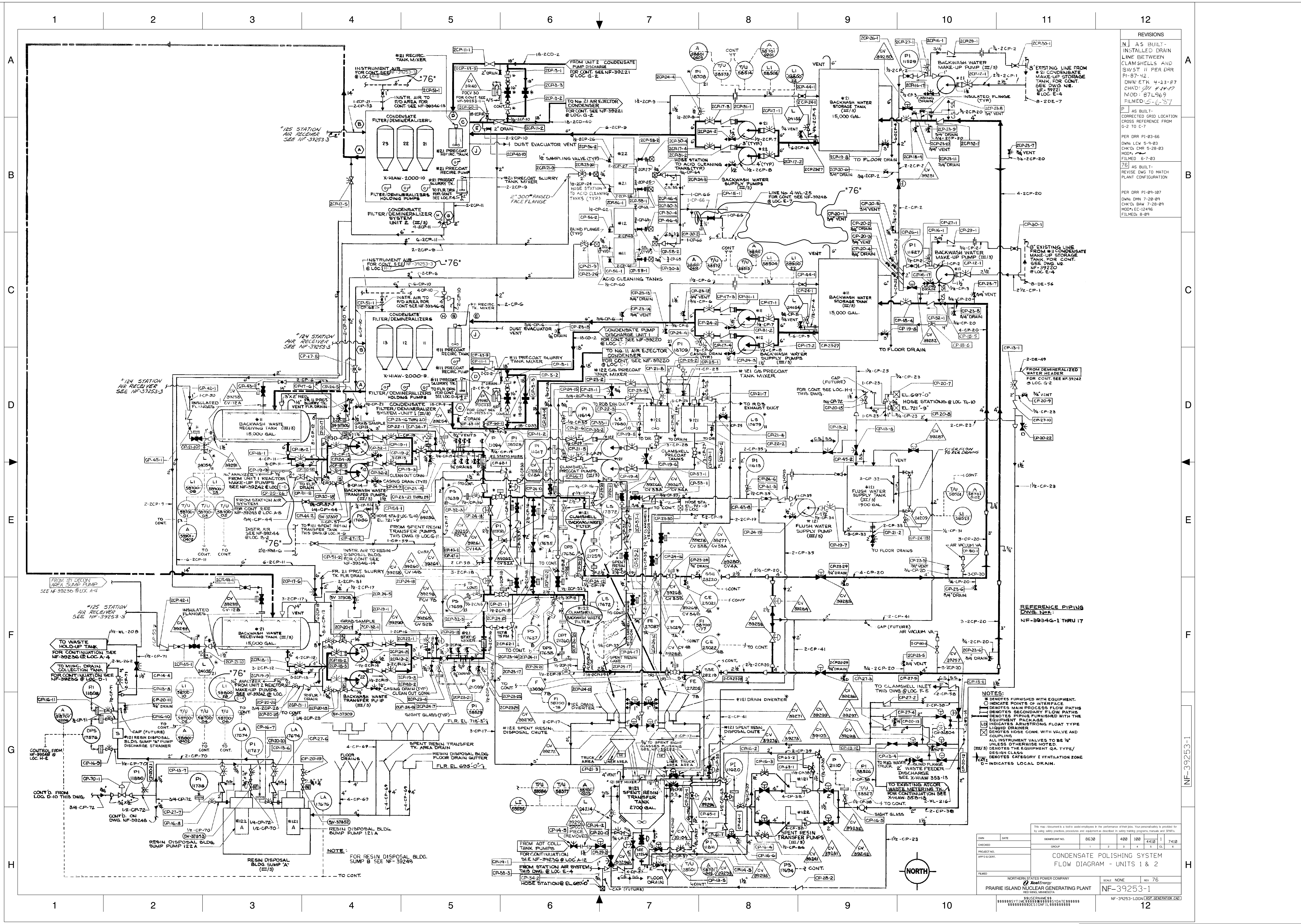


FIGURE 11.1-18 REV. 18



60300000133 1

FIGURE 11.1-19 REV. 35

CAD FILE: U11119.DGN

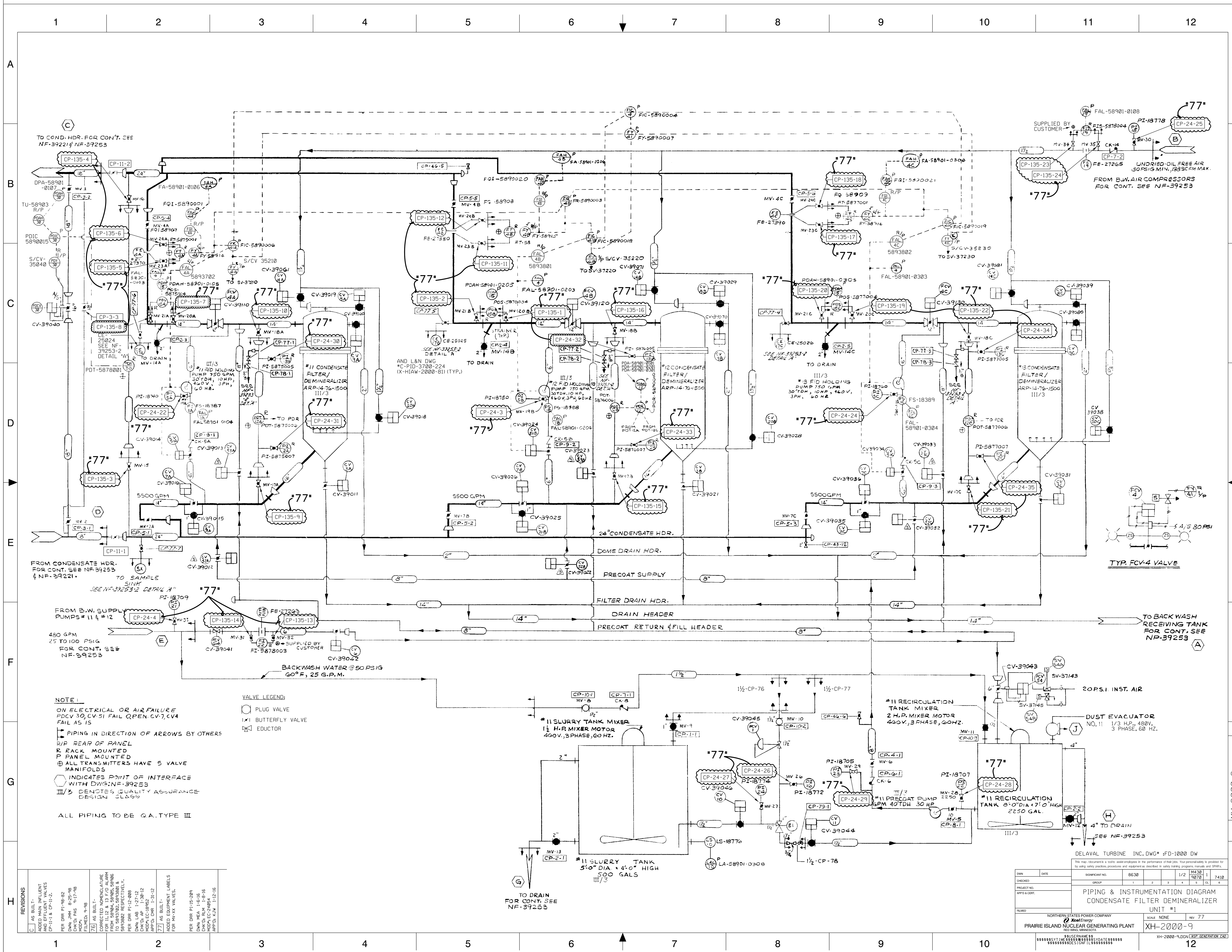


