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Safety Evaluation Report

NUREG-0053
Suppl. No. 10

U. S. Nuclear
Regulatory Commission

related to operation of
**North Anna Power Station
Unit 2**

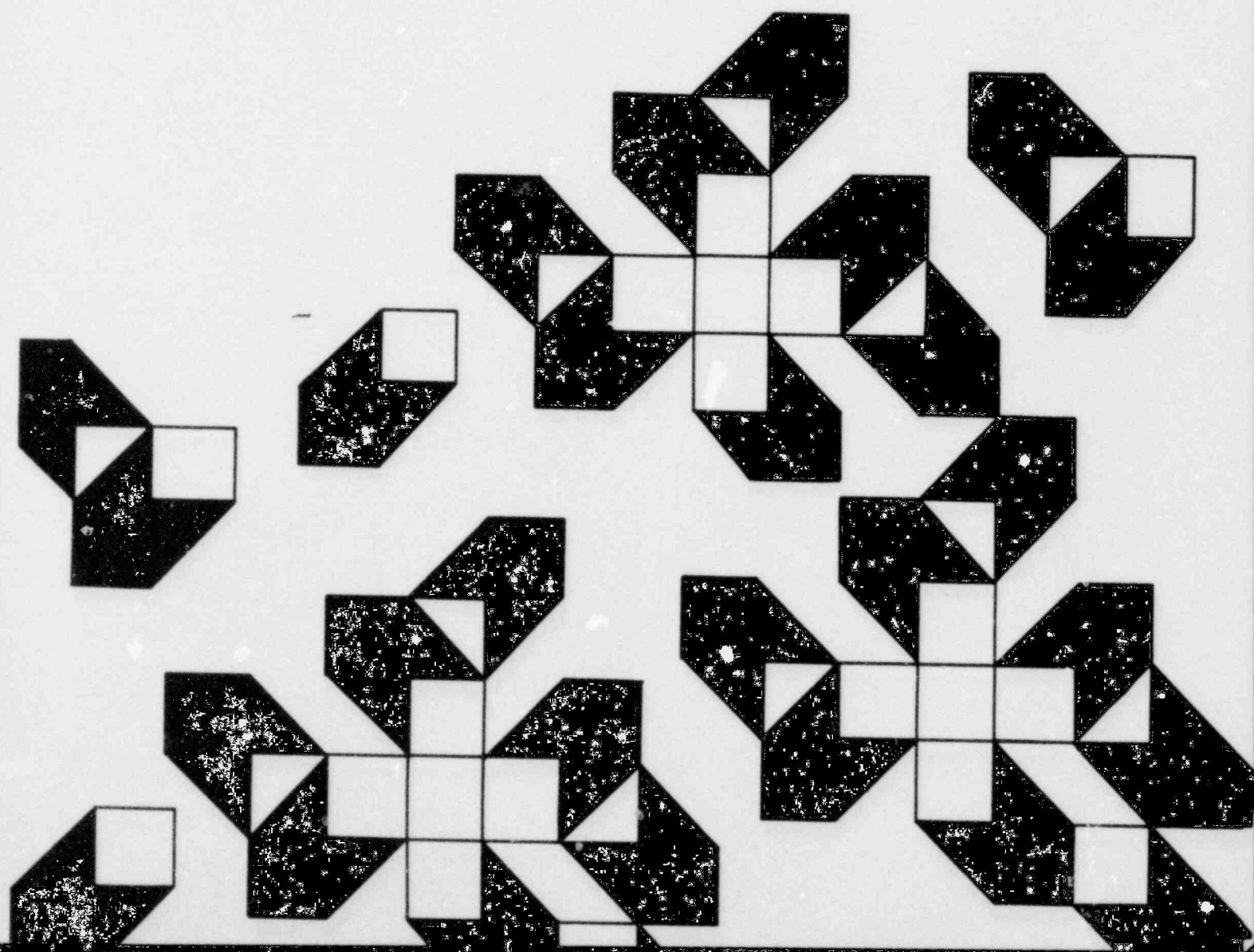
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Docket No. 50-339

Virginia Electric and Power Company

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Supplement No. 10

Date **APR 10 1980**

SUPPLEMENT NO. 10

TO THE

SAFETY EVALUATION REPORT

BY THE

OFFICE OF NUCLEAR REACTOR REGULATION

U.S. NUCLEAR REGULATORY COMMISSION

IN THE MATTER OF

VIRGINIA ELECTRIC AND POWER COMPANY

NORTH ANNA POWER STATION - UNIT 2

DOCKET NO. 50-339

FOREWORD

Supplement No. 10 to the Safety Evaluation Report for North Anna Power Station, Unit 2 consists of two parts:

PART I - Review and Evaluation of Non-TMI-2 Issues.

PART II - Review and Evaluation of TMI-2 Issues Related to Fuel Load and Low Power Test Program.

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PART I

1.0 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

On June 4, 1976, the Nuclear Regulatory Commission (Commission) issued its Safety Evaluation Report regarding the application by the Virginia Electric and Power Company (applicant) for licenses to operate the North Anna Power Station, Units 1 and 2. The Safety Evaluation Report was supplemented by Supplement Nos. 1 through 9 which documented the resolution of several outstanding issues.

On November 26, 1977, Facility Operating License NPF-4 was issued for North Anna Power Station, Unit 1. The license permitted fuel to be loaded into Unit 1. The license was subsequently amended; Amendment No. 3 to Facility Operating License NPF-4, dated April 1, 1978, permitted Unit 1 to operate at 100 percent power.

