Attachment 1

REQUEST FOR ADDITIONAL INFORMATION
WESTINGHOUSE NUCLEAR SERVICE ADVISORY LETTERS
EXTENDED POWER UPRATE LICENSE AMENDMENT APPLICATION
ARKANSAS NUCLEAR ONE, UNIT 2 (ANO-2)

Westinghouse has issued three Nuclear Service Advisory letters (NSAL), NSAL-02-3, 4, and 5, to document the problem with the steam generator (SG) water level setpoint uncertainties. NSAL-02-3, issued on February 15, 2002, deals with the uncertainties created by the mid-deck plate located between the upper and lower taps, which are used for SG water level measurements and affects the low-low-level trip setpoint. NSAL-02-4, issued on February 19, 2002, deals with the uncertainties created because the void contents of the two phase mixture above the mid-deck plate were not reflected in the calculation, and this affects the high-high-level trip setpoint. NSAL-02-5, issued on February 19, 2002, deals with the initial condition assumptions used for the SG water level related safety analyses, which may not be bounding because of velocity head effects or mid-deck plate pressure differentials, which have resulted in significant increases in the control system uncertainties. Discuss how ANO-2 accounts for all these uncertainties documented in these advisory letters in determining the SG water level setpoints and how it meets the licensing basis for the plant.

Attachment 2

Entergy

ARKANSAS NUCLEAR ONE
1448 S.R. 333
Russellville, AR 72802
(501) 858 - 4631

FAX COVERLETTER

DATE: March 3, 2002

TO:	Pat Sekarek
COMPANY or LOCATION:	U. S. Nuclear Regulatory Commission
TELEPHONE NUMBER	301-415-2623
FACSIMILE (FAX) NUMBER:	301-415-3061
VERIFICATION NUMBER:	301-415-2623

FROM:	Steve Bennett
TELEPHONE NUMBER:	501-858-4626
LOCATION:	Arkansas Nuclear One Licensing Department
OUR FAX NUMBER:	501-858-4685
OUR VERIFICATION NUMBER	501-858-4631
NUMBER OF PAGES INCLUDING COVER:	9

COMMENTS:

Pat,

Here is the draft of the proposed LTOP RAI response to get to Gene Hsii. We are on for the 2:00 PM EST call.

steve b

Response to Request for Additional Information Related to ANO-2 Low Temperature Overpressure Protection

Question 1:

For this proposed TS change with new pressure-temperature limits valid for 32 effective full power years, the peak transient pressure of the reactor coolant system (RCS) of 541.2 psia of the energy-addition event was based on previous low-temperature overpressure protection (LTOP) analysis performed for the replacement steam generator (Entergy letter no. 2CAN129907 to NRC dated December 21, 1999). That LTOP analysis was performed for (a.) the mass addition event with simultaneous injection of two HPSI pumps and all three charging pumps to a water solid RCS, and (b.) the energy addition transient with the start of an idle reactor coolant pump under water solid RCS conditions. Also, the analysis was based on the LTOP relief valve backpressure of 100 psig.

You have since identified a concern of higher backpressure on the pressurizer relief valve, compared to that assumed in the LTOP analysis due to potential flashing in the relief valve discharge line, and imposed two operating restrictions to address the concern:

Assure two HPSI pumps are in pull-to-lock while LTOP conditions are enabled, and,

Assure that the pressurizer water volume is less than 910 ft^3 when starting a reactor coolant pump.

Discuss how these two operating restrictions compensate for the increase in the relief valve backpressure relative to that assumed in the LTOP analysis of the mass-addition and energy-addition design basis events. The discussion should include: (a.) how the mass-addition and energy-addition design basis events were analyzed to verify the acceptability of the LTOP relief valve setpoint, (b.) the expected relief valve backpressure due to two-phase flow in the valve discharge line during the design basis transients, (c.) the effects of the increased relief valve backpressure on the relief valve discharge rate relative to the backpressure assumed in the analysis, (d.) how the restriction of one HPSI pump injecting into the RCS, compared to two HPSI pumps assumed in the analysis, compensates for the reduction In the relief valve discharge rate, and (e.) how the initial pressurizer void volume compared to the water solid assumption compensates for the reduced relief valve discharge rate.

ANO-2 Response:

The referenced LTOP transient analyses (energy –addition and mass-addition) accounted for such areas as RCS flow rates and steam generator parameters associated the replacement steam generators and the decay heat due to uprate power. These analyses used the Technical Specification lift setpoint of 430 psig, a vent path size of 6.38 in^2, and an enable temperature of 220°F. The calculated peak pressure in the pressurizer for the energy addition event was determined to be 539.0 psia. For the mass addition transient the peak pressure is 522.2 psia. There is an additional 2.2 psid due to the reactor coolant flow into the pressurizer through the surge line to replace the inventory lost through the relief valve during the transient mitigation. Therefore the design peak pressure is 541.2 psia.

With the setpoint listed above, the peak pressure does not violate the current LTOP pressure/temperature limits.

The maximum relief valve discharge flow rate for the energy addition transient is 1977 gpm. The flow rate due to the mass addition transient is 1594 gpm. These flow rates were determined assuming valve characteristics with 100 psig of backpressure.

A concern was identified with the operation of the LTOP valves where the backpressure at the valve discharge is higher than originally expected. Increased backpressure reduces valve capacity for a given valve inlet pressure. Of interest for the LTOP events is the valve capacity at a valve inlet pressure 10% above valve set pressure, since this is the maximum valve inlet pressure calculated to occur in the LTOP events.

The review of the backpressure impacts on the valve operation also established a maximum allowable backpressure. Operation of the valve was determined to be unstable when backpressure exceeded 50% of the set pressure. This limitation was found to restrict water flow through the valves to less than the values calculated for the LTOP events.

Consequently, operating restrictions must be established to limit the effects of the LTOP events such that the resulting flow through the valve produces a backpressure that is less than 50% of the set pressure. This flow must also be less than the capacity of the valve.

Given the replacement of the relief valve bellows, the following assumptions and conditions were made for the backpressure analysis:

- For water relief, the valves will not go into significant lift until about 8 to 9% over the set pressure, but once in significant lift, they will remain open until about 6% below the valve setpoint.

- For steam relief, the valves will go into significant lift very near the set pressure.