FIGURE 11.1-20 REV. 34

01516979

CAD FILE: U11120.DGN

FIGURE 11.2-1
DELETED

01406854

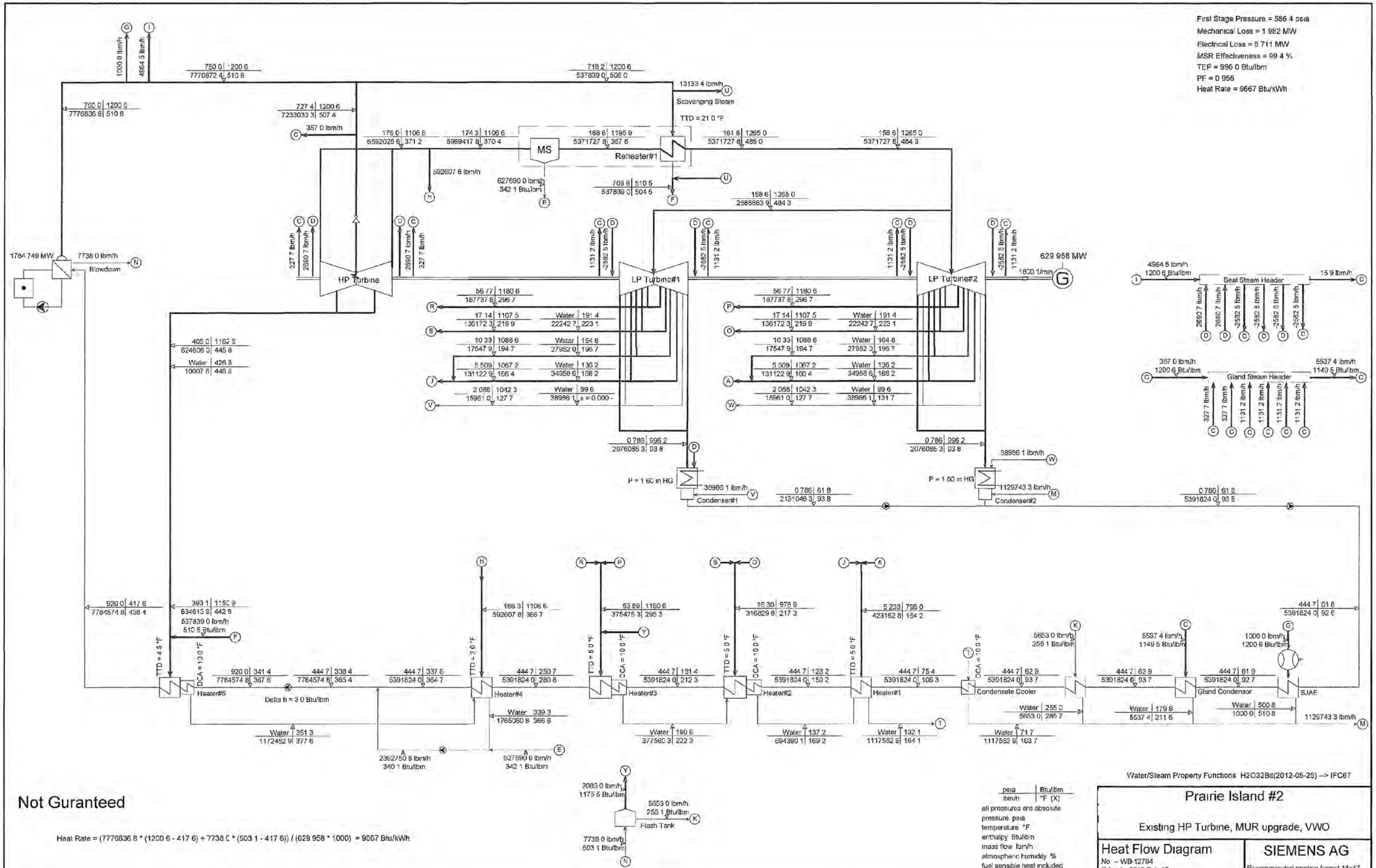


FIGURE 11.2-2 REV. 33

