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Subject: Arkansas Nuclear One - Unit 2
Docket No. 50-368
License No. NPF-6
Response to Request for Additional Information on Probabilistic Risk Assessment Regarding the ANO-2 Power Uprate License Application

Gentlemen:

By application dated December 19, 2000 (2CAN120001), Entergy Operations, Inc. submitted an "Application for License Amendment to Increase Authorized Power Level." Supplemental information was provided in letters dated June 28 (2CAN060110) and July 24, 2001 (2CAN070105). On September 18, 2001, personnel from the Dose Assessment Branch telefaxed a request for additional information containing six questions regarding the probabilistic safety assessment (PSA) portion of the license application. Verbal responses to these questions were discussed with the NRC staff during a telephone call on September 28, 2001. The attachment contains written responses.

This submittal contains no regulatory commitments.

I declare under penalty of perjury that the foregoing is true and correct. Executed on October 12, 2001.

Very truly yours,

Glenn R. Ashley

Glenn R. Ashley
Manager, Licensing

GRA/dwb
Attachment

A001

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Response to Request for Additional Information on Probabilistic Risk Assessment Regarding the ANO-2 Power Uprate License Application

NRC Question 1

Totaling up the individual impacts for the fire analysis, ANO-2 shows a change in core damage frequency (CDF) of 1.6E-5, with a base CDF value of just over 1E-4. This is in Region I on the chart in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," where "applications ... would not normally be considered." Please provide additional discussion and any additional analyses to justify why these high resulting values are acceptable and/or describe any mitigative or compensatory features that would reduce the major risk contributors (i.e., Cable Spreading Room, Diesel Corridor, Lower South Electrical/Piping Penetration Room, North and South Switchgear Rooms, MCC2B63 Room, etc.). Many of these impacts seem to be due to operator recovery actions available times, which were determined using the CENTS code by calculating the time to core uncovery as opposed to the time to core melt. Thus, the resulting human error probabilities (HEPs) have high, conservative values. What other conservatisms in the modeling may account for the resulting high fire CDFs? How would the results be affected by using the time to core melt and removing these other conservatisms from the CENTS code?

ANO Response

The fire portion of the ANO-2 Individual Plant Examination for External Events (IPEEE) response was performed using the Electric Power Research Institute (EPRI) Fire Induced Vulnerability Evaluation (FIVE) Methodology as documented in EPRI TR-100370s. This methodology was approved for this use in a letter from the NRC to the Nuclear Utility Management and Research Council (NUMARC) dated August 21, 1991, "NRC's Staff Evaluation Report on Revised NUMARC/EPRI Fire Vulnerability Evaluation (FIVE) Methodology."

As stated in the Introduction to EPRI Report TR-100370s, "FIVE is oriented toward uncovering limiting plant design or operating characteristics (vulnerabilities) that make certain fire-initiated events more likely than others." The FIVE methodology is not a fire risk analysis, but a fire vulnerability analysis; as such, it produces a conservatively high screening estimate, not a best-estimate value, for the Core Damage Frequency (CDF) for each fire zone. The CDF of each of the significant fire compartments (i.e., those with a CDF > 1E-6/rx-yr) was compared to the closure guidelines provided in Section 4.3 of NEI 91-04, Revision 1, "Severe Accident Issue Closure Guidelines," dated December 1994. Closure was obtained individually on each significant fire compartment. Consistent with the fact that the FIVE process is a vulnerability analysis and not a risk analysis, a single fire CDF (i.e., the sum of fire zone CDFs) was not reported as an estimate for the ANO-2 fire-induced CDF.

