ATTACHMENT C

REVISED TECHNICAL SPECIFICATIONS AND TECHNICAL SPECIFICATION BASES PAGES

Page Number

3/4.7-16
3/4.7-17
3/4.8-5
B 3/4.7-5
B 3/4.7-6

3.7 - LIMITING CONDITIONS FOR OPERATION

K. Suppression Chamber

The suppression chamber shall be OPERABLE with:

1. The suppression pool water level between 14' 6.5" and 14' 10.5",
2. A suppression pool maximum average water temperature of ≤~~75~~ (95)°F during OPERATIONAL MODE(s) 1 or 2, except that the maximum average temperature may be permitted to increase to:
   a. ≤~~85~~ (105)°F during testing which adds heat to the suppression pool.
   b. ≤~~100~~ (110)°F with THERMAL POWER ≤1% of RATED THERMAL POWER.
   c. ≤~~110~~ (120)°F with the main steam line isolation valves closed following a scram.
3. A total leakage between the suppression chamber and drywell of less than the equivalent leakage through a 1 inch diameter orifice at a differential pressure of 1.0 psid.

APPLICABILITY:

OPERATIONAL MODE(s) 1, 2 and 3.

ACTION:

1. With the suppression pool water level outside the above limits, restore the water level to within the limits

4.7 - SURVEILLANCE REQUIREMENTS

K. Suppression Chamber

The suppression chamber shall be demonstrated OPERABLE:

1. By verifying the suppression pool water level to be within the limits at least once per 24 hours.
2. At least once per 24 hours by verifying the suppression pool average water temperature to be ≤~~75~~ (95)°F, except:
   a. At least once per 5 minutes during testing which adds heat to the suppression pool, by verifying the suppression pool average water temperature to be ≤~~85~~ (105)°F.
   b. At least once per hour when suppression pool average water temperature is ≥ ~~75~~ (95)°F, by verifying:
      1) Suppression pool average water temperature to be ≤ ~~100~~ (110)°F, and
      2) THERMAL POWER to be ≤ 1% of RATED THERMAL POWER after suppression pool average water temperature has exceeded ~~75~~ (95)°F for more than 24 hours.
   c. At least once per 30 minutes with the main steam isolation valves closed following a scram and suppression pool average water temperature >~~75~~ (95)°F, by verifying suppression pool average water temperature to be ≤~~110~~ (120)°F.

3.7 - LIMITING CONDITIONS FOR OPERATION

within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. In OPERATIONAL MODE(s) 1 or 2 with the suppression pool average water temperature >75°F, except as permitted above, restore the average temperature to ≤75°F within 24 hours or reduce THERMAL POWER to ≤1% RATED THERMAL POWER within the next 12 hours.

3. With the suppression pool average water temperature >85°F during testing which adds heat to the suppression pool, except as permitted above, stop all testing which adds heat to the suppression pool and restore the average temperature to ≤75°F within 24 hours or reduce THERMAL POWER to ≤1% RATED THERMAL POWER within the next 12 hours.

4. With the suppression pool average water temperature >100°F, immediately place the reactor mode switch in the Shutdown position and operate at least one low pressure coolant injection loop in the suppression pool cooling mode.

5. With the suppression pool average water temperature >110°F, depressurize the reactor pressure vessel to <150 psig (reactor steam dome pressure) within 12 hours.

4.7 - SURVEILLANCE REQUIREMENTS

3. Deleted.

4. Deleted.

5. At least once per 18 months by conducting a drywell to suppression chamber bypass leak test at an initial differential pressure of 1.0 psid and verifying that the measured leakage is within the specified limit. If any drywell to suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 9 months until two consecutive tests meet the specified limit, at which time the 18 month test schedule may be resumed.

BASES

and de-inerted as soon as possible in the plant shutdown. As long as reactor power is below 15% of RATED THERMAL POWER, the potential for an event that generates significant hydrogen is low and the primary containment does not need to be inert. Furthermore, the probability of an event that generates hydrogen occurring within the first 24 hours of a reactor startup or within the last 24 hours before a shutdown is low enough that these windows, when the primary containment is not inerted, are also justified. The 24 hour time frame is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

3/4.7.K Suppression Chamber

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure during primary system blowdown from full operating pressure.

<insert A>

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from ~1000 psig. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss of coolant accident, the pressure of the liquid and gas must not exceed 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 is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

An allowable bypass area between the primary containment and the drywell and suppression chamber is identified based on analysis considering primary system break area, suppression chamber effectiveness, and containment design pressure. Analyses show that the maximum allowable bypass area is equivalent to all vacuum breakers open the equivalent of 1/16 inch at all points along the seal surface of the disk.

Using the minimum or maximum water levels given in this specification (as measured from the bottom of the suppression chamber), primary containment maximum pressure following a design basis accident is approximately 48 psig, which is below the design pressure. The maximum water level results in a downcomer submergence of 4 feet and the minimum level results in a submergence approximately 4 inches less. If it becomes necessary to make the suppression chamber inoperable, it is done in accordance with the requirements in Specification 3.5.C.

Once per 24 hours

Because of the large volume and thermal capacity of the suppression pool, the level and temperature normally change very slowly and monitoring these parameters daily is sufficient to establish any trend. By requiring the suppression pool temperature to be more frequently monitored during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken. The requirement for an external visual examination following any event where potentially high loadings could occur provides assurance that no significant damage was encountered. Particular attention should be focused on structural

Insert A to page B 3/4.7-5

safety/relief valve discharges or from Design Basis Accidents (DBAs). This is the essential mitigative feature of a pressure-suppression containment that ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from the High Pressure Coolant Injection turbine system exhaust lines. Suppression pool average temperature, in conjunction with suppression pool water level, is a key indication of the capacity of the suppression pool to fulfill these requirements.

BASES

discontinuities in the vicinity of the relief valve discharge since these are expected to be the points of highest stress.

Under full power operating conditions, blowdown to the suppression chamber with an initial water temperature of 95°F results in a water temperature of approximately 145°F. This peak temperature is low enough to provide complete condensation via T-quencher devices. However, a maximum average suppression pool temperature of 75°F and approximately 2 psi of containment pressure is required to assure adequate net positive suction pressure for the ECCS pumps during the first 10 minutes following certain analyzed accidents. No positive containment pressure is required to assure adequate net positive suction pressure for the ECCS pumps after the first 10 minutes.

insert B

Experimental data indicates that excessive steam condensing loads can be avoided if the peak temperature of the suppression pool is maintained sufficiently low during any period of safety relief valve operation for T-quencher devices. Specifications have been placed on the envelope of reactor operating conditions so that the reactor can be depressurized in a timely manner to avoid the regime of potentially high suppression chamber loadings. 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 safety or relief valve inadvertently opens or sticks open. As a minimum this action shall include: (1) use of all available means to close the valve, (2) initiate suppression pool water cooling, (3) initiate reactor shutdown, and (4) if other safety or relief valves are used to depressurize the reactor, their discharge shall be separated from that of the stuck-open safety or relief valve to assure mixing and uniformity of energy insertion to the pool.

In conjunction with the Mark I Containment Short Term Program, a plant unique analysis was performed which demonstrated a factor of safety of at least two for the weakest element in the suppression chamber support system and attached piping. The maintenance of a drywell-suppression chamber differential pressure and a suppression chamber water level corresponding to a downcomer submergence range of 3.67 to 4.00 feet will assure the integrity of the suppression chamber when subjected to post-LOCA suppression pool hydrodynamic forces.

3/4.7.1 Suppression Chamber and Drywell Spray

Following a Design Basis Accident (DBA), the suppression chamber spray function of the low pressure coolant injection (LPCI)/containment cooling system removes heat from the suppression chamber air space and condenses steam. The suppression chamber is designed to absorb the sudden input of heat from the primary system from a DBA or a rapid depressurization of the reactor pressure vessel through safety or relief valves. There is one 100% capacity containment spray header inside the suppression chamber. Periodic operation of the suppression chamber and drywell sprays may also be used following a DBA to assist the natural convection and diffusion mixing of hydrogen and oxygen when other ECCS requirements are met and oxygen concentration exceeds 4%. Since the spray system is a function of the LPCI/containment cooling system, the loops will not be aligned for the spray function during normal operation, but all components required to operate for proper alignment must be OPERABLE.

Insert B to page B 3/4.7-5

A limitation of the suppression pool average temperature is required to ensure that the containment conditions assumed in the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heat-up of the suppression pool. The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Input to the safety analyses include initial suppression pool water volume and suppression pool temperature. An initial pool temperature of 95 °F is assumed for these analyses. Reactor shutdown at 110 °F and vessel de-pressurization at a pool temperature of 120 °F are also assumed for these analyses. The limit of 105 °F at which testing is terminated, is not used in the safety analyses because DBAs are assumed not to initiate during plant testing.

The suppression pool is also designed to quench the energy from safety/relief valve discharges. Thus, the safety analyses related to the suppression pool must consider all accident scenarios that involve safety/relief valve actuation's. The limit for the suppression pool average temperature is set low enough to preclude local boiling due to safety/relief valve discharge via the T-quencher devices. In accordance with GE NEDO-30832, local suppression pool temperature limits are not required because the emergency core cooling system pump inlets are located below the elevation of the quenchers.

The available net positive suction head may be less than that required by the emergency core cooling system pumps, thus there is dependency on containment over pressure during the accident injection phase.

3.8 - LIMITING CONDITIONS FOR OPERATION

C. Ultimate Heat Sink

The ultimate heat sink shall be OPERABLE with:

1. A minimum water level at or above elevation 500 ft Mean Sea Level, and

2. An average water temperature of ≤75°F.
   95

APPLICABILITY:

OPERATIONAL MODE(s) 1, 2, 3, 4, 5 and *.

ACTION:

With the requirements of the above specification not satisfied:

1. In OPERATIONAL MODE(s) 1, 2 or 3, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.

2. In OPERATIONAL MODE(s) 4 or 5 declare the diesel generator cooling water system inoperable and take the ACTION required by Specification 3.8.B.

3. In OPERATIONAL MODE *, declare the diesel generator cooling water system inoperable and take the ACTION required by Specification 3.8.B. The provisions of Specification 3.0.C are not applicable.

4.8 - SURVEILLANCE REQUIREMENTS

C. Ultimate Heat Sink

The ultimate heat sink shall be determined OPERABLE at least once per 24 hours by verifying the average water temperature and water level to be within their limits.

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* When handling irradiated fuel in the secondary containment, during CORE ALTERATION(s), and operations with a potential to drain the reactor vessel.

3.7 - LIMITING CONDITIONS FOR OPERATION

K. Suppression Chamber

The suppression chamber shall be OPERABLE with:

1. The suppression pool water level between 14' 6.5" and 14' 10.5",

2. A suppression pool maximum average water temperature of ≤95°F during OPERATIONAL MODE(s) 1 or 2, except that the maximum average temperature may be permitted to increase to:

   a. ≤105°F during testing which adds heat to the suppression pool.

   b. ≤110°F with THERMAL POWER ≤1% of RATED THERMAL POWER.

   c. ≤120°F with the main steam line isolation valves closed following a scram.

3. A total leakage between the suppression chamber and drywell of less than the equivalent leakage through a 1 inch diameter orifice at a differential pressure of 1.0 psid.

APPLICABILITY:

OPERATIONAL MODE(s) 1, 2 and 3.

ACTION:

1. With the suppression pool water level outside the above limits, restore the water level to within the limits

4.7 - SURVEILLANCE REQUIREMENTS

K. Suppression Chamber

The suppression chamber shall be demonstrated OPERABLE:

1. By verifying the suppression pool water level to be within the limits at least once per 24 hours.

2. At least once per 24 hours by verifying the suppression pool average water temperature to be ≤95°F, except:

   a. At least once per 5 minutes during testing which adds heat to the suppression pool, by verifying the suppression pool average water temperature to be ≤105°F.

   b. At least once per hour when suppression pool average water temperature is ≥ 95°F, by verifying:

      1) Suppression pool average water temperature to be ≤ 110°F, and

      2) THERMAL POWER to be ≤ 1% of RATED THERMAL POWER after suppression pool average water temperature has exceeded 95°F for more than 24 hours.

   c. At least once per 30 minutes with the main steam isolation valves closed following a scram and suppression pool average water temperature >95°F, by verifying suppression pool average water temperature to be ≤120°F.

3.7 - LIMITING CONDITIONS FOR OPERATION

within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

2. In OPERATIONAL MODE(s) 1 or 2 with the suppression pool average water temperature >95°F, except as permitted above, restore the average temperature to ≤95°F within 24 hours or reduce THERMAL POWER to ≤1% RATED THERMAL POWER within the next 12 hours.

3. With the suppression pool average water temperature >105°F during testing which adds heat to the suppression pool, except as permitted above, stop all testing which adds heat to the suppression pool and restore the average temperature to ≤95°F within 24 hours or reduce THERMAL POWER to ≤1% RATED THERMAL POWER within the next 12 hours.

4. With the suppression pool average water temperature >110°F, immediately place the reactor mode switch in the Shutdown position and operate at least one low pressure coolant injection loop in the suppression pool cooling mode.

5. With the suppression pool average water temperature >120°F, depressurize the reactor pressure vessel to <150 psig (reactor steam dome pressure) within 12 hours.

4.7 - SURVEILLANCE REQUIREMENTS

3. Deleted.

4. Deleted.

5. At least once per 18 months by conducting a drywell to suppression chamber bypass leak test at an initial differential pressure of 1.0 psid and verifying that the measured leakage is within the specified limit. If any drywell to suppression chamber bypass leak test fails to meet the specified limit, the test schedule for subsequent tests shall be reviewed and approved by the Commission. If two consecutive tests fail to meet the specified limit, a test shall be performed at least every 9 months until two consecutive tests meet the specified limit, at which time the 18 month test schedule may be resumed.

BASES

and de-inerted as soon as possible in the plant shutdown. As long as reactor power is below 15% of RATED THERMAL POWER, the potential for an event that generates significant hydrogen is low and the primary containment does not need to be inert. Furthermore, the probability of an event that generates hydrogen occurring within the first 24 hours of a reactor startup or within the last 24 hours before a shutdown is low enough that these windows, when the primary containment is not inerted, are also justified. The 24 hour time frame is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

3/4.7.K Suppression Chamber

The specifications of this section ensure that the primary containment pressure will not exceed the design pressure during primary system blowdown from full operating pressure.

The suppression chamber water provides the heat sink for the reactor coolant system energy release following a postulated rupture of the system. The suppression chamber water volume must absorb the associated decay and structural sensible heat released during reactor coolant system blowdown from safety/relief valve discharges or from Design Basis Accidents (DBAs). This is the essential mitigative feature of a pressure-suppression containment that ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from the High Pressure Coolant Injection turbine system exhaust lines. Suppression pool average temperature, in conjunction with suppression pool water level, is a key indication of the capacity of the suppression pool to fulfill these requirements. Since all of the gases in the drywell are purged into the suppression chamber air space during a loss of coolant accident, the pressure of the liquid and gas must not exceed 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 is discharged to the suppression chamber and that the drywell volume is purged to the suppression chamber.

An allowable bypass area between the primary containment and the drywell and suppression chamber is identified based on analysis considering primary system break area, suppression chamber effectiveness, and containment design pressure. Analyses show that the maximum allowable bypass area is equivalent to all vacuum breakers open the equivalent of 1/16 inch at all points along the seal surface of the disk.

Using the minimum or maximum water levels given in this specification (as measured from the bottom of the suppression chamber), primary containment maximum pressure following a design basis accident is approximately 48 psig, which is below the design pressure. The maximum water level results in a downcomer submergence of 4 feet and the minimum level results in a submergence approximately 4 inches less. If it becomes necessary to make the suppression chamber inoperable, it is done in accordance with the requirements in Specification 3.5.C.

BASES

Because of the large volume and thermal capacity of the suppression pool, the level and temperature normly and monitoring these parameters once per 24 hours is sufficient to establish any trend. By requiring the suppression pool temperature to be more frequently monitored during periods of significant heat addition, the temperature trends will be closely followed so that appropriate action can be taken.

A limitation of the suppression pool average temperature is required to ensure that the containment conditions assumed in the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heat-up of the suppression pool. The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Input to the safety analyses include initial suppression pool water volume and suppression pool temperature. An initial pool temperature of 95°F is assumed for these analyses. Reactor shutdown at 110°F and vessel de-pressurization at a pool temperature of 120°F are also assumed for these analyses. The limit of 105°F at which testing is terminated, is not used in the safety analyses because DBAs are assumed not to initiate during plant testing.

The suppression pool is also designed to quench the energy from safety/relief valve discharges. Thus, the safety analyses related to the suppression pool must consider all accident scenarios that involve safety/relief valve actuation's. The limit for the suppression pool average temperature is set low enough to preclude local boiling due to safety/relief valve discharge via the T-quencher devices. In accordance with GE NEDO-30832, local suppression pool temperature limits are not required because the emergency core cooling system pump inlets are located below the elevation of the quenchers.

The available net positive suction head may be less than that required by the emergency core cooling system pumps, thus there is dependency on containment over pressure during the accident injection phase.

In conjunction with the Mark I Containment Short Term Program, a plant unique analysis was performed which demonstrated a factor of safety of at least two for the weakest element in the suppression chamber support system and attached piping. The maintenance of a drywell-suppression chamber differential pressure and a suppression chamber water level corresponding to a downcomer submergence range of 3.67 to 4.00 feet will assure the integrity of the suppression chamber when subjected to post-LOCA suppression pool hydrodynamic forces.

BASES

3/4.7.L Suppression Chamber and Drywell Spray

Following a Design Basis Accident (DBA), the suppression chamber spray function of the low pressure coolant injection (LPCI)/containment cooling system removes heat from the suppression chamber air space and condenses steam. The suppression chamber is designed to absorb the sudden input of heat from the primary system from a DBA or a rapid depressurization of the reactor pressure vessel through safety or relief valves. There is one 100% capacity containment spray header inside the suppression chamber. Periodic operation of the suppression chamber and drywell sprays may also be used following a DBA to assist the natural convection and diffusion mixing of hydrogen and oxygen when other ECCS requirements are met and oxygen concentration exceeds 4%. Since the spray system is a function of the LPCI/containment cooling system, the loops will not be aligned for the spray function during normal operation, but all components required to operate for proper alignment must be OPERABLE.

3.8 - LIMITING CONDITIONS FOR OPERATION

C. Ultimate Heat Sink

The ultimate heat sink shall be OPERABLE with:

1. A minimum water level at or above elevation 500 ft Mean Sea Level, and
2. An average water temperature of ≤95°F.

APPLICABILITY:

OPERATIONAL MODE(s) 1, 2, 3, 4, 5 and *.

ACTION:

With the requirements of the above specification not satisfied:

1. In OPERATIONAL MODE(s) 1, 2 or 3, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN within the next 24 hours.
2. In OPERATIONAL MODE(s) 4 or 5 declare the diesel generator cooling water system inoperable and take the ACTION required by Specification 3.8.B.
3. In OPERATIONAL MODE *, declare the diesel generator cooling water system inoperable and take the ACTION required by Specification 3.8.B. The provisions of Specification 3.0.C are not applicable.

4.8 - SURVEILLANCE REQUIREMENTS

C. Ultimate Heat Sink

The ultimate heat sink shall be determined OPERABLE at least once per 24 hours by verifying the average water temperature and water level to be within their limits.

* When handling irradiated fuel in the secondary containment, during CORE ALTERATION(s), and operations with a potential to drain the reactor vessel.

ATTACHMENT D

CALCULATIONAL LISTING

DESCRIPTION	PROPRIETARY STATUS	REV.	DATE
1. DRE 97-010 Dresden LPCI/Core Spray NPSH Analysis post DBA-LOCA - long term - Design Basis, Rev. 0 (att. G, reference 1)	Non-proprietory	0	2/13/97
2. DRE 97-012 Dresden LPCI/Core Spray NPSH Analysis post DBA-LOCA - short term - Design Basis/GE SIL 151 (att. G, reference 2)	Non-proprietory	0	2/13/97
3. DRE 96-0214 Minimum available CCSW flow to maintain a 20 psi differential between LPCI and CCSW heat exchanger (att. G, reference 3)	Non-proprietory	0	2/6/97
4. GE-NE-T23000740-1 Dresden Station Nuclear Power Station Units 2 and 3 Containment Analyses of the DBA-LOCA based on long term LPCI/Containment Cooling System configuration of one LPCI/Containment Cooling Pump and 2 CCSW pump. (att. G, reference 4)	Non-proprietory		12/96
5. Containment Pressure and Temperature Analysis for Dresden NPSH Evaluations - 2 CCSW pump flow of 5400 gpm (att. G reference 5)	Non-proprietory		11/18/96
6. Containment Pressure and Temperature Analysis for Dresden NPSH Evaluations. 1 LPCI/Containment Cooling Pump Flow of 5000 gpm. 2 CCSW pump flow of 5000 gpm (att. G, reference 6)	Non-proprietory		12/26/96
7. Containment Pressure and Temperature Analysis for Dresden NPSH Evaluations, short-term (600 seconds) containment response, 4-LPCI/Containment Cooling Pump Flow of 5150 gpm per pump, 2-CS Pump Flow of 5800 gpm per pump (att. G, reference 19)	Non-proprietory		1/28/97

ATTACHMENT E

REVISED UFSAR

UFSAR CHANGE DFL 97011
SHORT-TERM/LONG-TERM CONTAINMENT PRESSURE AND TEMP

VOLUME	SECTION	PARAG.	PAGE	DESCRIPTION/REASON FOR CHANGE
3	SECTION 6.0, LIST OF TABLES	N/A	6-iv	Revised title of Table 6.2-3, added Tables 6.2-3a and 6.2-3b, deleted Table 6.2-6 and replaced Tables 6.3-17 and 6.3-18 to reflect new containment temperature and pressure responses.
3	SECTION 6.0, LIST OF FIGURES	N/A	6-v	Added Figures 6.2-19a, 6.2-19b, 6.2-20a, 6.2-20b, 6.2-20c and 6.2-20d to reflect new containment temperature and pressure responses.
3	6.2.1.3.2	1	6.2-19	Added a description to identify the short term and long term containment response to a Loss of Coolant Accident(LOCA). This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	6.2.1.3.2.1 (new)	N/A	6.2-19	Added subsection to identify discussion for original containment short term response to a design bases accident. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	6.2.1.3.2.2 (new)	N/A	6.2-24	Added new subsection which covers the new evaluation for the containment short term response to a design bases accident (DBA) LOCA for minimum NPSH available. The discussion covers the worse case condition for the first 600 seconds of the accident. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	6.2.1.3.3	1,3 to 8	6.2-25	Renumbered subsection to 6.2.1.3.2.3 to maintain consistency in the LOCA discussion. Included statement that LPCI and core spray will help remove the noncondensible gases during the first 10 minutes (paragraph 1). In paragraphs 3 through 8, references to the original licensing basis for long term cooling were removed to reflect the current licensing basis being initiated for the long term DBA-LOCA. This current basis reflects the worse case condition for LPCI and core spray operation and its acceptability. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	6.2.1.3.3.1	1 to 4	6.2-26	Subsection and references to the original licensing basis for long term cooling were removed to reflect the current licensing basis being initiated for the long term DBA-LOCA. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	6.2.1.3.3.2	1 to 3	6.2-27	Subsection and references to the original licensing basis for long term cooling were removed to reflect the current licensing basis being initiated for the long term DBA-LOCA. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	6.2.1.3.3.3	1	6.2-27	Subsection and references to the original licensing basis for long term cooling were removed to reflect the current licensing basis being initiated for the long term DBA-LOCA. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	6.2.1.3.3.4	1 & 2	6.2-27 6.2-28	Subsection and references to the original licensing basis for long term cooling were removed to reflect the current licensing basis being initiated for the long term DBA-LOCA. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	6.2.1.3.6.4.3	All	6.2-48 6.2-49	Original safety relief valve discharge device limitations were removed and new discussion was added to reflect the current licensing basis being initiated for the long term DBA-LOCA. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.