01406854

CAD FILE: U11202.DGN

FIGURE 11.2-3
DELETED

01406854

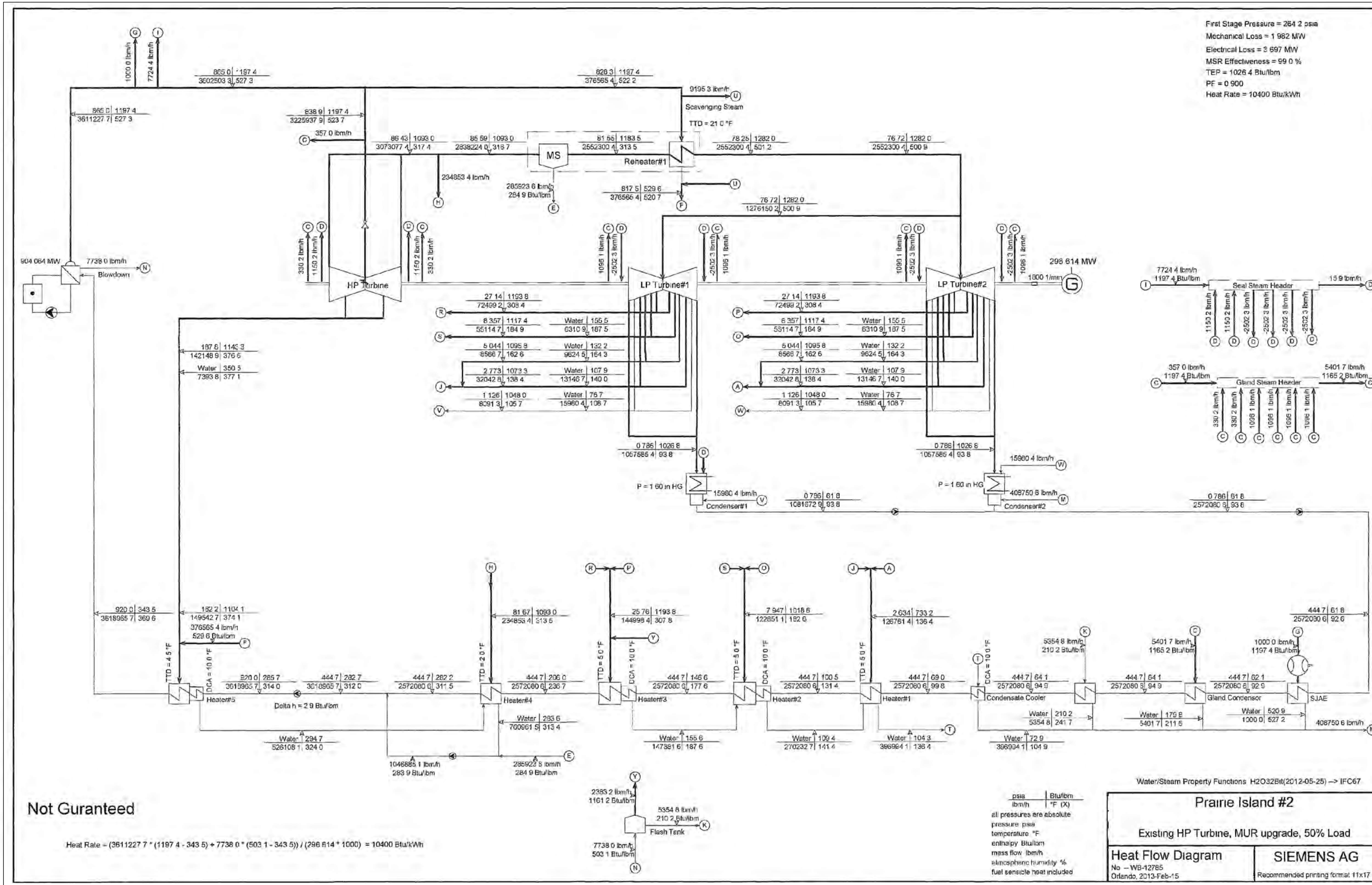
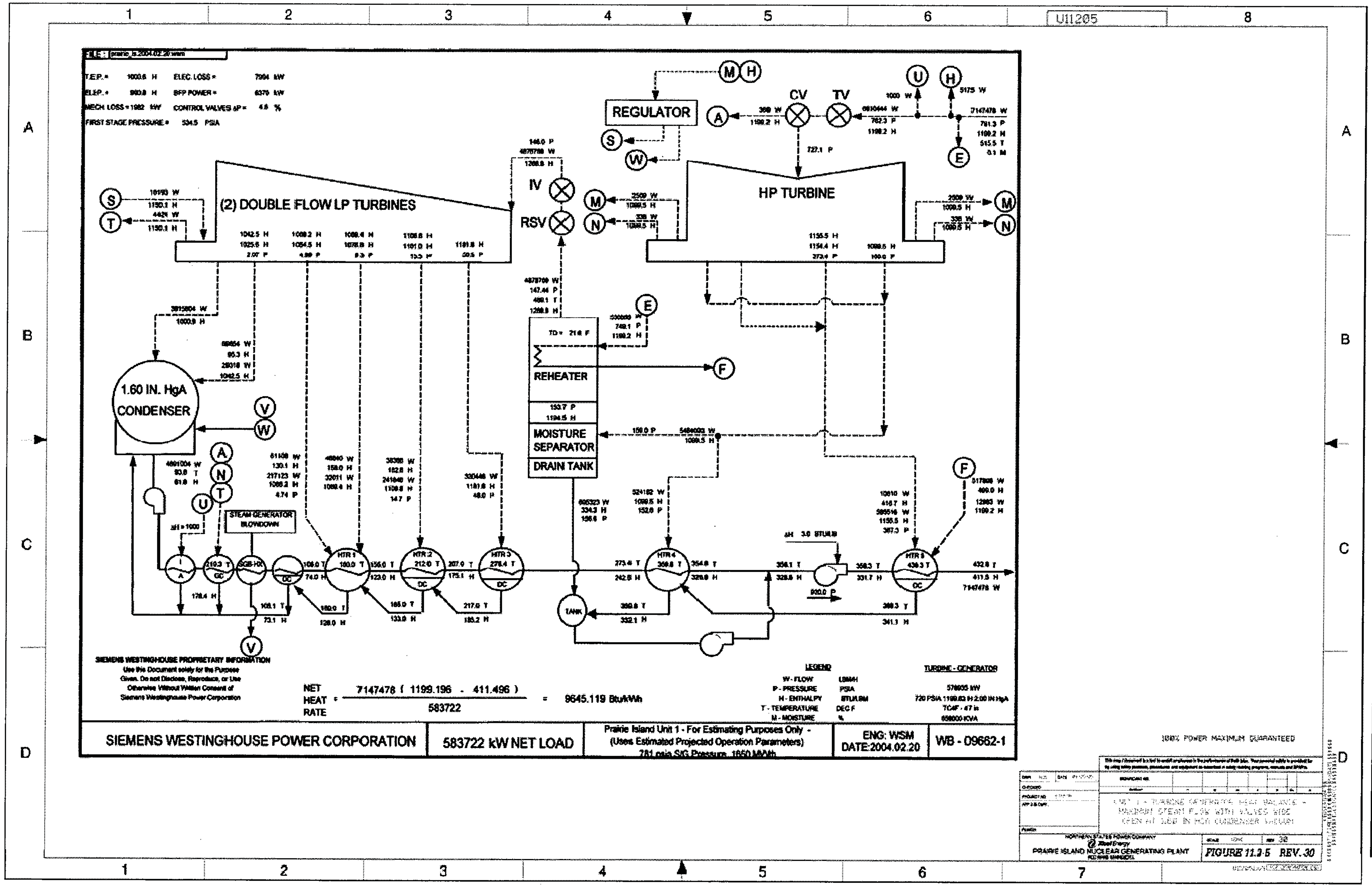


