L. Design Power - Design power means a steady-state power level of 1998 thermal megawatts.

M. Primary Containment Integrity - Primary containment integrity means that the drywell and pressure suppression chamber are intact and all of the following conditions are satisfied:

1. All manual containment isolation valves on lines connected to the reactor coolant system or containment which are not required to be open during accident conditions are closed.

2. At least one door in each airlock is closed and sealed.

3. All blind flanges and manways are closed.

4. All automatic primary containment isolation valves and all instrument line flow check valves are operable or at least one containment isolation valve in each line having an inoperable valve shall be deactivated in the isolated condition.

5. All containment isolation check valves are operable or at least one containment valve in each line having an inoperable valve is secured in the isolated position.

N. Secondary Containment Integrity - Secondary containment integrity means that the reactor building is intact and the following conditions are met:

1. At least one door in each access opening is closed.

2. The standby gas treatment system is operable.

3. All automatic ventilation system isolation valves are operable or secured in the isolated position.

O. Operating Cycle - Interval between the end of one refueling outage and the end of the next subsequent refueling outage.

P. Refueling Frequencies:

1. Refueling Outage - Refueling outage is the period of time between the shutdown of the unit prior to a refueling and the startup of the plant after that refueling. For the purpose of designating frequency of testing and surveillance, a refueling outage shall mean a regularly scheduled outage; however, where such outages occur within 11 months of completion of the previous refueling outage, the required surveillance testing need not be performed until the next regularly scheduled outage. (Definitions U and V apply)

2. Refueling Interval - Refueling interval applies only to ASME Code, Section XI IWP and IWV surveillance tests. For the purpose of designating frequency of these code tests, a refueling interval shall mean at least once every 24 months.

NOTES FOR TABLE 3.2.A (Cont)

3. Instrument set point corresponds to 137.86 inches above top of active fuel.

4. Instrument set point corresponds to 79.86 inches above top of active fuel.

5. Not required in Run Mode (bypassed by Mode Switch).

6. Each steam line is monitored by two instrument trip channels per trip system. Therefore, the minimum number of main steam line high flow instruments required to be operable is four per main steam line unless the line is isolated.

7. These signals also start SBGTS and initiate secondary containment isolation.

8. Only required in Run Mode (interlocked with Mode Switch).

9. Deleted.

PNPS
TABLE 3.2.D

RADIATION MONITORING SYSTEMS THAT INITIATE AND/OR ISOLATE

Minimum # of Operable Instrument Channels Per Trip system (1)	Trip Function	Trip Level Setting	Action (2)
2	Refuel Area Exhaust Monitors	Upscale, <100 mr/hr	A or B
2	Refuel Area Exhaust Monitors	Downscale	A or B

NOTES FOR TABLE 3.2.D

1. Whenever the systems are required to be operable, there shall be two operable or tripped trip systems. If this cannot be met, the indicated action shall be taken.

2. Action

   A. Cease operation of the refueling equipment.
   B. Isolate secondary containment and start the standby gas treatment system.

TABLE 3.2.F (Cont)

SURVEILLANCE INSTRUMENTATION

Minimum # of Channels	Operable Instrument Instrument #	Parameter	Type Indication and Range	Notes
2	TI-5021-2A TRU-5021-1A	Suppression Chamber Water Temperature	Indicator/ Multipoint Recorder 30-230°F (Bulk)	(1) (2) (3) (4)
	TI-5022-2B TRU-5022-1B	Suppression Chamber Water Temperature	Indicator/ Multipoint Recorder 30-230°F (Bulk)	(1) (2) (3) (4)
1	PID-5021	Drywell/Torus Diff. Pressure	Indicator -.25 - +3.0 psig	(1) (2) (3) (4)
1	PID-5067A PID-5067B	Drywell Pressure Torus Pressure	Indicator -.25 - +3.0 psig Indicator - 1.0 - +2.0 psig	(1) (2) (3) (4)
1/Valve	(a)Primary or (b) Backup	Safety/Relief Valve Position	(a) Acoustic monitor (b) Thermocouple	(5)
1/Valve	(a)Primary or (b) Backup	Safety Valve Position Indicator	(a) Acoustic monitor (b) Thermocouple	(5)
1/Valve	See Note (6)	Tail Pipe Temperature Indication	Thermocouple	(6)
2	LI-1001-604A LR-1001-604A	Torus Water Level (Wide Range)	Indicator/Multipoint Recorder 0-300" H_20	(1) (2) (3) (4)
	LI-1001-604B LR-1001-604B	Torus Water Level (Wide Range)	Indicator/Multipoint Recorder 0-300" H_20	(1) (2) (3) (4)