3	6.2.2.2	8 & 11		Removed heat exchanger references to maximum suppression pool temperature of 170°F in Paragraph 8. This is being removed since the current licensing basis being initiated for the long term DBA-LOCA sets this temperature at 176°F. In paragraph 11, unnecessary information on tube replacement for the LPCI heat exchanger is being removed to enhance the section description. The loss of 6% heat transfer addresses both plugged and replaced tubes.
3	6.2.2.3.2	7	6.2-59	Added ECCS strainer design information for design consistency and to ensure incorporation into the UFSAR. This information was included in UFSAR pending change DFL-96140.
3	Table 6.2-3	N/A	1	Revised Table 6.2-3 which documented the original DBA-LOCA design parameters to reflect the design parameters from the new evaluations performed for the containment short term and long term responses to a DBA-LOCA , including minimum NPSH available. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	Table 6.2-3a 6.2-3b	N/A	New	Added Tables 6.2-3a and 6.2-3b to reflect the design parameters from the new evaluations performed for the containment short term and long term responses to a DBA-LOCA , including minimum NPSH available. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	Table 6.2-6	N/A	1 to 4	Deleted Table 6.2-6 as it relates to safety relief valve discharge device limitations (Section 6.2.1.3.6.4.3) which were removed to reflect the current licensing basis being initiated for the long term DBA-LOCA. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	Table 6.2-7	N/A	1	Added containment cooling specifications for various LPCI and CCSW heat exchanger flows as related to the new evaluations performed for the containment short term and long term responses to a DBA-LOCA , including minimum NPSH available. The change to this table initiated under UFSAR change DFL 96140 is being deleted with this design change. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	Table 6.2-19	N/A	N/A	Initiated Tables 6.2-19a and 6.2-19b to reflect the new suppression pool temperature and suppression chamber pressure responses evaluated for the containment short term response to a design bases accident (DBA) LOCA for minimum NPSH available. The discussion covers the worse case condition for the first 600 seconds of the accident. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
3	Table 6.2-20	N/A	N/A	Initiated Tables 6.2-20a, 6.2-20b, 6.2-20c and 6.2-20d to reflect the new suppression pool temperature and suppression chamber pressure responses evaluated for the containment long term response to a design bases accident (DBA) LOCA for minimum NPSH available. The discussion covers the worse case condition after 600 seconds into the accident. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
4	6.3.3.4.3	1 to 4	6.3-77 6.3-78	Deleted the design description (Insert G) for NPSH issued under DFL 96141 and added a new Insert G description to identify the short term and long term containment response to a Loss of Coolant Accident(LOCA). This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.

4	6.3.3.4.3.1	All	N/A	Deleted the description (Insert G) for NPSH issued under DFL 96141 and added new description (Insert G)to the subsection which covers the new evaluation for the CS/LPCI pump Post-LOCA short term response for minimum NPSH available. The discussion covers the minimum suppression pool pressure required to meet pump NPSH requirements for the first 600 seconds of the accident. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
4	6.3.3.4.3.2	All	N/A	Deleted the description (Insert G) for NPSH issued under DFL 96141 and added new description (Insert G) to the subsection which covers the new evaluation for the CS/LPCI pump Post-LOCA long term response for minimum NPSH available. The discussion covers the minimum suppression pool pressure required to meet pump NPSH requirements for greater than 600 seconds of the accident. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
4	6.3.3.4.3.3	All	N/A	Deleted the description (Insert G) for NPSH issued under DFL 96141 and added new description to the subsection which identifies the NPSH margin available. The discussion covers the pump NPSH requirements and the abilities to throttle the pumps to an acceptable operating condition. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
4	6.3.3.4.3.4 (New)	All	N/A	Added new subsection which identifies the HPCI NPSH . This information was already in the UFSAR and is not being changed by the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
4	Table 6.3-17	N/A	N/A	Deleted table reflecting original design information.
4	Table 6.3-18	N/A	N/A	Deleted table reflecting original design information and replaced it with a table designating long term throttling requirements.
4	Figure 6.3-80	N/A	N/A	Deleted figure reflecting original design information and reissued the figure with the current design information.
4	Figure 6.3-83	N/A	N/A	Initiated a new figure reflecting the current design information.
4	Figure 6.3-89	N/A	N/A	Initiated a new figure reflecting the current design information.
5	9.2.1.3	4	9.2.2	Added design information that identifies the operation and location of the differential pressure control valve for the LPCI heat exchanger and the minimum CCSW flow of 5000 gpm for containment cooling. A change issued under DFL96140 identifying a different flow rate is being deleted by this change. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.
5	Table 9.2-1	N/A	N/A	A change to the table initiated under DFL 96140 identifying a flow rate of 5600 gpm is being deleted. The table should only reflect containment cooling service water equipment specifications. This change is a result of the Licensing Amendment to reevaluate LPCI and Core Spray pump requirements.

6.0 ENGINEERED SAFETY FEATURES
LIST OF TABLES

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

Figure

ADD FIG. 6.2-20a, 20b, 20c, 20d from attached insert 6-v

ADD FIG. 6.2-19a & -19b from attached insert

Insert for Page 6-v

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

Figure

analyses to restore the margin of safety required in the original containment design.

After completion of the Mark I Containment Program, it was determined that the water volumes specified in the plant unique load definition [8] and the plant unique analysis[7] actually correspond to a downcomer submergence of 3.21 to 3.54 feet at zero differential pressure. An evaluation concluded that affected components were still within the allowables established for the Mark I Containment Program[9]. This evaluation concluded that the present volume, corrected for the 1.0 psid overpressure in the drywell, does not adversely affect the existing analyses, and that the maximum component stresses reported in the plant unique analysis are still valid and meet the criteria of NUREG-0661. See Section 6.2.1.3.6.2 for additional discussion of the Mark I acceptance criteria. Refer to Section 6.2.1.3.6.4.2 for a description of the details of the reevaluation.

(INSERT 1)

6.2.1.3.2 Containment Response to a Loss-of-Coolant Accident

6.2.1.3.2.1 Containment Short Term Response to a Design Basis Accident

The spectrum of postulated break sizes with respect to reactor core response is discussed in Section 6.3.3.2. The following information covers the effects of a LOCA on the containment, with particular emphasis on the most severe break: the doubled-ended rupture of one of the 28-inch-diameter recirculation pump suction lines. For the purpose of sizing the primary containment, an instantaneous, circumferential break of this line was hypothesized. The LOCA involving the recirculation pump suction line would occur upstream of point 1 on Figure 6.2-14.

For the vessel blowdown, the reactor was assumed to be operating at a full power of 2527 MWt with the equalizer line valves between the recirculation loops open, even though these valves will be closed during power operation. Note that the equalizer line and valves were removed from the Unit 3 recirculation loops as described in Section 5.4.1.

Assuming the equalizer line valves are open, the flow area through the equalizer line must be considered in determining the total blowdown flow area. The total blowdown flow area is equal to the sum of all parallel flow areas and is given by:

$$A_B = A_R + A_E + NA_N \qquad (1)$$

where:

A_B = Total equivalent break area (or blowdown flow area)

A_R = Flow area of recirculation line = 3.57 ft^2

A_E = Flow area of equalizer line valve port = 1.48 ft^2

N = Number of jet pumps on one header = 10

A_N = Flow area of a single jet pump nozzle = 0.057 ft^2

Insert 1 for Page 6.2-19

In order to identify containment response to a Loss of Coolant (LOCA) accident, several analysis were performed. These analysis were performed to evaluate the containment short-term and long term pressure and temperature response following the Design Basis Accident (DBA) LOCA. Short-term is defined as a time period from the beginning of the DBA LOCA to 600 seconds. There is no credit taken for operator actions during this short-term interval. Long-term is defined as a time period after short-term, namely from 600 seconds into the event, at which time the operator takes actions to initiate containment cooling or to control pump flows

Statement B may appear to contradict existing test data which shows as much as an 11-psi increase in peak drywell pressure due to prepurging. This apparent disparity is attributable to the effects of two phenomena discussed below.

A. Condensation on drywell walls: Due to the high ratio of drywell wall surface area to blowdown flow area, the effects of condensation reduced the peak drywell pressure in tests with cold drywell walls. Prepurging eliminated any significant surface condensation, and higher peak drywell pressures resulted. The calculation of peak drywell pressure did not take credit for surface condensation with or without prepurging.

B. Liquid carryover into drywell vents: The calculation of peak drywell pressure assumes complete carryover of all liquid in the drywell into the drywell vents which increases the peak drywell pressure. However, test data from the Humboldt Bay series of pressure suppression tests[12] reveal that carryover is more likely to be complete if the drywell is initially hot. Hence, the increased carryover would increase the measured pressure compared to a test with less carryover; i.e., one with no purge. Hence, prepurging of the drywell does not significantly affect the peak drywell pressure so long as condensation is neglected and complete liquid carryover is assumed for both the prepurged and nonprepurged cases.

The pressure and temperature responses of the containment, as originally calculated using Moody's model, are shown in Figures 6.2-19 and 6.2-20. As can be seen in Figure 6.2-19, the calculated peak drywell pressure is 47 psig, which is well below the design allowable pressure of 62 psig.

Additional analyses of the containment pressure and temperature response to small break accidents (SBA), intermediate break accidents (IBA), and the DBA were conducted as part of the Mark I Program. Refer to Section 6.2.1.3.6.4 for a description of these additional analyses.

On June 5, 1970, Dresden Unit 2 experienced a transient which caused a safety valve to open and fail to reseat. As a result, the containment atmosphere is postulated to have reached 320°F after approximately 1 hour. A general case in which the containment wall is postulated to be 340°F has been analyzed to demonstrate the adequacy of the containment. It was found that as a result of thermal expansion of the drywell shell against the concrete walls of the containment structure, the thermally induced loads for 340°F at 0.5 psig are the same as for the design condition of 281°F at zero psig. At 340°F and zero psig the loads are slightly greater and result in a slight decrease in safety factor from 2.2 to 1.9. Therefore, it was concluded that the containment structure (design temperature of 281°F) provides adequate safety margin for the maximum steam superheat temperature of 340°F.

6.2.1.3.2.2

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6.2.1.3.2.2 Containment Short-Term Response to a (DBA) LOCA for Minimum NPSH Available

Various cases involving different pump combinations, pump flow rates, initial conditions and assumptions were analyzed as shown in Tables 6.2-3, 6.2-3a and 6.2-3b. The short-term scenarios (0-600 seconds) that resulted in the minimum net positive suction head (NPSH) are described as follows:

- Four (4) LPCI pumps and two (2) Core Spray (CS) pumps for vessel makeup and no containment cooling up to 600 seconds following the DBA-LOCA with no operator actions required (Case 6a2 in Tables 6.2-3, 6.2-3a and 6.2-3b). This analysis was performed to determine the short-term (0-600 seconds) suppression pool temperature and suppression chamber pressure response for a postulated break in the recirculation discharge line with all 4 LPCI pumps and 2 Core Spray pumps available for vessel injection and with the assumed single failure of the loop selection logic which allows all the LPCI flow to be directed to the containment from the broken loop. It was assumed that all LPCI flow was injected directly into the drywell

- Two (2) LPCI pumps and one (1) Core Spray pump for vessel makeup and no containment cooling up to 600 seconds following the DBA-LOCA with no operator action required (Case 2a1 with 100% thermal mixing in Tables 6.2-3, 6.2-3a and 6.2-3b). This scenario provides the minimum conditions for NPSH with the single failure of an Emergency Diesel Generator.

The GE computer Model SHEX-04 with decay heat based on the ANS 5.1, 1979 decay heat model (without adders) was used in each analyses. Analyses performed to benchmark analyses with the SHEX-04 code to the Dresden FSAR analyses were performed. The benchmarking analyses included sensitivity studies to quantify the effect on peak suppression pool temperature due to differences between the updated analyses and the FSAR original analysis.

Various assumptions were used in the analysis. These assumptions are included in Section 6.2.1.3.3.3. Additional assumptions for the short-term response are as follows:

- With a signal for LPCI initiation, all 4 LPCI pumps start vessel injection mode and inject directly into the drywell (no flow to the vessel) at a flow rate of 5,150 gpm per pump for 6a2 and 5,000 gpm per pump for 2a1 during the first ten minutes of this event.
- After receiving a signal for CS initiation, the 2 CS pumps start injecting into the vessel at a flow rate of 5,800 gpm per pump for the first ten minutes of this event.
- There is 60% thermal mixing efficiency of the break liquid with the drywell atmosphere for Case 6a2 and 100% thermal mixing efficiency of the break liquid with the drywell atmosphere for Case 2a1. These thermal mixings were chosen as appropriate for the conditions represented.

As a result of the large LPCI injection directly into the drywell during the first ten minutes, a significant reduction in drywell pressure and temperature produced a reduction of pressure in the suppression chamber. The results of this analysis are summarized in Case 6a2 of Table 6.2-3 and include the suppression pool temperature and suppression chamber pressure at 600 seconds (at initiation of operator actions). Figures 6.2-19a, 6.2-19b, 6.2-20a and 6.2-20b shows the suppression pool temperature and suppression chamber pressure responses. Various other evaluations were performed assuming different pump scenarios and mixing levels. The results of these are also listed in Table 6.2-3. The results of the Case 6a2, 60% thermal mixing and Case 2a1, 100% thermal mixing analyses, which provide the minimum NPSH in the short term, are input to the 0-600 second short-term position of the NPSH analysis in Section 6.3.3.4.3.1.

.2.3

6.2.1.3.3 Containment Long-Term Response to a Design Basis Accident

and during LPCI and core spray injection for the first ten minutes.

The original DBA analyses showed that after the blowdown immediately following a postulated recirculation line break, the temperature of the suppression chamber water would approach 130°F, and the primary containment system pressure would equalize at about 27 psig as discussed in Section 6.2.1.3.2. Most of the noncondensible gases would be transported to the suppression chamber during blowdown. However, soon after initiation of the containment spray, the gases would redistribute between the drywell and the suppression chamber via the vacuum-breaker system as the spray reduces drywell pressure.

The core spray system would remove decay heat and stored heat from the core, thereby minimizing core heatup and any metal-water reaction. The core heat is removed from the reactor vessel through the broken recirculation line in the form of hot liquid. This hot liquid combines with liquid from the containment spray and flows into the suppression chamber via the drywell-to-suppression-chamber connecting vent pipes. Steam flow would be negligible. The energy transported to the suppression chamber water would ultimately be removed from the primary containment system by the containment cooling heat exchangers.

To assess the long-term pressure and temperature response of the primary containment after the postulated blowdown, and to demonstrate the adequacy and redundancy of the core and containment cooling systems, an analysis was made of the recirculation line break under various conditions of core and primary containment cooling. The ~~original~~ current licensing basis long-term pressure and temperature response of the primary containment was analyzed for ~~the following cooling conditions:~~ various flow rates and mixing conditions.

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A. Operation of two core spray system loops and one of the two containment cooling loops with two LPCI pumps in service;

B. Operation of only one of the two core spray system loops and both of the containment cooling loops each with two LPCI pumps in service;

C. Operation of only one of the two core spray system loops and one of the two containment cooling loops with two LPCI pumps in service; and

D. Operation of only one of the two core spray system loops and one-half of one containment cooling loop, i.e., one LPCI pump in service.

For each of the above listed analyses, two containment cooling service water (CCSW) pumps providing a total flow of 7000 gal/min per operating heat exchanger were assumed to be in service.

The initial pressure response of the system while the reactor vessel is blowing down (the first 30 seconds after the break) is as reported in Section 6.2.1.3.2 for all cases considered here. For each case, the temperature of the suppression pool was calculated as a function of time, conservatively considering the pool to be the only heat absorber in the system. The effects of decay energy, stored energy in the core,

INSERT 3 for Page 6.2-25

For containment cooling after 600 seconds, two CCSW pumps providing flows evaluated at 5,000 gal/min, 5,400 gal/min and 7,000 gal/min per operating containment cooling heat exchanger were assumed to be in service at a cooling water temperature of less than or equal to 95 degrees F. LPCI and CS pump flow rates were also evaluated for different values. Analyses were performed at these LPCI, CS and CCSW pump flows by GE using the SHEX computer code with current standard assumptions for containment cooling analyses , including the use of the ANS 5.1 decay heat model. Long term temperature is maximized and NPSHA minimized with a thermal mixing efficiency of 20%.

All analyses cases (except 6a1 and 6a2 as described in Section 6.2.1.3.2.2) were performed assuming that during the first 10 minutes, two LPCI pumps and one CS pump are conservatively used for vessel makeup to provide the initial conditions for the long term cooling analysis. This assumes a single failure of an emergency diesel generator. At 10 minutes into the event, the operator shuts down one LPCI pump and aligns the other LPCI pump from the vessel injection mode to the containment cooling mode. At the same time, two CCSW pumps and one LPCI heat exchanger are lined up for long term cooling. The resulting long-term containment cooling configuration consists of 1 LPCI pump, two CCSW pumps and one LPCI heat exchanger. The various analyses used different pump flow rates and heat exchanger performance values which were also evaluated for the various flows. The evaluated heat exchanger performance values are identified in Table 6.2.3b.

Different initial containment conditions were used for each combination of pump flow rates. Sensitivity cases were also analyzed to minimize the suppression chamber pressure response. The sensitivity parameters include heat sinks and the efficiency of thermal mixing between liquid break flow and drywell atmosphere. Additionally, the input assumptions were chosen to conservatively minimize the suppression chamber pressure and in the 'a' cases, minimize the available NPSH.

Assumptions

1. The reactor is assumed to be operating at 102% of the rated thermal power.
2. Vessel blowdown flow rates are based on the Homogeneous Equilibrium Model.
3. The core decay heat is based on ANSI/ANS-5.1-1979 decay heat.
4. Feedwater flow into the RPV continues until all the feedwater above 180°F is injected into the vessel.
5. Thermodynamic equilibrium exists between the liquids and gases in the drywell.
6. The heat transfer to the drywell airspace from the liquid flow from the break which does not flash is assumed to be partial (20%) or full (100%), depending upon cases to minimize the containment pressure. Thermal equilibrium conditions are imposed between the held-up liquid and the fluids in the drywell as described in Assumption No. 5 above. The liquid not held up is assumed to flow directly to the suppression pool without heat transfer to the drywell fluids.
7. The vent system flow to the suppression pool consists of a homogenous mixture of the fluid in the drywell.
8. The initial suppression pool volume is at the minimum to maximize the calculated suppression pool temperature.
9. For the 'a' and 'a1' cases, the initial drywell and suppression chamber pressure are at the minimum expected operating values to minimize the containment pressure.
10. For the 'a' and 'a1' cases, the maximum operating value of the drywell temperature of 150°F and a relative humidity of 100% are used to minimize the initial non-condensable gas mass and minimize the long-term containment pressure for the NPSH evaluation.
11. The initial suppression pool temperature is at the maximum TS value (95°F) to maximize the calculated suppression pool temperature.
12. Consistent with the UFSAR analysis, containment sprays are available to cool the containment. Once initiated at 600 seconds, it is assumed that containment sprays are operated continuously with no throttling of the LPCI p0.
13. umps below rated flow.

14. Passive heat sinks in the drywell, suppression chamber air space and suppression pool are conservatively neglected to maximize the suppression pool temperature. For the 'a1' cases, heat sink inputs were developed based on the Dresden drywell geometry parameters which were compiled and used during the Mark I Containment Long Term Program and which are documented in GE Document 22A5743 and GE Document 22A5744, Containment Data, September , 1982. The drywell and torus shell condensation heat transfer coefficient is based on the Uchida correlation with a 1.2 multiplier. The inclusion of the heat sinks conservatively minimizes suppression chamber pressure.
15. All Core Spray and LPCI system pumps have 100% of their horsepower rating converted to a pump heat input which is added either to the RPV liquid or suppression pool water.
16. Heat transfer from the primary containment to the reactor building is neglected.
17. The effect of containment leakage is negligible considering that conservative input assumptions are used to minimize containment pressure.