- The LTOP event volumetric flow rates that must be accommodated to assure RCS pressure remains acceptably low are on the order of 2000 gpm. If used to relieve steam at these volumetric rates, the capacity of the LTOP valves is more than sufficient. Also, steam release at these flow rates will not produce appreciable backpressure. Consequently, this analysis deals only with water relief capacity and backpressure considerations.

- The allowable range of setpoints for the LTOP valves is between 417 and 430 psig.

- The maximum RCS pressure while on shutdown cooling is 300 psia. This forms an upper limit for the pump start event. Before shutdown cooling is established (or after it is terminated) with RCPs in operation and with temperature below the LTOP enable limit of 220°F, it is possible (although remotely) that pressure could be as high as 400 psia. This analysis will consider the effects of this higher initial pressure on the mass addition event.

Flow Limits Due to Backpressure

The maximum LTOP valve backpressure limit is 50% of the set pressure. Since the valve set pressure can vary from 417 to 430 psig, the backpressure limit will vary from 208.5 to 215 psig or 223.2 to 229.7 psia. Backpressure values for a range of flow rates, water temperatures and valve inlet pressures were determined. The results of this determination are provided below.

Pressure (psia)	Temperature (°F)	Flow (gpm)	Backpressure (psia)
487.7	445	1603	241
487.7	445	1202	201
473.4	445	1600	241
473.4	445	1200	201
487.7	417	1959	236
487.7	417	1498	204
473.4	417	2002	239
473.4	417	1601	211

The pressures 473.4 and 487.7 psia represent the valve inlet pressure at the 10% overpressure condition for valve setpoints of 417 and 430 psig, respectively. The temperatures of 417°F and 445°F are the saturation temperatures for pressurizer water at 300 psia and 400 psia, respectively, which are the maximum assumed starting pressures for the energy and mass addition LTOP events.

From these results, the flow limitation for each combination of valve inlet pressure and water temperature can be determined by interpolation. The resulting limits are:

Pressure (psia)	Backpressure Limit (psia)	Temperature (°F)	Flow Limit (gpm)
487.7	229.7	445	1490
473.4	223.2	445	1422
487.7	229.7	417	1869
473.4	223.2	417	1776

The flow rates determined in the original analyses of the LTOP events exceed these limits. Therefore, the analyzed events must be limited by additional operating restrictions to keep the flow rates below the values listed above.

Valve Capacity

The capacity of the valve is determined in the same manner as it was in the LTOP analyses. The capacity of the valve at 10% overpressure, with water temperature of 445°F and a backpressure of 230 psia was determined to be 6.74 E+5 lbm/hr. This mass flow rate is then converted to a volume flow in gpm. However, the methodology used determines the volume flow at the discharge of the valve. In this analysis the volume flow of water out of the pressurizer to the valve inlet is of concern. These flow conditions can be approximated using the pressurizer temperature of 445°F and the valve inlet pressure of 478.7 psia. At these conditions, the flow rate is 1623 gpm.

Valve inlet flow capacities at the other temperature and pressure conditions are calculated in the same manner. The resulting flow capacities are presented in the following table.

Pressure (psia)	Temperature (°F)	Mass Flow (lbm/hr)	Flow Capacity (gpm)
487.7	445	6.74 E+5	1623
473.4	445	6.49 E+5	1563
487.7	417	8.46 E+5	1991
473.4	417	8.13 E+5	1915

The valve capacities at 10% overpressure are compared to the flow limits due to backpressure in the following table.

Pressure (psia)	Temperature (°F)	Backpressure Flow Limit (gpm)	Flow Capacity (gpm)
487.7	445	1490	1623
473.4	445	1422	1563
487.7	417	1869	1991
473.4	417	1776	1915

This indicates that for this range of pressure and temperature conditions, the backpressure limit is reached before the valve capacity is exceeded. Consequently, if the flow rates from the LTOP events are reduced below the backpressure flow limits, they will also be less than the valve flow capacity.

Energy Addition Event

The energy addition event can produce a maximum flow rate of 1977 gpm through the LTOP valves at a valve inlet pressure of 472.7 psia. This flow rate is essentially independent of pressure at the LTOP valve. The flow rate from this event as currently analyzed would exceed the backpressure limit.

To resolve this concern, credit is taken for the steam space that exists in the pressurizer prior to starting an RCP instead of assuming the pressurizer is water solid. This steam space can accommodate the initial expansion caused by the event. By the time the pressurizer is filled and the LTOP valve begins to pass water, the flow rate from the expansion will be well below the backpressure flow limit.

It was determined that the flow rate from the energy addition event would be less than about 1765 gpm at 15 seconds into the event. This is less than the minimum backpressure flow limit of 1776 gpm assuming the event started at pressurizer conditions of 300 psia and 417°F.

Assuming that a pressurizer maximum water inventory of 910 ft^3 is imposed, consistent with the existing Technical Specification in Modes 1 through 3 for pressurizer level, and using a nominal pressurizer volume of 1200 ft^3, the pressurizer will have a steam space of 290 ft^3. Reducing this to account for instrument uncertainty, the steam space is conservatively

calculated to be 170 ft^3 or 1270 gallons. Conservatively assuming the peak flow rate of ~1980 gpm as a constant flow rate, the available steam space would not be filled for about 38 seconds. The flow rate would be less than 1000 gpm at this time.

Therefore, with the additional operating restriction to assure that the pressurizer water volume is less than 910 ft^3 when starting a RCP with no other pump running, the maximum flow through the LTOP valves from this event will be below the flow restrictions imposed by the backpressure limits.

Mass Addition Event

At equilibrium, the mass addition event can produce a flow rate of 1594 gpm through the LTOP valves at a valve inlet pressure of 467.5 psia. The flow rate would decrease slightly as pressure increased to the 10% overpressure values, but the mass addition event as it is currently analyzed would clearly exceed the backpressure flow limit.

To resolve this issue, this analysis credits the actions currently taken by Operations, which ensures that two of the three HPSI pumps are in Pull to Lock when LTOP is enabled. This will then reduce the number of HPSI pumps assumed to start from two to only one.

A summary of the inputs assumed for the mass addition event is as follows.

RCS Pressure (psig)	Pressurizer Pressure (psia)	Flow Rate, gpm			
		2 HPSI Pumps	3 Charging Pumps	Additional Input	Total
0	5.8	1674	138	129	1941
200	205.8	1542	138	129	1809
400	405.8	1401	138	129	1668
600	605.8	1246	138	129	1513

This table is repeated below using the flow from one HPSI pump instead of two. The flow rates are increased by 5%.

