Dockets Nos. 50-259
and ~~50-260~~

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Tennessee Valley Authority
ATTN: Mr. Godwin Williams, Jr.
Manager of Power
818 Power Building
Chattanooga, Tennessee 37201

Gentlemen:

The Commission has issued the enclosed Amendments Nos. 28 and 25 to Facility Licenses Nos. DPR-33 and DPR-52 for the Browns Ferry Nuclear Plant, Units 1 and 2. These amendments consist of changes to the Technical Specifications in response to your requests of September 1, October 1 and October 12, 1976.

The amendments change the Technical Specifications to add containment isolation valves associated with the drywell to torus differential pressure control system to the valve listing (Table 3.7.D) for the limiting condition for operation and surveillance requirements of primary containment. A clarification in the wording of the temperature surveillance requirement for the torus water has also been made. This latter change is different from what you had proposed in your October 1, 1977 request but your staff has agreed that this modification sufficiently clarifies the specification. In addition, the allowable operating time with two inoperable Automatic Depressurization System (ADS) valves has been reduced from thirty days to seven days to reflect the fact that the ECCS Appendix K analysis was performed with five of the six ADS valves operable rather than four as stated previously. We are also taking this opportunity to correct typographical errors, page misnumbering, and valve misnumbering that occurred when the specifications were reissued in their entirety on August 20, 1976.

Copies of the Safety Evaluation and the Federal Register Notice are also enclosed.

Sincerely,

Original Signed By

A. Schwencer, Chief
Operating Reactors Branch #1
Division of Operating Reactors

Enclosures and cc's:
See next page

x27433:tsb

OFFICE➤	ORB#1	OELD	ORB#1		
SURNAME➤	TVWambach		ASchwencer		
DATE➤	2/9/77	2/15/77	2/15/77		

Enclosures:
1. Amendment No. 28 to DPR-33
2. Amendment No. 25 to DPR-52
3. Corrected Pages to Amendments
   Nos. 27 & 24
4. Safety Evaluation
5. Federal Register Notice

cc w/enclosures:
See next page

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

TENNESSEE VALLEY AUTHORITY

DOCKET NO. 50-259

BROWNS FERRY NUCLEAR PLANT, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 28
License No. DPR-33

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The applications for amendment by Tennessee Valley Authority (the licensee) dated September 1, October 1 and October 12, 1976, comply with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C(2) of Facility License No. DPR-33 is hereby amended to read as follows:

    (2) Technical Specifications

    The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 28, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

A. Schwencer

A. Schwencer, Chief
Operating Reactors Branch #1
Division of Operating Reactors

Attachment:
Changes to the Technical Specifications

Date of Issuance: February 15, 1977

ATTACHMENT TO LICENSE AMENDMENTS

AMENDMENT NO. 28 TO FACILITY LICENSE NO. DPR-33

AMENDMENT NO. 25 TO FACILITY LICENSE NO. DPR-52

DOCKETS NOS. 50-259 & 50-260

Revise Appendix A as follows:

Remove pages 157, 158, 167, 227, 259, and 262 and replace with identically numbered pages.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.5.F Reactor Core Isolation Cooling	4.5.F Reactor Core Isolation Cooling
2. If the RCICS is inoperable, the reactor may remain in operation for a period not to exceed 7 days if the HPCIS is operable during such time.	2. When it is determined that the RCICS is inoperable, the HPCIS shall be demonstrated to be operable immediately and weekly thereafter.
3. If specifications 3.5.F.1 or 3.5.F.2 are not met, an orderly shutdown shall be initiated and the reactor shall be depressurized to less than 122 psig within 24 hours.	
G. Automatic Depressurization System (ADS)	G. Automatic Depressurization System (ADS)
1. Five of the six valves of the Automatic Depressurization System shall be operable: (1) prior to a startup from a Cold Condition, or, (2) whenever there is irradiated fuel in the reactor vessel and the reactor vessel pressure is greater than 105 psig, except as specified in 3.5.G.2 and 3.5.G.3 below.	1. During each operating cycle the following tests shall be performed on the ADS: a. A simulated automatic actuation test shall be performed prior to startup after each refueling outage. Manual surveillance of the relief valves is covered in 4.6.D.2.
2. If more than one ADS valve is known to be incapable of automatic operation, the reactor may remain in operation for a period not to exceed 7 days, provided the HPCI system is operable. (Note that the pressure relief function of these valves is assured by section 3.6.D of these specifications and that this specification only applies to the ADS function.)	2. When it is determined that more than one of the ADS valves are incapable of automatic operation, the HPCIS shall be demonstrated to be operable immediately and daily thereafter as long as Specification 3.5.G.2 applies.

LIMITING CONDITIONS FOR OPERATION

3.5.G Automatic Depressurization System (ADS)

3. If specifications 3.5.G.1 and 3.5.G.2 cannot be met, an orderly shutdown will be initiated and the reactor vessel pressure shall be reduced to 105 psig or less within 24 hours.

H. Maintenance of Filled Discharge Pipe

Whenever the core spray systems, LPCI, HPCI, or RCIC are required to be operable, the discharge piping from the pump discharge of these systems to the last block valve shall be filled.

SURVEILLANCE REQUIREMENTS

4.5.G Automatic Depressurization System (ADS)

H. Maintenance of Filled Discharge Pipe

The following surveillance requirements shall be adhered to to assure that the discharge piping of the core spray systems, LPCI, HPCI, and RCIC are filled:

3.5.G Automatic Depressurization System (ADS)

This specification ensures the operability of the ADS under all conditions for which the depressurization of the nuclear system is an essential response to station abnormalities.

The nuclear system pressure relief system provides automatic nuclear system depressurization for small breaks in the nuclear system so that the low-pressure coolant injection (LPCI) and the core spray subsystems can operate to protect the fuel barrier. Note that this specification applies only to the automatic feature of the pressure relief system.

Specification 3.6.D specifies the requirements for the pressure relief function of the valves. It is possible for any number of the valves assigned to the ADS to be incapable of performing their ADS functions because of instrumentation failures yet be fully capable of performing their pressure relief function.

Because the automatic depressurization system does not provide makeup to the reactor primary vessel, no credit is taken for the steam cooling of the core caused by the system actuation to provide further conservatism to the CSCS.
With one ADS valve known to be incapable of automatic operation, five valves remain operable to perform their ADS function. The ECCS loss-of-coolant accident analyses for small line breaks assumed that five of the six ADS valves were operable. Reactor operation with two ADS valves inoperable is only allowed to continue for seven days provided that the HPCI system is demonstrated to be operable.

LIMITING CONDITIONS FOR OPERATION

3.7 CONTAINMENT SYSTEMS

Applicability

Applies to the operating status of the primary and secondary containment systems.

Objective

To assure the integrity of the primary and secondary containment systems.

Specification

A. Primary Containment

1. At any time that the irradiated fuel is in the reactor vessel, and the nuclear system is pressurized above atmospheric pressure or work is being done which has the potential to drain the vessel, the pressure suppression pool water volume and temperature shall be maintained within the following limits except as specified in 3.7.A.2.

a. Minimum water volume - 123,000 ft^3

b. Maximum water volume - 135,000 ft^3

c. With the suppression pool water temperature > 95°F initiate pool cooling and restore the temperature to $\leq$ 95°F within 24 hours or be in at least hot shutdown within the next 6 hours and in cold shutdown within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7 CONTAINMENT SYSTEMS

Applicability

Applies to the primary and secondary containment integrity.

Objective

To verify the integrity of the primary and secondary containment.

Specification

A. Primary Containment

1. Pressure Suppression Chamber

a. The suppression chamber water level be checked once per day. Whenever heat is added to the suppression pool by testing of the ECCS or relief valves the pool temperature shall be continually monitored and shall be observed and logged every 5 minutes until the heat addition is terminated.