The design parameters determined by the evaluations for the various LPCI, CS and CCSW flow rates , including the sensitivity cases, are shown in Table 6.2-3. The table includes the suppression pool temperature and suppression chamber pressure at 600 seconds (at initiation of operator actions), the minimum suppression chamber pressure following initiation of containment (drywell and suppression chamber) sprays and the suppression pool temperature and suppression chamber pressure at the time of peak suppression pool temperature. A comparison of the results between the 'a' and the 'a1' cases show that the heat sinks have a negligible effect on the suppression pool temperature. As for the impact of the suppression chamber pressure, the inclusion of the heat sinks resulted in a reduction of approximately 0.8 psi at 600 seconds, and a reduction of approximately 0.2 psi in the minimum suppression chamber pressure following initiation of suppression chamber sprays. However, the heat sink effect on the suppression chamber pressure is negligible at the time of peak suppression chamber temperature. The results demonstrate that once containment sprays are initiated, the effects of heat sinks become insignificant.

The parameters identified in the evaluation performed for Case 2a1 (see Table 6.2-3), 'Above nominal pump flow rate for LPCI pump (5,800 gpm) and CS (5,800 gpm) for first 10 minutes and nominal pump flow for LPCI (5,000 gpm) and CS (4,500 gpm) rate after 10 minutes -Containment Initial conditions to minimize containment pressure, drywell and torus shell heat sinks modeled', provides the minimum NPSH. Figures 6.2-20a, 6.2-20b, 6.2-20c and 6.2-20d shows the suppression pool temperature and suppression chamber pressure responses. This case provides the limiting condition for evaluating available NPSH after initiation of containment sprays including available NPSH at the time of the peak suppression pool temperature. The analyses performed for Case 5a1 of Table 6.2-3 identifies the maximum suppression temperature to be 176°F. These design and operating parameters are such that they ensure that plant safety margins are met.

The results of the new analysis indicate that the heat removal capability of the containment heat removal system remains sufficient to maintain containment integrity following DBA's with a peak suppression pool temperature of 176°F. The consequences of this higher peak temperature have been analyzed and found to be acceptable. The results of the Case 2a1 analysis, which provides the minimum NPSH in the long term, are input to the greater than 600 second long-term position of the NPSH analysis in Section 6.3.3.4.3.2.

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at a cooling water inlet temperature of 95 degrees F. The plant is currently operating under temperature limitations which prohibit operation when the cooling water inlet temperature or the torus bulk water temperature exceeds 75 degrees F. Under the current temperature limit, a CCSW flowrate of 5600 gpm ensures that the required 20 psi differential between the CCSW and LPCI systems is maintained at the LPCI heat exchanger during the limiting DBA LOCA with a diesel generator failure and a containment cooling pump combination of 1 LPCI pump/2 CCSW pumps.

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and energy from any metal-water reaction on the pool temperature were included. Also, the effect of heat from operating LPCI pumps was included.

The drywell temperature was calculated considering an energy balance on the containment cooling and core spray systems. The containment cooling flow was assumed to enter the containment at the discharge temperature of the heat exchanger, and the core spray flow was assumed to enter the reactor at the suppression pool temperature. The combined flows (containment cooling and core spray) would then drain back to the suppression pool, having been heated by the decay energy, stored energy in the core, and any metal-water reaction chemical energy. The drywell temperature was then taken to be 5°F hotter than the exiting flow.

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The total number of moles of noncondensible gas in the containment system was determined from the amount of gas originally in the system plus gas generation from any metal-water reaction.

Using the drywell temperature, suppression pool temperature, and moles of gas in the system, the system pressure was calculated assuming the drywell and suppression chamber gases to be saturated. Also, it was assumed that the drywell and suppression chamber would be at equal pressure. This is reasonable because the pressure difference cannot exceed 4 feet of water (1.8 psi), the vent submergence depth, after the initial reactor blowdown.

6.2.1.3.3.1 Case A — Operation of Two Core Spray Loops and One Containment Cooling Loop with Two LPCI Pumps

The analysis presented here assumed that both of the core spray systems were operating following the recirculation line break. Core spray system operation does not produce full flow until the reactor vessel pressure has decreased to 90 psig. The analysis assumed that the systems commenced operation 30 seconds after the recirculation line break. This time is well within the time calculated for the vessel pressure to reach 115 psig.

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This analysis also assumed that only two of the four LPCI pumps in the two containment spray cooling subsystems commenced containment spray 400 seconds after the recirculation line break. The heat exchanger associated with these two LPCI pumps was assumed to be available with two CCSW pumps operating for removal of energy from the suppression chamber water at this time. The flowrate for this condition is shown in Table 6.2-3, Case a.

The calculated core heatup and extent of metal-water reaction was found to be essentially the same as for operation of only one core spray system as shown in Figure 6.2-19. The total metal-water reaction was calculated to be less than 0.1%. The pressure and temperature response of the system is shown as Curve a in Figures 6.2-19 and 6.2-20, respectively. After the postulated blowdown, the drywell and suppression chamber pressures would equalize at about 27 psig. Initiation of the containment spray would result in quenching of the steam in the drywell and in a corresponding containment pressure reduction. Energy addition due to core decay heat would result in a long-term pressure increase to the maximum shown in Table 6.2-3. Thereafter, energy removal by the containment cooling heat exchanger would exceed the addition rate from all sources, resulting in decreasing containment pressure.

6.2.1.3.3.2 Case B — Operation of One Core Spray Loop and Four LPCI Pumps

For this analysis only one of the two core spray systems was assumed to commence operation 30 seconds after the recirculation line break. The analysis also assumed that all four LPCI pumps in the containment cooling mode and all four CCSW pumps would commence operation 400 seconds after the recirculation line break. The flowrates corresponding to these operating conditions are shown in Table 6.2-3, Case b.

Core heatup and the extent of metal-water reaction were found to be as discussed above for the two core spray case. It is the same for a single core spray system because each of the two independent core spray systems are designed to maintain continuity of cooling in the event of a LOCA, and experimental results show that increasing the flow above that delivered by the single core spray system does not appreciably change the heat transfer characteristics during spray cooling. Therefore, core heatup and extent of metal-water reaction would be the same for one and two core spray pump operation.

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Initiation of containment spray cooling would result in quenching the steam in the drywell and in a corresponding reduction in containment pressure. Energy addition due to core decay heat would result in a long-term pressure increase to the maximum shown in Table 6.2-3. The containment pressure and temperature are shown as Curve b in Figures 6.2-19 and 6.2-20, respectively.

6.2.1.3.3.3 Case C — Operation of One Core Spray System and Two LPCI Pumps

Core spray and containment spray operation for this analysis was assumed to be as discussed in Case A. The flowrates corresponding to these conditions are shown in Table 6.2-3, Case c. The results of this analysis were found to be the same as presented for Case A. The containment spray cooling flow used was identical to that analyzed in Case A and the cooling characteristics of one and two core spray pump operation do not change. The containment pressure and temperature are shown as Curve c in Figures 6.2-19 and 6.2-20, respectively.

6.2.1.3.3.4 Case D — Operation of One Core Spray Loop and One LPCI Pump

This analysis assumed that only one of the two core spray systems commenced operation 30 seconds after the recirculation line break. However, only one of the four LPCI pumps in the containment spray mode and two CCSW pumps were assumed to commence operation 600 seconds after the recirculation line break. The flowrates corresponding to these conditions are shown in Table 6.2-3, Case d.

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Again, the core heatup and extent of metal-water reaction are as discussed above. The containment pressure and temperature are shown as Curve d in Figures 6.2-19 and 6.2-20. Following the initiation of the single LPCI pump, two CCSW pumps, and the associated heat exchanger in the containment spray mode, the containment pressure would decrease initially, then slowly increase to the maximum shown in Table 6.2-3, due to addition of decay-energy to the containment. Thereafter, energy removal by the single LPCI pump and heat exchanger would exceed the addition rate from all sources, resulting in decreasing containment pressure.

Containment spray itself does not significantly affect the peak post-accident pressure rise. It does, however, result in a somewhat faster depressurization immediately following the completion of the blowdown. The controlling parameter affecting the post-accident secondary pressure peak is the heat removal capability of the containment cooling heat exchanger relative to the core decay heat production.

Additional analyses of the short-term containment pressure and temperature response to a SBA, IBA, and DBA have been conducted as part of the Mark I Program. Refer to Section 6.2.1.3.6.4 for a description of these analyses.

6.2.1.3.4 Mark I Program Description for Reevaluation of Containment Response to Hydrodynamic Loads

This subsection describes the analysis performed to resolve new loadings identified after the original design of the primary containment.[13]

The first generations of GE BWR nuclear steam supply systems are housed in a containment structure designated as the Mark I containment system. Dresden Units 2 and 3 utilize Mark I Containments.

The original design of the Mark I containment system considered postulated accident loads previously associated with containment design. These included pressure and temperature loads associated with a LOCA, seismic loads, dead weight loads, jet impingement loads, hydrostatic loads due to water in the suppression chamber, overload pressure test loads, and construction loads.

In the course of performing large-scale testing of an advanced design pressure-suppression containment (Mark III), and during in-plant testing of Mark I containments, new suppression pool hydrodynamic loads, which had not been explicitly included in the original Mark I containment design basis, were identified. These additional loads result from dynamic effects of drywell air and steam being rapidly forced into the suppression pool (torus) during a postulated LOCA and from mass after drywell air carryover. The larger initial torus water mass has only approximately a 1°F effect on peak pool temperature. These effects result in a calculated increase in peak torus pressure of about 0.6 psi. For the IBA and SBA the peak drywell pressure increases by an equal amount. For the DBA, the increase in containment pressure increases the density of the vent flow which reduces the vent system pressure drop. This partially offsets the torus pressure increase and results in only a 0.3 psi increase in the peak drywell pressure.

6.2.1.3.6.4.3 Safety Relief Valve Discharge Device Limitations

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As a result of studies of the instabilities in the condensation process previously described in Section 6.2.1.3.5.3 for the SRV discharge transients, it was determined that the magnitude of the SRV discharge-related loads is a function of the type of discharge device used and the suppression pool temperature. In the past, a ramshead discharge device was used to direct the steam flow from an SRV into the torus. During the Mark I program, a T-quencher SRV discharge device, which includes perforated pipe sections, was installed on each SRV discharge line. The T-quencher device has been found to reduce substantially the hydrodynamic discharge loads in comparison to those observed for the other discharge devices. Refer to Section 5.2 for a description of the SRV discharge devices.

To preclude unstable condensation and eliminate the concern that SRV actuation at elevated pool temperatures could result in severe vibratory pressure loads, a suppression pool temperature limit has been established.

To establish this limit, the difference between the local and bulk temperature was determined. Local temperature denotes an average water temperature in the vicinity of the discharge device and represents the relevant temperature which controls the behavior of the condensation process occurring at the pipe exit.

The bulk temperature is a calculated value based on the total energy and mass release into the pool, assuming the pool acts as a uniform heat sink. Since bulk temperature is used in plant transient analyses, the difference between the bulk and local values must be specified so that the analysis can demonstrate operation within the prescribed limits.

To determine the difference between bulk and local conditions for the T-quencher device, the Mark I Owners Group relied on the in-plant tests at Monticello.[28] The results indicated that the difference between bulk and local temperature is 43°F for the test without the RHR system in operation and 38°F for the tests with RHR operation. The test with RHR was conducted with only one RHR loop operating in the pool recirculation mode. Note that RHR at Monticello is equivalent to LPCI containment cooling mode at Dresden.

In late 1978, the Mark I Owners Group conducted an adjunct series of tests at the same facility.[29] The purpose of the tests was to investigate methods to improve thermal mixing in the suppression pool and to reduce the bulk to local pool temperature difference. These methods include modifications of T-quencher design

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Dresden Station is equipped with safety/ relief valves (SRVs) to protect the reactor from overpressurization during operating transients. When the SRVs open, steam released from the reactor vessel is routed through SRV discharge lines to the suppression pool where it is condensed. Extended steam blowdown into the suppression pool, however, can create temperature conditions near the discharge location that can lead to instability of the condensation process. These instabilities can, in turn, lead to severe vibratory loading on containment structures. This effect is termed condensation oscillation. This is mitigated at Dresden Station by the usage of quenchers at the end of the SRV discharge lines, as well as restrictions on the allowable bulk suppression pool water temperature, in order to ensure that the local pool temperature stays within acceptable ranges. Technical Specification Section 3/4.7.K provides Limiting Conditions for Operation and Action requirements, regarding the suppression chamber temperature.

By letter dated March 21, 1995, the BWR Owners' Group (BWROG) requested the NRC staff review and approve GE report, NEDO-30832 entitled, "Elimination of Limit on BWR Suppression Pool Temperature." NEDO-30832 presented a discussion of test data and analysis that supports deletion of the requirement to maintain the local suppression pool temperature 20 °F below the saturation temperature of the pool during SRV discharge.

Dresden has eliminated the local suppression pool temperature limits. The test data and analysis presented within NEDO-30832 is applicable to Dresden Station. The NRC Staff Safety Evaluation Report (SER) approval of NEDO-30832, dated August 29, 1994, concluded that the elimination of the local suppression pool temperature limit is acceptable if the plant has emergency safety features pump inlet located below the elevation of the quencher. Because Dresden Station's pump inlet is below the elevation of the quencher, NEDO-30832 is applicable to Dresden Station (see UFSAR Figures 1.2-7 and 3.8-17. The NRC staff found that the quencher device is effective in maintaining the unstable condensation oscillation load to benign levels when the suppression pool is operated at temperatures nearing saturation.

and the LPCI suppression pool cooling mode discharge pipe configuration. The T-quencher was modified by adding a number of holes on the tips of one of the quencher arms. The LPCI system was modified by installing a 90° elbow, with a reducing nozzle, at the end of the existing discharge lines. These modifications were intended to promote mixing in the suppression pool during SRV discharge. Test results show a substantial improvement in pool mixing. The difference between bulk and local temperature was reduced to approximately 15°F for the test, with one loop of LPCI operating in the suppression pool cooling mode.

A plant-specific analysis was performed to determine the suppression pool temperature limit for Dresden. Figure 6.2-39 shows the resulting local pool temperature limit for Dresden Units 2 and 3 as a function of reactor pressure.

Figure 6.2-39 shows that for all plant transients involving SRV operation during which the steam flux through the T-quencher perforations exceeds 94 lbm/ft^2-sec, the suppression pool local temperature limit is 200°F. For all plant transients involving SRV operations during which the steam flux through the T-quencher perforations is less than 42 lbm/ft^2-sec, the suppression pool local temperature limit shall ensure 20°F subcooling.

The Dresden T-quenchers are submerged in 9.17 feet of water corresponding to 18.53 psia. The saturation temperature at 18.53 psia is 224°F. Thus, to achieve 20°F subcooling the local temperature limit with a steam flux of less than 42 lbm/ft^2-sec is 204°F.

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To demonstrate that the local pool temperature limit is satisfied, seven limiting transients involving SRV discharges were analyzed. Table 6.2-6 presents a summary of the transients analyzed and the corresponding pool temperature results. Three of the transients conservatively assumed the failure of one RHR loop, in addition to the single equipment malfunction or operator error which initiated the event. This conservative assumption exceeds the current licensing basis for anticipated operational transients. As noted in Table 6.2-6, the containment cooling heat exchanger heat transfer rate assumed in these analyses is 416.7 Btu/s-°F per loop. This was derived from the containment cooling heat exchanger specification which states an overall heat transfer rate of 105 x 10^6 Btu/hr is achieved given CCSW flow of 7000 gal/min at 95°F, and LPCI flow through the heat exchanger of 10,700 gal/min at 165°F.

Each of the SRV discharge transients was analyzed assuming an initial pool temperature of 95°F, which is the Technical Specification pool temperature limit for normal power operation. The notes to Table 6.2-6 list other initial conditions and assumptions included in these analyses.

The analyses of Table 6.2-6, Case 2C, normal depressurization at isolated hot shutdown, shows a maximum local pool temperature of 153°F. This demonstrates that with no system failures and in the event of a nonmechanistic scram, depressurization of the reactor pressure vessel via SRVs at 100°F/hr results in local pool temperatures well below the condensation stability limit shown in Figure 6.2-39.

INSERT B to page 6.2-49

This limit ensures that an equivalent amount of containment heat removal is provided assuming an overall LPCI heat exchanger duty of 98.6 E6 BTU/hr.

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Insert B ADDED AS A RESULT OF DFL 96140

Table 6.2-6, Case 3A, a SBA with one RHR loop available, results in a maximum local pool temperature of 180°F, which is below the condensation stability limit of 204°F. The local to bulk temperature difference at the time of maximum local temperature is 26°F.

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The maximum local pool temperature of all other cases also remains below the condensation stability limit throughout the transient.

To ensure adequate monitoring of the suppression pool temperature, the SPTMS was installed to monitor bulk pool temperature. The SPTMS is described in Section 6.2.1.2.8.

6.2.1.3.7 Containment Capability

6.2.1.3.7.1 Potential For Hydrogen Generation

If, as a result of a severe accident, Zircaloy in the reactor core was to be heated above about 2000°F in the presence of steam, an exothermic chemical reaction would occur in which zirconium oxide and hydrogen would be formed. The corresponding energy release of about 2800 Btu per pound of zirconium reacted,would be absorbed in the suppression pool. The hydrogen formed, however, would result in an increased pressure due simply to the added moles of gas in the fixed volume. Although very small quantities of hydrogen would be produced during a DBA, the containment has the inherent ability to accommodate much larger amounts.

The Dresden containment is normally provided with an inerted atmosphere to preclude the possibility of a hydrogen combustion event within the containment. The oxygen deficient atmosphere assures that hydrogen build-up due to metal-water reaction is not a concern.

The generation of significant quantities of hydrogen due to a metal-water reaction from high fuel cladding temperatures is prevented by assurance of adequate core cooling. During normal operation, there are several systems, including feedwater and control rod drive (CRD), which add water directly to the reactor pressure vessel. A reliable, automatic means of cooling the core is provided by ECCS. This system is designed to provide adequate cooling in accordance with 10 CFR 50.46 limits assuming any single failure in addition to loss of offsite power. Refer to Section 6.3 for an evaluation of the ECCS performance.

Following a postulated LOCA, both oxygen and hydrogen may be produced by the radiolytic decomposition of primary coolant and suppression pool water. Decomposition would occur due to the absorption of gamma and beta energy released by fission products into reactor coolant and suppression pool water. Radiolysis is the only significant reaction mechanism whereby oxygen, the limiting combustion reactant, is produced within the containment. Therefore, radiolysis is the primary focus relative to combustible gas control for containments with inerted

The containment cooling heat exchangers are sized on the basis of their required duty to meet the containment capability. This duty is determined by calculating the amount of heat which must be rejected from the suppression pool (assuming HPCI operation) to ensure that in the event of a LOCA, the terminal suppression pool temperature does not exceed 170°F. Refer to Section 6.2.1 for a description of the suppression pool cooling requirements. The heat exchangers are designed to withstand the maximum pressures corresponding to the shutoff heads of the CCSW and LPCI pumps. When service water is flowing, the pressure on the tube side of the heat exchanger is maintained 20 psi above the pressure on the shell side to prevent shell side water leakage into the service water and subsequent discharge to the river. Local instrumentation is provided to monitor the ΔP between the LPCI heat exchanger tube side and shell side. Additional containment cooling heat exchanger design information is provided in Table 6.2-7.

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Since the LPCI flow passes through the containment cooling heat exchangers, containment heat may be rejected during post-LOCA LPCI mode operation by starting the CCSW pumps (when sufficient electrical power is available) to provide cooling to the heat exchangers. This results in the transfer of heat from the suppression pool to the CCSW system. During this mode of operation, suction is taken from the suppression pool, pumped through the containment cooling heat exchangers to the reactor vessel, and back to the drywell via the postulated break. When the drywell water level reaches the level of the containment vent pipes, the water flows through the vent pipes to the suppression pool.

Stagnant water conditions in the containment cooling heat exchangers (EPNs 2(3)-1503-A&B) during standby conditions cause both pitting and corrosion of the 70-30 CuNi tubes.[34] This has resulted in heat exchanger tube leaks and excessive equipment outage durations. Various materials were evaluated for better corrosion resistance and AL-6XN was selected as the replacement tube material. A limited number of tubes will be replaced with AL-6XN tubes as tubes fail. (AL-6XN has been accepted by ASME under Code Case N-438).

A heat transfer analysis was performed by the heat exchanger manufacturer to demonstrate that the use of AL-6XN tubes will not change the heat removal capabilities of the heat exchanger to the extent that the suppression pool temperature would exceed its licensing limit. The analysis used Heat Transfer Research Institute proprietary computer programs. The heat exchanger heat transfer rate was calculated to be 95.2 X 10^6 Btu/hr assuming that all the tubes were replaced. This would constitute a 9% drop from the original heat exchanger design duty of 105 X 10^6 Btu/hr and a 7% drop from the FSAR value of 102 X 10^6 Btu/hr. To ensure that other design basis evaluations are not invalidated by replacement of these tubes, the number of tubes plugged or replaced in each heat exchanger will be limited such that the total reduction in heat removal capability will not exceed that which would result from plugging 6% of the 70-30 CuNi heat exchanger tubes. The 6% limit is based on the number of excess tubes provided in the containment cooling heat exchanger design. The 6% replacement limitation will ensure that the design basis heat exchanger capability will not be reduced. The relationship between plugging tubes and replacing 70-30 CuNi tubes with AL-6XN tubes is shown in Figure 6.2-42.

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Fibrous insulation is a molded insulation used only on parts of the recirculation system and the 4-inch and smaller lines. The total amount of such material used in the drywell is only 0.16% by volume or 0.05% by weight of the suppression pool water. Any postulated accident would dislodge only a fraction of this material.