RCS Pressure (psig)	Pressurizer Pressure (psia)	Flow Rate, gpm			
		1 HPSI Pumps	3 Charging Pumps	Additional Input	Total
0	5.8	856	138	129	1123
200	205.8	789	138	129	1056
400	405.8	716	138	129	983
600	605.8	637	138	129	904

By inspection, it is clear that with the operating restriction to assure two HPSI pumps are in Pull to Lock while LTOP is enabled, the maximum flow from the mass addition event will be below the flow restrictions imposed by the backpressure limits.

CONCLUSIONS

With the operating restriction to assure that the pressurizer water volume is less than 910 ft^3 when starting a RCP with no other pumps running, the maximum liquid flow through the LTOP valves from the energy addition event will be less than 1000 gpm.

With the operating restriction to assure two of the three HPSI pumps are in Pull to Lock while LTOP is enabled, the maximum flow from the mass addition event will be less than 1000 gpm.

These LTOP valve flow rates are below the flow restrictions imposed by the backpressure limits and are well within the capacity of the LTOP valves, over the full range of allowable LTOP valve setpoints. With these limitations, the peak pressure values for the mass and energy addition events remain bounding.

As discussed above the current Technical Specification lift setpoint of 430 psig, a vent path size of 6.38 in^2, and an enable temperature of 220°F were used in the LTOP analyses. There are no changes proposed to these inputs. The analyses demonstrated the peak transient pressure is 541.2 psia. The above analysis demonstrated this value remains bounding for the existing backpressure. The LTOP pressure/temperature limits changed due to the recent vessel pressure/temperature work. The new minimum LTOP pressure/temperature limit is 607.7 psia using the K_{IC} methodology. Based on the above adequate LTOP protection is provided with the two operating restrictions.

Question 2:

Since the restriction of the pressurizer water volume to less than 910 ft^3 when starting a reactor coolant pump is an initial condition in the energy-addition design basis event to comply with the pressure-temperature limits, why is this restriction not included in the LTOP limiting condition for operation (LCO) 3.4.12? Your answer should describe why this does or does not meet Title 10 of the Code of Federal Regulations Part 50.36(c)(2)(ii)(B) Criterion 2.

Response:

The previously proposed change to TS 3.4.12 (page 3/4 4-28) regarding the Low Temperature Overpressure Protection System is being further revised to include restrictions for pressurizer volume prior to starting an idle reactor coolant pump. Attachment 2 contains the revised markup of TS 3.4.12. This restriction is consistent with the discussion and the Bases to TS 3/4.4.12 previously proposed in Reference 1.

TS 3.4.12 was also modified to add "pump" to the LCO where it now reads:

The LTOP system shall be OPERABLE with each SIT isolated that is pressurized to ≥ 300 psig, and a maximum of one HPSI pump capable of injecting into the RCS and . . .

REACTOR COOLANT SYSTEM

LOW TEMPERATURE OVERPRESSURE PROTECTION (LTOP) SYSTEM

LIMITING CONDITION FOR OPERATION

3.4.12 The LTOP system shall be OPERABLE with each SIT isolated that is pressurized to ≥ 300 psig, and a maximum of one HPSI pump capable of injecting into the RCS and:

a. Two LTOP relief valves with a lift setting of ≤ 430 psig, or

b. The Reactor Coolant System depressurized with an RCS vent path ≥ 6.38 square inches.

APPLICABILITY: MODE 4 with T_c ≤ 220°F, MODE 5, MODE 6 with reactor vessel head in place.*

ACTION:

a. With one LTOP relief valve inoperable in MODE 4, restore the inoperable valve to OPERABLE status within 7 days or depressurize and vent the RCS through a ≥ 6.38 square inch vent path within the next 8 hours.

b. With one LTOP relief valve inoperable in MODE 5 or 6, restore the inoperable relief valve to OPERABLE status within 24 hours or depressurize and vent the RCS through a ≥ 6.38 square inch vent path within the next 8 hours.

c. With both LTOP relief valves inoperable, depressurize and vent the RCS through a ≥ 6.38 square inch vent path within 8 hours.

d. With a SIT not isolated and pressurized to ≥ 300 psig, isolate the affected SIT within 1 hour. If the affected SIT is not isolated within 1 hour, either:

(1) Depressurize the SIT to < 300 psig within the next 12 hours, or

(2) Increase cold leg temperature to > 220°F within the next 12 hours.

e. With more than one HPSI pump capable of injecting into the RCS, immediately initiate action to verify a maximum of one HPSI pump capable of injecting into the RCS.

~~e~~f. The provisions of Specification 3.0.4 are not applicable.

* - when starting the first reactor coolant pump, the pressurizer volume will be < 910 ft^3.

REACTOR COOLANT SYSTEM

BASES

3/4.4.12 LOW TEMPERATURE OVERPRESSURE PROTECTION SYSTEM

Low temperature overpressure protection (LTOP) of the RCS, including the reactor vessel, is provided by redundant relief valves on the pressurizer which discharge from a single discharge header. Each relief valve is isolated from the RCS by two motor operated block valves. Each LTOP relief valve is a direct action, spring-loaded relief valve, with orifice area of 6.38 in^2 and a lift setting of ≤ 430 psig, and is capable of protecting the RCS from overpressurization ~~when~~ from the limiting transient. The relief valves will be able to mitigate ~~is either~~ (1) the starting ~~of an idle~~of the first reactor coolant pump~~, under water-solid conditions~~ when the pressurizer volume is < 910 ft^3, and ~~with~~ when the secondary water temperature of the steam generator is less than or equal to 100°F above the RCS cold leg temperature (energy addition event), or (2) the simultaneous injection of ~~two~~ one HPSI pumps and all three charging pumps. ~~to the water-solid RCS~~ (mass addition event). The action to prevent the capability of injection of more than one HPSI pump into the RCS will typically be accomplished by placing the HPSI pumps in pull-to-lock. The limiting LTOP design basis event is the energy addition event. The analyses assume that the safety injection tanks (SITs) are either isolated or depressurized such that they are unable to challenge the LTOP relief setpoints.