This perspective on the conservative nature of the FIVE methodology and on the conservative nature of its CDF results is discussed by the Staff in its draft version of NUREG-1742, Vol.1, "Perspectives Gained from the Individual Plant Examination of External Events (IPEEE) Program," dated April 2001 (Draft Report for Public Comment). In Section 3.4.1 of this report, it was noted that "FIVE … is largely equivalent to a fire area/zone screening analysis. It is not intended to produce a detailed quantification of fire CDF, but rather, to identify those plant areas/zones that might represent important fire CDF contributors." Section 1.3 of the report notes that "IPEEEs are intended to yield predominantly qualitative perspectives, rather than more quantitative findings." Section 3.3 further elaborates that although "CDF is the primary measure of fire-induced plant risk that emerges from the IPEEE fire analyses … the direct comparison of absolute CDF results was not generally considered to be appropriate …". Section 3.4.1 states that the "perception that FIVE is generally a conservative approach in comparison to fire PRA methods appears to be confirmed when the total CDF for various methodologies are compared. …Those submittals based solely on FIVE, in general, reported larger fire-induced CDF results than the submittals that used other methods."

The conservative nature of the FIVE methodology described in NUREG-1742 applies to the ANO-2 fire analysis. The ANO-2 IPEEE fire analysis was performed via a series of screening analyses of the various zones. The first of these screenings assumed failure of all components in the zone and components with cables (i.e., power, control, or instrumentation cables) in the zone. Any zone not screened using this approach was identified for further analysis. This additional analysis involved identifying the dominant failures in each unscreened zone. For each unscreened zone, these dominant failures were individually assessed to determine whether a fire would indeed have failed the component of interest. If a determination was made that a component would not be affected by a fire in the zone, the zone was requantified with the component set to its nominal failure value. Iterations were performed on the unscreened zones until they screened or until the CDF for the zone was reduced to some frequency that was deemed to be acceptable. Potential fire vulnerabilities were identified based on the unscreened zones. Since the iterations on the unscreened zones were concluded when it was felt that the intent of GL-88-20 was met, CDF results are not indicative of a true fire risk.

Besides the conservative nature of the ANO-2 FIVE methodology, other conservatisms are present in the ANO-2 fire IPEEE analysis and the fire analysis submitted as part of the ANO-2 power uprate submittal. Important among these conservatisms is the use of operator recovery action available times that are based on the CENTS-generated time to core uncovery as opposed to the time to core melt. Another important conservative assumption of the fire analysis is that for each fire zone it was assumed that all failure modes occur for equipment with cables routed in the zone. The Appendix R cable routing database and additional investigations were used to identify the unaffected equipment. It should also be noted that the fire analyses conservatively took no credit for the Alternate AC (AAC) Diesel Generator (also known as the Station Blackout Diesel Generator).

Thus, the conservative nature of the ANO-2 FIVE-based fire analysis and conservatisms used in this analysis make it inappropriate to make a direct comparison of the sum of the fire zone CDFs with the Regulatory Guide 1.174 risk acceptance guidelines. If the total fire CDF is used as a figure of merit, it is probably more appropriate to compare the change in the fire CDF to the change in the internal events CDF expected as a result of the 7.5% increase in power: the 16.8% increase in the sum of the fire zone CDFs is very consistent with the estimated 15.8% increase in the internal events CDF. The fire risk results should be considered acceptable, given that they are consistent with the internal events CDF results, which is acceptable using the Regulatory Guide 1.174 risk acceptance guidelines. Based on this perspective, additional analysis of the ANO-2 fire-induced risk associated with the extended power uprate was not performed.

NRC Question 2

The licensee indicated that the potential for creating an initiating event due to a spurious main steam isolation signal (MSIS) or containment spray actuation signal (CSAS) is compensated by trip hardening their signals. Though this modification is argued to compensate for the potential increases in spurious signals, it is stated that it is not quantified. How are these signals addressed in the ANO-2 probabilistic risk assessment (PRA) models? Does the ANO-2 EPU PRA explicitly model these signals as designed (and to be installed), considering their benefits (i.e., reduced frequency due to trip hardening) and potential adverse impacts (e.g., spurious operation) on initiating event frequency and following an initiating event? If not, will these signals be incorporated as part of a future update of the model and is this planned update prior to entering EPU operations?