Miscellaneous items are expected to contribute a negligible volume of contaminates in comparison to the suppression pool water volume. Any particles contributed are expected either to be stopped by strainers if they reach that position or to be colloidal rust type particles which would have little or no effect on ECCS pump seals or bearings.

As well as having limited contaminate sources, minimal probability of problems exist because of the circuitous path from the drywell to ECCS pump suctions. Particles first must pass through 1 x 1 ½-foot openings from the drywell to the 8-foot suppression pool downcomers. The downcomers are connected to large spherical shells which are interconnected by 4-foot diameter pipes forming the inner suppression pool ring header. From this header, the path to the suppression pool is through 96 circumferentially spaced 24-inch diameter pipes which extend below the suppression pool water line. The path then proceeds through four suppression pool suction strainers located about ⅓ of the suppression pool water level height above the suppression pool bottom. From the strainers the path leads into a 24 inch suction ring header and then to the pump suctions. This path is quite circuitous, providing many places to trap foreign objects and also spreading the particles that do get through uniformly throughout the suppression pool volume. Larger pieces of metal will settle to the bottom of the suppression pool, and lighter materials such as unibestos will float rather than be drawn into the ECCS pump inlets.

The average water velocity in the suppression pool during ECCS equipment operation is less than 0.1 ft/s and is not sufficient to transport particles (except for the smaller pieces in colloidal suspension). However, during a postulated blowdown from the drywell to the suppression pool, there will be a less idealized situation. The suppression pool water will be disturbed and a certain portion of materials will be near the suction strainers. The strainers are stainless steel perforated plates with 3/32 inch diameter openings. Larger pieces and part of longer pieces (of smaller diameter) will be stopped and the strainer effective area will be somewhat reduced. To account for this possibility, hydraulic performance of the ECCS pump system is based on 100% plugging of one of the four strainers with one foot head loss assumed across each of the remaining strainers. Therefore, more than a 33% extra strainer capacity is available. This conclusion is conservatively based on simultaneous operation of all ECCS equipment at full rated flow.

Extended operation of all ECCS pumps is not required in order to satisfy long term decay heat removal requirements. Short term DBA-LOCA cooling analyses assume the use of two LPCI pumps and one core spray pump, or two core spray pumps, to provide adequate core cooling. However, on a long-term basis, only one LPCI and one core spray pump are necessary to provide required cooling to the containment and the core. This flow would require only one-eighth of the total screen area. Also, the suppression pool water is demineralized and does not contain special additives. Therefore, the pH is expected to remain essentially

Table 6.2-3

~~MAXIMUM~~ CONTAINMENT PRESSURE AND PEAK TORUS TEMPERATURE FOR VARIOUS COMBINATIONS OF CONTAINMENT SPRAY AND CORE SPRAY PUMP OPERATION

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	Containment Spray			Core Spray		CCSW			
Case[1]	Number of Loops	Pumps per Loop	Total Flow (gal/min)	Number of Loops	Total Flow (gal/min)	Number of Pumps per HX	Total Flow (gal/min)	Peak Torus Temperature (°F)	Maximum Containment Pressure (psig)
a	1	2	10,000	2	9,000	2	7,000	—	6.5
b	2	2	20,000	1	4,500	2	14,000	—	4.5
c	1	2	10,000	1	4,500	2	5,600	168	7.2
d	1	1	5,000	1	4,500	1	3,500	180	8.6
C	1	2	8,916	1	4,500	2	4,795	171	7.6
D	1	1	3,881	1	4,500	1	3,071	186	9.4

Notes:

1. Refer to Figures 6.2-22 and 6.2-23.

HISTORICAL

SEE New Table 6.2-3

FOR INFORMATION ONLY

Table 6.2-3

CONTAINMENT PRESSURE AND PEAK TORUS TEMPERATURE FOR VARIOUS COMBINATIONS OF CONTAINMENT SPRAY AND CORE SPRAY PUMP OPERATION

SUMMARY OF DRESDEN CONTAINMENT ANALYSIS RESULTS

CASE **	1	1a	1a	2	2a	2a	2a1	2a1	3	3a	3a	3a1	3a1	4	4a	4a	4a1	4a1	5	5a	5a	5a1	5a1	6a1	6a2
Thermal Mixing Efficiency (%)	100	100	20	100	100	20	100	20	100	100	20	100	20	100	100	20	100	20	100	100	20	100	20	100	60
Heat Sinks	no	no	no	no	no	no	yes	yes	no	no	no	yes	yes	no	no	no	yes	yes	no	no	no	yes	yes	yes	yes
Suppression Pool Temperature at 600 sec (°F) (At initiation of operator actions)	148	149	148	150	150	150	149	148	150	150	150	149	148	150	150	150	149	148	150	150	150	149	148	149	149
Suppression Chamber Airspace Pressure at 600 sec (psig) (At initiation of operator actions)	11.3	8.5	16.5	8.7	6.3	12.5	5.5	10.9	8.8	6.2	12.3	5.5	11.0	8.7	6.3	12.5	5.5	10.9	8.7	6.3	12.5	5.5	10.9	2.9	3.1
Minimum Suppression Chamber Pressure Following Initiation of Containment Spray (psig)	6.9	4.5	2.7	6.3	4.0	2.2	3.6	1.9	6.2	3.9	2.0	3.5	1.7	6.3	4.0	2.4	3.7	2.0	6.4	4.0	2.4	3.7	2.0	N/A	N/A
Peak Long-term Suppression Pool Temperature (°F)	173	173	173	173	173	173	172	173*	171	171	171	171	171	175	175	175	175	175	176	176	176	175	176	N/A	N/A
Suppression Chamber Airspace Pressure at time of Peak Suppression Pool Temperature (psig)	7.2	4.9	3	7.3	4.9	3	4.8	2.9	7.2	4.7	3.1	4.7	3.1	7.6	5.3	3.4	5.2	3.3	7.8	5.4	3.5	5.3	3.5	N/A	N/A

*Temperature rounded up - actual temperature 172.1 °F

**A description of the containment analysis case specific assumptions are as follows:

the long-term this trend is reversed. After the drywell sprays reduce the drywell temperature to below the vessel liquid temperature, the break liquid heats up drywell temperature. Therefore a lower mixing efficiency results in reduced heating of the drywell by the break liquid, which minimizes suppression chamber pressure.

In addition, Case 2a and Case 3a are also evaluated with heat sinks. For these cases, which are identified as Case 2a1 and Case 3a1, the drywell shell, vent system and torus shell are modeled as heat sinks. Both of these cases are evaluated with high and low mixing efficiency.

Table 3 identifies input values (relative to nominal values) used to minimize the suppression chamber pressure response. Heat sinks used for Cases 2a1 and 3a1 were developed based on the Dresden drywell and torus geometry parameters which were compiled during the Mark I Containment Long Term Program and which are documented in Reference 10.

Case-specific containment input parameters for the different cases are summarized in Tables 6 and 7. Except as identified below and in Tables 6 and 7, the input values used in the analyses for this report are the same as previously used in the analysis described in Reference 1 and Reference 2.

A description of the containment analysis cases is provided below.

Case Specific Assumptions

Insert for Table 6.2-3

OMIT

Case 1 - *Nominal Pump Flow Rate -Nominal Containment Initial Conditions*

In Case 1 it is assumed that the LPCI/Containment Cooling pumps are operating at the nominal pump flow of 5000 gpm per pump and the CS pump is operating at the rated pump flow of 4500 gpm throughout the event.

Case 1a - *Nominal Pump Flow Rate -Containment Initial Conditions to Minimize Containment Pressure*

Same as Case 1 except that conservative input assumptions are used to minimize suppression chamber pressure. This case was analyzed with both 100% and 20% thermal mixing efficiency.

Case 2 - *Above nominal flow rate for LPCI/Containment Cooling Pump and CS for first 10 minutes and Nominal Pump Flow Rate after 10 minutes - Nominal Containment Initial Conditions*

In Case 2 it is assumed that the LPCI/Containment Cooling pumps are operating with an above nominal pump flow of 5800 gpm per pump and the CS pump is operating at an above rated pump flow of 5800 gpm for the first 10 minutes. It is assumed that at 10 minutes the operator reduces the LPCI/Containment Cooling pump flows to the nominal flow of 5000 gpm per pump and the CS pump flow to the nominal pump flow of 4500 gpm.

Case 2a - *Above nominal pump flow rate for LPCI/Containment Cooling Pump and CS for first 10 minutes and Nominal Pump Flow Rate after 10 minutes - Containment Initial Conditions to Minimize Containment Pressure*

Same as Case 2 except that conservative input assumptions are used to minimize suppression chamber pressure. This case was analyzed with both 100% and 20% thermal mixing efficiency.

Case 2a1 - *Above nominal pump flow rate for LPCI/Containment Cooling Pump and CS for first 10 minutes and Nominal Pump Flow Rate after 10 minutes - Containment Initial Conditions to Minimize Containment Pressure, Drywell and Torus shell heat sinks modeled*

Same as Case 2a except that the drywell shell, vent system, and torus shell are modeled as heat sinks. This case was analyzed with both 100% and 20% thermal mixing efficiency.

Case 3 - *Above Nominal Pump Flow Rate -Nominal Containment Initial Conditions*

In Case 3 it is assumed that the LPCI/Containment Cooling pumps are operating at the above nominal pump flow of 5800 gpm per pump and the CS pump is operating at the above nominal pump flow of 5800 gpm throughout the event.

Case 3a - *Above Nominal Pump Flow Rate - Containment Initial Conditions to Minimize Containment Pressure*

Same as Case 3 except that conservative input assumptions are used to minimize suppression chamber pressure. This case was analyzed with both 100% and 20% thermal mixing efficiency.

Table 6.2-3 ~~&~~ insert page 2

Case 3a1 - *Above Nominal Pump Flow Rate - Containment Initial Conditions to Minimize Containment Pressure, Drywell and Torus shell heat sinks modeled*

Same as Case 3a except that the drywell shell, vent system, and torus shell are modeled as heat sinks. This case was analyzed with both 100% and 20% thermal mixing efficiency.

Case 4 - *Above nominal flow rate for LPCI/Containment Cooling Pump and CS for first 10 minutes and Nominal Pump Flow Rate after 10 minutes - Nominal Containment Initial Conditions*

In Case 4 it is assumed that the LPCI/Containment Cooling pumps are operating with an above nominal pump flow of 5800 gpm per pump and the CS pump is operating at an above rated pump flow of 5800 gpm for the first 10 minutes. It is assumed that at 10 minutes the operator reduces the LPCI/Containment Cooling pump flows to the nominal flow of 5000 gpm per pump and the CS pump flow to the nominal pump flow of 4500 gpm.

Case 4a - *Above nominal pump flow rate for LPCI/Containment Cooling Pump and CS for first 10 minutes and Nominal Pump Flow Rate after 10 minutes - Containment Initial Conditions to Minimize Containment Pressure*

Same as Case 4 except that conservative input assumptions are used to minimize suppression chamber pressure.

Case 4a1 - *Above nominal pump flow rate for LPCI/Containment Cooling Pump and CS for first 10 minutes and Nominal Pump Flow Rate after 10 minutes - Containment Initial Conditions to Minimize Containment Pressure, Drywell and Torus shell heat sinks modeled*

Same as Case 4a except that the drywell shell, vent system, and torus shell are modeled as heat sinks.

Case 5 - *Above nominal flow rate for LPCI/Containment Cooling Pump and CS for first 10 minutes and Nominal Pump Flow Rate after 10 minutes - Nominal Containment Initial Conditions*

In Case 5 it is assumed that the LPCI/Containment Cooling pumps are operating with an above nominal pump flow of 5800 gpm per pump and the CS pump is operating at an above rated pump flow of 5800 gpm for the first 10 minutes. It is assumed that at 10 minutes the operator reduces the LPCI/Containment Cooling pump flows to the nominal flow of 5000 gpm per pump and the CS pump flow to the nominal pump flow of 4500 gpm.

Case 5a - *Above nominal pump flow rate for LPCI/Containment Cooling Pump and CS for first 10 minutes and Nominal Pump Flow Rate after 10 minutes - Containment Initial Conditions to Minimize Containment Pressure*

Same as Case 5 except that conservative input assumptions are used to minimize suppression chamber pressure.

Case 5a1 - *Above nominal pump flow rate for LPCI/Containment Cooling Pump and CS for first 10 minutes and Nominal Pump Flow Rate after 10 minutes - Containment Initial Conditions to Minimize Containment Pressure, Drywell and Torus shell heat sinks modeled*

Same as Case 5a except that the drywell shell, vent system, and torus shell are modeled as heat sinks.

Case 6a1 & 6a2 - With a signal for LPCI inititiation all 4 LPCI/Containment Cooling pumps start vessel injection mode and inject directly into the drywell (no flow to the vessel) at a flow rate of 5150 gpm per pump during the first 10 minutes of this event.

After receiving a signal for CS initiation, the 2 CS pumps are injecting into the vessel at a flow rate of 5800 gpm per pump for the first 10 minutes of this event.

For Case 6a1 it is assumed that there is 100% thermal mixing efficiency of the break liquid with the drywell atmosphere.

For Case 6a2 it i assumed that there is 60% thermal mixing efficiency of the break liquid with the drywell atmosphere.

Table 6.2-3a

Key Parameters for Containment Analysis

	CASE 1	CASE 1a	CASE 2	CASE 2a CASE 2a1	CASE 3	CASE 3a CASE 3a1	CASE 4	CASE 4a CASE 4a1	CASE 5	CASE 5a CASE 5a1	CASE 6a1	CASE 6a2
DECAY HEAT MODEL	ANS 5.1	ANS 5.1	ANS 5.1	ANS 5.1	ANS 5.1	ANS 5.1	ANS 5.1	ANS 5.1	ANS 5.1	ANS 5.1	ANS 5.1	ANS 5.1
INITIAL SUPPRESSION POOL TEMPERATURE ($^{\circ}$F)	95	95	95	95	95	95	95	95	95	95	95	95
FEEDWATER ADDED	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
PUMP HEAT ADDED	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
HEAT EXCHANGER K-VALUE (BTU/SEC-^{0}F)	307.4	307.4	307.4	307.4	325.4	325.4	288	288	281.7	281.7	N/A	N/A
INITIAL DRYWELL PRESSURE (PSIA)	15.95	15.7	15.95	15.70	15.95	15.70	15.95	15.70	15.95	15.70	15.70	15.70
INITIAL SUPPRESSION CHAMBER PRESSURE (PSIA)	14.85	14.70	14.85	14.70	14.85	14.70	14.85	14.70	14.85	14.70	14.70	14.70
INITIAL DRYWELL TEMPERATURE	135	150	135	150	135	150	135	150	135	150	N/A	N/A
INITIAL DRYWELL RELATIVE HUMIDITY (%)	20	100	20	100	20	100	20	100	20	100	N/A	N/A
INITIAL SUPPRESSION CHAMBER RELATIVE HUMIDITY (%)	100	100	100	100	100	100	100	100	100	100	N/A	N/A
MIXING EFFICIENCY BETWEEN BREAK LIQUID AND DRYWELL FLUID (%)	100	100/20**	100	100/20**	100	100/20**	100	100/20**	100	100/20**	100	60

* Case 2a1, 3a1, 4a1, 5a1, and 6a2 are the same as case 2a, 3a, 4a, 5a, and 6a1 respectively except that the drywell shell, vent system and torus shell are modeled as heat sinks.

** Case 1a, 2a, 2a1, 3a, 3a1, 4a, 4a1, 5a and 5a1 are evaluated with 100% mixing efficiency between the break liquid and drywell fluid and with 20% mixing efficiency between the break liquid and drywell fluid.

TABLE 6.2-3b
Heat Exchanger Heat Transfer Rate

Case	Shell Side Flow Rate (LPCI Pump) GPM	Tube Side Flow Rate (CCSW Pump) GPM	K-Value BTU/SEC- F.	Heat Transfer Rate (165 F Shell Side Temperature, 95 F Tube Side Pressure) Million BTU/hr..
1 1a 2 2a 2a1	5,000	7,000	307.4	77.5
3 3a 3a1	5,800	7,000	325.4	81.8
4 4a 4a1	5,000	5,400	288.0	72.6
* 5 5a 5a1	5,000	5,000	281.7	71.0
6a1 6a2	N/A	N/A	N/A	N/A

* Parameter identified in Case 5, 5a, and 5a1 reflect the new basis for system capability.

Table 6.2-6

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SUMMARY OF DRESDEN UNIT 2 AND 3
POOL TEMPERATURE RESPONSE TO SRV TRANSIENTS

Case Number	Event	Number of SRVs Manually Opened	Maximum Cooldown Rate (°F/hr)	Maximum Bulk Pool Temperature (°F)	Maximum Local Pool Temperature (°F)
1A	SORV at power, one RHR loop	0	1919	131	161
1B	SORV at power, spurious isolation, two RHR loops	0	530	129	167
2A	Rapid depressurization at isolated hot shutdown, one RHR loop	1	258	113	156
2B	SORV at isolated hot shutdown, two RHR loops	1	517	122	160
2C	Normal depressurization at isolated hot shutdown, two RHR loops	2	258	115	153
3A	SBA—accident mode, one RHR loop	5 ADS	2100	154	180
3B	SBA—failure of shutdown cooling mode, two RHR loops	5	100	147	156

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Notes to Table 6.2.1-6

1. Reactor operation at 102% of rated thermal power (2578 MWt).
2. Minimum Technical Specification suppression pool water volume (112,203 ft^3).
3. The suppression pool has no initial velocity.
4. Wetwell and drywell airspaces are at normal operating conditions.
5. Normal auxiliary power is available.
6. Offsite power is assumed available for all cases.
7. Normal automatic operation of the Plant Auxiliary System (HPCI, ADS).
8. The core spray pumps have a manual shutoff at vessel high water level (level 8 elevation). They are reactivated when the level drops as needed to maintain water level and may be shut off again.
9. Control rod drive flow is maintained constant at 11.11 lbm/s.
10. SRV (manual, automatic, ADS) capacities are at 122.5% of ASME-rated flow to conservatively calculate maximum pool temperatures.
11. The licensed decay-heat curve (May-Witt) for containment analysis is used.
12. No heat transfer is considered in the drywell or wetwell airspace.
13. The MSIVs close 3 seconds after a ½-second delay for the isolation signal.
14. Operator actions are based on normal operator action times and licensing basis delays during the given event.

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Notes to Table 6.2-6 (Continued)

15. The shutdown cooling system and the pool cooling mode of the RHR-LPCI system are two independent systems. The actuation of one system is not dependent on turning-off the other system. The operator action time to turn on the shutdown cooling system is assumed to be 16 minutes.

16. Once it is turned on, the pool cooling function stays on and is not affected by the actuation of the shutdown cooling system. There are two loops of pool cooling and one loop can be assumed failed, as demonstrated in Event Cases 1A, 2A, and 3A.

17. Drywell fan coolers are initially available in SORV events and isolation events to keep the drywell pressure below the high drywell pressure trip setpoint (< 2 psig).

18. The ADS system is modeled by fully opening five SRVs in the ADS mode. The ADS system may be actuated manually at a high suppression pool temperature of 120°F.

19. All RHR and ECCS pumps have 100% of their horsepower rating converted to a pump heat input (Btu/s) and added directly to the pool as an enthalpy rise over the time of pump operation. This assumption adds conservatism to the pool temperature results.

20. The feedwater temperature is taken as the actual temperature in the feedwater system. However, for that portion of feedwater which is lower than 170°F, the temperature is conservatively assumed to be 170°F.

21. The service water temperature for the RHR heat exchangers is assumed constant at 93°F, giving a heat transfer capacity of 127.4 Btu/s-°F per loop for shutdown cooling function, and 416.7 Btu/s-°F per loop for pool cooling function.

22. The 10-inch RHR-LPCI discharge line is directed parallel to flow in the discharge bay.

23. The break flow mass and energy are added to flow through the quenchers for SBA cases. This approach makes the results of SBA cases more conservative because it maintains a "hot spot" around the quenchers at all times.

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Notes to Table 6.2-6 (Continued)

24. The analyses are terminated when the pool temperature reaches a maximum and turns around, or when the steam discharging activities of the SRVs are over.

25. The operator will attempt to reclose an SORV. Based on available operating plant data prior to the implementation of the requirements of IE Bulletin 80-25 (Reference 20), SORVs have been shown to reclose at an average pressure of 260 psig. The lowest reclosure pressure recorded was 50 psig, and this value is conservatively assumed for this analysis.

26. The isolation condenser can be actuated by a high reactor pressure signal of 1085 psia sustained for 15 seconds. However, an additional 60-second delay for its tube side outlet valve opening is assumed to line up the condenser for full operation. A total of 90,000 gallons is available from the condensate storage tank to supply the shell side water inventory whenever needed. The isolation condenser has a designed cooling rate of 252.5 x 10^6 Btu/hr.

Table 6.2-7

CONTAINMENT COOLING EQUIPMENT SPECIFICATIONS

Containment Cooling Heat Exchangers

Number	2
dP - river water to containment water	20 psi
Primary (shell) design pressure	375 psi
Secondary (tube) design pressure	375 psi

Containment Cooling Heat Exchanger Capability

Basis	LPCI Flow (gal/min)	LPCI[1] Temp. °F	CCSW Flow (gal/min)	CCSW[2] Temp. °F	Heat Load (Btu/hr)
Heat exchanger design specification (ORIGINAL)	10,700	165	7000 ~~(1)~~ 2	95 ~~(2)~~ 2	~~105 x 10^6^~~ 98.6x10^6^ 3

Heat Exchanger Codes

Shell Side	Carbon Steel A212, Grade B
Code	ASME Section III (1965, Class C) Requirements per manufacturer's specification sheet. Certificate of Shop Inspection indicates construction per applicable code. Berlin Chapman Specification Sheet specifies heat exchanger built to ASME Section III.
Radiography requirements	Tested in accordance with GE Specification 21A5451, Section 4.0 which states testing per ASME Section III, Class C. Manufacturer's data sheet specified joint efficiency of 100% and radiography as complete.