Since neither the LTOP relief valves nor the RCS vent is analyzed for the pressure transient produced from SIT injection, the LCO requires each SIT that is pressurized to ≥ 300 psig to be isolated. The isolated SITs must have their discharge valves closed and the associated MOV power supply breaker in the open position. The individual SITs may be unisolated when pressurized to < 300 psig. The associated instrumentation uncertainty is not included in the 300 psig value and therefore, the procedural value for unisolating the SITs with the LTOPs in service will be reduced.

The LTOP system, in combination with the RCS heatup and cooldown limitations of LCO 3.4.9.1 and ~~administrative~~ restrictions on RCP operation, provides assurance that the reactor vessel non-ductile fracture limits are not exceeded during the design basis event at low RCS temperatures. These non-ductile fracture limits are identified as LTOP pressure-temperature (P-T) limits, which were specifically developed to provide a basis for the LTOP system. These LTOP P-T limits, along with the LTOP enable temperature, were developed using guidance provided in ASME Code Section XI, Division 1, Code Case N-~~514~~ 641. This code case allows using an alternate means of determining LTOP P/T condition ~~that mandates that~~ but limits ~~"LTOP systems shall limit~~ the maximum pressure in the vessel to ~~110~~100% of the pressure ~~determined to satisfy Appendix G, paragraph G-2215 of Section XI, Division 1"~~ using the K1C approach allowed by the Code Case.

The enable temperature of the LTOP isolation valves is based on any RCS cold leg temperature reaching 220°F (including a 20°F uncertainty). Although each relief valve is capable of mitigating the design basis LTOP event, both LTOP relief valves are required to be OPERABLE below the enable temperature to meet the single failure criterion of NRC Branch Technical Position RSB 5-2, unless any RCS vent path of 6.38 in^2 (equivalent relief valve orifice area) or larger is maintained.

Attachment 3

ANO-2 Response to Westinghouse Nuclear Safety Letter NSAL-02-3

Westinghouse Nuclear Safety Letter NSAL-02-3, "Steam Generator Mid-Deck Plate Pressure Loss Issue" was issued on February 15, 2002. It notifies plants with Westinghouse–designed steam generators of the possibility that setpoint calculations for the low steam generator (SG) level actuation setpoint may not account for the presence of a pressure drop across the mid deck plate (MDP) at the top of the primary separator assembly. Steam flows across the plate result in measurable pressure drops if the plate is located between the elevations of the upper and lower level measuring taps. The level transmitter, unable to distinguish the flow-induced delta pressure (DP) from the level-induced DP, may read a level higher than actual if the effects are not compensated for in the calibration setup of the transmitter. The positive error could result in non-conservative (lower than required) actuation of the reactor trip or Emergency Feedwater Actuation Signal (EFAS) if not accounted for within the calibration and setpoint calculations.

ANO-2 has previously supplied information on instrumentation effects for the Feedwater Line Break (FWLB) accident in correspondence dated December 5, 2001 (2CAN120105). This letter included discussion of the MDP effect as part of the licensing process for ANO-2 Power Uprate in response to NRC questions concerning the dynamic effects present in the steam generators and possible inaccuracies they potentially impose upon level measurement. However, in a telephone call between the NRC Staff and Entergy personnel on February 28, 2002, the Staff requested additional information on the adequacy of the ANO-2 setpoint calculations in view of the recent Westinghouse NSAL letter.

ANO-2 SG level transmitter calibration calculations and Plant Protection System (PPS) setpoint calculations account for the MDP effect including other dynamic flow-induced effects within the SGs. Other, more traditional instrument and process related uncertainties are also accounted for in the setpoint calculations such as drift, calibration errors, environmental effects, water/steam density effects, etc. but are not the subject of this NSAL and are not discussed further. These dynamic flow factors were supplied by Westinghouse during 1999 in response to questions posed by ANO-2 personnel during the replacement steam generator (RSG) project. ANO-2 requested inputs from Westinghouse concerning the effects of MDP pressure drop, downcomer pressure drops, and fluid velocity effects at the upper and lower level measurement taps, as well as any recommendations for other dynamic effects that should be considered. In response, Westinghouse supplied detailed information for the MDP, downcomer, and tap velocity effects at both the current power level, as well as the uprated power level. Westinghouse's response stated that these three (3) effects were proper ones to consider in the ANO-2 calibration and setpoint calculations.

These factors affect level measurement accuracy along with assumptions made for height of liquid/steam column measured, reference leg height, and density assumptions. The PPS narrow range SG level transmitters are differential pressure transmitters calibrated to read accurately at normal, full power conditions. It has always been the practice to minimize the error presented to the operator during normal operating conditions. This also reduces any conflicts with other, separate control grade indications off those differential pressure transmitters used for the non safety-grade Feedwater Control System (FWCS) which are also calibrated for normal, full power conditions.

Thus, the PPS and FWCS transmitters are calibrated for the same conditions. The calibration calculations algebraically sum (each with appropriate sign) the vessel steam/water head pressures, reference leg head pressures, MDP, downcomer, and velocity effects to calculate the calibration equivalent differential pressures in inches of water (INH2O). The resulting calibration points are further corrected for static pressure effects on the transmitter. These conditions are those expected at normal, full power Cycle 15 conditions. The MDP pressure drop of 0.17 psi, supplied by Westinghouse in 1999 during the RSG project and listed in the NSAL, is the same value used in our calibration calculation. Cycle specific variation in nominal operating parameters and their effects are considered in the calibration calculations and the calibration points are adjusted if needed.

Steam/feedwater flow rates above, or below, the value assumed for the MDP effect calibration correction can introduce errors. For example, at low steam flow rates during low power or after SG isolation in the unaffected SG can cause the MDP effect to have a negative (low) effect on the level reading. The bounding value of the error at low flow rates can conservatively be determined by assuming no flow. This results in a bias equal in magnitude to the correction factor above. Also, excess steam/feedwater demand events such as a steam line break or FWLB prior to SG isolation can result in flow rates greatly in excess of the amount MDP has been corrected in the calibration process. That scenario results in a positive (high) effect on the level reading.

For the safety analyses, where the low-level trip and EFAS actuation are credited, the FWLB event was determined to be the bounding analysis. A low steam generator level reactor trip is credited in the Loss of Condenser Vacuum (LOCV), Loss of Feedwater (LOFW) and FWLB analyses. Of these three events, the FWLB analysis results in the greatest potential for increased flow. Therefore, it is used in the determination of the setpoint. An EFAS actuation on low steam generator level is credited in the LOFW and FWLB analyses. Of these two events, again the FWLB is the most limiting with respect to the potential for increased flow.