FIGURE 11.2-4 REV. 33

01406854

CAD FILE: U11204.DGN

FIGURE 11.2-5
UNIT 1 – TURBINE GENERATOR HEAT BALANCE – 100% POWER - VALVES WIDE OPEN AT 1.60 IN HGA CONDENSER VACUUM



01086710

FIGURE 11.2-5

FIGURE 11.2-6
UNIT 1 – TURBINE GENERATOR HEAT BALANCE – MAXIMUM STEAM FLOW WITH VALVES WIDE OPEN AT 1.60 IN HGA CONDENSER VACUUM

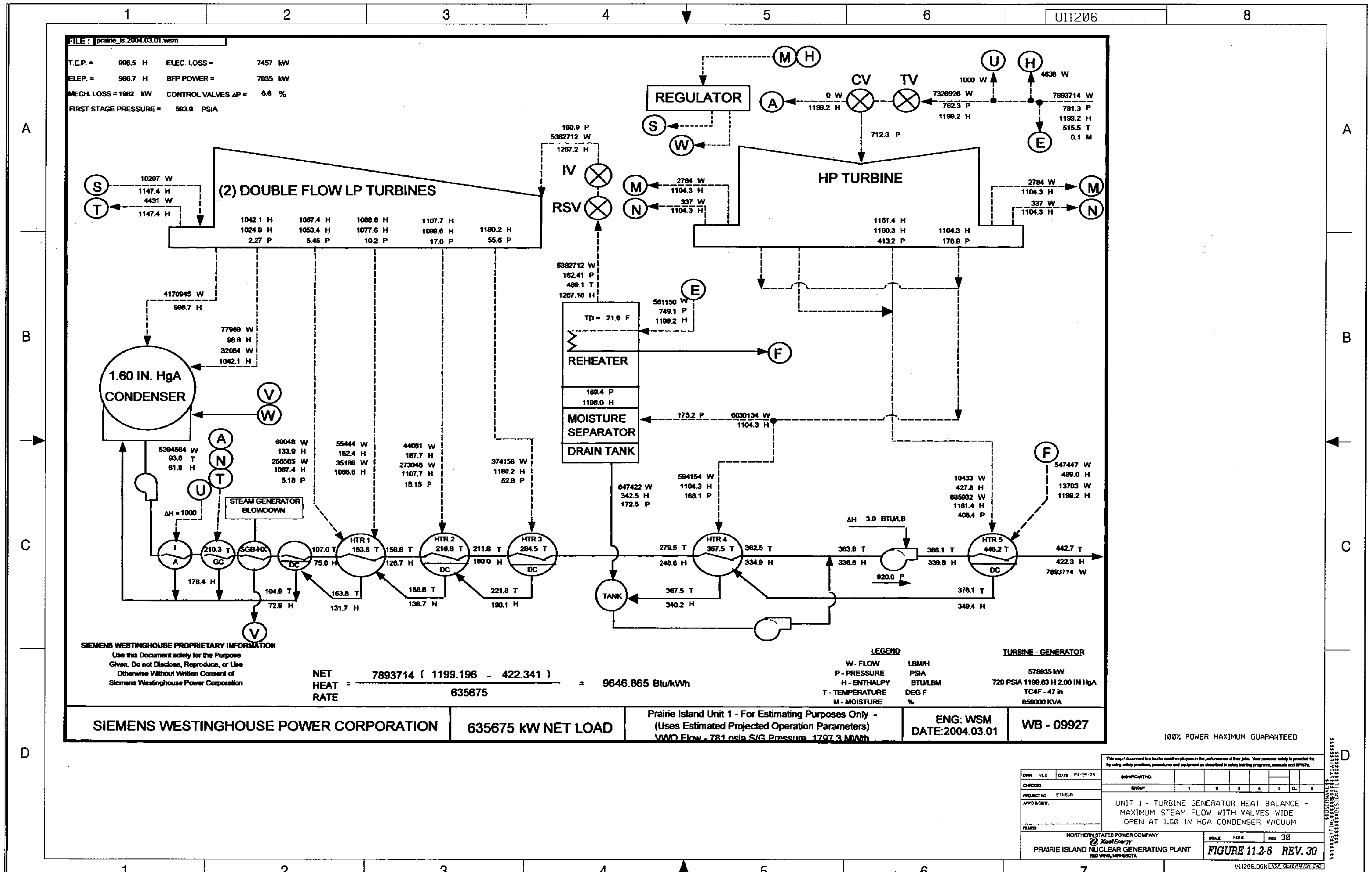


FIGURE 11.2-6

01086710