ADD

Basis	LPCI Flow (gal/min)	LPCI Temp. °F	CCSW Flow (gal/min)	CCSW Temp. °F	Heat Load (BTU/hr)
Heat exchanger design Specification (new)	5,000	165	5000	95	71.0 x10^6^

INSERT C to Table 6.2-7

Notes

(1) CCSW flow is 5600 gpm to maintain the required pressure differential between CCSW and LPCI systems when LPCI is operating at rated flows during the limiting DBA LOCA with a Diesel Generator failure and a containment cooling pump combination of 1 LPCI/2 CCSW pumps. The pressure differential across the LPCI heat exchanger prevents release of radioactivity in the event of a tube leak in the LPCI heat exchanger during a design basis accident.

(2) CCSW inlet temperature is limited to less than or equal to 75 degrees F when the plant is operating to compensate for the reduced flow, heat exchanger duty and resolve low pressure ECCS net positive suction head concerns.

(3) Actual heat exchanger performance is 98.6 E6 BTU/hr.

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UNDER DFL 96140.

Table 6.2-7 (continued)

CONTAINMENT COOLING EQUIPMENT SPECIFICATIONS

<u>Containment Spray Headers</u>	
Drywell Spray Headers	
Number	2
Size	8 in. schedule 160
No. of nozzles (each)	160
Type nozzle	Fog jet
Suppression Chamber Spray Header	
Number	1
Size	4 in. schedule 40
No. of nozzles	12
Type	Fog jet

Notes:
1. Containment water design temperature.
2. River water design temperature.

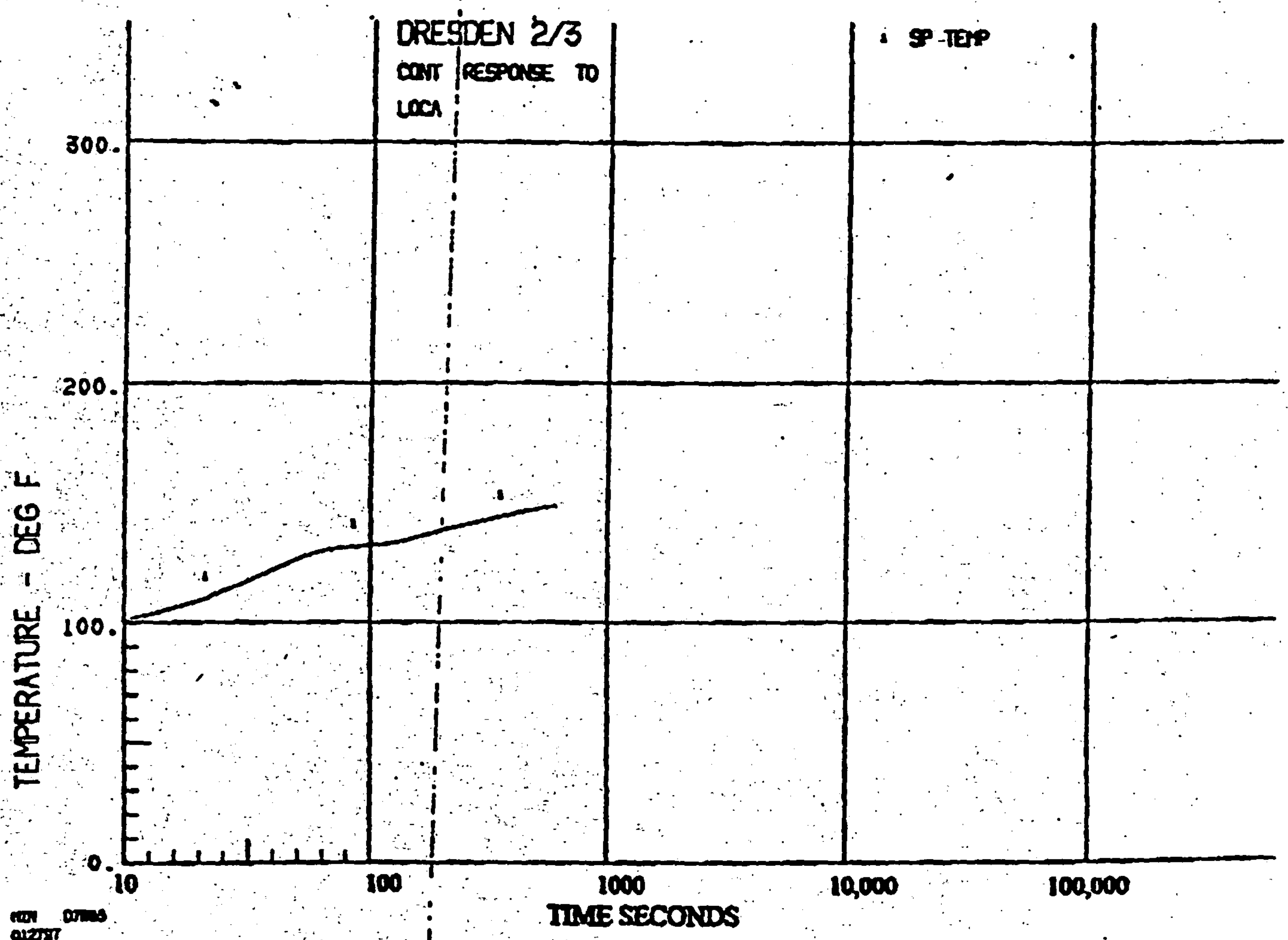

Figure 6.2-19a - Short Term Supression Pool Temperature Response · **Case 6a2 - 60% Mixing Efficiency**

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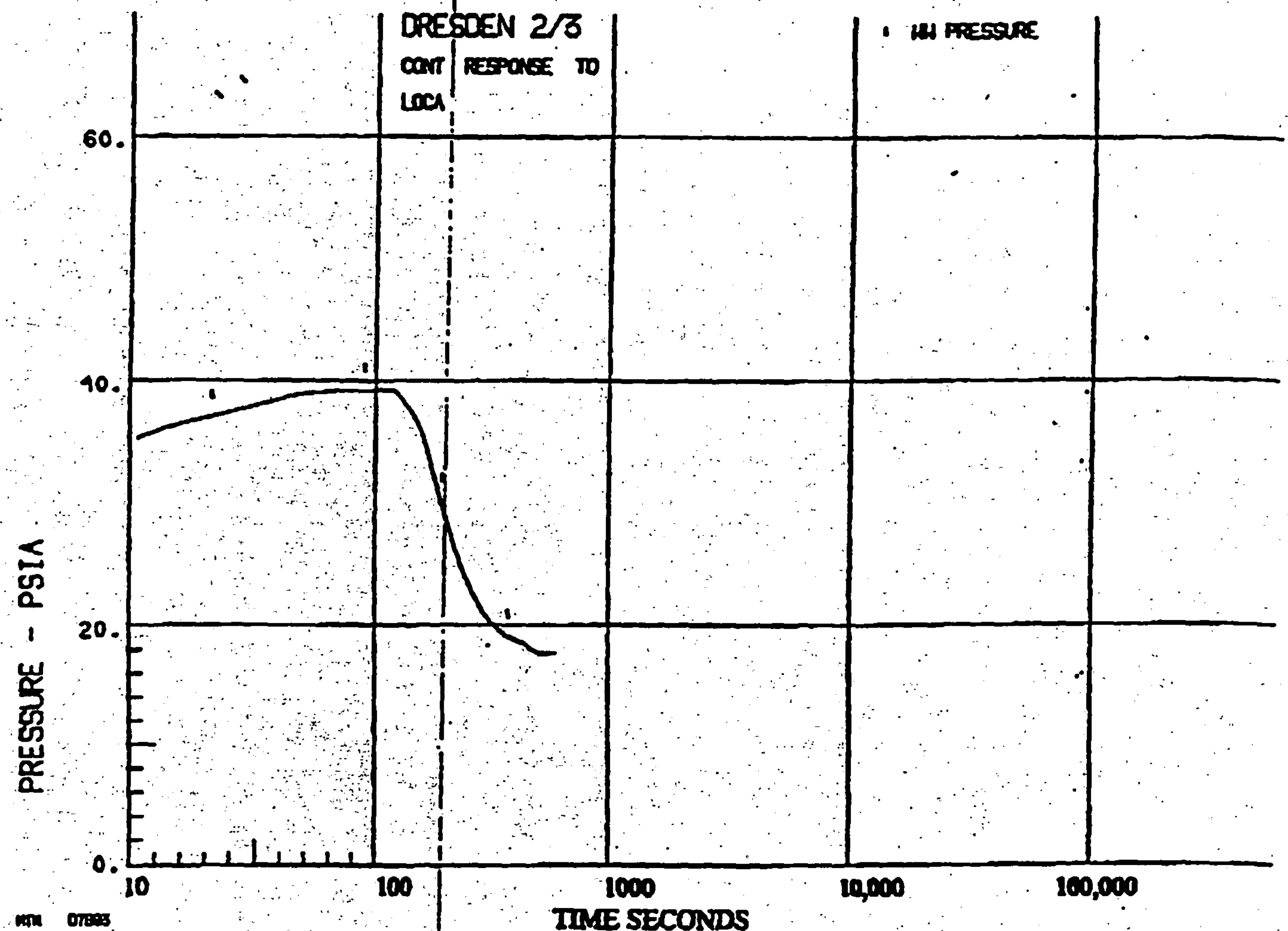

Figure 6.2-19b - Short Term Suppression Chamber Pressure Response . Case 6a2 - 60% Mixing Efficiency

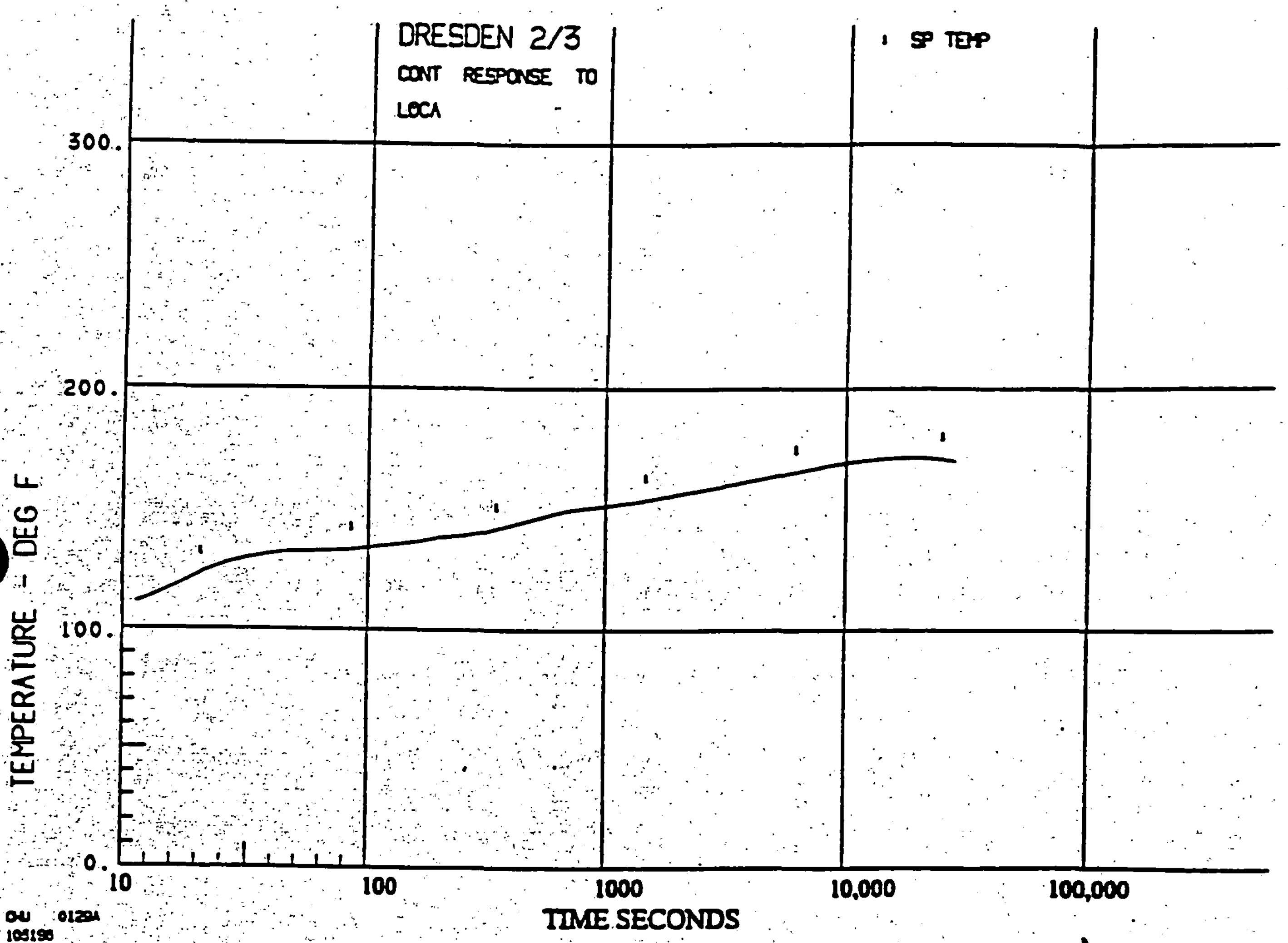

Figure 6.2-20a - Long Term Supression Pool Temperature Response. Case 2a1 - High (100%) Mixing Efficiency

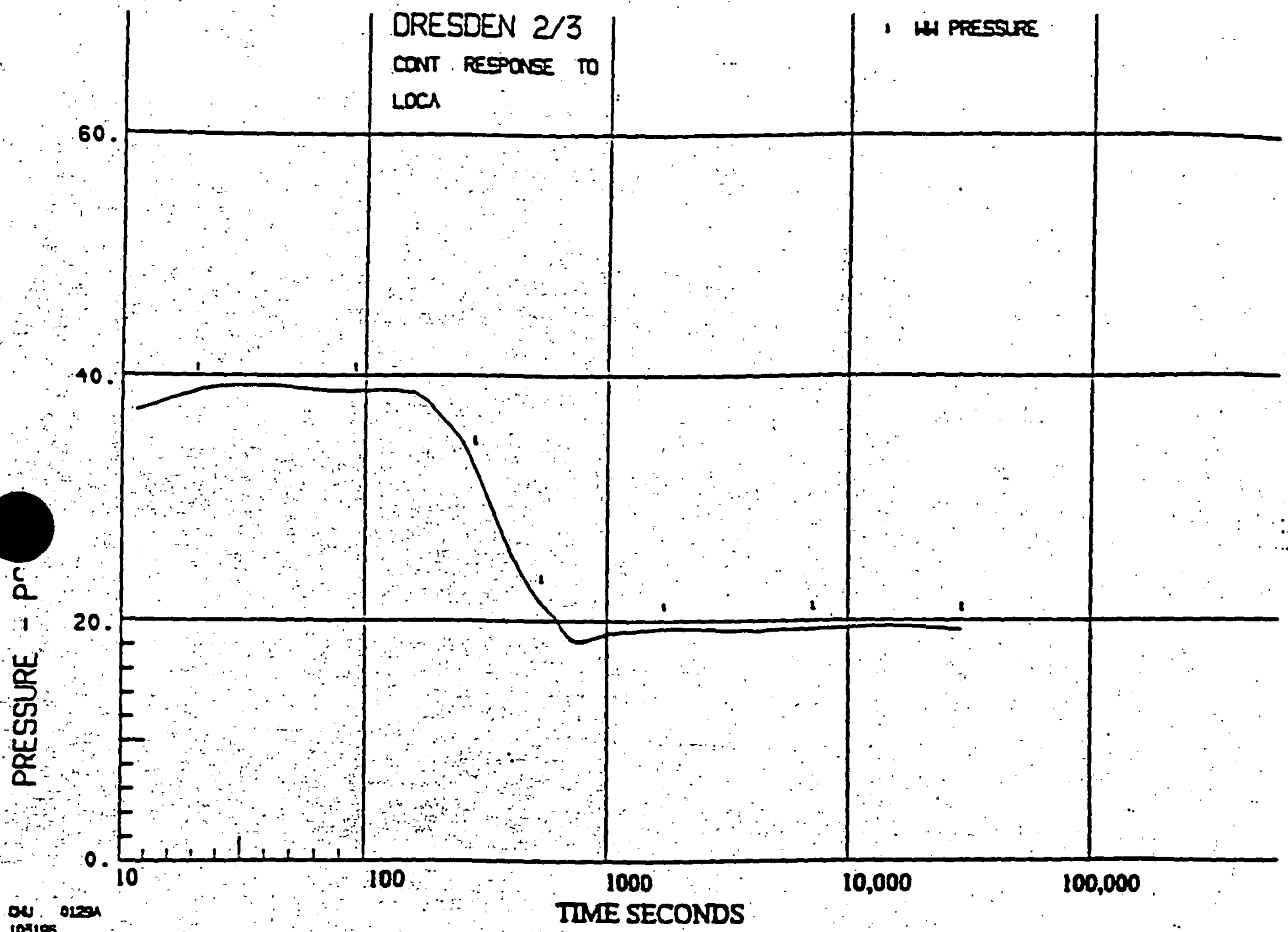

Figure 6.2-20b - Long Term Suppression Chamber Pressure Response Case 2a1 - High (100%) Mixing Efficiency

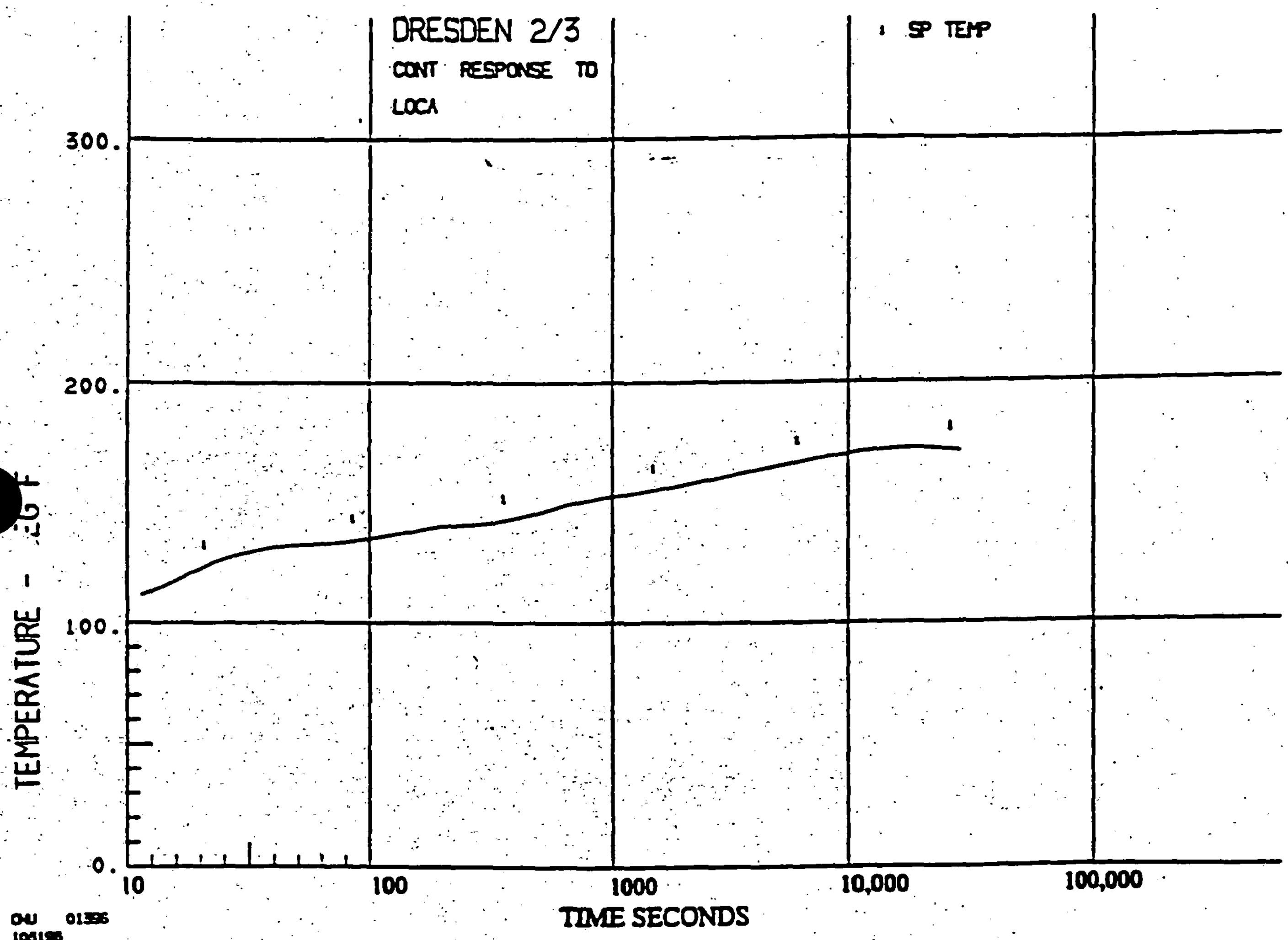

Figure 6.2-20c - Long Term Supression Pool Temperature Response. Case 2a1 -Low (20%) Mixing Efficiency