The EFAS actuation is also modeled in the Steam Generator Tube Rupture (SGTR) and Main Steam Line Break (MSLB) analyses. However, for these events, early actuation is considered conservative. For SGTR, early EFAS actuation accentuates SG secondary depressurization which conservatively increases tube leakage. For a MSLB event, early actuation of emergency feedwater (EFW) is modeled to accentuate the overcooling. For a MSLB, EFW is needed eventually to restore long-term decay heat removal. In the short term the timeliness of EFW actuation is not critical due to the overcooled condition of the RCS. In 1999, during the RSG project, Westinghouse was requested to provide dynamic effects for the bounding FWLB event and determined MDP to be 0.44 psi for Cycle 15 at current power levels and 0.53 psi for Cycle 16 and beyond at uprated power levels. By taking the difference between the MDP calibration adjustment and the bounding MDP value, the appropriate error can be determined for the event of concern. It should be noted that for the FWLB, safety analyses for Cycle 15 credit actuation on low SG level in the intact SG presently. For Power Uprate the safety analyses have been changed to credit actuation in the affected (faulted) SG. The December 5, 2001, letter contains justification that the FWLB will cause flow reversal across the MDP in the affected SG resulting in a lower than actual reading which is conservative.

The PPS setpoint calculation considers the appropriate safety analysis analytical limits for the normal and accident events for which this low-level actuation function is credited

as described above. To each analytical limit, the appropriate instrument uncertainty allowance is added for the conditions expected during the event to derive the final setpoint. The MDP effect, in addition to the other dynamic effects, process effects, and instrument hardware uncertainties previously discussed, were considered for the flow conditions in such a manner that the sign and magnitude were appropriate and conservative (i.e., SG isolated or not isolated, flow direction, high or low flow, etc.). The highest setpoint is conservatively selected from the event specific setpoint analyses. The current low level setpoint of 22.2% narrow range level remains conservative for Cycle 15 and Cycle 16.

In conclusion, ANO-2 setpoint analyses for the low SG level reactor trip and EFAS functions are unaffected by this NSAL because the analyses already account for the MDP effect.

ANO-2 Response to Westinghouse Nuclear Safety Letter NSAL-02-4

Westinghouse Nuclear Safety Letter NSAL-02-3, "Steam Generator Mid-Deck Plate Pressure Loss Issue" was issued on February 19, 2002. This letter (NSAL) notifies plants with Westinghouse–designed steam generators of the possibility that setpoint calculations for the high steam generator water level trip function may be non conservative. As the level rises above the mid deck plate (MDP) located at the top of the primary separators, the two phase steam/water mixture may introduce additional level measuring uncertainties as the void content of the mixture may not be correctly reflected in calibration and setpoint calculations.

According to the NSAL, the level sensing instrumentation may not actuate due to the two-phase mixture even when the level mixture is at the elevation of the upper level sensing tap. All differential pressure (DP) based level measuring systems compare the pressure of the steam/water column in the steam generator (SG). The measurement is taken at the lower tap to the head pressure of the filled reference leg that comes off the upper tap and is connected to the other port of the transmitter. As level rises from the lower tap to the upper tap, the DP decreases from its maximum value in DP to its minimum value at the upper tap. Normally the transmitter output is at its maximum value at the minimum DP (upper tap). Any level above the upper tap saturates the output and is not measured. Therefore, any trip setpoint based upon level must be above the lower tap but below the upper tap.

Evidently, from the Westinghouse NSAL, the point of obtaining the minimum DP, when at high levels above the MDP, may actually occur at a lower level than the upper tap elevation due to the voiding in the two-phase mixture. This is referred to as the Maximum Reliable Indicated Level (MRIL). If a plant sets their high-level trip setpoint at or near the elevation of the upper tap, the setpoint actuation may not occur at the intended point when the steam/water mixture level reaches the intended setpoint elevation. This occurs because the voiding in the mixture, as level rises above the MDP, causes the output signal from the level transmitter to read lower than it should with level at, or near, the upper tap. Therefore, the trip setpoint would have to be set at the MRIL, or a lower setpoint based on other possible safety analysis considerations, to ensure appropriate actuation when needed.

The NSAL highlights this condition as a potential safety concern for plants with Westinghouse-designed steam generators which credit this trip for overfill protection and the possible ensuing steam line break. However, ANO-2 does not credit the high SG level trip in any safety analyses. The trip is equipment protective in nature to minimize the potential for turbine damage due to excessive moisture carryover as described in the SAR and associated Technical Requirements Manual (TRM) bases. In fact, the high level trip was recently relocated from the Technical Specifications to the Technical Requirements Manual in view of its lesser safety significance compared to other Plant Protection System (PPS) setpoints appropriately maintained within the Technical Specifications. This was approved by the NRC in the safety evaluation for ANO-2 license amendment 216.

Additionally, ANO-2 currently maintains a high-level trip setpoint of 86.7% of narrow range level span based upon a not-to-exceed actual level limit of 88.7% imposed to limit

excessive moisture carryover. The setpoint for Cycle 16 at power uprate conditions will be set even lower. These levels are below the top of the mid deck plate which is at approximately 90% level. Therefore, the setpoint is conservative with respect to not exceeding the MDP elevation where the voiding concern is applicable.

In conclusion, ANO-2 safety analyses do not credit the high SG level trip. Additionally, the current Cycle 15 or planned Cycle 16 setpoint is not in the range of values where the level phenomenon described in the NSAL could become a concern.

ANO-2 Response to Westinghouse Nuclear Safety Letter NSAL-02-5

Westinghouse Nuclear Safety Letter NSAL-02-3, "Steam Generator Mid-Deck Plate Pressure Loss Issue" was issued on February 19, 2002. This letter (NSAL) notifies plants with Westinghouse–designed steam generators of the possibility that typical uncertainty calculations for steam generator (SG) water level control systems may not be bounding. The concern seems to arise from recent considerations at other Westinghouse plants that all instrument error effects such as the mid deck plate (MDP) pressure drop, velocity effects, etc. at normal conditions were not accounted for properly. This has been discussed in detail in our response to NSAL-02-3. With the normal water level control system uncertainty possibly non-conservative due to improper accounting of the MDP effect and other effects, the bounding nature of the initial conditions assumed for the safety analyses with respect to SG water level can in turn be affected.