Figure 11.2-7 PRAIRIE ISLAND UNIT 1 HBD-MUR

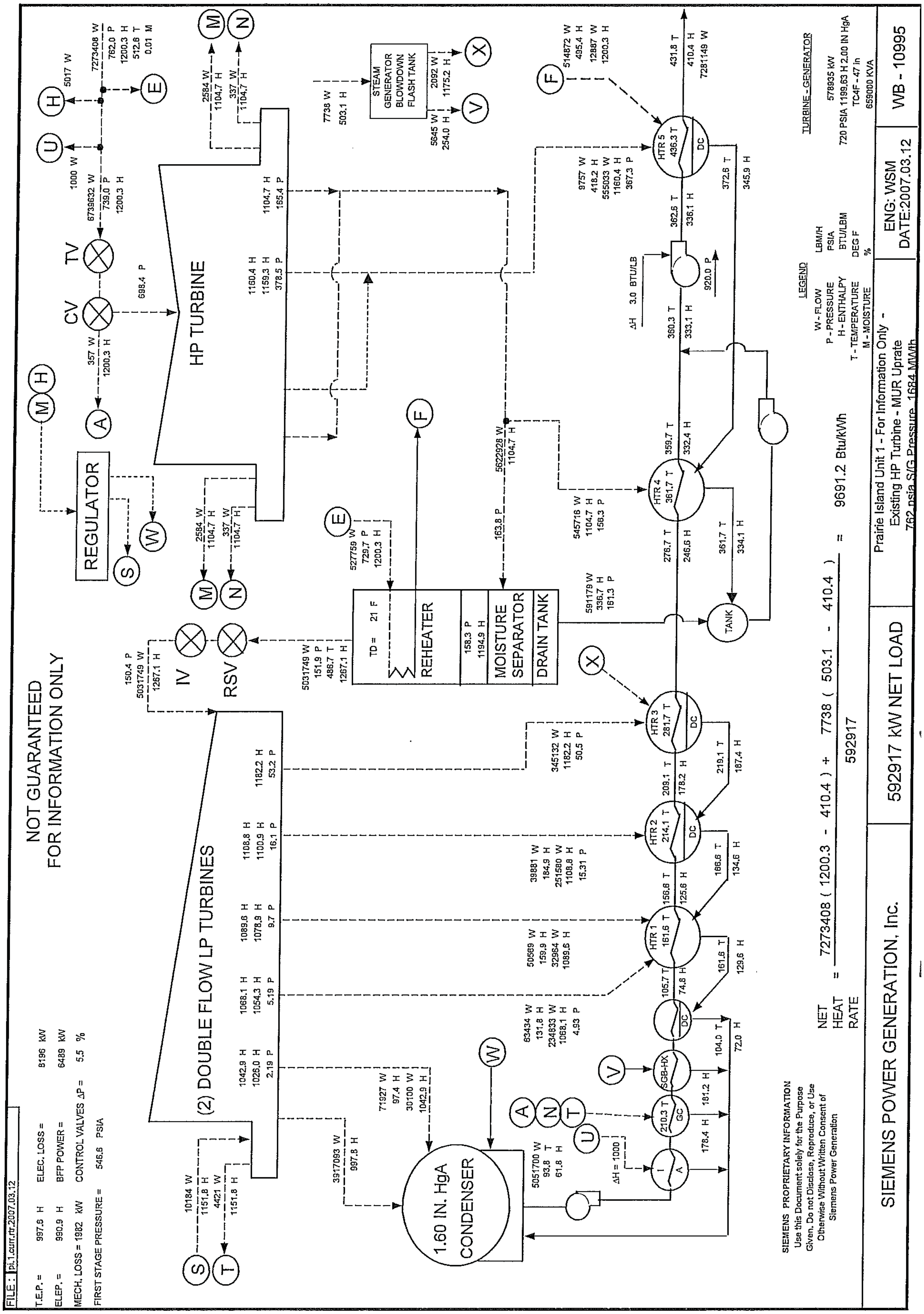


FIGURE 11.2-7

01214630

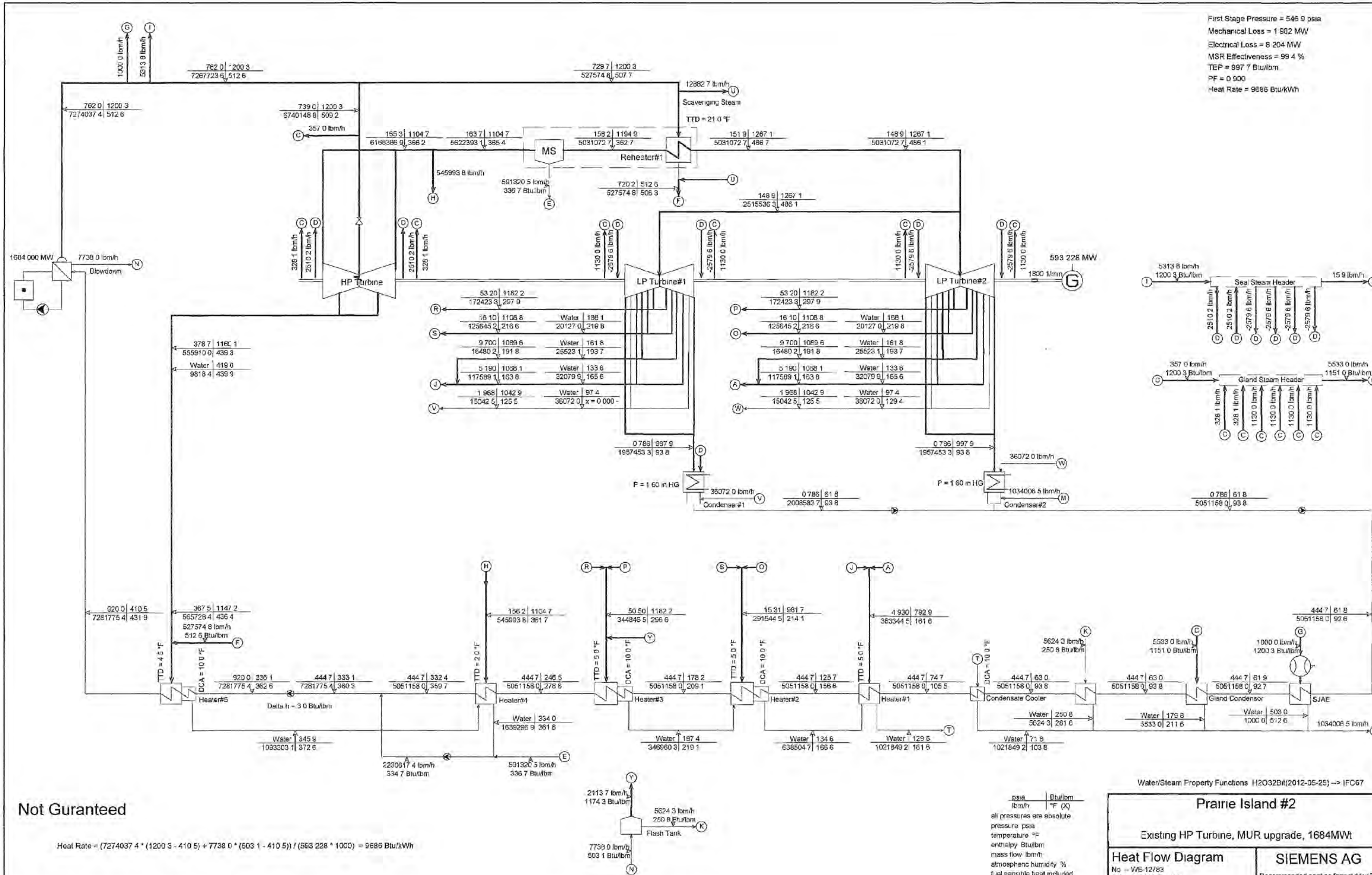
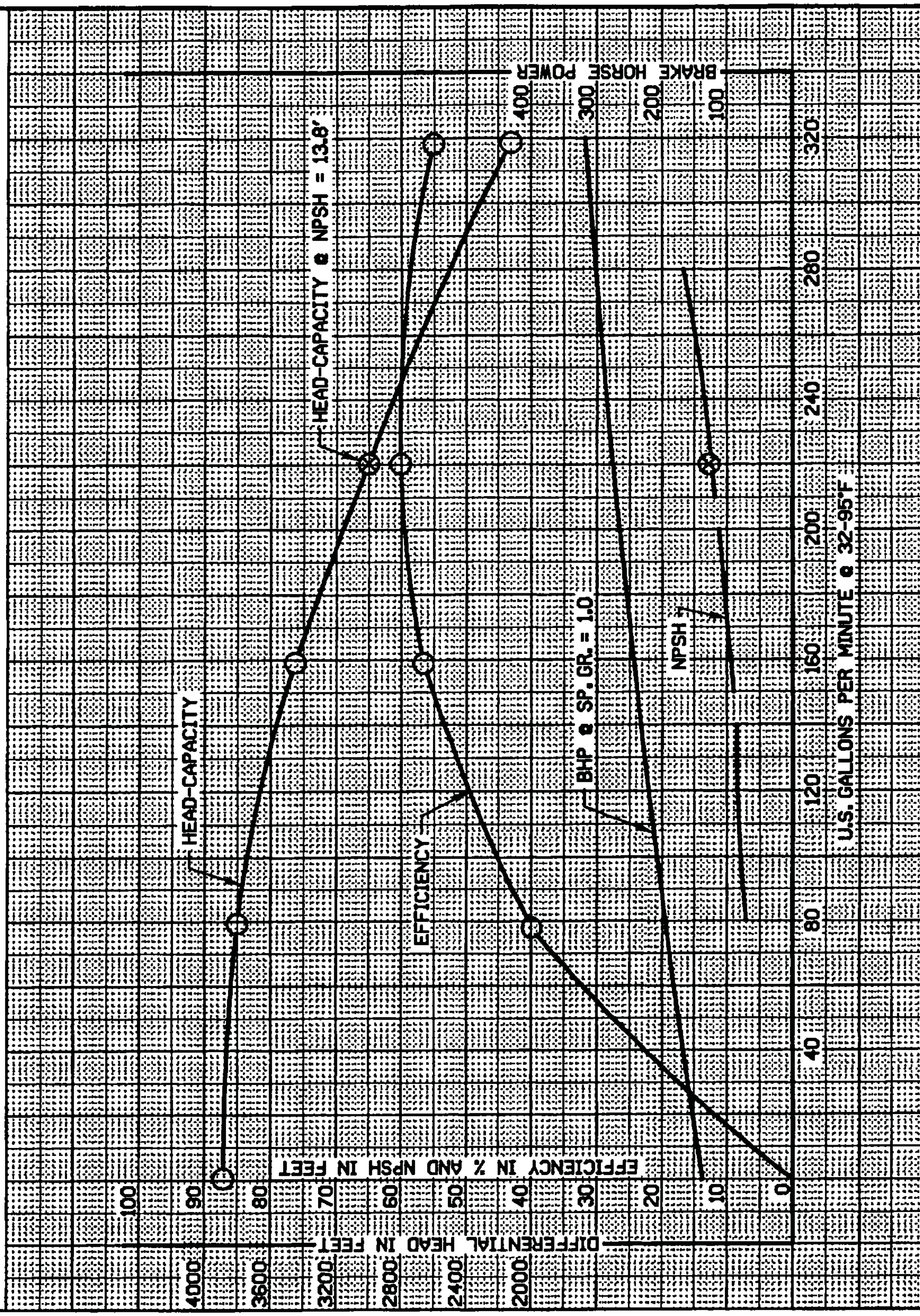