ENCLOSURE 1

TABLE 3.7.D (Continued)

Valves	Valve Identification	Test Medium	Test Method
43-28B	RHR Suppression Chamber Sample Lines	Water(2)	Applied between 74-226 and 43-28B
43-29A	RHR Suppression Chamber Sample Lines	Water(2)	Applied between 74-227 and 43-29A
43-29B	RHR Suppression Chamber Sample Lines	Water(2)	Applied between 74-227 and 43-29B
64-17	Drywell and Suppression Chamber air purge inlet	Air(1)	Applied between 64-17, 64-18, 64-19, and 76-24
64-18	Drywell air purge inlet	Air(1)	Applied between 64-17, 64-18, 64-19, and 76-24
64-19	Suppression Chamber air purge inlet	Air(1)	Applied between 64-17, 64-18, 64-19, and 76-24
64-20	Suppression Chamber vacuum relief	Air(1)	Applied between 64-20 and 64-(ck)
64-(ck)	Suppression Chamber vacuum relief	Air(1)	Applied between 64-20 and 64-(ck)
64-21	Suppression Chamber vacuum relief	Air(1)	Applied between 64-21 and 64-(ck)
64-(ck)	Suppression Chamber vacuum relief	Air(1)	Applied between 64-21 and 64-(ck)
64-29	Drywell main exhaust	Air(1)	Applied between 64-29, 64-30, 64-32 64-33 and 84-19
64-30	Drywell main exhaust	Air(1)	Applied between 64-29, 64-30, 64-32, 64-33 and 84-19
64-31	Drywell exhaust to Standby	Air(1)	Applied between 64-31, 64-141, 84-20 and 64-140
64-32	Suppression Chamber Main Exhaust	Air(1)	Applied between 64-32, 64-33, 64-29, 64-30 and 84-19
64-33	Suppression Chamber Main Exhaust	Air(1)	Applied between 64-32, 64-33, 64-29, 64-30 and 84-19
64-34	Suppression Chamber to Standby Gas Treatment	Air(1)	Applied between 64-34, 64-141 and 64-139

Valves	Valve Identification	Test Medium	Test Method
90-257A	Radiation Monitor Discharge	Air(1)	Applied between 90-257A and 90-257
90-257B	Radiation Monitor Discharge	Air(1)	Applied between 90-257A and 90-257
84-8A	Containment Atmospheric Dilution	Air	Applied between 84-8A and 84-600
84-8B	Containment Atmospheric Dilution	Air	Applied between 84-8B and 84-601
84-8C	Containment Atmospheric Dilution	Air	Applied between 84-8C and 84-603
84-8D	Containment Atmospheric Dilution	Air	Applied between 84-8D and 84-602
84-19	Containment Atmospheric Dilution	Air	Applied between 64-32, 64-33, 64-29, 64-30, and 84-19

(1) Air/nitrogen test to be displacement flow.
(2) Water test to be injection loss or downstream collection.

Valves	Valve Identification	Test Medium	Test Method
76-215	Containment Atmospheric Monitor	Air(1)	Applied between 76-215 and 76-218
76-217	Containment Atmospheric Monitor	Air	Applied between 76-217 and 76-218
76-220	Containment Atmospheric Monitor	Air	Applied between 76-220 and 76-223
76-222	Containment Atmospheric Monitor	Air	Applied between 76-222 and 76-223
76-225	Containment Atmospheric Monitor	Air	Applied between 76-225 and 76-227
76-226	Containment Atmospheric Monitor	Air	Applied between 76-226 and 76-227
76-229	Containment Atmospheric Monitor	Air	Applied between 76-229 and 76-231
76-230	Containment Atmospheric Monitor	Air	Applied between 76-230 and 76-231
76-237	Containment Atmospheric Monitor	Air	Applied between 76-237 and 76-240
76-239	Containment Atmospheric Monitor	Air	Applied between 76-239 and 76-240
76-242	Containment Atmospheric Monitor	Air	Applied between 76-242 and 76-244
76-243	Containment Atmospheric Monitor	Air	Applied between 76-243 and 76-244
76-248	Containment Atmospheric Monitor	Air	Applied between 76-248 and 76-251
76-250	Containment Atmospheric Monitor	Air	Applied between 76-250 and 76-251
76-253	Containment Atmospheric Monitor	Air	Applied between 76-253 and 76-255
76-254	Containment Atmospheric Monitor	Air	Applied between 76-254 and 76-255
84-20	Main Exhaust to Standby Gas Treatment	Air(1)	Applied between 84-20, 64-141, 64-140, and 64-31
84-600	Main Exhaust to Standby Gas Treatment	Nitrogen(1)	Applied between 84-8A and 84-600
84-601	Main Exhaust to Standby Gas Treatment	Nitrogen	Applied between 84-8B and 84-601
84-602	Main Exhaust to Standby Gas Treatment	Nitrogen	Applied between 84-8C and 84-603
84-603	Main Exhaust to Standby Gas Treatment	Nitrogen	Applied between 84-8D and 84-602
64-141	Drywell Pressurization, Comp. Bypass	Air (1)	Applied between 64-141, 64-140, 64-30, and 84-20
64-140	Drywell Pressurization, Comp. Disc.	Air(1)	Applied between 64-141, 64-140, 64-31, and 84-20
64-139	Drywell Pressurization, Comp. Suction	Air(1)	Applied between 64-139, 64-141, and 64-34

(1) Air/nitrogen test to be displacement flow
(2) Water test to be injection loss or downstream collection.

CORRECTED PAGES TO

AMENDMENT NO. 27 TO DPR-33

AMENDMENT NO. 24 TO DPR-52

DATED AUGUST 20, 1976

Revise Appendix A as follows:

Remove the following pages:

36	252	357
44	267 thru 270	
54	286	
89 thru 95	295	
123	296	
124	322	
143	326	
144	332	
145	333	
146	337	
150	346	
151	349	
154	350	
185	354	
187	356	

and replace with identically numbered pages.

10. Not required to be operable when the reactor pressure vessel head is not bolted to the vessel.

11. The APRM downscale trip function is only active when the reactor mode switch is in run.

12. The APRM downscale trip is automatically bypassed when the IRM instrumentation is operable and not high.

13. Less than 14 operable LPRM's will cause a trip system trip.

14. Channel shared by Reactor Protection System and Primary Containment and Reactor Vessel Isolation Control System. A channel failure may be a channel failure in each system.

15. The APRM 15% scram is bypassed in the Run Mode.

16. Channel shared by Reactor Protection System and Reactor Manual Control System (Rod Block Portion). A channel failure may be a channel failure in each system.

17. Not required while performing low power physics tests at atmospheric pressure during or after refueling at power levels not to exceed 5 MW(t).

18. Operability is required when normal first-stage pressure is below 30% ($\leq$ 154 psig).

19. Action 1.A or 1.D shall be taken only if the permissive fails in such a manner to prevent the affected RPS logic from performing its intended function. Otherwise, no action is required.

20. An alarm setting of 1.5 times normal background at rated power shall be established to alert the operator to abnormal radiation levels in primary coolant.

modes. In the power range the APRM system provides required protection. Ref. Section 7.5.7 FSAR. Thus, the IRM System is not required in the Run mode. The APRM's and the IRM's provide adequate coverage in the startup and intermediate range.

The high reactor pressure, high drywell pressure, reactor low water level and scram discharge volume high level scrams are required for Startup and Run modes of plant operation. They are, therefore, required to be operational for these modes of reactor operation.

The requirement to have the scram functions as indicated in Table 3.1.1 operable in the Refuel mode is to assure that shifting to the Refuel mode during reactor power operation does not diminish the need for the reactor protection system.

The turbine condenser low vacuum scram is only required during power operation and must be bypassed to start up the unit. Below 154 psig turbine first stage pressure (30% of rated), the scram signal due to turbine stop valve closure, turbine control valve fast closure, and turbine control valve loss of control oil pressure, is bypassed because flux and pressure scram are adequate to protect the reactor.

Because of the APRM downscale limit of ≥ 3% when in the Run mode and high level limit of ≤ 15% when in the Startup Mode, the transition between the Startup and Run Modes must be made with the APRM instrumentation indicating between 3% and 15% of rated power or a control rod scram will occur. In addition, the IRM system must be indicating below the High Flux setting (120/125 of scale) or a scram will occur when in the Startup Mode. For normal operating conditions, these limits provide assurance of overlap between the IRM system and APRM system so that there are no "gaps" in the power level indications (i.e., the power level is continuously monitored from beginning of startup to full power and from full power to shutdown). When power is being reduced, if a transfer to the Startup mode is made and the IRM's have not been fully inserted (a maloperational but not impossible condition) a control rod block immediately occurs so that reactivity insertion by control rod withdrawal cannot occur.