As discussed in our response to NSAL-02-3, the level transmitters used for normal SG water level control by the Feedwater Control System, as well as the transmitters used for the PPS functions, account for steam/water densities, static pressure effect corrections, MDP pressure drop, downcomer pressure drop effects, and flow velocities past the level taps when calculating the calibration points. These calibration parameters are based upon normal, full power flowing conditions to ensure adequate accuracy for water level control at the conditions where the plant operates most of the time. Cycle specific variation in nominal operating parameters and their effects are considered in the calibration calculations and the calibration points are adjusted if needed. Biases such as the MDP effect, velocity effects, etc. are essentially null at full power conditions due to this calibration method.

In conclusion ANO-2 does not need to account for additional uncertainties such as the MDP effect on SG level control systems because the normal calibration process already accounts for, and minimizes, these effects at the normal, full power condition where the plant operates most of the time.

Attachment 4

Grand Gulf Nuclear Station (GGNS)

PROPOSED CHANGES TO GRAND GULF TS TO REMOVE OPERATING MODE RESTRICTIONS FOR PERFORMING EMERGENCY DIESEL GENERATOR (EDG) TESTING

(Ref. GNRO-2001/00083 dated November 15, 2001)

During review of the proposed changes in the referenced submittal, the staff has prepared the following DRAFT questions for discussion and clarification during a forthcoming telephone conference:

1) You stated that the analysis of bus voltage traces taken from previous load rejection tests have shown that the voltage drop which occurs, is such that voltage during "transient" remains well above the minimum required voltage for plant loads, and typically recovers well within 2 seconds. Thus, the voltage "transient" experienced by loads on the affected bus is minor. However, these tests were conducted during plant shutdown when the plant voltages were significantly higher resulting in less perturbation in the electrical distribution system. The proposed testing will be performed during power operation when the expected voltage will be lower, and could cause more perturbation in the electrical distribution system. Please explain how the perturbation during power operation is comparable to the previous test results.

   Also, demonstrate that the voltage drop on the safety bus after load rejection is well above the setpoints of a degraded grid and loss of voltage relays.

2) SR 3.8.1.17 requires verification that, with an EDG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by returning the EDG to ready-to-load operation, and automatically energizing the emergency loads from offsite power. If this SR was to be performed during power operation, how do you demonstrate compliance with SR 3.8.1.17.b without sequencing safety loads during power operation.

   Also, describe how the ECCS signal is simulated during power operation to perform this surveillance without disturbing the redundant EDGs.

Attachment 5

REQUEST FOR ADDITIONAL INFORMATION ENTERGY REQUEST FOR EXEMPTION FROM THE DEFINITION OF TOTAL EFFECTIVE DOSE EQUIVALENT (TEDE)

1. The response to Question 1 in Attachment 2 to the July 20, 2001, letter appears to conflict with the exemption request in the body of the letter itself. Verify that Entergy intends to estimate effective dose equivalent (not deep-dose equivalent) with the EPRI method referenced, when you are demonstrating compliance with 10 CFR 20.1201(a)(1)(i) using the requested alternate definition of TEDE. Also verify that compliance with the limit on total organ dose will be demonstrated using deep-dose equivalent (as specified in 10 CFR 20.1201(a)(1)(ii) and 20.1201(c)) instead of as stated in your response.

2. Your July 20, 2001, letter states that the EPRI method is applicable to "all radiation exposure situations" (see Attachment 1, page 3) and requests approval to use the weighted two-badge algorithm (A3)* when "there is expected to be a significant difference between the deep-dose equivalent [DDE] and the effective dose equivalent [EDE]." However, the algorithms used in the EPRI method for estimating EDE were developed for directional, broad parallel beam gamma exposures. They are not valid for all non-uniform exposures situations. Verify that the method will only be applied in those situations that approximate exposure to directional parallel gamma beams (e.g., no significant dose-rate gradient across the space occupied by the body, ignoring the shielding of the body itself).

   * Since the one-badge (A1) "algorithm" discussed in the EPRI documents is consistent with dosimetry practices allowed under the current regulation, no exemption from Part 20 is needed.

3. Your response to the question above need not discuss body-to-dosimeter self shielding, since it is covered by your response in the July 20, 2001, letter (Question 2 in Attachment 2), to ensuring that at least one dosimeter "see" the major exposure source at all times. However, the statement in this response that "job-specific Radiation Work Permits will require the worker to move about to ensure this requirement is met" seems impractical. Please clarify.

4. Verify that the front and back dosimeters used in the A3 method of assessing EDE will be calibrated to read DDE at the point of measurement.

5. The published paper, "Two Methods For Examining Angular Response of Personnel Dosimeters," by P. Plato, et. al. (Reference 5.13 in the July 20, 2001, letter), provides evidence that the Panasonic UD-802 dosimeter, currently in use in the Entergy system, has angular dependent response characteristics suitable to support the EPRI algorithms. Is the Entergy request narrowly restricted to the use of the UD-802 dosimeter? If not, commit to using dosimeters that have an angular response at least as good as that described in the paper, "A Study of the Angular Dependence Problem in Effective Dose Equivalent Assessment," by X. Xu, et. al. (Reference 5.7 in the July 20, 2001, letter).

6. The guidelines for implementation of the EPRI methodology for assessing EDE in Reference 5.8 in the July 20, 2001, letter are vague as to whether the EPRI algorithms (specifically A3) are valid for assessing EDE from point sources (or hot particles) on or near the surface of the body. Therefore, it is unclear if assessing EDE from external point sources is included in the Entergy request. The information in Volumes 1 and 2 of EPRI TR-101909 (July 20, 2001, letter, References 5.4 and 5.6, respectively), is insufficient for the staff to conclude that the A3 method is valid for assessing EDE from point sources in all cases. Verify that Entergy does not intend to use this method for assessing EDE from point sources on or near the surface of the body or provide the following information.

   6.1 The "true" EDE (calculated by Monte Carlo method) values resulting from point source exposures, provided in Tables 5, 6 and 7 of Volume 1, are not based on the organ weighting factors given in Part 20 and therefore not appropriate for demonstrating compliance with the requirement in 20.1201(a)(1)(i). The geometry of these calculations is constrained to locations on the trunk of the body (from 6 cm to 61cm above the point the legs join the body). It is easy to describe an exposure situation, outside the bounds of these calculations, where a point source (i.e., located on the inside of upper thigh) would result in a significant EDE. Describe how a conservative EDE, consistent with the definition in Part 20, will be assessed for all exposures to point sources located on, or near, the surface of the entire body.