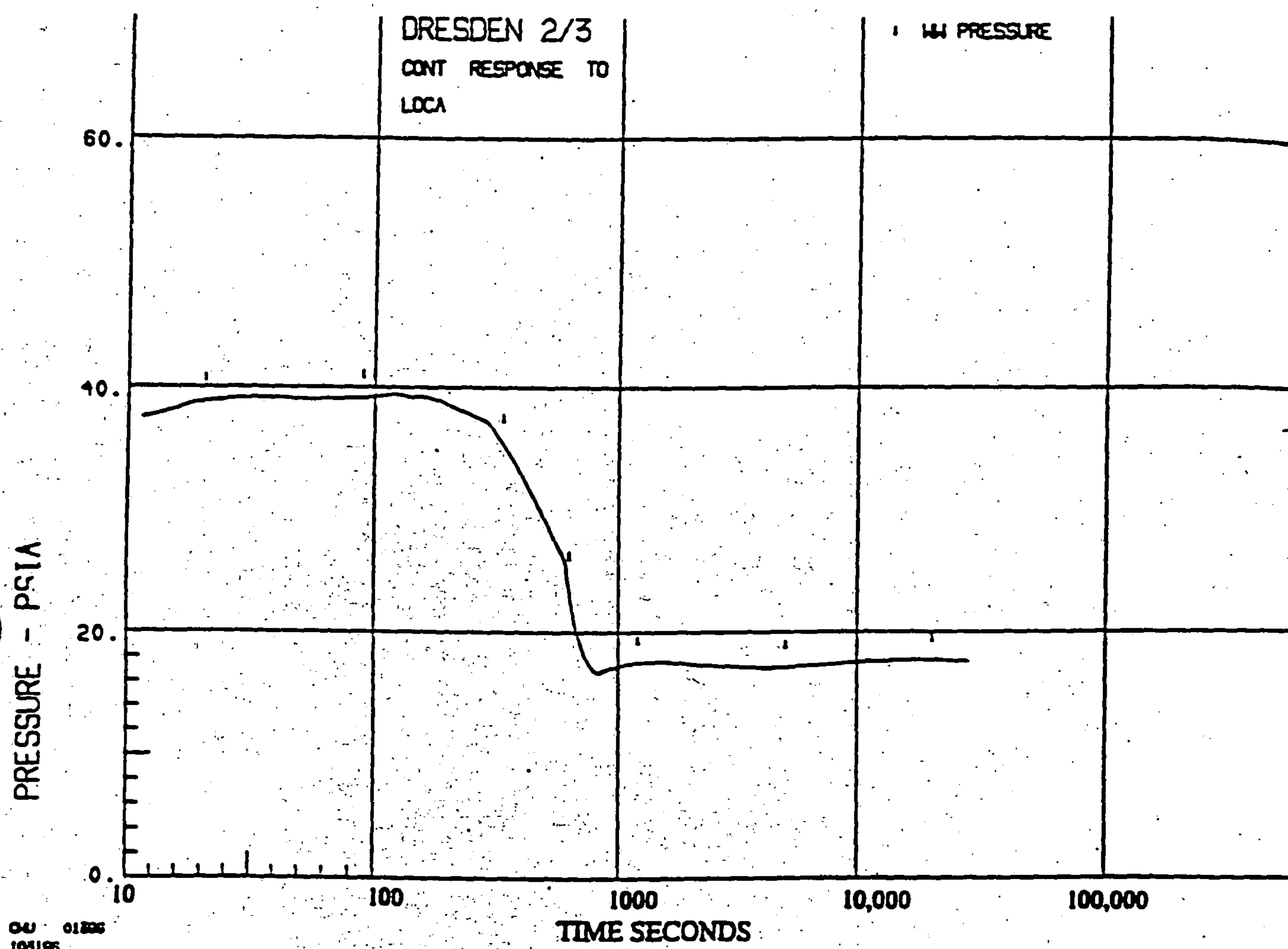

Figure 6.2-20d - Long Term Suppression Chamber Pressure Response. Case 2a1 - Low (20%) Mixing Efficiency

that could be accommodated without any clad temperature rise would be extended from 0.2 to 0.7 square feet. The 0.7 square foot break is equivalent to a double-ended rupture in an 8-inch line. For very large breaks the continued injection of feedwater does not influence the peak clad temperature curve so markedly. These breaks would cause the vessel to blowdown very rapidly with or without feedwater. The resultant core thermal transient would be terminated by flooding the inner shroud and since any feedwater flow would enter the vessel outside the shroud, feedwater cannot be considered as part of the flooding capacity. Hence, the end points of curves C and D are at essentially the same peak clad temperature.

6.3.3.4.3 Net Positive Suction Head for ECCS Pumps

Insert G

To demonstrate that adequate net positive suction head (NPSH) will be available to the core spray and LPCI pumps at all times, an analysis was performed based on the following degraded conditions:

A. An indefinite loss of offsite power.

B. An indefinite loss of one onsite diesel generator.

C. The maximum service water temperature — normally the service water is at least 10°F cooler than maximum, which would reduce the peak pool temperature.

D. The maximum pre-accident drywell temperature (150°F) and relative humidity (100%). Normal operating conditions are about 135°F/35% relative humidity which increases NPSH by about 4 feet due to increased gas pressure resulting from the increased moles of noncondensible gases in the containment. Even if a small leak preceded the accident, thereby increasing the drywell temperature and relative humidity, the moles of noncondensible gases contained in the primary containment would still be specified by the normal conditions since venting of these gases is not allowed. Therefore, the assumed initial conditions are very conservative.

E. A minimum pre-accident containment pressure (0 psig) — normal operating pressure is currently 1.10 to 1.25 psig, and there are no circumstances under which a subatmospheric pressure would occur.

F. Accidental actuation of containment sprays at rated flow — procedurally the operator will actuate the sprays only in the event of an abnormal rise in containment pressure. Therefore, actuation of the containment sprays requires an operator error. Actuation of the containment sprays will rapidly reduce the containment pressure.

G. Containment gas leakage at the rate of 5% per day.

DFL 96075

The results of the analysis are summarized in Figure 6.3-80 where the containment pressure available is shown to always exceed the containment pressure required to operate the pumps at rated flow. An evaluation was performed using the orginal design basis information and assumptions that validated this figure for the existing 1LPCI/2CCSW pump configuration.

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Additional analyses were performed to determine the available NPSH for LPCI pumps assuming various malfunctions as defined in GE SIL 151. The analyses considered the following LPCI pump operating configurations:

A. Case 1 — Three and four pump combinations injecting simultaneously into both recirculation loops with one broken loop.

B. Case 2 — Three and four pump combinations injecting into one broken loop. The break in this case is assumed at the injection point in the recirculation loop, and no credit is taken for recirculation piping resistance.

C. Case 3 — Three and four pump combinations injecting into the intact loop with the discharge valve open.

The following assumptions were made in the calculations:

A. Torus water temperature of 130°F was assumed and was considered to be the maximum temperature.

B. No credit was taken for the increase in torus level after the LOCA.

C. Atmospheric pressure about the suppression pool and in the drywell was taken to be 14.7 psia.

D. Reactor pressure was taken as 56 psig.

E. The containment cooling heat exchanger bypass valve was assumed open.

F. LPCI design flow point of 5350 gal/min was used.

G. Runout was interpreted as a point on the flow characteristic curve at which cavitation occurs because the net positive suction required exceeds the available NPSH.

LPCI pump (DFL 96-068)

H. The suction valve isolates even if the discharge valve does not and, thus, will prevent backflow through the pump.

The results of these analyses are presented in Tables 6.3-17 and 6.3-18. A review of the data indicates only a few instances in which the required NPSH exceeds the available NPSH. In fact, all configurations for which a small deficit in required NPSH exists involve postulated failures or breaks which prevent the reflooding of the vessel by the LPCI system. The most extreme case is a 3-foot deficiency in one of the Case 2 three-pump combinations. The presence of a 2-psig pressure in the drywell will offset this deficiency, and 2 psig in the drywell is one of the signals which initiates the ECCS. Although drywell pressure is taken as atmospheric, for the breaks assumed in the calculations, there will be an estimated 20 to 35 psig in the drywell and suppression chamber. It is, therefore, concluded that a condition will not exist wherein the NPSH will not be sufficient to prevent cavitation. However, the pump vendor has conducted cavitation tests at points between 4000 and 6000 gal/min with no significant effect on the pump internals after an hour of such operation.

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The evaluation of post LOCA NPSH for Core Spray and LPCI pumps was divided into two portions:

- Short Term (less than 600 seconds-no operator action credited-vessel injection phase)
- Long Term (greater than 600 seconds-operator action credited-containment cooling phase)

It should be noted that the 600 second mark for operator action was established per UFSAR Sections 6.2.1.3.2.3 as the time in which credit for manual initiation of containment cooling can be taken.

6.3.3.4.3.1 <u>CS/LPCI PUMP Post-LOCA Short Term Evaluation</u>

A calculation was performed to evaluate LPCI and Core Spray NPSH requirements in the short-term post-DBA LOCA. Short-term is considered the time period from initiation of the Design Basis LOCA until 10 minutes post-accident when operator action is credited.

The most limiting failures relating to Peak Clad temperature (PCT) were considered:

1) SF-LPCI: failure of a LPCI Injection Valve
   This case results in two (2) Core Spray pumps injecting at maximum flow with four (4) LPCI pumps running on minimum flow only.

2) SF-DG: Loss of a Diesel Generator
   This case results in two (2) LPCI pumps and one (1) Core Spray pump injecting at maximum flow.

The most limiting failure with regards to LPCI/CS pump NPSH, however, is failure of the LPCI Loop Select Logic (SF-LSL). This scenario involves the LPCI pumps injecting into a broken reactor recirculation loop and is discussed in detail in GE SIL 151. From a PCT perspective, this case is identical to the SF-LPCI case since the net result of each scenario is two Core Spray pumps injecting into the core with no contribution from the LPCI pumps. SF-LSL is the NPSH limiting scenario due to the LPCI/CS pumps operating at the highest achievable flow rates, resulting in the maximum pump suction losses and NPSH requirements. Additionally, the LPCI water escaping to the containment results in reduced containment and suppression pool pressures, which limit the available NPSH, See Section 6.2.1.3.2.2. Both the SP-LSL and SF-DG single failure cases were evaluated in the calculation. The SF-LPCI case is bounded by the SF-LSL case.

The calculation uses the following inputs:

1. Maximum LPCI and Core Spray pump flow conditions (un-throttled system, reactor pressure at 0 psid), maximizing suction friction losses and NPSH required.

   a. Maximum LPCI and Core Spray pump flows-Case SF-LSL

CS	1-Pump Maximum Injection Flow:	5800 gpm
LPCI	3-Pump Maximum Injection Flow:	16,750 gpm [5610/11,140]
LPCI	4-Pump Maximum Injection Flow:	20,600 gpm

   b. Maximum LPCI and Core Spray pump flows-Case SF-DG

CS	1-Pump Maximum Injection Flow:	5800 gpm
LPCI	2-Pump Maximum Injection Flow:	11,600 gpm

2. Increased clean, commercial steel suction piping friction losses by 15% to account for potential aging effects, thus maximizing suction losses.

3. To account for strainer plugging, the most limiting of the four torus strainers is assumed 100% blocked, while the remaining three strainers are assumed clean.

4. Containment conditions used in the analysis are given in UFSAR Section 6.2.1.3.2.3 which minimize NPSH available..

5. Initial suppression pool temperature is 95°F, which is the maximum allowable pool temperature under normal operating conditions. This value is used as the initial pool temperature to maximize pool peak temperature, and is used as a minimum temperature during the LOCA to maximize piping friction losses (maximum viscosity).

6. The minimum suppression pool level elevation using a maximum drawdown of 2.1 ft. is 491'5", (491.4 ft). LPCI and Core Spray pump centerline elevation is 478.1 ft.

7. The suppression pool strainers have a 100% clean head loss of 5.8 ft. @ 10,000 gpm.

8. NPSHR values at various LPCI/CS pump flows are taken from the vendor pump curves.

The minimum suppression pool pressure required to meet LPCI/CS pump NPSH requirements was determined for both the SF-LSL and SF-DG single failure cases. The minimum pool pressure required was compared to the minimum pool pressure available post-LOCA for two cases:

- Case 6a2 with 60% thermal mixing used for SF-LSL containment conditions.
- Case 2a1 with 100% thermal mixing used for the SF-DG containment conditions.

If the pressure available is greater than the pressure required, then adequate NPSH exists. If the available pressure is less than the pressure required, then the potential exists for the pumps to cavitate, resulting in reduced flows.

For the SF-LSL case, no cavitation is expected to occur for the first 290 seconds post-LOCA. During this time, the LPCI and CS pumps will deliver maximum flow of 5800 gpm per pump. Since PCT occurs at about 170 seconds, the CS pumps will deliver adequate flow to ensure no impact on PCT. After 290 seconds, the LPCI and CS pumps may cavitate, resulting in reduced flows. The CS pump NPSH deficit reaches a maximum of 10.0 feet at 533 seconds. Under these conditions for NPSH, Core Spray pump flow will reduce from 11,600 gpm (5800 gpm per pump) at 290 seconds to about 10,200 gpm (5100 gpm per pump). This represents the minimum expected flow from the Core Spray pump for the 290 to 600 second interval. Figure 6.3-83a gives pool pressure, temperature, and LPCI & CS pump required pressure for several pump combinations over the short-term period for the SF-LSL case.

As stated above, a potential exists for the LPCI and CS pumps to cavitate after the first 290 seconds post-LOCA. However, as part of the original design of the plant, the pump vendor performed a cavitation test on a LPCI pump (a Quad Cities (RHR) pump was actually used). The Cavitation Test Report for Bingham 12x14x14x1/2 CVDS pump demonstrated no evidence of any damage to the pump components from cavitation with up to one hour of operation at the cavitating condition.

This analysis was reviewed with respect to the Core Spray pump and the results determined to be applicable. The rationale for this determination is the following:

- Core Spray and LPCI are the same make and model pump (only impeller diameter is different.

- LPCI and Core Spray utilize the same impeller pattern, and therefore the same overall characteristics.

- All LPCI and Core Spray pumps have tested NPSHR curves that are essentially identical (within 1%).

For the SF-DG case, adequate suppression pool pressure is available to satisfy LPCI/CS pump NPSH requirements for the entire 10 minute period. That is, no LPCI/CS pump cavitation will occur, nor will any reduction take place from 5800 gpm for Core Spray and 11,600 gpm for LPCI (5800 gpm per pump). Figure 6.3-83b gives pool pressure, temperature, and LPCI & CS pump required pressure for several pump combinations over the short-term period for the SF-DG case.

LPCI/CS pump flow requirements are as follows:

- For the SF-LSL and SF-LPCI cases, a two-pump Core Spray flow of ≥11,300 gpm up to the 200 second mark results in a PCT of ≤2030°F.

- For the SF-DG case, a two-pump LPCI flow of at least 9000 gpm and a single Core Spray pump flow of at least 5650 gpm are required for PCT considerations.

- Only a constant nominal total pump flow of 9000 gpm is required to achieve 2/3 core reflood in less than 5 minutes.

Therefore, under the most limiting single failures, the ECCS will still perform its function in the short term with no credit for operator action.

6.3.3.4.3.2 <u>CS/LPCI PUMP Post-LOCA Long Term Evaluation</u>

The evaluation examined the Net Positive Suction Head (NPSH) available to the Dresden LPCI and Core Spray (CS) pumps after the first 600 seconds following a DBA LOCA for several pump combinations.

If the suppression pool pressure available is greater than the pressure required for adequate NPSH to the LPCI and CS pumps, then these pumps have adequate NPSH for operation. If the suppression pool pressure available is less than the pressure required by the pumps, then there is in-adequate NPSH for operation and potential pump cavitation. In these situations, LPCI pump flows were reduced below nominal values and new cases were run to establish the ability of the operator to throttle the pumps to an acceptable condition.

A spectrum of pump combinations was explored to determine the bounding NPSH case for the LPCI and Core Spray pumps. It will be shown that the 4 LPCI/2 CS pump case is bounding for NPSH.

The calculation uses the following inputs:

1. Various LPCI and Core Spray pump flow conditions are evaluated (See table 6.3-18).

2. Increased clean, commercial steel suction piping friction losses by 15% to account for potential aging effects, thus maximizing suction losses.

3. It is assumed that at 10 minutes into the accident, operator action will be taken to ensure that the LPCI/CS pumps have been throttled to their rated flows (5000 and 4500 gpm respectively). Therefore, the pumps are at their rated flows at the time of peak suppression pool temperature (~20,000 seconds).

4. To account for strainer plugging, the most limiting of the four torus strainers is assumed 100% blocked, while the remaining three strainers are assumed clean.

5. Initial suppression pool temperature is 95°F. This is the maximum allowable suppression pool temperature under normal operating conditions.

6. The containment pressure and pressure responses provided in case 2a(1) with 20% mixing as shown in UFSAR Section 6.2.1.3.2.3 are used. These responses result in the bounding NPSH case.

7. The minimum torus level elevation with a maximum drawdown of 2.1 ft is 491.4 ft. At the time of peak suppression pool temperature, a recovery of 1.1 ft occurs, resulting in a net drawdown of 1 ft.

8. The torus strainers have a head loss of 5.8 ft @ 10,000 gpm clean.

9. LPCI and Core Spray pump centerline elevation is 478.1 ft.

The calculation determined the minimum suppression pool pressure required to meet pump NPSH requirements for several ECCS pump combinations. The calculation shows that adequate NPSH exists to meet Core Spray pump requirements post-LOCA for all ECCS pump combinations. However, potential exists for the LPCI pumps to cavitate at rated flows in the 4 LPCI/2 CS and 3 LPCI/2 CS pump scenarios. For these cases, throttling of the LPCI pumps to below rated flows may be required to ensure NPSH requirements are met. A minimum of 5000 gpm total LPCI flow is required for containment cooling. Table 6.3-18 provides NPSH margin for throttled LPCI cases. Figure 6.3-84 gives the pool pressure and LPCI pump pressure requirements for several pump combinations over the long-term period.

Operators have been trained to recognize cavitation conditions and to protect their equipment by throttling flow if evidence of cavitation should occur due to inadequate NPSH. The control room has indication of both discharge pressure and flow on each division of Core Spray and LPCI. The Emergency Operating Procedures (EOP's) also provided guidance to maintain adequate NPSH for the Core Spray and LPCI pumps. The NPSH curves provided in the EOP's utilize torus bulk temperature and torus bottom pressure to allow the operator to determine maximum pump or system flow with adequate NPSH. These curves are utilized as long as the core is adequately flooded.

6.3.3.4.3.3 <u>NPSH Margin</u>

Figure 6.3-80 gives a graphical representation of the minimum required containment pressure to meet NPSH requirements for both LPCI and Core Spray pumps. The chart covers both the short-term (≤ 600 seconds) and long-term (> 600 seconds) periods.

The containment pressure response shown on the chart, and covered in UFSAR Section 6.2.1.3.2.3, is for the following pump combinations over the short and long-term periods:

≤ 600 sec	4 LPCI pumps/ 2 CS pumps	Case 6a1-60% thermal mixing
> 600 sec	1 LPCI pump/1 CS pump	Case 2a1-20% thermal mixing

The LPCI and Core Spray required containment pressure on the chart is for the following pump combinations and flows over the short and long-term periods:

≤ 600 seconds	4 LPCI pumps @ 5150 gpm each/ 2 CS pumps @ 5800 gpm each
> 600 seconds	4 LPCI pumps @ 2500 gpm each/ 2 CS pumps @ 4500 gpm each

At runout flows, the Core Spray pumps have the potential to cavitate for a short period of time (290 sec-600 sec) during the ≤ 600 second period.

This is acceptable per the discussion in UFSAR Section 6.3.3.4.3.1. Figure 6.3-80 also shows graphically the ability to throttle the Core Spray and LPCI pumps to an acceptable long term operating condition as discussed in UFSAR Section 6.3.3.4.3.2.

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The evaluation of post LOCA NPSH for Core Spray and LPCI pumps was divided into two portions:

- Short Term (less than 600 seconds- no operator action credited -vessel injection phase)
- Long Term (greater than 600 seconds -operator action credited - containment cooling phase)

It should be noted that the 600 second mark for operator action was established per UFSAR Sections 6.2.1.3.3 as the time in which credit for manual initiation of containment cooling can be taken.

<u>CS/LPCI PUMP Post-LOCA Short Term Evaluation</u>

This calculation examines the Net Positive Suction Head (NPSH) available to the Dresden LPCI and Core Spray (CS) pumps in the first 600 seconds following a DBA-LOCA. Specifically, the GE SIL 151 case was evaluated, which postulates a failure of the LPCI Loop Select logic. Such a failure results in 4 LPCI and 2 CS pumps operating, with the LPCI pumps injecting into a broken reactor recirculation loop (minimizing flow to reactor for Peak Clad Temperature considerations). Due to the high flows anticipated, the Core Spray pumps may cavitate, resulting in reduced system flow. This reduced flow was calculated and compared to the minimum flow required of the CS system. This calculation will be performed using a reduced initial torus temperature of 75°F and a torus pressure of 2 psig.

The minimum suppression pool pressure required to satisfy LPCI and CS pump NPSH requirements was determined under short-term post-LOCA conditions. If the pool pressure required is greater than the pressure available, then the potential exists for the pumps to cavitate, resulting in reduced flows. A minimum Core Spray system flow of 10,552 (5276 per pump) is required for the first 200 seconds post-accident to ensure the PCT remains below 2200°F while a nominal Core Spray flow of 4500 gpm is acceptable beyond 200 seconds.

NPSH Required (NPSHR) curves for the LPCI/CS pumps are provided on the original vendor pump curves. These NPSHR curves represent the point at which a 3% reduction in pump developed head has occurred. Cavitation tests were performed on this pump model by the vendor at various flow rates. The test data indicates that the pump remains stable for several feet below the NPSHR value, which is expected, before the pump head collapses (full cavitation). Based on the flow rates at which the pumps were tested, it is possible to develop a reduced NPSHR curve that represents the point at which full cavitation has been achieved. Thus, given a known set of conditions (temperature, pressure, level), the reduced flows at which the pumps will operate was determined as follows:

1. Assume initial operating pump flow rate (maximum pump flow).

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2. Determine the suppression pool pressure required to satisfy the pump's reduced NPSH requirements using the assumed pump flow and the expected torus temperature at 200 seconds post-LOCA.
3. Reduce pump flow estimate until the pool pressure required equals the minimum pool pressure available. It is at this flow that the pump will be in full cavitation and the total developed head (TDH) will drop off. Since this drop-off is essentially vertical, the pump curve will intersect the system curve at this flow, i.e., this is the flow at which the system will operate.