3.2.J Seismic Monitoring Instrumentation

1. The seismic monitoring instruments listed in table 3.2.J shall be operable at all times.

2. With the number of seismic monitoring instruments less than the number listed in table 3.2.J, restore the inoperable instrument(s) to operable status within 30 days.

3. With one or more of the instruments listed in table 3.2.J inoperable for more than 30 days, submit a Special Report to the Commission pursuant to specification 6.7.3.C within the next 10 days describing the cause of the malfunction and plans for restoring the instruments to operable status.

4.2.J Seismic Monitoring Instrumentation

1. Each of the seismic monitoring instruments shall be demonstrated operable by performance of tests at the frequencies listed in table 4.2.J.

2. Data shall be retrieved from all seismic instruments actuated during a seismic event and analyzed to determine the magnitude of the vibratory ground motion. A Special Report shall be submitted to the Commission pursuant to specification 6.7.3.D within 10 days describing the magnitude, frequency spectrum, and resultant effect upon plant features important to safety.

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89 thru 95   Amendments Nos. 27 & 24

3.3.B Control Rods

b. During the shutdown procedure no rod movement is permitted between the testing performed above 20% power and the reinstatement of the RSCS restraints at or above 20% power. Alignment of rod groups shall be accomplished prior to performing the tests.

c. Whenever the reactor is in the startup or run modes below 20% rated power the Rod Worth Minimizer shall be operable or a second licensed operator shall verify that the operator at the reactor console is following the control rod program.

d. If Specifications 3.3.B.3.a through .c cannot be met the reactor shall not be started, or if the reactor is in the run or startup modes at less than 20% rated power, it shall be brought to a shutdown condition immediately.

4.3.B Control Rods

a. The capability of the RSCS to properly fulfill its function shall be verified by the following tests:

Sequence portion - Select a sequence and attempt to withdraw a rod in the remaining sequences. Move one rod in a sequence and select the remaining sequences and attempt to move a rod in each. Repeat for all sequences.

Group notch portion - For each of the six comparator circuits go through test initiate; comparator inhibit; verify; reset. On seventh attempt test is allowed to continue until completion is indicated by illumination of test complete light.

b. The capability of the Rod Worth Minimizer (RWM) shall be verified by the following checks:

1. The correctness of the control rod withdrawal sequence input to the RWM computer shall be verified before reactor startup or shutdown.

2. The RWM computer on line diagnostic test shall be successfully performed.

3. Prior to startup, proper annunciation of the selection error of at least one out-of-sequence control rod shall be verified.

4. Prior to startup, the rod block function of the RWM shall be verified by moving an out-of-sequence control rod.

5. Prior to obtaining 20% rated power during rod insertion at shutdown, verify the latching of the proper rod group and proper annunciation after insert errors.

L˜ ˜TING CONDITIONS FOR OPERATION

3.3.B Control Rods

4. Control rods shall not be withdrawn for startup or refueling unless at least two source range channels have an observed count rate equal to or greater than three counts per second.

5. During operation with limiting control rod patterns, as determined by the designated qualified personnel, either:

   a. Both RBM channels shall be operable:
   or

   b. Control rod withdrawal shall be blocked:

C. Scram Insertion Times

1. The average scram insertion time, based on the deenergization of the scram pilot valve solenoids as time zero, of all operable control rods in the reactor power operation condition shall be no greater than:

% Inserted From Fully Withdrawn	Avg. Scram Insertion Times (sec)
5	0.375
20	0.90
50	2.0
90	5.0

SURVEILLANCE REQUIREMENTS

4.3.B Control Rods

   c. When required, the presence of a second licensed operator to verify the following of the correct rod program shall be verified.

4. Prior to control rod withdrawal for startup or during refueling, verify that at least two source range channels have an observed count rate of at least three counts per second.

5. When a limiting control rod pattern exists, an instrument functional test of the RBM shall be performed prior to withdrawal of the designated rod(s) and at least once per 24 hours thereafter.

C. Scram Insertion Times

1. After each refueling outage all operable rods shall be scram time tested from the fully withdrawn position with the nuclear system pressure above 950 psig (with saturation temperature). This testing shall be completed prior to exceeding 40% power. Below 20% power, only rods in those sequences (A_{12} and A_{34} or B_{12} and B_{34}) which were fully withdrawn in the region from 100% rod density to 50% rod density shall be scram time tested. During all scram time testing below 20% power the RWM shall be operable.

3.5 CORE AND CONTAINMENT COOLING SYSTEMS

Applicability

Applies to the operational status of the core and containment cooling systems.

Objective

To assure the operability of the core and containment cooling systems under all conditions for which this cooling capability is an essential response to plant abnormalities.

Specification

A. Core Spray System (CSS)

1. The CSS shall be operable:

   (1) prior to reactor startup from a cold condition, or

   (2) when there is irradiated fuel in the vessel and when the reactor vessel pressure is greater than atmospheric pressure, except as specified in specifications 3.5.A.2, 3.5.B.2, or 3.9.B.3.

4.5 CORE AND CONTAINMENT COOLING SYSTEMS

Applicability

Applies to the surveillance requirements of the core and containment cooling systems when the corresponding limiting condition for operation is in effect.

Objective

To verify the operability of the core and containment cooling systems under all conditions for which this cooling capability is an essential response to plant abnormalities.

Specification

A. Core Spray System (CSS)

1. Core Spray System Testing.

	Item	Frequency
a.	Simulated Automatic Actuation test	Once/ Operating Cycle
b.	Pump Operability	Once/ month
c.	Motor Operated Valve Operability	Once/ month
d.	System flow rate: Each loop shall deliver at least 6250 gpm against a system head corresponding to a	Once/3 months

3.5.A Core Spray System (CSS)

2. If one CSS loop is inoperable, the reactor may remain in operation for a period not to exceed 7 days providing all active components in the other CSS loop and the RHR system (LPCI mode) and the diesel generators are operable.

3. If specification 3.5.A.1 or specification 3.5.A.2 cannot be met, the reactor shall be shutdown in the Cold Condition within 24 hours.

4. When the reactor vessel pressure is atmospheric and irradiated fuel is in the reactor vessel at least one core spray loop with one operable pump and associated diesel generator shall be operable, except with the reactor vessel head removed as specified in 3.5.A.5 or prior to reactor startup as specified in 3.5.A.1.

5. When irradiated fuel is in the reactor vessel and the reactor vessel head is removed, core spray is not required provided work is not in progress which has the potential to drain the vessel, provided the fuel pool gates are open and the fuel pool is maintained above the low level alarm point, and provided one RHRSW pump and associated valves supplying the standby coolant supply are operable.

4.5.A Core Spray System (CSS)

105 psi differential pressure between the reactor vessel and the primary containment.

e. Check Valve Once/Operating Cycle

2. When it is determined that one core spray loop is inoperable, at a time when operability is required, the other core spray loop, the RHRS (LPCI mode), and the diesel generators shall be demonstrated to be operable immediately. The operable core spray loop shall be demonstrated to be operable daily thereafter.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS

3.5.B <u>Residual Heat Removal System (RHRS)</u> (LPCI and Containment Cooling)

1. The RHRS shall be operable:

   (1) prior to a reactor startup from a Cold Condition; or

   (2) when there is irradiated fuel in the reactor vessel and when the reactor vessel pressure is greater than atmospheric, except as specified in specifications 3.5.B.2, through 3.5.B.7 and 3.9.B.3.

2. With the reactor vessel pressure less than 105 psig, the RHRS may be removed from service (except that two RHR pumps-containment cooling mode and associated heat exchangers must remain operable) for a period not to exceed 24 hours while being drained of suppression chamber quality water and filled with primary coolant quality water provided that during cooldown two loops with one pump per loop or one loop with two pumps, and associated diesel generators, in the core spray system are operable.

3. If one RHR pump (LPCI mode) is inoperable, the reactor may remain in operation for a period not to exceed 7 days provided the remaining RHR pumps (LPCI mode) and both access paths of the RHRS (LPCI mode) and the CSS and the diesel generators remain operable.