   6.2 The data in Table 9 of Volume 2 is too limited to demonstrate that the EDE values assessed with the EPRI methodology are valid for hot particle exposures. The geometry of the exposure situation, discussed in 6.1 above, is further restricted such that the two dosimeters are located either at the hip or mid-torso, with the point sources located at the same height (e.g., in the same plane cutting horizontally through the body) as the dosimeters. No information is provided on how the calculated, or indicated, EDE varies as the source is moved up or down the body away from the plane of the dosimeters. The ratio of the EDE calculated by the A3 method to the "true" EDE, is presented for just five grid locations radially around the body in each dosimeter plane. The potential for self shielding of both dosimeters from the point source is not addressed since the source grid locations evaluated are not on the surface of the body. Provide data that demonstrates that the EDE calculated with the A3 method is a conservative (e.g., the ratio of the calculated to "true" EDE is greater than or equal to one) estimate of the EDE for all point source locations on, or near, the surface of the entire body.

Attachment 6

Clarifications on Entergy's 12/10/01 Letter on Environmental Impact of ANO-2 Power Uprate

The following clarifications were provided by the licensee during a phone call on 03/12/01:

Page 4 of 25, last paragraph - The licensee agreed that "cooling water facilities will have no adverse effects on the local environment..." because the extended power uprate results in no increase in the water use permitted.

The following references to ANO should have been for ANO-2:

Page 13 of 25, 2nd paragraph - "Averaging *ANO-2's* dose for the three most recent years..."
Page 14 of 25, last paragraph - "Averaging *ANO-2's* dose for the three most recent years..."
Page 17 of 25, 4th paragraph - "Non-outage year doses at *ANO-2* have gone from 49 rem..."

In addition, the licensee provided the following 3 pages, which are excerpts from their National Pollutant Discharge Elimination System (NPDES) permit.

STATE OF ARKANSAS
DEPARTMENT OF POLLUTION CONTROL AND ECOLOGY
8001 NATIONAL DRIVE, P.O. BOX 8913
LITTLE ROCK, ARKANSAS 72219-8913
PHONE: (501) 682-0744
FAX: (501) 682-0910

CERTIFIED MAIL RETURN RECEIPT REQUESTED (P 411 486 394)

September 30, 1997

Mr. C.R. Hutchinson
Arkansas Nuclear One
1448 S.R. 333
Russellville AR 72801

RE: Application to Discharge to Waters of the State, Permit Number AR0001392

Dear Mr. Hutchinson:

Enclosed is the Department's final permit decision and a copy of the response to comments and the final permit. The response to comments describes any substantial changes from the draft permit.

The applicant, and any other person submitting written comments during the comment period, and any other person entitled to do so, may request an adjudicatory hearing and Commission review on whether the decision of the Department should be revised or modified. Such a request shall be in the form and manner required by Department Regulation No. 8.

CERTIFICATE OF SERVICE

I, Chuck Bennett, hereby certify that a copy of this NPDES permit has been mailed by first class mail to Mr. C.R. Hutchinson, Arkansas Nuclear One, 1448 S.R. 333, Russellville AR 72801, on or before this 30th day of September, 1997.

Chuck C. Bennett
Chief, Water Division

CCB:mb

cc: Betty Buchanan
Mo Shafii
Laura Brown

Enclosure

AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM AND THE ARKANSAS WATER AND AIR POLLUTION CONTROL ACT

In accordance with the provisions of the Arkansas Water and Air Pollution Control Act (Act 472 of 1949, as amended, Ark. Code Ann. 8-4-101 et seq.), and the Clean Water Act (33 U.S.C. 1251 et seq.),

Arkansas Nuclear One
1448 S.R. 333
Russellville, AR 72801

is authorized to discharge from a facility located at

Latitude: 35° 18' 49"; Longitude: 93° 13' 32"

approximately 1.5 miles south of I-40 and 3.5 miles northwest of the City of Russellville in Sections 27, 28, 33, and 34, Township 8 North, Range 21 West in Pope County, Arkansas.

to receiving waters named:

Outfall 001: Latitude: 35° 18' 31"; Longitude: 93° 13' 50"
Outfall 002: Latitude: 35° 18' 36"; Longitude: 93° 14' 03"
Outfall 003: Latitude: 35° 18' 34"; Longitude: 93° 13' 43"
Outfall 004: Latitude: 35° 18' 37"; Longitude: 93° 13' 48"
Outfall 005: Latitude: 35° 18' 32"; Longitude: 93° 14' 12"
Outfall 006: Latitude: 35° 18' 28"; Longitude: 93° 13' 49"
Outfall 007: Latitude: 35° 18' 28"; Longitude: 93° 14' 20"
Outfall 008: Latitude: 35° 18' 38"; Longitude: 93° 13' 54"
Outfall 009: Latitude: 35° 18' 49"; Longitude: 93° 14' 10"

Lake Dardanelle, an impoundment of the Arkansas River(Outfalls 001 through 007) and an unnamed ditch then to Lake Dardanelle (Outfalls 008 and 009)in Segment 3F of the Arkansas River Basin.