G. Structural Integrity

The Pilgrim Nuclear Power Station Inservice Inspection Program conforms to the requirements of 10CFR50.55a(g). Where practical, the inspection of ASME Section XI Class 1, 2, and 3 components conforms to the edition and addenda of Section XI of the ASME Boiler and Pressure Vessel Code required by 10CFR50.55a(g). When implementation of an ASME Code required inspection has been determined to be impractical for PNPS, a request for relief from the inspection requirement is submitted to the NRC in accordance with 10CFR50.55a(g)(5)(iii).

Requests for relief from the ASME Code inspection requirements will be submitted to the NRC prior to the beginning of each 10 year inspection interval for which the inspection requirement is known to be impractical. Requests for relief from inspection requirements which are identified to be impractical during the course of the inspection interval will be reported to the NRC on an annual basis throughout the inspection interval.

I. Shock Suppressors (Snubbers)

Snubbers are designed to prevent unrestrained pipe motion under dynamic loads as might occur during an earthquake or severe transient, while allowing normal thermal motion during startup and shutdown. The consequence of an inoperable snubber is an increase in the probability of structural damage to piping as a result of a seismic or other event initiating dynamic loads. It is therefore required that all snubbers required to protect the primary coolant system and all other safety related systems or components be operable during reactor operation.

The visual inspection frequency is based on maintaining a constant level of snubber protection to systems. The cumulative number of inoperable snubbers detected during any inspection interval is the basis for establishment of the subsequent inspection interval and the existing inspection interval should remain in effect until its completion.

When the cause of the rejection of a snubber is clearly established and remedied for that snubber and verified by inservice functional testing, that snubber may be exempted from being counted as inoperable.

Generically susceptible snubbers are those which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection, and are exposed to the same environmental conditions such as temperature, radiation, and vibration.

When a snubber is found inoperable, an engineering evaluation is initiated, in addition to the determination of the snubber mode of failure, in order to determine if any safety-related component or system has been adversely affected by the inoperability of the snubber. Initiating this evaluation within 72 hours ensures that prompt corrective action will be afforded.

capability of the structure over its service lifetime. Additional margin to maintain the containment in the "as built" condition is achieved by establishing the allowable operational leak rate. The allowable operational leak rate is derived by multiplying the maximum allowable leak rate or the allowable test leak rate by 0.75 thereby providing a 25% margin to allow for leakage deterioration which may occur during the period between leak rate tests.

The primary containment leak rate test frequency is based on maintaining adequate assurance that the leak rate remains within the specification. The leak rate test frequency is in accordance with 10CFR50 App. J.

The penetration and air purge piping leakage test frequency, along with the containment leak rate tests, is adequate to allow detection of leakage trends. Whenever a bolted double-gasketed penetration is broken and remade, the space between the gaskets is pressurized to determine that the seals are performing properly. It is expected that the majority of the leakage from valves, penetrations and seals would be into the reactor building. However, it is possible that leakage into other parts of the facility could occur. Such leakage paths that may affect significantly the consequences of accidents are to be minimized. The personnel air lock is tested at 10 psig, because the inboard door is not designed to shut in the opposite direction.

Primary Containment Isolation Valves

Double isolation valves are provided on lines penetrating the primary containment and open to the free space of the containment. Closure of one of the valves in each line would be sufficient to maintain the integrity of the pressure suppression system. Automatic initiation is required to minimize the potential leakage paths from the containment in the event of a loss of coolant accident.