FIGURE 11.2-8 REV. 33

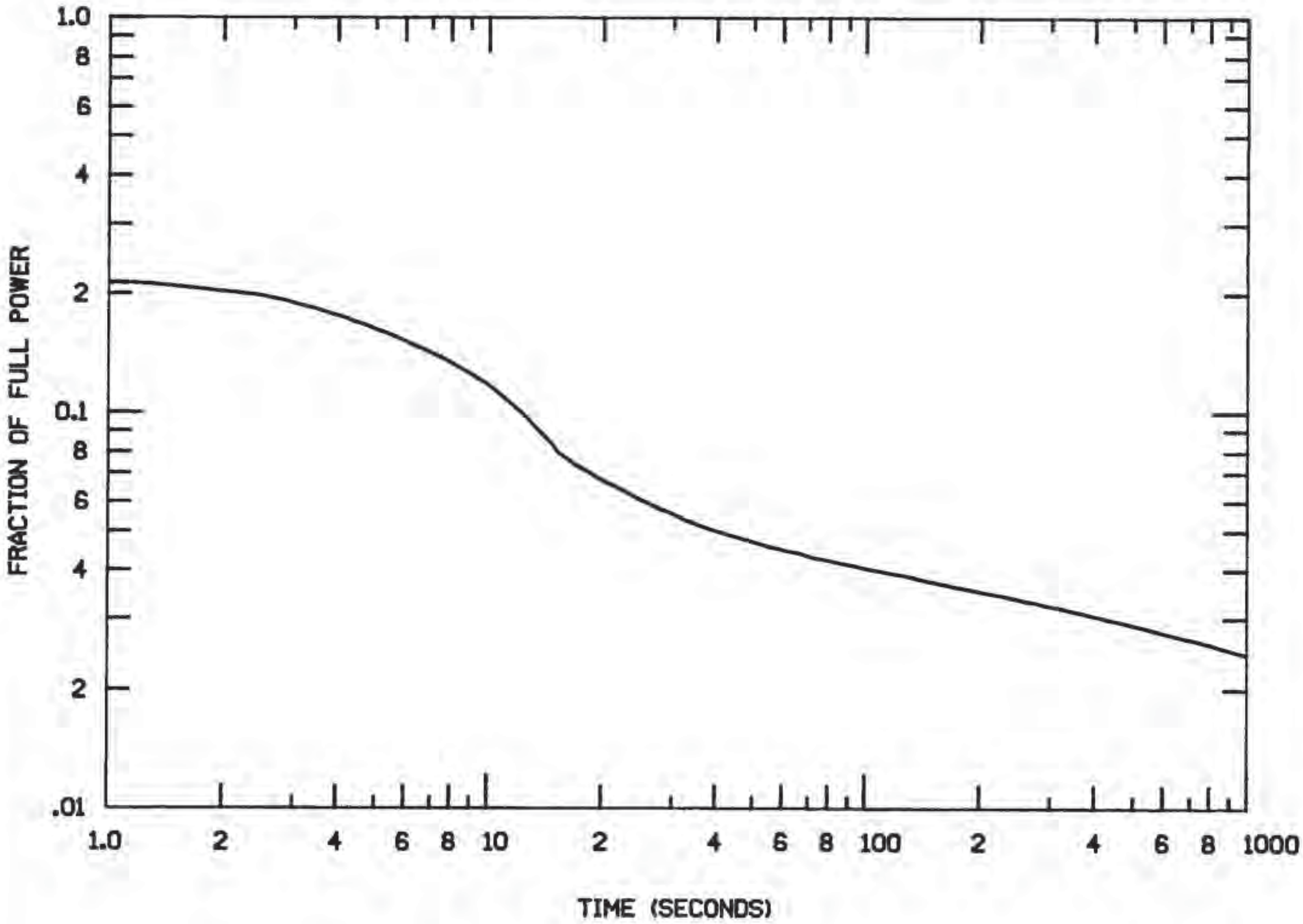
01406854

CAD FILE: U11208.DGN



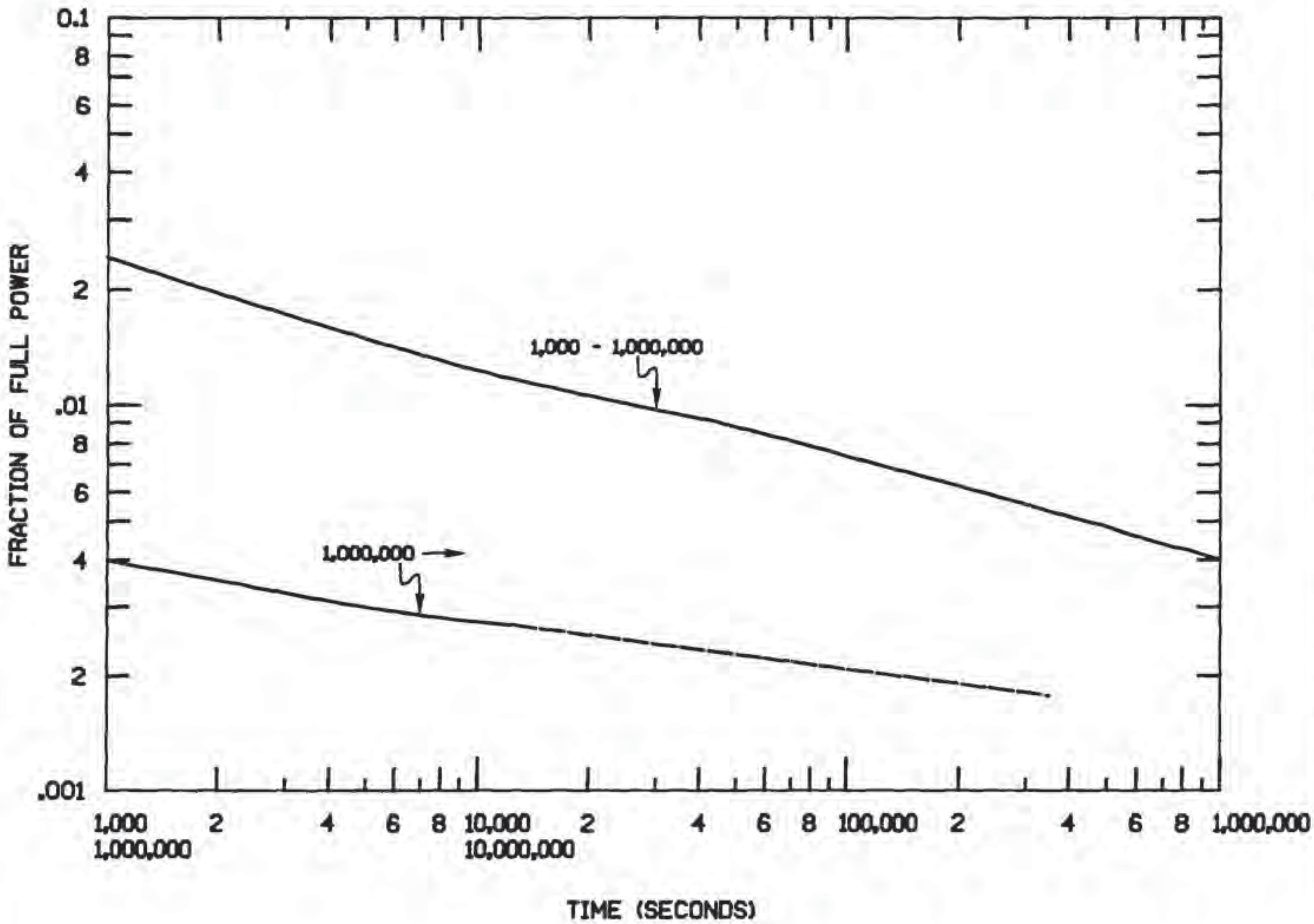
AUXILIARY FEEDWATER PUMP
CHARACTERISTIC CURVES

DWN L. BORCHARDT	DATE 6-23-99	NORTHERN STATES POWER COMPANY	SCALE: NONE	
CHECKED	CAD FILE U11901.DGN	PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA	FIGURE 11.9-1	REV. 18



DECAY HEAT CURVE
1 TO 1000 SECONDS

DWN L. BORCHARDT	DATE 6-23-99	NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA	SCALE: NONE
CHECKED	CAD FILE U11904A.DGN		FIGURE 11.9-4A REV. 18



DECAY HEAT CURVE
GREATER THAN 1000 SECONDS

DWN L. BORCHARDT	DATE 6-23-99	NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA	SCALE: NONE
CHECKED	CAD FILE U11904B.DGN		FIGURE 11.9-4B REV. 18