4.5.B <u>Residual Heat Removal System (RHRS)</u> (LPCI and Containment Cooling)

1.

a.	Simulated Automatic Actuation Test	Once/ Operating Cycle
b.	Pump Operability	Once/ month
c.	Motor Operated valve operability	Once/ month
d.	Pump Flow Rate	Once/3 months
e.	Test Check Valve	Once/ Operating Cycle

Each LPCI pump shall deliver 9,000 gpm against an indicated system pressure of 125 psig. Two LPCI pumps in the same loop shall deliver 15,000 gpm against an indicated system pressure of 200 psig.

2. An air test on the drywell and torus headers and nozzles shall be conducted once/5 years. A water test may be performed on the torus header in lieu of the air test.

3. When it is determined that one RHR pump (LPCI mode) is inoperable at a time when operability is required, the remaining RHR pumps (LPCI mode) and active components in both access paths of the RHRS (LPCI mode) and the CSS and the diesel generators shall be demonstrated to be operable immediately. The operable RHR pumps (LPCI mode) shall be demonstrated to be operable every 10 days thereafter until the inoperable pump is returned to normal service.

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LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
inoperability, pipe break, etc), the reactor may remain in operation for a period not to exceed 30 days provided the remaining RHR pump and associated diesel generator are operable.	a time when operability is required, the remaining RHR pump and associated heat exchanger on the unit cross-connection and the associated diesel generator shall be demonstrated to be operable immediately and every 15 days thereafter until the inoperable pump and associated heat exchanger are returned to normal service.
13. If RHR cross-connection flow or heat removal capability is lost, the unit may remain in operation for a period not to exceed 10 days unless such capability is restored.	12. All recirculation pump discharge valves shall be tested for operability during any period of reactor cold shutdown exceeding 48 hours, if operability tests have not been performed during the preceding 31 days.
14. All recirculation pump discharge valves shall be operable prior to reactor startup (or closed if permitted elsewhere in these specifications).	

3.5.C <u>RHR Service Water and Emergency Equipment Cooling Water Systems (EECWS)</u>

1. Prior to reactor startup from a cold condition, 9 RHRSW pumps must be operable, with 7 pumps (including pump D1 or D2 for unit 1 and one of pumps D1, D2, B1, or B2 for unit 2) assigned to RHRSW service and 2 automatically starting pumps assigned to EECW service.

4.5.C <u>RHR Service Water and Emergency Equipment Cooling Water Systems (EECWS)</u>

1. a. Each of the RHRSW pumps normally assigned to automatic service on the EECW headers will be tested automatically each time the diesel generators are tested. Each of the RHRSW pumps and all associated essential control valves for the EECW headers and RHR heat exchanger headers shall be demonstrated to be operable once every three months.

   b. Annually each RHRSW pump shall be flow-rate tested. To be considered operable, each pump shall pump at least 4500 gpm through its normally assigned flow path.

LIMITING CONDITIONS FOR OPERATION

3.5.D Equipment Area Coolers

1. The equipment area cooler associated with each RHR pump and the equipment area cooler associated with each set of core spray pumps (A and C or B and D) must be operable at all times when the pump or pumps served by that specific cooler is considered to be operable.

2. When an equipment area cooler is not operable, the pump(s) served by that cooler must be considered inoperable for Technical Specification purposes.

E. High Pressure Coolant Injection System (HPCIS)

1. The HPCI system shall be operable:

   (1) prior to startup from a Cold Condition; or

   (2) whenever there is irradiated fuel in the reactor vessel and the reactor vessel pressure is greater than 122 psig, except as specified in specification 3.5.E.2.

SURVEILLANCE REQUIREMENTS

4.5.D Equipment Area Coolers

1. Each equipment area cooler is operated in conjunction with the equipment served by that particular cooler; therefore, the equipment area coolers are tested at the same frequency as the pumps which they serve.

E. High Pressure Coolant Injection System (HPCIS)

1. HPCI Subsystem testing shall be performed as follows:

a.	Simulated Automatic Actuation Test	Once/ operating cycle
b.	Pump Operability	Once/ month
c.	Motor Operated Valve Operability	Once/ month
d.	Flow Rate at normal reactor vessel operating pressure	Once/3 months
e.	Flow Rate at 150 psig	Once/ operating cycle

The HPCI pump shall deliver at least 5000 gpm during each flow rate test.

3.6 PRIMARY SYSTEM BOUNDARY

H. Shock Suppressors (Snubbers)

1. During all modes of operation except Cold Shutdown and Refuel, all safety-related snubbers shall be operable except as noted in 3.6.H.2 through 3.6.H.5 below.

4.6 PRIMARY SYSTEM BOUNDARY

H. Shock Suppressors (Snubbers)

The following surveillance requirements apply to all hydraulic snubbers listed in 3.6.H.2.

1. All hydraulic snubbers whose seal material has been demonstrated by operating experience, lab testing or analysis to be compatible with the operating environment shall be visually inspected. This inspection shall include, but not necessarily be limited to, inspection of the hydraulic fluid reservoir, fluid connections, and linkage connections to the piping and anchor to verify their operability in accordance with the following schedule:

Number of Snubbers Found Inoperable During Inspection or During Inspection Interval	Next Required Inspection Interval
0	Operating Cycle ±25%
1	12 months ±25%
2	6 months ±25%
3,4	124 days ±25%
5,6,7	62 days ±25%
≥8	31 days ±25%

The required inspection interval shall not be lengthened more than one step at a time.

3.6 PRIMARY SYSTEM BOUNDARY

4. If the requirements of 3.6.H.1 and 3.6.H.3 cannot be met, an orderly shutdown shall be initiated and the reactor shall be in a cold shutdown condition within 36 hours.

5. If a snubber is determined to be inoperable while the reactor is in the shutdown or refuel mode, the snubber shall be made operable or replaced prior to reactor startup.

6. Snubbers may be added to safety-related systems without prior license amendment to Table 3.6.H provided that a revision to Table 3.6.H is included with a subsequent license amendment request.

4.6 PRIMARY SYSTEM BOUNDARY

4. Once each refueling cycle, a representative sample of 10 snubbers or approximately 10% of the snubbers, whichever is less, shall be functionally tested for operability including verification of proper piston movement, lock up and bleed. For each unit and subsequent unit found inoperable, an additional 10% or ten snubbers shall be so tested until no more failures are found or all units have been tested. Snubbers of rated capacity greater than 50,000 lb need not be functionally tested.

TABLE 3.7.A (Continued)

Group	Valve Identification	Number of Power Operated Valves Inboard	Number of Power Operated Valves Outboard	Maximum Operating Time (sec.)	Normal Position	Action on Initiating Signal
6	Suppression Chamber purge inlet (FCV-64-19)		1	100	C	SC
6	Drywell/Suppression Chamber nitrogen purge inlet (FCV-76-17)		1	10	C	SC
6	Drywell Exhaust Valve Bypass to Standby Gas Treatment System (FCV-64-31)		1	10	C	SC
6	Suppression Chamber Exhaust Valve Bypass to Standby Gas Treatment System (FCV-64-34)		1	10	C	SC
7	RCIC Steamline Drain (FCV-71-6A, 6B)		2	5	0	GC
7	RCIC Condensate Pump Drain (FCV-71-7A, 7B)		2	5	0	GC
7	HPCI Hotwell pump discharge isolation valves (FCV-73-17A, 17B)		2	5	C	SC
7	HPCI steamline drain (FCV-75-57, 58)		2	5	0	GC
8	TIP Guide Tubes (5)		1 per guide tube	NA	C	GC

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BASES

3.7.A & 4.7.A Primary Containment

The integrity of the primary containment and operation of the core standby cooling system in combination, limit the off-site doses to values less than those suggested in 10 CFR 100 in the event of a break in the primary system piping. Thus, containment integrity is specified whenever the potential for violation of the primary reactor system integrity exists. Concern about such a violation exists whenever the reactor is critical and above atmospheric pressure. An exception is made to this requirement during initial core loading and while the low power test program is being conducted and ready access to the reactor vessel is required. There will be no pressure on the system at this time, thus greatly reducing the chances of a pipe break. The reactor may be taken critical during this period; however, restrictive operating procedures will be in effect again to minimize the probability of an accident occurring. Procedures and the Rod Worth Minimizer would limit control worth such that a rod drop would not result in any fuel damage. In addition, in the unlikely event that an excursion did occur, the reactor building and standby gas treatment system, which shall be operational during this time, offer a sufficient barrier to keep offsite doses well below 10 CFR 100 limits.