ANO Response

A containment spray actuation signal (CSAS) has been added to main feedwater and main steam components to ensure isolation of these systems following a main steam line break (MSLB) on high containment pressure. This modification was added as part of the replacement steam generator effort and is already installed in the plant. The larger steam generator inventory to accommodate power uprate necessitated this new signal; hence, this plant change was added to the power uprate model.

The CSAS signals and relays are modeled in the power uprate as basic events in the fault trees to each component as a potential failure to actuate when the signal is needed for the event mitigation. The spurious actuation causing an inadvertent loss of feedwater was not modeled in the power uprate effort due to the minimal impact it has on the model and the difficult model update required. A Model Change Request (internal process used to track potential changes to the PSA Model) entry has been made for this item which will ensure it is considered for inclusion, commensurate with its importance, in a future revision to the ANO-2 PSA model.

The spurious actuation of an MSIS or CSAS relay is also considered in the initiating event frequency, %T16. The pre-uprated model only considered the MSIS signal. The power uprate model considered the additional CSAS signal in the basic events but did not update the initiating event frequency. Hence, the additional system failures due to the new CSAS signal have been considered in the model, however, no credit has been taken for a reduction in the initiating event frequency. A reduction in the initiating event frequency is due to the logic change described below.

A new signal was added to critical main feedwater and main steam components. Actuation of these components can cause a plant trip and loss of feedwater; however, the logic was improved by installing two relays in series. With the old plant configuration, an individual relay failure could cause a plant trip and loss of feedwater. The revised plant configuration adds the CSAS signal to feedwater and main steam components but changes the relay configuration to require two relay failures to initiate a spurious actuation of CSAS or MSIS.

NRC Question 3

The information states in a couple [of] places that the uprate could cause components to wear out more quickly or involve more often preventive maintenance. How did the licensee address these conditions within the EPU PRA model? Were failure rates and/or maintenance outage rates increased for selected equipment that would be affected by the EPU? If so, please identify the equipment affected and provide the old and new failure rate/maintenance outage values (or if multiple components were increased by a proportional amount, provide the percentage increase). If not, please briefly explain why not and the basis for the acceptability of the potential increases in equipment being unavailable due to maintenance without modeling them in the EPU PRA (e.g., maintenance times used in model bound EPU projected maintenance times).

ANO Response

The effects of increased component wear out and increased frequency of preventive maintenance were not explicitly incorporated into the ANO-2 Power Uprate PRA model. Per our response in our letter dated June 28, 2001 (2CAN060110), we recognized the increased potential for equipment wear out and indicated that the existing component monitoring programs will trend and minimize any additional wear that may result from the power uprate. Component failure rates are not expected to change with the power uprate. It is noted that train-level changes to equipment unavailability for systems modeled in the ANO-2 PSA are tracked as part of our PSA model maintenance. We periodically review equipment unavailabilities and update the model with their values. It should be noted that the periodic updating of plant failure and unavailability data used in the PSA model is only one aspect of maintaining the PSA model consistent with the as-built plant. By procedure, all plant changes, including hardware and procedural changes,

are periodically reviewed, prioritized in terms of their impact on the model, and incorporated into the model in a manner consistent with their priority. In addition, although currently an informal process, we review our CDF history on a quarterly basis. This process provides further assurance that we identify risk-significant trends.

NRC Question 4

For shutdown operations, what is the shortest "time to boiling" calculated during a typical outage and when in the outage does this occur (e.g., mid-loop operations)? Describe other typical shutdown operations in which the containment cannot be closed within the estimated "time to boiling." For these shutdown operations and any other times of extremely short "time to boiling" duration, does ANO-2 take any additional precautionary/mitigative actions other than those cited in their response of June 28, 2001?