Group 1 - process lines are isolated by reactor vessel low-low water level in order to allow for removal of decay heat subsequent to a scram, yet isolate in time for proper operation of the core standby cooling systems. The valves in group 1 are also closed when process instrumentation detects excessive main steam line flow, low pressure, main steam space high temperature, or reactor vessel high water level.

Group 2 - isolation valves are closed by reactor vessel low water level or high drywell pressure. The group 2 isolation signal also "isolates" the reactor building and starts the standby gas treatment system. It is not desirable to actuate the group 2 isolation signal by a transient or spurious signal.

Group 3 - isolation valves can only be opened when the reactor is at low pressure and the core standby cooling systems are not required. Also, since the reactor vessel could potentially be drained through these process lines, these valves are closed by low water level.

Attachment C

Marked-up Technical Specification Pages

1.0 DEFINITIONS (Cont)

L. Design Power - Design power means a steady-state power level of 1998 thermal megawatts.

M. Primary Containment Integrity - Primary containment integrity means that the drywell and pressure suppression chamber are intact and all of the following conditions are satisfied:

1. All manual containment isolation valves on lines connected to the reactor coolant system or containment which are not required to be open during accident conditions are closed.

2. At least one door in each airlock is closed and sealed.

3. All blind flanges and manways are closed.

and all instrument line flow check valves

4. All automatic primary containment isolation valves are operable or at least one containment isolation valve in each line having an inoperable valve shall be deactivated in the isolated condition.

5. All containment isolation check valves are operable or at least one containment valve in each line having an inoperable valve is secured in the isolated position.

N. Secondary Containment Integrity - Secondary containment integrity means that the reactor building is intact and the following conditions are met:

1. At least one door in each access opening is closed.

2. The standby gas treatment system is operable.

3. All automatic ventilation system isolation valves are operable or secured in the isolated position.

O. Operating Cycle - Interval between the end of one refueling outage and the end of the next subsequent refueling outage.

P. Refueling Frequencies:

1. Refueling Outage - Refueling outage is the period of time between the shutdown of the unit prior to a refueling and the startup of the plant after that refueling. For the purpose of designating frequency of testing and surveillance, a refueling outage shall mean a regularly scheduled outage; however, where such outages occur within 11 months of completion of the previous refueling outage, the required surveillance testing need not be performed until the next regularly scheduled outage. (Definitions U and V apply)

2. Refueling Interval - Refueling interval applies only to ASME Code, Section XI IWP and IWV surveillance tests. For the purpose of designating frequency of these code tests, a refueling interval shall mean at least once every 24 months.

NOTES FOR TABLE 3.2.A (Cont)

3. Instrument set point corresponds to 137.86 inches above top of active fuel.

4. Instrument set point corresponds to 79.86 inches above top of active fuel.

5. Not required in Run Mode (bypassed by Mode Switch).

6. ~~Two required for each steam line~~.

7. These signals also start SBGTS and initiate secondary containment isolation.

8. Only required in Run Mode (interlocked with Mode Switch).

9. Deleted.

Each steam line is monitored by two ~~RPS~~ instrument trip channels per trip system. Therefore, the minimum number of Main Steam High Flow Instruments required to be operable is four per main steam line unless the line is isolated.

PNPS
TABLE 3.2.D

RADIATION MONITORING SYSTEMS THAT INITIATE AND/OR ISOLATE

Minimum # of Operable Instrument Channels Per Trip system (1)	Trip Function	Trip Level Setting	Action (2)
2	Refuel Area Exhaust Monitors	Upscale, <100 mr/hr	A or B
2	Refuel Area Exhaust Monitors	Downscale	A or B

NOTES FOR TABLE 3.2.D

1. Whenever the systems are required to be operable, there shall be two operable or tripped trip systems. If this cannot be met, the indicated action shall be taken.

~~1.~~ 2. Action

A. Cease operation of the refueling equipment.
B. Isolate secondary containment and start the standby gas treatment system.