The pressure suppression pool water provides the heat sink for the reactor primary system energy release following a postulated rupture of the system. The pressure suppression chamber water volume must absorb the associated decay and structural sensible heat released during primary system blowdown from 1,035 psig. Since all of the gases in the drywell are purged into the pressure suppression chamber air space during a loss of coolant accident, the pressure resulting from isothermal compression plus the vapor pressure of the liquid must not exceed 62 psig, the suppression chamber maximum pressure. The design volume of the suppression chamber (water and air) was obtained by considering that the total volume of reactor coolant to be condensed is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

Using the minimum or maximum water volumes given in the specification, containment pressure during the design basis accident is approximately 49 psig which is below the maximum of 62 psig. Maximum water volume of 135,000 ft^3 results in a downcomer submergence of 5'2-3/32" and the minimum volume of 123,000 ft^3 results in submergence approximately 12 inches less. The majority of the Bodega tests were run with a submerged length of 4 feet and with complete condensation. Thus, with respect to downcomer submergence, this specification is adequate. The maximum temperature at the end of blowdown tested during the Humbolt Bay and Bodega Bay tests was 170°F and this is conservatively taken to be the limit for complete condensation of the reactor coolant, although condensation would occur for temperatures above 170°F.

Should it be necessary to drain the suppression chamber, this should only be done when there is no requirement for core standby cooling systems operatibility. Under full power operation conditions, blowdown from an initial suppression chamber water temperature of 95°F results in a peak long term water temperature of 170°F which is sufficient for complete condensation. At this temperature and atmospheric pressure, the available NPSH exceeds that required by both the RHR and core spray pumps, thus there is not dependency on containment overpressure.

Experimental data indicate that excessive steam condensing loads can be avoided if the peak temperature of the suppression pool is maintained below 160°F during any period of relief valve operation with sonic conditions at the discharge exit. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressuirzed in a timely manner to avoid the regime of potentially high suppression chamber loadings.

Limiting suppression pool temperature to 105°F during RCIC, HPCI, or relief valve operation when decay heat and stored energy is removed from the primary system by discharging reactor steam directly to the suppression chamber assures adequate margin for controlled blowdown anytime during RCIC operation and assures margin for complete condensation of steam from the design basis loss-of-coolant accident.

In addition to the limits on temperature of the suppression chamber pool water, operating procedures define the action to be taken in the event a relief valve inadvertently opens or sticks open. This action would include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling heat exchangers (3) initiate reactor shutdown, and (4) if other relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open relief valve to assure mixing and uniformity of energy insertion to the pool.

If a loss-of-coolant accident were to occur when the reactor water temperature is below approximately 330°F, the containment pressure will not exceed the 62 psig code permissible pressures even if no condensation were to occur. The maximum allowable pool temperature, whenever the reactor is above 212°F, shall be governed by this specification. Thus, specifying water volume-temperature requirements applicable for reactor-water temperature above 212°F provides additional margin above that available at 330°F.

Inerting

The relatively small containment volume inherent in the GE-BWR pressure suppression containment and the large amount of zirconium in the core are such that the occurrence of a very limited (a percent or so) reaction of the zirconium and steam during a loss-of-coolant accident could lead to the liberation of hydrogen combined with an air atmosphere to result in a flammable concentration in the containment. If a sufficient amount of hydrogen is generated and oxygen is available in stoichiometric quantities the subsequent ignition of the hydrogen in rapid recombination rate could lead to failure of the containment to maintain a low leakage integrity. The 4% oxygen concentration minimizes the possiblity of hydrogen combustion following a loss-of-coolant accident.

BASES

The occurrence of primary system leakage following a major refueling outage or other scheduled shutdown is much more probable than the occurrence of the loss-of-coolant accident upon which the specified oxygen concentration limit is based. Permitting access to the drywell for leak inspections during a startup is judged prudent in terms of the added plant safety offered without significantly reducing the margin of safety. Thus, to preclude the possibility of starting the reactor and operating for extended periods of time with significant leaks in the primary system, leak inspections are scheduled during startup periods, when the primary system is at or near rated operating temperature and pressure. The 24-hour period to provide inerting is judged to be sufficient to perform the leak inspection and establish the required oxygen concentration.

To ensure that the oxygen concentration does not exceed 4% following an accident, liquid nitrogen is maintained on-site for containment atmosphere dilution. About 2260 gallons would be sufficient as a 7-day supply, and replenishment facilities can deliver liquid nitrogen to the site within one day; therefore, a requirement of 2500 gallons is conservative. Following a loss of coolant accident the Containment Air Monitoring (CAM) System continuously monitors the oxygen and hydrogen concentration of the containment volume. Two independent systems (a system consists of one oxygen and one hydrogen sensing circuit) are installed in the drywell and one system is installed in the torus. Each sensor and associated circuit is periodically checked by a calibration gas to verify operation.

Failure of a drywell system does not reduce the ability to monitor system atmosphere as a second independent and redundant system will still be operable. Failure of the torus system would require a reactor shutdown as no means would be available under accident conditions to monitor torus atmosphere. Until a redundant system becomes available in the torus, the monitoring requirements of either a hydrogen or oxygen sensing circuit will be utilized. While this reduces the offered protection slightly, one sensor can be used to prevent a combustible atmosphere. In additition the torus atmosphere will be mixed with the drywell atmosphere through the drywell to torus check valves and any increase in the torus hydrogen or oxygen concentration would proportionally change the drywell atmosphere.

C. Mechanical Vacuum Pump

1. The mechanical vacuum pump shall be capable of being automatically isolated and secured on a signal of high radioactivity in the steam lines whenever the main steam isolation valves are open.

2. If the limits of 3.8.C.1 are not met, the vacuum pump shall be isolated.

D. Miscellaneous Radioactive Materials Sources

1. Source Leakage Test

Each sealed source containing radioactive material in excess of those quantities of byproduct material listed in 10 CFR 30.71 Schedule B and all other sources, including alpha emitters, in excess of 0.1 microcurie, shall be free of $\geq$ 0.005 microcurie of removable contamination. Each sealed source with removable contamination in excess of the above limit shall be immediately withdrawn from use and (a) either decontaminated and repaired, or (b) disposed of in accordance with Commission regulations.

C. Mechanical Vacuum Pump

At least once during each operating cycle verify automatic securing and isolation of the mechanical vacuum pump.

D. Miscellaneous Radioactive Materials Sources

1. Surveillance Requirement
Tests for leakage and/or contamination shall be performed by the licensee or by other persons specifically authorized by the Commission or an agreement State, as follows:

a. Each sealed source, except startup sources subject to core flux, containing radioactive material, other than Hydrogen 3, with a half-life greater than thirty days and in any form other than gas shall be tested for leakage and/or contamination at intervals not to exceed six months. The leakage test shall be capable of detecting the presence of 0.005 microcurie of radioactive material on the test sample.

b. The periodic leak test required does not apply to sealed sources that are stored and not being used. The sources excepted from this test shall be tested for leakage prior to any use or transfer to another user unless they have been leak tested within six months prior to the date or use or transfer. In the absence of a certification from a transferor indicating that a test has been made within six months prior to the transfer, sealed sources shall not be put into use until tested.

c. Startup sources shall be leak tested prior to and following any repair or maintenance and before being subjected to core flux.

LIMITING CONDITIONS FOR OPERATION

3.9.B Operation with Inoperable Equipment

Whenever a reactor is in Startup mode or Run mode and not in a cold condition, the availability of electric power shall be as specified in 3.9.A, except as specified herein.

1. From and after the date that one 161-kV line or one common station transformer and its parallel cooling tower transformer or one start bus becomes inoperable, reactor operation is permissible under this condition for seven days.
2. When one of the units 1 and 2 diesel generator is inoperable, continued reactor operation is permissible during the succeeding 7 days, provided that both off-site 161-kV transmission lines and both common station transformers or one common transformer and one cooling tower transformer (not parallel with the energized common transformer) are available, and all of the CS, RHR (LPCI and Containment Cooling) Systems, and the remaining three units 1 and 2 diesel generators are operable. If this requirement cannot be met, an orderly shutdown shall be initiated and both reactors shall be shutdown and in the cold condition within 24 hours.