ANO Response

The shortest time to boiling following entry into cold shutdown conditions during a "typical" outage is approximately 20 minutes. This shortest time is most likely to occur during the first reduced inventory window (i.e., during mid-loop operation). However, typical shutdown operations never result in a containment closure time that exceeds the estimated time to boiling, even during mid-loop operation. Of all containment breaches that usually occur during an outage, closure of the equipment hatch is most limiting in terms of the amount of time required. In numerous tests, ANO-2 has demonstrated its ability to effect equipment hatch closure in 5 to 15 minutes, usually in less than 10 minutes. Even so, during mid-loop operation, the containment equipment hatch is typically closed. For other breaches during this time, the ANO-2 Outage Risk Management Guidelines (ORMGs) require that closure materials be staged in advance and when possible, closure capability be established from the outside. A person capable of quickly closing the flow path through the penetration must also be present. These actions assure that any breach of containment will be closed well in advance of any boiling should a loss of shutdown cooling occur.

The ORMGs also state:

> "During Reduced Inventory conditions, the only containment breaches allowed without specific approval of the Operations Manager are LLRT openings and via the containment ventilation/purge system. All containment breaches will have the capability to be closed within 45 minutes and, where possible, within the estimated time to boiling."

The 45-minute closure time is based on a requirement of NRC Generic Letter 88-17, Loss of Decay Heat Removal." However, in recognition that the containment could become "uninhabitable" very quickly after the onset of boiling, ANO makes every effort to ensure containment closure can be completed in less than the estimated time to boiling. A

Shutdown Operations Protection Plan (SOPP) is developed for each outage based on the ORMGs. This plan identifies the minimum set of "safety functions/systems" required for various expected plant conditions during the outage. One of the "safety functions" addressed in the SOPP is containment closure. The outage schedule is then reviewed against the requirements of the ORMGs and SOPP to ensure all requirements are met, including minimizing containment breaches while fuel is in the reactor and ensuring the capability to close containment prior to the estimated time to boiling for those breaches that are scheduled. Thus, while the ORMGs allow for a containment breach that cannot be closed prior to the estimated time to boiling, such a breach is not considered in the outage schedule and would most likely only occur if a gross penetration failure is found while at reduced inventory. Even then, the Operations Manager would have to be convinced that acceptance of the temporary condition is prudent, versus exiting the reduced inventory condition, after weighing all plant conditions at the time.

While decay heat will increase due to power uprate, the above guidelines and philosophy for managing ANO-2 outages will not. That is, the time to boiling at any given time following plant shutdown will decrease slightly following power uprate, compared to the current licensed power level, but ANO-2 will continue to plan its outages to ensure that containment breaches can be closed prior to the estimated time to boiling.

NRC Question 5

Is all equipment operated within its rated design capacity (e.g., transformers, switchgear, pumps, etc.)? If not, please identify the equipment operated beyond its rating and state why the equipment operations are acceptable (e.g., operator actions required to manually load shed overloaded transformer within a set time). If there are operator actions involved in the actions to protect the equipment, what are these actions and have they been assessed and incorporated into the EPU PRA?

ANO Response

All equipment will operate within its rated design capacity for power uprate with no increase in operator actions. Since the inception of the replacement steam generators and power uprate projects, significant changes have been made to major ANO-2 structures, systems and components (SSCs) to make this statement true. A list of equipment changes is listed in Table 2-2 of the power uprate licensing report (PULR). There is one correction to Table 2-2. The modification to increase cooling for the main transformers has been deferred and will not be installed during 2R15. A letter will be sent within the next few weeks providing additional information.

A review of the table indicates that no safety-related equipment has been modified for power uprate. As part of containment uprate, the safety-related containment service water cooling coils were replaced. These are now installed and available for service during

accident conditions. As stated in the various sections of the PULR, all other safety-related equipment has adequate margin to perform its design basis function.