Maximum LPCI and Core Spray pump flows used are as follows. These flows were calculated at 0 psid between the reactor and the containment.

Core Spray 1-Pump Maximum Injection Flow	5800 gpm
LPCI 4-Pump Maximum Injection Flow to broken loop	20,600 gpm

For the purposes of this evaluation, a suppression pool pressure of 2 psig was assumed. This is consistent with the discussion provided in Dresden UFSAR Section 6.3.3.4.3, in which the presence of 2 psig in the drywell is expected since this is one of the signals which initiates the ECCS. This assumption is conservative based on the following:

- The Dresden post-LOCA containment pressure response (Dresden UFSAR Figure 6.2-19) indicates an expected suppression pool pressure of >15 psig at 200 seconds, and >10 psig at 600 seconds.
- The Quad Cities post-LOCA expected suppression pool pressure is >20 psig at 200 seconds and 600 seconds (Quad Cities UFSAR Figure 6.2-16).

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While no Dresden-specific short-term containment temperature response exists, a reasonable estimate can be made using the following existing analyses:

- The temperature profiles for Quad Cities are available and are considered representative for use at Dresden, based on plant similarities with respect to containment size, core power, and reactor operating parameters. The Quad Cities containment response (Quad Cities UFSAR Figure 6.2-18) indicates the pool temperature at 200 seconds is 144°F, and at 600 seconds is 147°F, based on a 90°F initial pool temperature. These values were developed using original analysis techniques, including the May-Witt decay heat model, no feedwater flow and no pump heat added. If corrected to a 95°F initial pool temperature (assuming a one-to-one short-term temperature relationship), these values are conservative.

Therefore, for the purposes of this evaluation, the conservative Quad Cities temperatures will be used.

It is assumed that a reduction in initial suppression pool temperature will result in a corresponding linear reduction in the short-term pool temperature response, since pool cooling is not active. Given this assumption, therefore, for a reduced initial pool temperature of 75°F (15°F reduction from Quad Cities values based on 90°F initial torus temperature), the pool temperature at 200 seconds post-LOCA is 129°F, and at 600 seconds is 132°F.

A drawdown of 2.1 feet was used.

GE SIL 151 includes a case of all 4 LPCI pumps injecting into both reactor recirculation loops simultaneously, with one loop broken. While it is expected that this case may result in slightly higher LPCI pump flow rates, a significant amount of water will be injected into the reactor through the intact loop. Therefore, any reduction in Core Spray system flow due to cavitation below the minimum required flow will be made up by the LPCI flow injecting into the reactor. Therefore, it is expected that the PCT will not be challenged in this case.

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It was determined that when all six ECCS pumps are running, the potential exists for the LPCI and Core Spray pumps to cavitate. The LPCI pump NPSH deficit is relatively small and will result in a negligible reduction in flow due to cavitation (< 100 gpm per pump). The reduced flow at which the Core Spray pumps will operate in the first 200 seconds was estimated to be greater than 5300 gpm per pump, which is adequate to ensure the PCT remains below 2200°F. The Core Spray pump reduced flow beyond 200 seconds would be at least 5300 gpm per pump, which is greater than the nominal 4500 gpm per pump required. Therefore, it is concluded that adequate NPSH exists to ensure the LPCI/CS pumps can perform their safety function using a reduced initial torus temperature of 75°F and a torus pressure of 2 psig.

CS/LPCI Pump Post-LOCA Long Term Evaluation

The minimum suppression pool pressure required to ensure LPCI and CS pump protection was determined under long-term post-LOCA conditions at the bounding NPSH condition. Since the suppression pool pressure remains constant after 600 seconds (14.7 psia), the bounding NPSH condition occurs at the time of peak suppression pool temperature. If the pressure required is less than 14.7 psia, then the pump NPSH requirements have been met. If the required pressure is greater than 14.7 psia, then the potential exists for the pumps to cavitate. In these situations, LPCI pump flows will be reduced to below-nominal values and new cases were run to establish the ability of the operator to throttle the pumps to an acceptable condition. This acceptable condition was defined by the following criteria:

1) Adequate NPSH to the pumps - minimum pressure available is greater than minimum pressure required for the LPCI and CS pumps.

2) Adequate containment cooling - the minimum containment cooling flow analyzed is 5000 gpm (LPCI) through a single LPCI heat exchanger.

If an acceptable condition cannot be achieved by throttling, then cases involving reduced suppression pool temperatures was explored.

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Various pump combinations were explored to determine the bounding NPSH case for the LPCI and Core Spray pumps. It was shown that NPSH for the LPCI/CS pumps with 4 LPCI/2 CS pumps running is the bounding NPSH case. This calculation is bounding for NPSH due to use of the following conservative inputs:

- maximum long-term suppression pool temperature post-LOCA, thus maximizing the vapor pressure and minimizing NPSH margin
- torus pressure at time of peak temperature is atmospheric, thus minimizing NPSH margin
- Technical Specifications minimum suppression pool level including drawdown, minimizing elevation head and minimizing NPSH margin
- increased clean, commercial steel suction friction losses by 15% to account for aging effects

An NPSH analysis was performed for the LPCI/CS pumps under bounding, long-term post-accident conditions with atmospheric pressure in the torus. Selecting inputs to minimize NPSH margin, it was determined that the potential exists for the LPCI and CS pumps to cavitate in most of the pump scenarios. For these cases, throttling of the LPCI pumps may be required to ensure NPSH requirements are met. Specific cases involving throttled LPCI pumps were evaluated to establish the ability of the operator to throttle the pumps to an acceptable condition. The results of these cases were as follows:

- In the 3 LPCI/2 Core Spray case, the single pump LPCI loop may need to be throttled to below 5000 gpm, and containment heat removed with the 2-pump loop. This will ensure the LPCI heat exchanger receives its rated LPCI flow. Alternatively, a LPCI pump can be dropped to gain the required NPSH margin.

- In the 1 LPCI/2 Core Spray case, an NPSH deficit still exists after maximum throttling of the LPCI pump to 5000 gpm. It was determined that a reduction in the peak suppression pool temperature to 160°F would result in positive NPSH margin. This is achieved by maintaining a CCSW maximum inlet temperature of 75 deg F and a torus water maximum initial temperature of 75 deg F.

Therefore, at a reduced suppression pool peak temperature of 160°F, it is concluded that under all post-LOCA pump combinations, positive NPSH margin can be obtained by throttling the available LPCI pumps.

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Operators have been trained to recognize cavitation conditions and to protect their equipment by throttling flow if evidence of cavitation which would occur if adequate NPSH was not available is observed. The control room has indication of both discharge pressure and flow on each division of Core Spray and LPCI. The Emergency Operating Procedures (EOP's) also provided guidance to maintain adequate NPSH for the Core Spray and LPCI pumps. The NPSH curves provided in the EOP's utilize torus bulk temperature and torus bottom pressure to allow the operator to determine maximum pump or system flow with adequate NPSH. These curves are utilized as long as the core is adequately flooded.

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The original TS Bases 3.7A states that a full loop of suppression pool cooling (2 LPCI/2 CCSW) will provide sufficient cooling that reliance on overpressure is not required to assure adequate NPSH for the ECCS pumps. This case is less restrictive than the above analysis in that offsite power would need to be available to support the equipment lineup. The above analysis demonstrates that in the most limiting scenario, NPSH requirements can be met without crediting overpressure, but with little or no margin.

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During a LOCA, the operator's concern will be restoration of the vessel water level. The LPCI flow will be among the parameters closely monitored in the minutes immediately after the LOCA. The operator has several motor-operated valves available to him in the main control room to adjust flowrates or even isolate flow paths. It is, therefore, concluded that operator observation and response to flow conditions will be completed shortly after the LOCA.

Because of the falling head characteristics of these pumps, the brake horsepower requirements are nearly constant from 4000 to 6000 gal/min. It is thus concluded that no overload will occur for either the LPCI pumps or for the emergency diesel generators powering them in the event of a loss of offsite power.

It is, therefore, concluded that for the conditions evaluated, no threat to the long-term cooling capability exists.

Hence, adequate NPSH is ensured at all times to allow continuous operation of the LPCI and core spray pumps. ~~at rated flow.~~

6.3.3.4.3.4 HPCI NPSH

The HPCI subsystem takes suction from the condensate storage tank which remains cold throughout the plant cooldown so that the NPSH available is unaffected by torus heatup. If suction were taken from the torus, the maximum torus water temperature would be less than 140°F and the minimum NPSH available would be 30 feet compared to the 21 feet required by the HPCI pump.

6.3.4 Tests and Inspections

6.3.4.1 Core Spray Subsystem

Provisions have been designed into the core spray subsystem to test the performance of its various components. These provisions and tests are summarized as follows:

A. Instrumentation

- Operational test of entire subsystem.
- Periodic subsystem tests using test lines.

B. Valves

- Preoperational test of entire subsystem.
- Periodic subsystem tests using test lines.
- Test leak-off lines between isolation valves.
- Test drainline on pump side of outboard isolation valves.
- Motor-operated valves can be exercised independently.

C. Pumps

- Preoperational test of entire subsystem.
- Periodic subsystem tests using test lines.
- Monitoring pump seal leakage.

Table 6.3-17

LPCI SYSTEM PERFORMANCE WITH THREE PUMPS IN OPERATION FOR CASES OUTLINED IN GENERAL ELECTRIC SIL 151

Case No.	Pump Flows (gal/min)		NPSHR (feet of water)		NPSHA at 130°F (feet of water)	
	A and/or B	C and/or D	A and/or B	C and/or D	A and/or B	C and/or D
1	11,220	5,920	35	39	34	41
	5,750	11,620	37	37	41	34
2	11,490	5,920	37	39	34	41
	5,880	11,620	39	37	41	34
3	10,370	5,300	30	32	36	41
	5,300	10,320	32	30	41	36

Case No. 1 — Three pumps injecting into two recirculation loops with one loop broken.

Case No. 2 — Three pumps injecting into one broken loop. Break at the injection point in the recirculation loop. No credit taken for recirculation piping resistance.

Case No. 3 — Three pumps injecting into one intact loop with the discharge valve open.

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Table 6.3-18

LPCI SYSTEM PERFORMANCE WITH FOUR PUMPS IN OPERATION FOR CASES OUTLINED IN GENERAL ELECTRIC SIL 151

Case No.	Pump (Pair) Flows (gal/min)		NPSHR (feet of water)	NPSHA at 130°F (feet of water)
	AB Pair	CD Pair		
1	10,860	11,000	34.0	33.9
2	10,640	10,770	33.0	34.3
3	9,560	9,470	28	36.1

The following assumptions were used in the calculations:

1. Design flow, pump pair: 10,700 gal/min.
2. Runout flow, pump pair: 12,000 gal/min.
3. NPSH calculated for greater pump flow in each case.
4. Friction drop for NPSH calculation at flows other than design obtained by square of flows factor.
5. Torus water temperature from GE process diagram 730E775.
6. Pressure above torus 14.7 psia (reference Regulatory Guide 1.1).
7. Strainer nearest pump is plugged (reference GE 730E775).

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Table 6.3-18

EFFECT OF THROTTLING ON LONG-TERM LPCI NPSH MARGIN

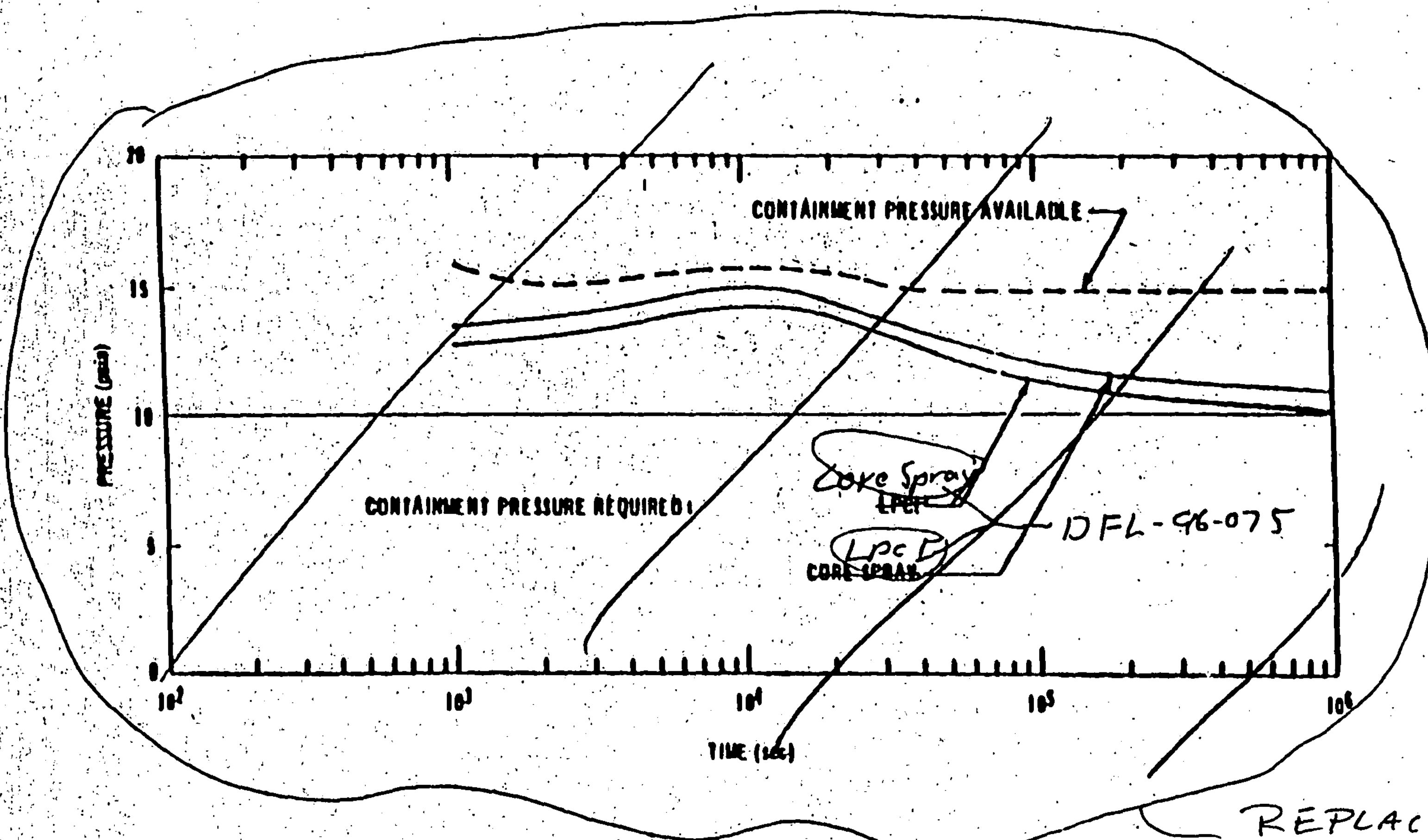
NPSH margins for all attainable pump combinations at flow rates 5000 gpm LPCI and 4500 gpm CS:

LPCI/CS Pumps	Minimum LPCI Margin (ft)	Minimum CS Margin (ft)
4/2	-4.8	1.0
3/2	-1.7	4.2
2/2	0.7	6.8
1/2	3.8	8.5

NPSH margins with throttled LPCI flows:

LPCI/CS Pumps (LPCI flow rates per pump) All CS flow rates @ 4500 gpm per pump.	Minimum LPCI Margin (ft)	Minimum CS Margin (ft)
4/2 (2500)	10.6	6.6
3/2 (2500/5000)*	2.0	6.6
2/2 (2500)	12.4	8.6
1/2 (5000)	3.8	8.5

*Two pumps @ 2500, one pump @ 5000



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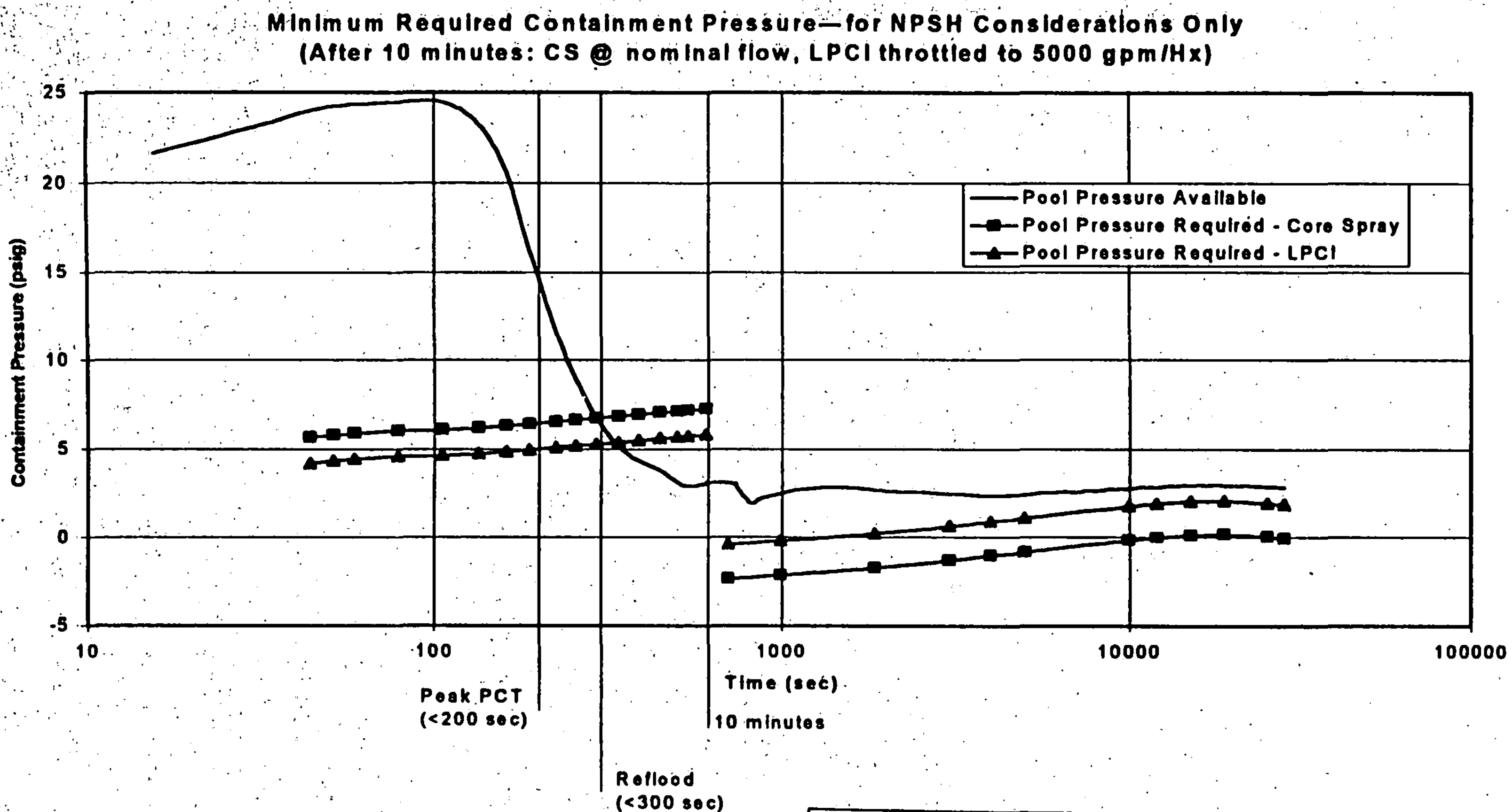
DRESDEN STATION
UNITS 2 & 3