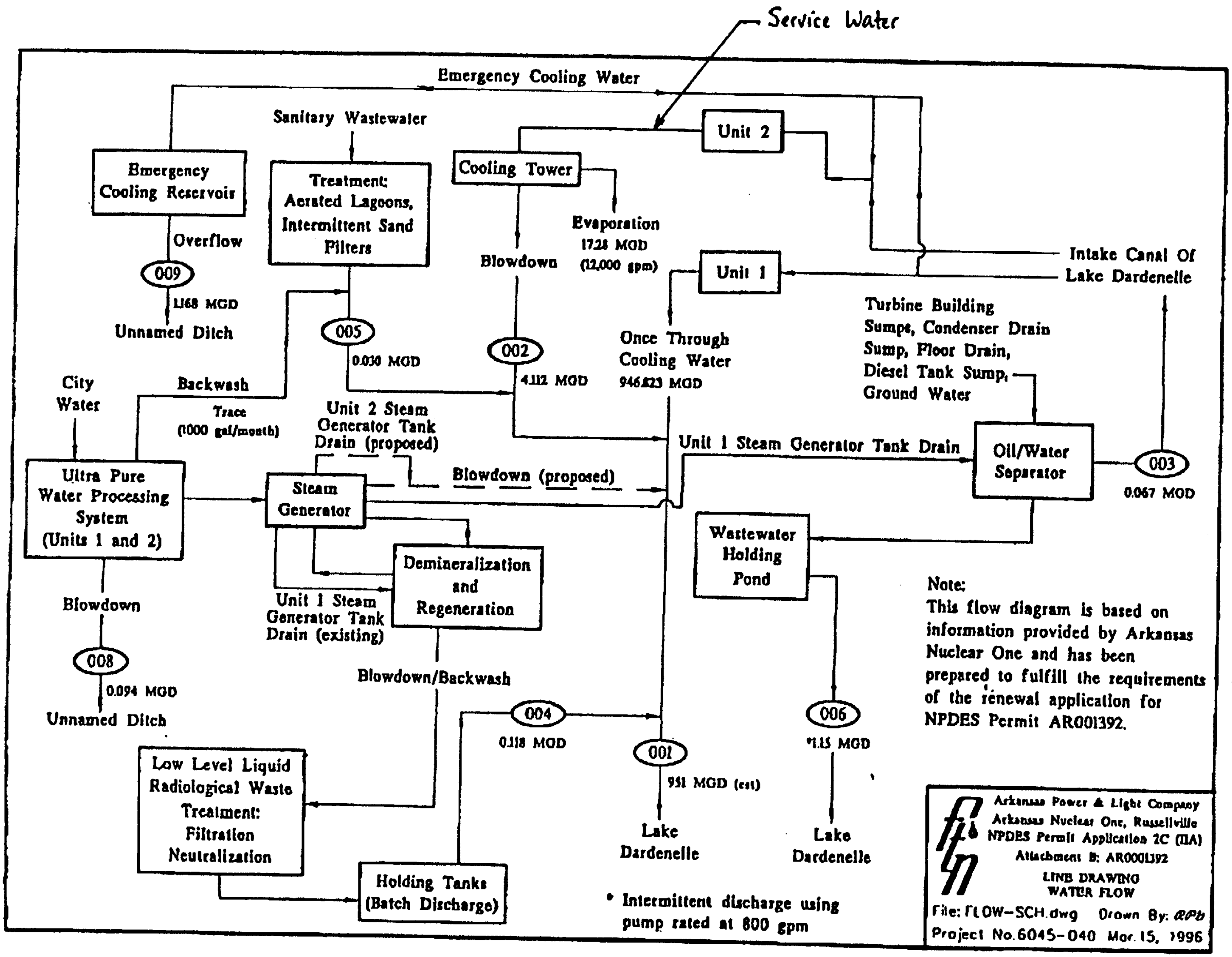
in accordance with effluent limitations, monitoring requirements, and other conditions set forth in Parts I, II (Version 2), III, and IV (Version 2) hereof.

This permit shall become effective on November 1, 1997

This permit and the authorization to discharge shall expire at midnight, October 31, 2002

Signed this 30th day of September, 1997

Chuck C. Bennett
Chief, Water Division
Arkansas Department of Pollution Control and Ecology



Note:
This flow diagram is based on information provided by Arkansas Nuclear One and has been prepared to fulfill the requirements of the renewal application for NPDES Permit AR001392.

Arkansas Power & Light Company
Arkansas Nuclear One, Russellville
NPDES Permit Application 2C (IIA)
Attachment B: AR0001392
LINE DRAWING
WATER FLOW

File: FLOW-SCH.dwg Drawn By: RPB
Project No.6045-040 Mar.15, 1996

Attachment 7

Response to Request for Additional Information Related to Relocation of Technical Specification 3.6.4.3, Containment Recirculation System, to Technical Requirements Manual

Question:

Please describe how the hydrogen mixing function and the components that provide the function are accounted for in the probabilistic risk assessment.

Response:

The containment recirculation system is not credited in the Arkansas Nuclear One, Unit 2 (ANO-2) probabilistic risk assessment (PRA) for accomplishing the hydrogen mixing function. The containment cooling units and/or the containment spray pumps, which are modeled, provide the mixing of the containment atmosphere. The containment recirculation system is judged to be non-risk significant as a means of providing containment atmosphere mixing.

Attachment 8

Response to NRC Request for Additional Information Received Via Telex on March 15, 2002

The following responses are provided in response to the two NRC questions received via telex earlier today. Our written response is consistent with our telephone discussion with members of the NRC staff yesterday afternoon. Although we have high confidence that the responses are accurate, our responses are based on a quick review of the Safety Analysis Report but have not been subjected to our correspondence certification and verification process.

NRC Question #1

Describe the most time sensitive operator action (i.e., the shortest duration response time) used in your deterministic Chapter 15 accident analysis.

ANO Response

The shortest duration response time assumed in the Chapter 15 accident analyses is 15 minutes. This time did not change for the power uprate analyses. The 15-minute operator response time is credited in the Boron Dilution events and following a Control Element Assembly (CEA) Drop. Following a Boron Dilution incident from cold shutdown, hot shutdown, hot standby, or critical conditions, the analyses verify that the operator has at least 15 minutes to secure the event (the 15 minutes is measured from the time of an alarm until a loss of shutdown margin). Following a CEA Drop, the safety analyses assume that the operators initiate a power-down consistent with Core Operating Limits Report (COLR) Figure 2.

NRC Question #2

Provide two or three additional examples of operator actions where the times were extended for the power uprate analysis.

ANO Response

During the replacement steam generator and power uprate safety analyses efforts, several increased operator response times were justified. Following a Steam Generator Tube Rupture (SGTR) event an increased operator response time from 30 minutes to 60 minutes to secure the affected steam generator was verified to be acceptable. Following a CEA Drop event, the operators are assumed to initiate a power down at 15 minutes consistent with COLR Figure 2. The new power-down figure allows operations up to 2 hours to restore the dropped rod versus one hour in the current COLR figure.

Attachment 9

REQUEST FOR ADDITIONAL INFORMATION
IMPACT OF OPERATOR ACTIONS IN DETERMINISTIC SPACE
EXTENDED POWER UPRATE LICENSE AMENDMENT APPLICATION
ARKANSAS NUCLEAR ONE, UNIT 2

1. Describe the most time sensitive operator action (i.e., the shortest duration response time) used in your deterministic Chapter 15 accident analysis.

2. Provide two or three additional examples of operator actions where the times were extended for the power uprate analysis.