SURVEILLANCE REQUIREMENTS

4.9.B Operation with Inoperable Equipment

1. When one 161-kV line or one common station transformer and its parallel cooling tower transformer or one start bus is found to be inoperable, all units 1 and 2 diesel generators and associated boards must be demonstrated to be operable immediately and daily there after.
2. When one of the units 1 and 2 diesel generator is found to be inoperable, all of the CS, RHR (LPCI and Containment Cooling) Systems and the remaining diesel generators and associated boards shall be demonstrated to be operable immediately and daily thereafter.

LIMITING CONDITIONS FOR OPERATION | SURVEILLANCE REQUIREMENTS

3.9.B Operation with Inoperable Equipment

3. When one units 1 and 2 4-kV shutdown board is inoperable, continued reactor operation is permissible for a period not to exceed 5 days, provided that both off-site 161-kV transmission lines and both common station transformers or one common transformer and one cooling tower transformer (not parallel with the energized common transformer) are available and the remaining 4-kV shutdown boards and associated diesel generators, CS, RHR (LPCI and Containment Cooling) Systems, and all 480 V emergency power boards are operable. If this requirement cannot be met, an orderly shutdown shall be initiated and both reactors shall be shutdown and in the cold condition within 24 hours.

4. From and after the date that one of the three 250-Volt unit batteries and/or its associated battery board is found to be inoperable for any reason, continued reactor operation is permissible during the succeeding seven days. Except for routine surveillance testing the NRC shall be notified within 24 hours of the situation, the precautions to be taken during this period and the plans to return the failed component to an operable state.

5. From and after the date that one of the four 250-volt shutdown

4.9.B Operation with Inoperable Equipment

3. When one 4-kV shutdown board is found to be inoperable, all remaining 4-kV shutdown boards and associated diesel generators, CS and RHR (LPCI and Containment Cooling) Systems supplies by the remaining 4-kV shutdown boards shall be demonstrated to be operable, immediately and daily thereafter.

3.11 FIRE PROTECTION SYSTEMS

E. Fire Protection System Inspection

1. An independent fire protection and loss prevention inspection and audit shall be performed annually utilizing either qualified TVA personnel or an outside fire protection firm.

2. An inspection and audit by an outside qualified fire consultant will be performed at intervals no greater than 3 years. (The first inspection and audit will be during the period of June - September 1977.)

F. If it becomes necessary to breach a fire stop, an attendant shall be posted on each aide of the open penetration until work is completed and the penetration is resealed.

G. The minimum in-plant fire protection organization and duties shall be as depicted in Figure 6.3-1.

4.11 FIRE PROTECTION SYSTEMS

E. Fire Protection Systems Inspection

Any inspection or audit will review and evaluate the effectiveness of fire prevention and protection by physical inspection of plant facilities, systems, and equipment as related to fire safety. Evaluations will be made of, but not necessarily limited to, the following:

Administrative control documentation, maintenance of fire related records, physical plant inspection, related historical research and application, and management interviews.

3.11 BASES

The High Pressure Fire and CO_2 Fire Protection specifications are provided in order to meet the preestablished levels of operability during a fire in either or all of the three units. Requiring a patrolling fire watch with portable fire equipment if the automatic initiation is lost will provide (as does the automatic system) for early reporting and immediate fire fighting capability in the event of a fire occurrence.

The High pressure Fire Protection System is supplied by three pumps aligned to the high pressure fire header. The reactors may remain in operation for a period not to exceed 7 days if two pumps are out of service. If at least two pumps are not made operable in seven days or if all pumps are lost during this seven day period, the reactors will be placed in the cold shutdown condition within 24 hours.

For the areas of applicability, the fire protection water distribution system minimum capacity of 2664 gpm at 250' head at the fire pump discharge consists of the following design loads:

1.	Sprinkler System (0.30 gpm/ft²/4440 ft² area)	1332 gpm
2.	1 1/2" Hand Hose Lines	200 gpm
3.	Raw Service Water Load	1132 gpm
	TOTAL	2664 gpm

The CO_2 Fire Protection System is considered operable with a minimum of 8 1/2 tons (0.5 tank) CO_2 in storage for units 1 and 2; and a minimum of 3 tons (0.5 tank) CO_2 in storage for unit 3. An immediate and continuous fire watch in the cable spreading room or any diesel generator building area will be established if CO_2 fire protection is lost in this room and will continue until CO_2 fire protection is restored.

To assure close supervision of fire protection system activities, the removal from service of any component in either the High Pressure Fire System or the CO_2 Fire Protection System for any reason other than testing or emergency operations will require Plant Superintendent approval.

Early reporting and immediate fire fighting capability in the event of a fire occurrence will be provided (as with the automatic system) by requiring a patrolling fire watch if more than one detector for a given protected zone is inoperable.

A roving fire watch for areas in which automatic fire suppression systems are to be installed will provide additional interim fire protection for areas that have been determined to need additional protection.

6.0 ADMINISTRATIVE CONTROLS

6.1 Organization

A. The plant superintendent has on-site responsibility for the safe operation of the facility and shall report to the Chief, Nuclear Generation Branch. In the absence of the plant superintendent, the assistant superintendnet will assume his responsibilities.

B. The portion of TVA management which relates to the operation of the plant is shown in Figure 6.1-1.

C. The functional organization for the operation of the station shall be as shown in Figure 6.1-2.

D. Shift manning requirements shall, as a minimum, be as described in section 6.8.

E. Qualifications of the Browns Ferry Nuclear Plant management and operating staff shall meet the minimum acceptable levels as described in ANSI - N18.1, Selection and Training of Nuclear Power Plant Personnel, dated March 8, 1971.

F. Retraining and replacement training of station personnel shall be in accordance with ANSI - N18.1, Selection and Training of Nuclear Power Plant Personnel, dated March 8, 1971. The minimum frequency of the retraining program shall be every two years.

G. An Industrial Security Program shall be maintained for the life of the plant.

H. Responsibilities of a post-fire overall restoration coordinator will consist of duties as described in section 6.9.

I. The Safety Engineer shall have the following qualifications:

a. Must have a sound understanding and thorough technical knowledge of safety and fire protection practices, procedures, standards, and other codes relating to electrical utility operations. Must be able to read and understand engineering drawings. Must possess an analytical ability for problem solving and data analysis. Must be able to communicate well both orally and in writing and must be able to write investigative reports and prepare written procedures. Must have the ability to secure the cooperation of management, employees and groups in the implementation of safety programs. Must be able to conduct safety presentations for supervisors and employees.

b. Should have experience in safety engineering work at this level or have 3 years experience in safety and/or fire protection engineering. It is desirable that the incumbent be a graduate of an accredited college or university with a degree in inductrial, mechanical, electrical, or safety engineering or fire protection engineering.

6.0 ADMINISTRATIVE CONTROLS

6.2 Review and Audit

The Manager of Power is responsible for the safe operation of all TVA power plants,-including the Browns Ferry Nuclear Plant. The functional organization for Review and Audit is shown in Figure 6.2-1.

Organizational units for the review of facility operation shall be constituted and have the responsibilities and authorities listed below.

A. Nuclear Safety Review Board (NSRB)

1. Membership

The NSRB shall consist of a chairman and at least five other members appointed or approved by the Manager of Power. A majority of the members shall be independent of the Division of Power Production. The qualifications of members shall meet the requirements of ANSI Standard N18.7-1972. Membership shall include at least one outside consultant and representatives of the following TVA organizations: Office of Engineering Design and Construction; Division of Environmental Planning; Division of Power Production; Division of Power Resource Planning. An alternate chairman may be designated by the chairman or, in his absence or incapacity, may be selected by the NSRB. The NSRB chairman shall appoint a secretary.

2. Minimum Meeting Frequency

The NSRB shall meet at least quarterly and at more frequent intervals at the call of the chairman, as required.

3. Quorum

A quorum shall consist of four members, a minority of which shall be from the Division of Power Production.

4. Responsibilities

a. Review proposed tests and experiments, and their results, when such tests or experiments may constitute an unreviewed safety question as defined in Section 50.59, Part 50, Title 10, Code of Federal Regulations.

b. Review proposed changes to equipment, systems or procedures, which are described in the Final Safety Analysis Report or which may involve an unreviewed safety question, as defined in Section 50.59, Part 50, Title 10, Code of Federal Regulations, or which are referred by the operating organization.

c. Review proposed changes to Technical Specifications or licenses.

j. Review adequacy of employee training programs and recommend change.