In addition to plant modifications, the engineering review process for power uprate has resulted in changes to SSCs or plant procedures in order to keep equipment within its rated design capacity. One example is the flow accelerated corrosion (FAC) program. Increases in fluid velocities due to power uprate are evaluated as part of this program. As cited in the PULR Table 2-2, the heater drain pump recirculation lines and control valves are being replaced with larger size components in order to reduce wear by reducing the velocities through these lines.

In summary, ANO has been diligent in making modifications for power uprate to all equipment, including some very major equipment as listed in the PULR Table 2-2. This equipment has adequate margin to operate within its design capacity.

NRC Question 6

The operator action available times affected by the EPU are expected to change inversely proportional to the increase in decay heat resulting from the EPU. However, many of the available times for operator actions listed by the licensee decrease by a larger percentage (17-23%) than expected, considering the EPU is only a 7.5% increase. What is the reason for these larger than expected decreases in available times? If this is related to the conservatisms identified in Item 1 above, how would the results be affected by using the time to core melt instead of time to core uncovery in the CENTS code?

ANO Response

The reductions in operator action available times were based on direct comparisons of CENTS results for the time to core uncovery before and after uprate. The time to core damage is not expected to significantly change the percentage change in operator response time. The times with the larger percentage changes are related to cases in which once through cooling is initiated as a back-up cooling method. For these cases, it is critical to open the emergency core cooling system (ECCS) vent valve early enough to allow for enough inventory in the core to keep the core cool until the RCS depressurizes to the point of high pressure safety injection. Due to the more complicated cooling mode, depressurization through the ECCS vent valve, increase in decay heat rates, and moisture carryover out the vent valve, a linear change in operator response time was not seen for these events.

It is noted that the quantification methods used to assess Human Failure Events (HFEs) in the fire portion of the power uprate risk assessment are the same as those used in the original fire portion of the ANO-2 IPEEE analysis. These methods are described in Section 3.4.3 of Entergy's letter dated August 28, 1992, "ANO-2 Individual Plant Examination for Severe Accident Vulnerabilities." The quantification technique was

developed for ANO by SAIC, the prime vendor supporting the ANO-2 individual plant examination analysis. This technique is nearly identical to that described as SHARP1. The primary quantification technique, the Human Cognitive Reliability (HCR) model is a Time Reliability Correlation system.

It is also noted that the assessment of HFEs in the internal events analysis portion of the power uprate risk assessment involved a compilation of state of the art Human Reliability Analysis methods. The approach incorporates the elements described in Regulatory Guide 1.174 and meets the expectations for a quality human reliability analysis as stated in draft NUREG-1560, "Individual Plant Examination Program: Perspectives on Reactor Safety and Plant Performance." Pre-initiator human errors (Type A HFEs) were quantified via a simplified form of the Technique for Human Error Rate Prediction (THERP) developed for the Accident Sequence Evaluation Program (ASEP). Proceduralized post-initiator human errors (Type C_P HFEs) were quantified via two complementary approaches: (1) the HCR correlation developed by EPRI, incorporating data from the Operator Reliability Experiments, described in the EPRI reports NP-6560L, "A Human Reliability Analysis Approach Using Measurements for Individual Plant Examinations," (December 1989) and TR-100259, "An Approach to the Analysis of Operator Actions in Probabilistic Risk Assessment," (June 1992) and (2) the cause-based methodology developed by EPRI and documented in the report TR-100259. The larger of the two results was used in the probabilistic safety assessment analysis. Non-proceduralized post-initiator human errors (Type C_R HFEs) were quantified via a revised Systematic Human Action Reliability Procedure (SHARP) developed by EPRI in TR-101711, Tier 2, ""A Revised Systematic Human Action Reliability Procedure" (December 1992). Dependencies between Post-Initiator HFEs were accounted for via use of the revised Systematic Human Action Reliability Procedure developed by EPRI in TR-101711, Tier 2.