MINIMUM CONTAINMENT PRESSURE AVAILABLE AND CONTAINMENT PRESSURE REQUIRED FOR PUMP NPSH

FIGURE 6.3-80

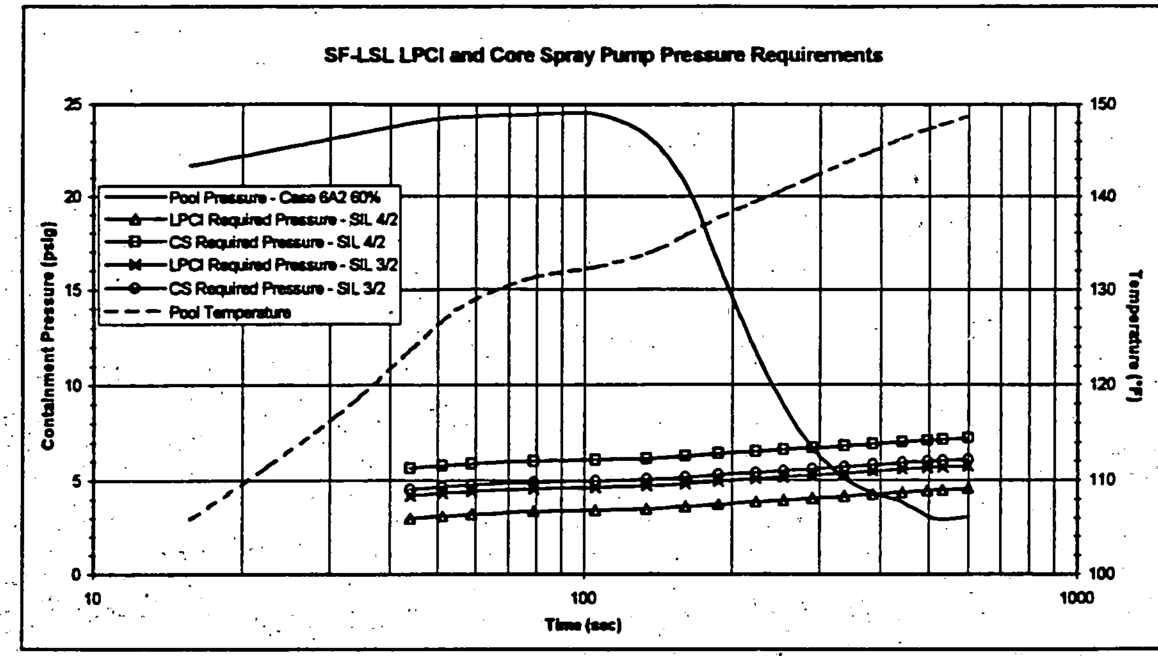


DRESDEN STATION
UNITS 2 & 3

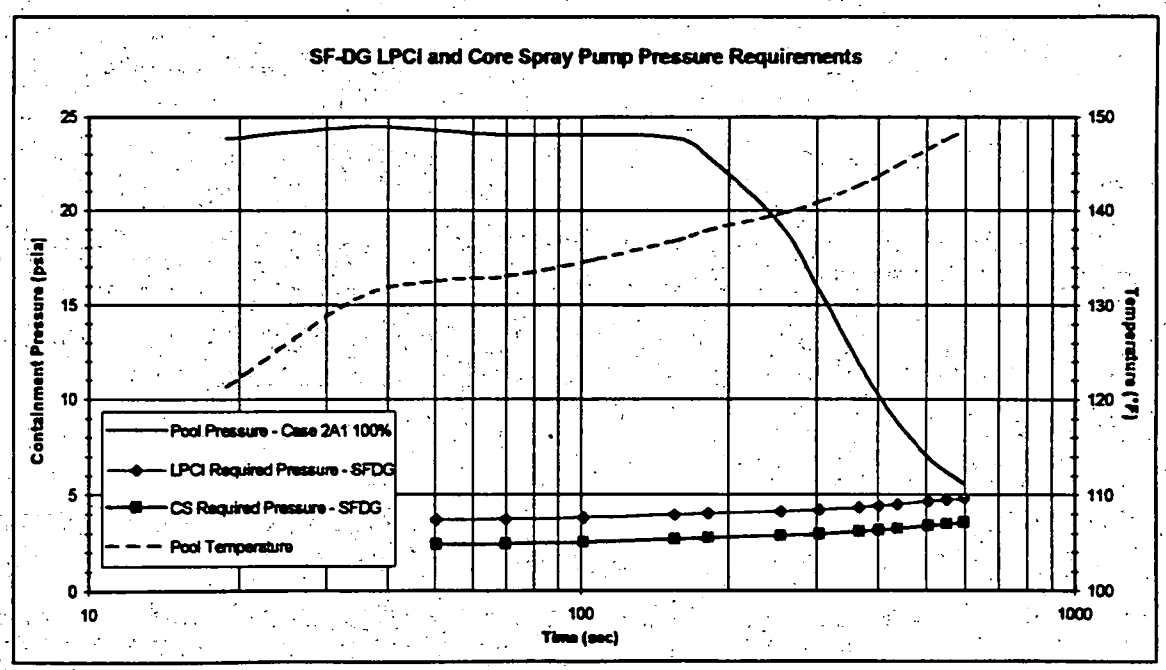
MINIMUM CONTAINMENT PRESSURE AVAILABLE AND CONTAINMENT PRESSURE REQUIRED FOR PUMP NPSH

FIGURE 6.3-80

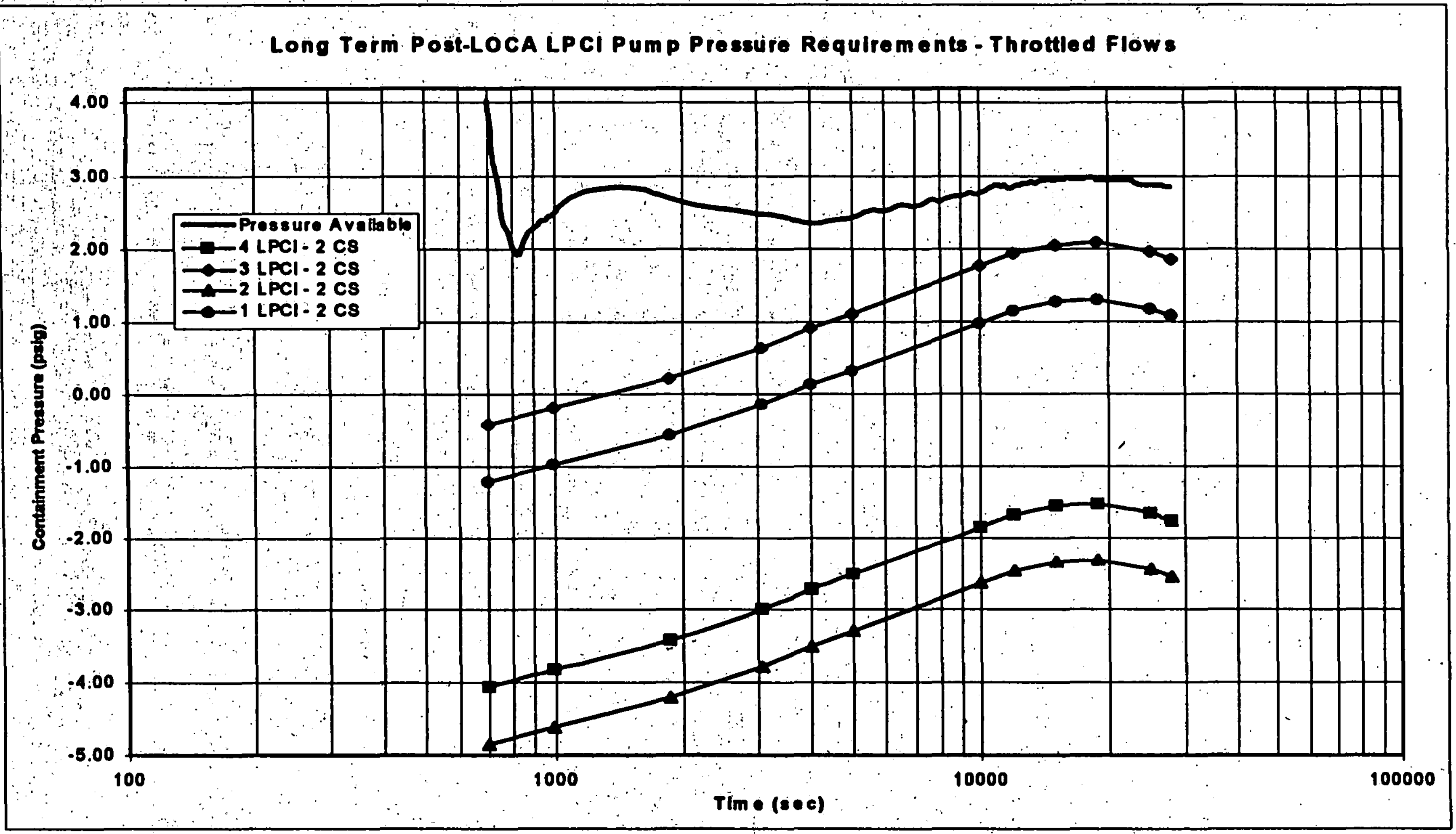
(a) SF-LSL CASE



(b) SF-DG CASE



DRESDEN STATION UNITS 2 & 3
SHORT TERM POST-LOCA LPCI & CS PUMP PRESSURE REQUIREMENTS
FIGURE 6.3-83



DRESDEN STATION UNITS 2 & 3
LONG TERM POST-LOCA LPCI PUMP PRESSURE REQUIREMENTS
FIGURE 6.3-84

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Page/Table/Figure No.	Revision	Page/Table/Figure No.	Revision
F 6.3-79	0	7.2-1	0
F 6.3-80	0	7.2-2	0
F 6.3-81	0	7.2-3	0
F 6.3-82	0	7.2-4	0
		7.2-5	0
6.4-1	0	7.2-6	0
6.4-2	0	7.2-7	0
6.4-3	0	7.2-8	0
6.4-4	01A	7.2-9	0
6.4-5	01A	7.2-10	0
6.4-6	0	7.2-11	0
6.4-7	0	7.2-12	0
6.4-8	0	7.2-13	0
6.4-9	0	7.2-14	0
6.4-10	0	7.2-15	0
6.4-11	0	7.2-16	0
6.4-12	01A	7.2-17	0
6.4-13	01A	7.2-18	0
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F 6.4-2	0	7.2-23	0
F 6.4-3	0	7.2-24	0
		7.2-25	0
6.5-1	0	7.2-26	0
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6.5-3	0	7.2-28	0
6.5-4	0	7.2-29	0
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		F 7.2-3	0
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		7.3-2	0
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6.6-3	0	7.3-5	0
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7.1-3	0	7.3-18	0
7.1-4	0	7.3-19	0
7.1-5	0	7.3-20	0
		7.3-21	0

diagrams of the CCSW systems for Units 2 and 3 are shown in Figures 9.2-1 (Drawing M-29, Sheet 2) and 9.2-2 (Drawing M-360, Sheet 2), respectively.

The CCSW system provides cooling water for the containment cooling heat exchangers during both accident and nonaccident conditions, as described in Section 6.2.2. System piping is arranged to form two separate, two pump, flow networks (loops). Each pair of CCSW pumps takes a suction from the crib house via separate supply piping. Two CCSW pumps discharge into a common header which routes the cooling water to that loop's associated heat exchanger. At the heat exchanger, heat is transferred from the low pressure coolant injection (LPCI) subsystem to the CCSW system, and subsequently to the river.

During normal plant operation, the CCSW system is not operating. Following an accident or other plant evolution which requires containment heat removal, the CCSW system is manually started. Each CCSW pump is rated at 500 hp with a service factor of 1.15. The CCSW pumps are powered by normal ac or diesel generator ac power. Additional CCSW pump information is provided in Table 9.2-1.

the manual operation of

The CCSW pumps develop sufficient head to maintain the cooling water heat exchanger tube side outlet pressure 20 psi greater than the LPCI subsystem pressure on the shell side ~~while maintaining rated heat exchanger flow~~. The ΔP is maintained by a differential pressure control valve. Maintaining this pressure differential prevents reactor water leakage into the service water and thereby into the river. A minimum of 5000 gpm is necessary to maintain containment cooling.

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The four CCSW pumps are located in the turbine building. Two of the four CCSW pumps (pumps B and C) are located in a single, common watertight vault for flood protection. To prevent the CCSW pump motors from overheating, the vault has two vault coolers. The cooling water for each cooler is provided from its respective CCSW pump discharge line through a four-way valve. This valve also permits flow reversal of the cooling water through these coolers to help clean the tubes. Refer to Section 3.4 for a discussion of the flood protection features at Dresden.

A continuous fill of the CCSW system is provided by the service water system or, in the case of a loss of power to the service water pumps, the diesel generator cooling water system may be aligned to provide the continuous fill. This eliminates the potential for water hammer upon CCSW system startup. The diesel generator cooling water system is discussed in Section 9.5.5.

The Unit 2 CCSW loops also provide a safety-related source of service water to the control room air conditioning condensers. Refer to Sections 6.4 and 9.4.1 for a description of the control room ventilation system.

in the CCSW outlet piping from the LPCI heat exchanger.

9.2.1.3 Safety Evaluation

Containment cooling is not immediately required following a design basis loss-of-coolant accident (LOCA). The required timing of the initiation of containment cooling functions by CCSW is described in Section 6.2.2. One of the two heat exchangers, two CCSW pumps, and one LPCI pump all in the same loop are the minimum requirements for containment cooling.

INSERT D to page 9.2-2

In order to maintain this pressure differential at rated LPCI flow, the CCSW flowrate is 5600 gpm during the limiting DBA LOCA with a diesel generator failure with a containment cooling pump combination of 1 LPCI/2 CCSW pumps operating in one loop.

DFL 96-140

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Table 9.2-1

CONTAINMENT COOLING SERVICE WATER EQUIPMENT SPECIFICATIONS

Containment Cooling Service Water Pumps

Number	4 (2 needed to provide required cooling capacity)
Type	Horizontal, centrifugal
Power source	Auxiliary transformer or emergency diesel
Capacity	3,500 gal/min each — ~~7,000~~ 5000 gal/min total
Head (approximately)	435 feet

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INSERT E to Table 9.2-1

During the limiting DBA LOCA with a diesel generator failure, the containment cooling pump combination is 1 LPCI/2 CCSW pumps. The CCSW pump flowrate of 5600 gpm will maintain the required pressure differential between the CCSW system and the LPCI system required to prevent the release of radioactivity in the event of a tube leak in the LPCI heat exchanger

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ATTACHMENT F

LPCI HEAT EXCHANGER PERFORMANCE ANALYSIS

LPCI/CCSW Heat Exchanger Performance Analysis

As discussed in Section 5.2.7 of this report, the proposed performance of the LPCI Heat Exchangers are based on the following parameters:

- LPCI minimum flow, 5000 gpm (See Section 4.2.5)
- CCSW minimum flow, 5000 gpm (See Section 4.2.3)
- Maximum CCSW inlet temperature, 95 °F
- Maximum tube side fouling resistance, 0.002 °F-ft^{2}hr/Btu
- Maximum shell side fouling resistance, 0.0005 °F-ft^{2}hr/Btu
- Number of tubes per heat exchanger, 2512 (6% of tubes are plugged)
- Heat transfer area per heat exchanger, 9880 ft^2

The above conditions result in a heat transfer capability of 71 x 10^6 Btu/hr when the LPCI inlet (suppression pool) temperature is 165 °F.

The heat exchanger heat transfer capability has been calculated by GE during the design basis reconstitution using a LPCI flow of 10,700 GPM and a CCSW flow of 7000 GPM.

Calculation of UA:

The overall heat transfer coefficient, U, is given by:

$$U=1/(Rw + Rf,s + Rf,t + Rfoul,s + Rfoul,t) \quad (5)$$

Where:

Rw = tube (CCSW) metal wall resistance
Rf,s = shell side fluid resistance
Rf,t = tube side fluid resistance
Rfoul,s = shell side fouling resistance
Rfoul,t = tube side fouling resistance

Reference x values
0.00025 °F-ft^2-hr/Btu

Values of the above thermal resistance's from Reference (25) are also shown above.

The reference flow conditions used in the present analysis are:

- 10700 gpm LPCI flow for shell side (2 LPCI/Cont. Cooling pumps)
- 165 °F LPCI inlet temperature for shell side
- 7000 gpm CCSW flow for tube side (2 CCSW pumps)
- 95 °F LPCI inlet temperature for tube side

Appropriate adjustments to the resistance values can be made to account for the impact of differences in flow conditions for the proposed license amendment.

Changes in Rf,s due to Changes to the Shell Side Flow

ATTACHMENT F

LPCI HEAT EXCHANGER PERFORMANCE ANALYSIS

The value of Rf,s is a reciprocal of the convective heat transfer coefficient. Namely,

Rf,s = 1/hfr,s

Where: hfr,s = convective heat transfer coefficient on shell side

The value of hfr,s is calculated from the following relationship

$$Nu_d = 0.33 Re_d^{0.6} Pr^{0.33} = (hfr.s*d)/kf$$

Where: Nu_d = Nusselt number
kf = fluid thermal conductivity
d = tube diameter
Pr = Prandtl Number = $(\mu C_p/kf)$
Re = Reynolds Number = $(\rho Vmd/\mu)$
ρ = fluid density
μ = fluid viscosity
C_p = specific heat

For this analysis it is assumed that the effect of fluid temperature change is negligible and the major effect is the effect of fluid velocity change. Therefore, the major impact of a reduction in pump flow rate is the impact due to a reduced fluid velocity. This means that if pump flow is changed then flow velocity is changed and the Reynolds number (Re) is changed.

Based on the relation for hfr,s given above, the effect on hfr,s due to a change on Re for the shell side is given by:

$$hfr,s\ (new\ shell\text{-}side\ flow) = hfr.s(reference\ flow) * (new\ shell\text{-}side\ flow/reference\ flow)^{0.6}$$

Since Rf.s=1/hfr,s

$$Rf.s\ (new\ shell\text{-}side\ flow) = Rf,s\ (reference\ flow) * (new\ shell\text{-}side\ flow/reference\ flow)^{-0.6} \quad (6)$$

<u>Changes in Rt,s due to Changes to the Tube Side Flow</u>

The value of Rf,t is a reciprocal of the convective heat transfer coefficient. Namely,

Rf,t=1/hfr,t

Where: hfr.s = convective heat transfer coefficient on tube side

The value of hfr,t is calculated from the following relationship;

$$Nu_d = 0.023 Re_d^{0.8} Pr^{0.333} = (hfr,t*d)/kf$$

For this analysis it is again assumed that the effect of fluid temperature is negligible and the major effect is the effect of fluid velocity. Therefore the major impact of a reduction in pump flow rate is the impact due to a reduced fluid velocity. This means that if pump flow is changed then flow velocity is changed and the Reynolds number (Re) is changed.

In a manner similar to that for the shell side,

ATTACHMENT F

LPCI HEAT EXCHANGER PERFORMANCE ANALYSIS

Rf,t (new tube-side flow) = Rf,t (reference flow) * (new tube-side flow/reference flow)$^{-0.8}$ (7)

Using the above relationships and the following assumptions, the U for the proposed license amendment can be calculated.

The impact of differences in the flow conditions on Rw. Rfoul,s and Rfoul,t is negligible with the range of flow conditions considered in the present analysis.

Rw = 0.00025
Rfoul,s = 0.0005
Rfoul,t = 0.0023

The fluid (convective heat transfer) resistances (Rf,s and Rf,t) are affected by the flow rate only within the range of flow conditions considered in the analysis, neglecting temperature effects. Using the procedure, calculating the values of Rf,s and Rf,t for different flow conditions described above, the following is calculated:

Rf,s = 0.000988
Rf,t = 0.001014

U = 197.9 Btu/hr - ft^2-ºF ***UA = 1.955 x 10^6 Btu/hr - ºF***

CALCULATION OF PROPOSED K:

The heat exchanger thermal performance, K, is used in the containment analysis performed with GE's SHEX code. The definition of K is given below:

$K = Q/(T_{hi}-T_{ci})$ (1)

Where: Q = heat exchanger heat transfer rate
T_{hi} = inlet temperature on hot fluid side (suppression pool water)
T_{ci} = inlet temperature on cold fluid side (service water)

A calculation procedure which is based on a parameter called heat exchanger effectiveness is used to calculate the heat exchanger performance parameter, K.

The heat exchanger effectiveness, ε, is defined in the following way:

ε = actual heat transfer/maximum possible heat transfer

Where: "actual heat transfer" is the actual heat transfer rate in the heat exchanger. Namely, this value is: Q defined above.

"maximum possible heat transfer" is the heat transfer rate when the fluid of lower flow rate in the heat exchanger reaches the inlet temperature of the other fluid. Namely, this value: $W_{min}\ C_P(T_{hi} - T_{ci})$.

In another way, ε is defined to be:

ATTACHMENT F

LPCI HEAT EXCHANGER PERFORMANCE ANALYSIS

$$\varepsilon = Q/(W_{min}C_P(T_{hi}-T_{ci})) \quad (2)$$

Where:

C_P = specific heat of water
W_{min} = lower value between shell-side and tube-side flow rates

From Equations (1) and (2) above, K can be calculated by the following equation:

$$K = \varepsilon\, W_{min}\, C_P \quad (3)$$

According to Reference (4), the value of ε for shell-tube heat exchangers is calculated by:

$$\varepsilon = 2*\{1+C+(1+C^2)^{1/2*}(1+\exp[-N(1+C^2)^{1/2}])/(1-\exp[-N(1+C^2)^{1/2}])\}^{-1} \quad (4)$$

Where:

$C = W_{min}/W_{max}$
$N = UA/W_{min}$

and

W_{max} = higher value between shell-side and tube-side flow rates.
W_{min} = lower value between shell-side and tube-side flow rates.
U = effective overall heat transfer coefficient
A= tube surface area

Thus, the K-value can be calculated for given shell-side and tube-side flow, using Equations (3) and (4), once the value of UA is determined.

For the evaluation of the Dresden Heat exchanger K-value, the value of UA is first determined as previously discussed. Then, the K-value is calculated using Equations (3) and (4), using the following proposed basis:

UA = 2.079×10^6 Btu/hr - °F (see previous discussion)

W_{max} = 5000 gpm = 2.5×10^6 lb/hr
W_{min} = 5000 gpm = 2.5×10^6 lb/hr

K = 281.7 Btu/sec - °F

Table F-2 below summarizes the results of the benchmark cases described above. Table F-3 below summarizes the results of the calculations to determine the K values for a long-term containment cooling configuration of one (1) LPCI Containment cooling pump and two (2) CCSW pumps.

TABLE F-2 - HEAT EXCHANGER - K VALUE BENCHMARK CASES			
Shell side flow rate (2 LPCI/Containment Cooling Pump)	Tube Side Flow Rate (2 CCSW pumps)	K Value	Heat Transfer Rate (165 °F shell side temperature, 95 °F tube side temperature
GPM	**GPM**	**BTU/SEC - °F**	**MBTU/HR**

LPCI HEAT EXCHANGER PERFORMANCE ANALYSIS

10700	7000	390.7	98.5
		391.3 (Ref. (20))	98.6 (Ref. (20))
5000	3500	249.5	62.87
		249.6 (Ref. (20))	62.89 (Ref. (20))

TABLE F-3 - LICENSE AMENDMENT CASE			
Shell side flow rate (1 LPCI/Containment Cooling Pump)	Tube Side Flow Rate (2 CCSW pumps)	K Value	Heat Transfer Rate (165 °F shell side temperature, 95 °F tube side temperature
GPM	**GPM**	**BTU/SEC - °F**	**MBTU/HR**
5000	5000	281.7	71.0

ATTACHMENT G

NON PROPRIETARY REFERENCES

Reference 1

DRE-97-0010 Dresden LPCI/Core Spray NPSH Analysis post-DBA LOCA - Long Term-Design Basis, Rev 0.