5. Authority

The PORC shall be advisory to the plant superintendent.

6. Records

Minutes shall be kept for all PORC meetings with copies sent to Director, Power Production; Chief, Nuclear Generation Branch; Chairman, NSRB.

7. Procedures

Written administrative procedures for committee operation shall be prepared and maintained describing the method for submission and content of presentations to the committee, review and approval by members of committee actions, dissemination of minutes, agenda and scheduling of meetings.

C. Quality Assurance and Audit Staff

The Office of Power Quality Assurance and Audit Staff (QA&AS) shall formally audit operation of the nuclear plant. Audits of selected aspects of plant operations shall be conducted on a frequency commensurate with their safety significance and in such a manner as to assure that an audit of safety-related activities is completed within a period of two years.

The audits shall be performed in accordance with appropriate written instructions or procedures and should include verification of compliance with internal rules, procedures (for example, normal off/normal, emergency, operating, maintenance, surveillance, test, security, and radiation control procedures and the emergency plan), regulations, and license provisions; training, qualification, and performance of operating staff; and corrective actions following reportable occurrences.

6.0 ADMINISTRATIVE CONTROLS

6.4 Actions to be Taken in the Event of a Reportable Occurrence in Plant Operation (Ref. Section 6.7)

A. Any reportable occurrence shall be promptly reported to the Chief, Nuclear Generation Branch and shall be promptly reviewed by PORC. This committee shall prepare a separate report for each reportable occurrence. This report shall include an evaluation of the cause of the occurrence and recommendations for appropriate action to prevent or reduce the probability of a repetition of the occurrence.

B. Copies of all such reports shall be submitted to the Chief, Nuclear Generation Branch, the Manager of Power, the Division of Power Resource Planning, and the Chairman of the NSRB for their review.

C. The plant superintendent shall notify the NRC as specified in Specification 6.7 of the circumstances of any reportable occurrence.

6.5 Action to be Taken in the Event a Safety Limit is Exceeded

If a safety limit is exceeded, the reactor shall be shut down and reactor operation shall not be resumed until authorized by the NRC. A prompt report shall be made to the Chief, Nuclear Generation Branch and the Chairman of the NSRB. A complete analysis of the circumstances leading up to and resulting from the situation, together with recommendations to prevent a recurrence, shall be prepared by the PORC. This report shall be submitted to the Chief, Nuclear Generation Branch, the Manager of Power, the Division of Power Resource Planning, and the NSRB. Notification of such occurrences will be made to the NRC by the plant superintendent within 24 hours.

6.6 Station Operating Records

A. Records and/or logs shall be kept in a manner convenient for review as indicated below:

1. All normal plant operation including such items as power level, fuel exposure, and shutdowns

2. Principal maintenance activities

3. Reportable occurrences

6.7 Reporting Requirements

In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following identified reports shall be submitted to the Director of the appropriate Regional Office of Inspection and Enforcement unless otherwise noted.

1. Routine Reports

   a. Startup Report. A summary report of plant startup and power escalation testing shall be submitted following (1) receipt of an operating license, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the plant. The report shall address each of the tests identified in the FSAR and shall in general include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

      Startup reports shall be submitted within (1) 90 days following completion of the startup test program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, completion of startup test program, and resumption or commencement of commerical power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.

   b. Annual Operating Report.[1] Routine operating reports covering the operation of the unit during the previous calendar year shall be submitted prior to March 1 of each year. The initial report shall be submitted prior to March 1 of the year following intial criticality.

6.0 ADMINISTRATIVE CONTROLS

The annual operating reports made by licensees shall provide a comprehensive summary of the operating experience gained during the year, even though some repetition of previously reported information may be involved. References in the annual operating report to previously submitted reports shall be clear.

Each annual operating report shall include:

(1) A narrative summary of operating experience during the report period relating to safe operation of the facility, including safety-related maintanance not covered in item 1.b.(2)(e) below.

(2) For each outage or forced reduction in power[2] of over twenty percent of design power level where the reduction extends for greater than four hours:

(a) the proximate cause and the system and major component involved (if the outage or forced reduction in power involved equipment malfunction);

(b) A brief discussion of (or reference to reports of) any reportable occurrences pertaining to the outage of power reduction;

(c) corrective action taken to reduce the probability of recurrence, if appropriate;

(d) operating time lost as a result of the outage or power reduction (for scheduled or forced outages,[3] use the generator off-line hours; for forced reductions in power, use the approximate duration of operation at reduced power);

(e) a description of major safety-related corrective maintenance performed during the outage or power reduction, including the system and component involved and identification of the critical path activity dictating the length of the outage or power reduction; and

(9) Performance of structures, systems, or components that requires remedial action or corrective measures to prevent operation in a manner less conservative than assumed in the accident analyses in the safety analysis report or technical specifications bases; or discovery during plant life of conditions not specifically considered in the safety analysis report or technical specifications that require remedial action or corrective measures to prevent the existence or development of an unsafe condition.

Note: This item is intended to provide for reporting of potentially generic problems.

b. Thirty-Day Written Reports. The reportable occurrences discussed below shall be the subject of written reports to the Director of the appropriate Regional Office within thirty days of occurrence of the event. The written report shall include, as a minimum, a completed copy of a licensee event report form. Information provided on the licensee event report form shall be supplemented, as needed, by additional narrative material to provide complete explanation of the circumstances surrounding the event.

(1) Reactor protection system or engineered safety feature instrument settings which are found to be less conservative than those established by the technical specifications but which do not prevent the fulfillment of the functional requirements of affected systems.

(2) Conditions leading to operation in a degraded mode permitted by a limiting condition for operation or plant shutdown required by a limiting condition for operation.

Note: Routine surveillance testing, instrument calibration, or preventative maintenance which require system configurations as described in items 2.b.(1) and 2.b.(2) need not be reported except where test results themselves reveal a degraded mode as described above.

(3) Observed inadequacies in the implementation of administrative or procedural controls which

6.0 ADMINISTRATIVE CONTROLS

B. Source Tests

Results of required leak tests performed on sources if the tests reveal the presence of 0.005 microcurie or more of removable contamination.

C. Special Reports (in writing to the Director of Regional Office of Inspection and Enforcement).

1. Reports on the following areas shall be submitted as noted:

a.	Secondary Containment Leak Rate Testing (5)	4.7.C	Within 90 days of completion of each test.
b.	Fatigue Usage Evaluation	6.6	Annual Operating Report
c.	Seismic Instrumentation Inoperability	3.2.J.3	Within 10 days after 30 days of inoperability

FOOTNOTES

1. A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station.

2. The term "forced reduction in power" is normally defined in the electric power industry as the occurrence of a component failure or other condition which requires that the load on the unit be reduced for corrective action immediately or up to and including the very next weekend. Note that routine preventive maintenance, surveillance, and calibration activities requiring power reductions are not covered by this section.

3. The term "forced outage" is normally defined in the electric power industry as the occurrence of a component failure or other condition which requires that the unit be removed from service for corrective action immediately or up to and including the very next weekend.