PNPS

TABLE 3.2.F (Cont)

SURVEILLANCE INSTRUMENTATION

Minimum # of Channels	Operable Instrument Instrument #	Parameter	Type Indication and Range	Notes
2	(TI-5021-0~~X~~2A (TRU-5021-~~0~~1A ((	Suppression Chamber Water Temperature	~~Dual~~ Indicator/ Multipoint Recorder 30-230°F (Bulk/~~Local~~)	(4) (1) (2) (3)
2	(TI-5022-0~~X~~2B (TRU-5022-~~0~~1B	Suppression Chamber Water Temperature	~~Dual~~ Indicator/ Multipoint Recorder 30-230°F (Bulk/~~Local~~)	(4) (1) (2) (3)
1	PID ~~PT~~-5021	Drywell/Torus Diff. Pressure	Indicator -.25 - +3.0 psig	(1) (2) (3) (4)
1	PID (~~PT~~-5067A	Drywell Pressure	Indicator -.25 - +3.0 psig	
	PID (~~PT~~-5067B	Torus Pressure	Indicator -1.0 - +2.0 psig	(1) (2) (3) (4)
1/Valve	(a)Primary (or (5) (b)Backup	Safety/Relief Valve Position	(a) Acoustic monitor (b) Thermocouple	(5)
1/Valve	(a)Primary (or (5) (b)Backup	Safety Valve Position Indicator	(a) Acoustic monitor (b) Thermocouple	(5)
1/Valve	See Note (6)	Tail Pipe Temperature Indication	Thermocouple	(6)
2	(LI 1001-604A (LR 1001-604A ((LI 1001-604B (LR 1001-604B	Torus Water Level (Wide Range)	Indicator/Multipoint Recorder 0-300" H_2O	(4) (1) (2) (3)

BASES:

3/4.6 PRIMARY SYSTEM BOUNDARY (Cont)

G. Structural Integrity

The Pilgrim Nuclear Power Station Inservice Inspection Program conforms to the requirements of 10CFR50.55a(g). Where practical, the inspection of ASME Section XI Class 1, 2, and 3 components conforms to the edition and addenda of Section XI of the ASME Boiler and Pressure Vessel Code required by 10CFR50.55a(g). When implementation of an ASME Code required inspection has been determined to be impractical for PNPS, a request for relief from the inspection requirement is submitted to the NRC in accordance with 10CFR50.55a(g)(5)(iii).

Requests for relief from the ASME Code inspection requirements will be submitted to the NRC prior to the beginning of each 10 year inspection interval for which the inspection requirement is known to be impractical. Requests for relief from inspection requirements which are identified to be impractical during the course of the inspection interval will be reported to the NRC on an annual basis throughout the inspection interval.

~~Certain ASME Code Class 1, Category B-J pressure retaining welds have been designated as Group I welds. These Group I welds shall be included in the sample of Class I welds requiring inspection during each ten year interval.~~

I. Shock Suppressors (Snubbers)

Snubbers are designed to prevent unrestrained pipe motion under dynamic loads as might occur during an earthquake or severe transient, while allowing normal thermal motion during startup and shutdown. The consequence of an inoperable snubber is an increase in the probability of structural damage to piping as a result of a seismic or other event initiating dynamic loads. It is therefore required that all snubbers required to protect the primary coolant system and all other safety related systems or components be operable during reactor operation.

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capability of the structure over its service lifetime. Additional margin to maintain the containment in the "as built" condition is achieved by establishing the allowable operational leak rate. The allowable operational leak rate is derived by multiplying the maximum allowable leak rate or the allowable test leak rate by 0.75 thereby providing a 25% margin to allow for leakage deterioration which may occur during the period between leak rate tests.

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Group 2 - isolation valves are closed by reactor vessel low water level or high drywell pressure. The group 2 isolation signal also "isolates" the reactor building and starts the standby gas treatment system. It is not desirable to actuate the group 2 isolation signal by a transient or spurious signal.

Group 3 - isolation valves can only be opened when the reactor is at low pressure and the core standby cooling systems are not required. Also, since the reactor vessel could potentially be drained through these process lines, these valves are closed by low water level.