4. This tabulation supplements the requirements of §20.407 of 10 CFR Part 20.

5. Each integrated leak rate test of the secondary containment shall be the subject of a summary technical report. This report should include data on the wind speed, wind direction, outside and inside temperatures during the test, concurrent reactor building pressure, and emergency ventilation flow rate. The report shall also include analyses and interpretations of those data which demonstrate compliance with the specified leak rate limits.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

TENNESSEE VALLEY AUTHORITY

DOCKET NO. 50-259

BROWNS FERRY NUCLEAR PLANT, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 25
License No. DPR-52

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The applications for amendment by Tennessee Valley Authority (the licensee) dated September 1, October 1 and October 12, 1976, comply with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C(2) of Facility License No. DPR-52 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 25 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

A. Schwencer

A. Schwencer, Chief
Operating Reactors Branch #1
Division of Operating Reactors

Attachment:
Changes to the Technical
Specifications

Date of Issuance: February 15, 1977

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

SUPPORTING AMENDMENT NO. 28 TO FACILITY LICENSE NO. DPR-33

AND AMENDMENT NO. 25 TO FACILITY LICENSE NO. DPR-52

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT UNITS NOS. 1 AND 2

DOCKETS NOS. 50-259 AND 50-260

Introduction

By application dated September 1, 1976, the Tennessee Valley Authority (TVA) requested amendments to the operating licenses for Browns Ferry Nuclear Plant, Unit No. 1 (DPR-33) and Unit No. 2 (DPR-52) to change the Technical Specifications by adding the isolation valves for a new, drywell-torus differential pressure control system to the containment isolation valves listed in the Technical Specifications for containment. By application dated October 1, 1976, TVA requested amendments to DPR-33 and DPR-52 to delete from the Technical Specifications the logging requirement for torus temperature when heat is being added to the torus. By application dated October 12, 1976, TVA requested amendments to DPR-33 and DPR-52 to correct the basis in the Technical Specifications for the number of Automatic Depressurization System (ADS) valves required to be operable and to reduce the allowable time for reactor operation with two ADS valves inoperable from 30 days to 7 days.

Isolation Valves for Differential Pressure Control System

Discussion

As a result of recent structural analyses performed in conjunction with a generic review of pool dynamic loads for Mark I pressure - suppression containments, it was determined that the margin of safety in the containment design for the Browns Ferry Nuclear Plant as related to pool dynamic loads resulting from a postulated loss-of-coolant accident was less than originally thought to exist. Consequently, TVA agreed to institute a "differential pressure control system" to mitigate the pool dynamic loads and thereby restore the original margin of safety in the containment design. The differential pressure control system establishes a positive pressure between the drywell and torus regions of the containment which reduces the height of the water leg in the downcomers and consequently reduces the hydrodynamic loads.

The differential pressure control system consists of a bypass installed in the containment purge line between the drywell and the torus. A compressor is installed in the bypass line which takes suction from the torus and pressurizes the drywell until the appropriate differential pressure is established. In conjunction with the piping modifications, three valves have been installed in the containment purge and bypass lines to serve as outboard containment isolation barriers and to provide proper system flow routing.

Evaluation

The piping modifications associated with the inclusion of the differential pressure control system result in the addition of three containment isolation valves. These valves serve as the redundant containment isolation valves and as such are designed to seismic Category I and Safety Class 2 criteria. Automatic isolation occurs upon the receipt of a reactor vessel low water level, high drywell pressure, or high reactor building exhaust radiation signal. These valves, their controls, actuation logic and installation meet all the requirements of the previously accepted criteria for Browns Ferry containment isolation valves. Provisions have been made in the piping modifications to permit local leak testing of the isolation valves in accordance with Appendix J to CFR 50.

The differential pressure control system is designed such that its inclusion will not interfere with the safety related features incorporated in the existing plant design. In addition, the system design is in conformance with the applicable regulations, regulatory guides, and staff positions. Therefore, we find the proposed modifications together with the addition of Technical Specifications requirements for these valves to be acceptable.

Torus Temperature Logging

The Technical Specifications include a requirement to log the torus water temperature every 5 minutes when heat is being added to the torus by the operation of relief valves. TVA's application of October 1, 1976 requested deletion of this requirement since the torus water (suppression pool) temperature is continuously recorded on a strip chart recorder and the operator will receive an alarm if the suppression pool temperature exceeds 95°F. TVA was concerned that the specification, as written, would require an operator to be logging temperatures during a period when abnormal conditions exist and safety priorities would require him to be doing other things in response to the abnormal conditions. It was not our intent to require such logging during transient or accident conditions. The limiting conditions for operation on suppression pool temperature include an allowance to exceed the normal 95°F limit up to 105°F during testing of ECCS and relief valves. Therefore, during such testing the temperature alarm could annunciate at 95°F (its alarm point) but there would be no further alarm annunciation to attract the attention of the operator should the water temperature exceed 105^{o}F. Consequently, the requirement to log the temperature at 5 minute intervals was specified. We have, with this change, clarified the wording of the specification to more clearly indicate its intent.

Automatic Depressurization System (ADS)

The basis for the limiting condition for operation for the ADS has stated that only four of the six valves are assumed operable for the small break analysis of the ECCS evaluation. On this basis operation with two inoperable valves was allowed for 30 days and operation with more than two inoperable valves was limited to seven days provided that the high pressure coolant injection system, which is a redundant alternate to ADS and low pressure coolant injection, is operable during that 7 days. TVA's October 12, 1976 application for amendment indicates that the ECCS Appendix K analysis was performed with five of the six valves assumed to be operable. Therefore, the time limit for continued operation must be reduced to seven days whenever more than one valve is inoperable provided that the high pressure coolant injection system is demonstrated to be operable daily. This change will maintain the reliability of the ECCS at a level commensurate with that previously evaluated and accepted and will maintain the margin of safety used as the basis for the Technical Specifications.

Environmental Considerations

We have determined that the amendments do not authorize a change in effluent types or total amounts nor an increase in power level and will not result in any significant environmental impact. Having made this determination, we have further concluded that the amendments involve an action which is insignificant from the standpoint of environmental impact and pursuant to 10 CFR §51.5(d)(4) that an environmental impact statement or negative declaration and environmental impact appraisal need not be prepared in connection with the issuance of the amendments.

Conclusion

We have concluded, based on the considerations discussed above, that: (1) because the amendments do not involve a significant increase in the probability or consequences of accidents previously considered and do not involve a significant decrease in a safety margin, the amendments do not involve a significant hazards consideration, (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (3) such activities will be conducted in compliance with the Commission's regulations and the issuance of these amendments will not be inimical to the common defense and security or to the health and safety of the public.

Date: February 15, 1977

UNITED STATES NUCLEAR REGULATORY COMMISSION

DOCKETS NOS. 50-259 AND 50-260

TENNESSEE VALLEY AUTHORITY

NOTICE OF ISSUANCE OF AMENDMENTS TO FACILITY OPERATING LICENSES

The U. S. Nuclear Regulatory Commission (the Commission) has issued Amendment No. 28 to Facility Operating License No. DPR-33 and Amendment No. 25 to Facility Operating License No. DPR-52 issued to Tennessee Valley Authority (the licensee), which revised Technical Specifications for operation of the Browns Ferry Nuclear Plant, Units Nos. 1 and 2, (the facility) located in Limestone County, Alabama. The amendments are effective as of the date of issuance.

The amendments change the Technical Specifications to add containment isolation valves associated with the drywell to torus differential pressure control system to the valve listing (Table 3.7.D) for the limiting condition for operation and surveillance requirements of primary containment. A clarification in the wording of the temperature surveillance requirement for the torus water has also been made. In addition, the allowable operating time with two inoperable Automatic Depressurization System (ADS) valves has been reduced from thirty days to seven days to reflect the fact that the ECCS Appendix K analysis was performed with five of the six ADS valves operable rather than four as stated previously.

The applications for the amendments comply with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations. The Commission has made appropriate findings as required by the Act and the Commission's rules and regulations in 10 CFR Chapter I, which are set forth in the license amendments. Prior public notice of these amendments was not required since the amendments do not involve a significant hazards consideration.

The Commission has determined that the issuance of these amendments will not result in any significant environmental impact and that pursuant to 10 CFR § 51.5(d)(4) an environmental impact statement or negative declaration and environmental impact appraisal need not be prepared in connection with issuance of these amendments.

For further details with respect to this action, see (1) the applications for amendments dated September 1, October 1 and October 12, 1976, (2) Amendment No. 28 to License No. DPR-33 and Amendment No. 25 to License No. DPR-52, and (3) the Commission's related Safety Evaluation. All of these items are available for public inspection at the Commission's Public Document Room, 1717 H Street, N. W., Washington, D. C. and at the Athens Public Library, South and Forrest, Athens, Alabama 35611. A copy of items (2) and (3) may be obtained upon request addressed to the U. S. Nuclear Regulatory Commission, Washington, D. C. 20555, Attention: Director, Division of Operating Reactors.

Dated at Bethesda, Maryland, this 15th day of February 1977.

FOR THE NUCLEAR REGULATORY COMMISSION

A. Schwencer

A. Schwencer, Chief
Operating Reactors Branch #1
Division of Operating Reactors