Since the time that Unit 1 was permitted to operate at 100 percent power, there have been changes in the NRC requirements, new licensing guidance has been put into effect, changes have been made on the design of the plant, additional experience has been gained at North Anna Power Station, Unit 1 as well as other pressurized water reactors and the Three Mile Island (TMI-2) accident occurred. As a result, we have requested, and the applicant has provided additional information regarding the facility.

Following the TMI-2 accident, the Commission "paused" in its licensing activities to assess the impact of TMI-2. During this "pause" the recommendations of several groups established to investigate the lessons learned from TMI-2 became available. These groups included the Presidential Commission to Investigate TMI-2, the NRC Special Inquiry Group and several staff task forces, such as the Lessons Learned Task Force and the Bulletins and Orders Task Force. All available recommendations were correlated and assimilated into a "TMI Action Plan Prerequisites for Resumption of Licensing."

The Commission has approved the prerequisites for authorizing Sequoyah Unit 1 to conduct Special Tests at power levels not exceeding five percent of full power. The Commission subsequently indicated that it would consider a similar authorization for the North Anna Power Station, Unit 2.

This supplement addresses the requirements for fuel loading and conducting low power testing of North Anna Unit 2 up to a power level of five percent of full power and (1) identifies the non-TMI-2 issues and their status since the issuance of the Safety Evaluation Report through Supplement No. 9 and (2) discuss matters related to the Three Mile Island accident. Each of the following sections of the supplement is

numbered the same as the corresponding sections of the Safety Evaluation Report. Except where noted, this supplement is an addition to the discussion in the Safety Evaluation Report and the supplements thereto. Appendix A is a continuation of the chronology of our principal actions related to the processing of the application.

As stated in the Foreword, this supplement consists of two parts:

Part I - Review and Evaluation of Non-TMI-2 Issues

Part II - Review and Evaluation of TMI-2 Issues Related to Fuel Load and Low Power Test Program.

1.9 Unresolved Safety Issues

On November 23, 1977, the Atomic Safety and Licensing Appeal Board issued a decision (ALAB-444) in connection with its consideration of the application for the River Bend Station, Unit Nos. 1 and 2 (Docket Nos. 50-458 and 50-459) which established specific requirements for addressing unresolved safety generic issues in connection with our licensing proceedings. Those requirements are applicable to the North Anna Power Station, Unit 2 application.

Appendix B to this supplement presents information for the North Anna Unit 2 application in conformance with the Appeal Board decision enunciated in ALAB-444.

1.10 Outstanding Issues

In the Safety Evaluation Report and its supplements, we presented the resolution to all of the then outstanding issues for North Anna Units 1 and 2. Since that time, we have identified nine new items which require resolution prior to the issuance of a full power operating license for Unit 2. These issues have been acceptably resolved for the low power test program and are discussed in this supplement as indicated below.

- (1) Section 3.10-3 - We require that the applicant provide information regarding the adequacy of qualification for all safety-related electrical equipment.
- (2) Section 4.2 - We must complete our review of the detailed evaluation provided regarding a restriction in the use of the PAD-3.3 code.
- (3) Section 5.4.2 - We require the applicant to provide information regarding the residual heat removal system.
- (4) Section 7.2.4 - The applicant must provide emergency operating procedures related to postulated anticipated transients without scram.
- (5) Section 7.9 - The applicant must provide information related to the Office of Inspection and Enforcement (IE) Bulletin 79-27 "Loss of Non-Class IE Instrumentation and Control Power System Bus During Operation."

- (6) Section 8.3.2 - We must complete our evaluation related to diesel generator reliability.
- (7) Section 13.2 - The Virginia Electric and Power Company must assure that it has sufficient number of licensed personnel for full power operation.
- (8) Section 15.2 - The applicant must provide a commitment regarding thermal margins in the event of a postulated feedline or steam line break accident.
- (9) Section 17.0 - We have not completed our review related to the Q-list.

2.0 SITE CHARACTERISTICS

2.4 Hydrologic Engineering

2.4.3 Low Water Considerations

2.4.3.1 Introduction

In Sections 2.4.3 and 9.2.3 of the Safety Evaluation Report, we stated that we would verify the acceptability of the service water reservoir for two unit operation after we had evaluated the results of field measurements taken during the Unit 1 preoperational testing program.

The applicant has instrumented the service water reservoir and has conducted performance tests on the spray field for limited heat inputs. The results of the performance tests were used to verify the applicant's service water reservoir performance calculational models. Using these calculational models the applicant subsequently calculated maximum temperatures and water losses to be expected during emergency operation of the ponds coincident with periods of adverse meteorology for two unit and four unit operation as presented in Report No. UC201-06, "The North Anna Power Station Service Water Reservoir and Spray System" - Ford Bacon and Davis Utah INC.

2.4.3.2 Description of Experiments and Computational Modeling

The applicant's service water reservoir was instrumented to measure the temperatures of water as it left the spray nozzles, and as it fell onto strategically located collection pans near the pond surface. The thermal performance of the sprays was determined directly from these measurements. Water losses during the test were measured by recording service water reservoir inventories and measuring the "drift" from the spray field using sensitized paper and collection pans.

Measurements of pertinent meteorological variables were taken at several locations near the perimeter of the pond and at the site meteorological station, in order to correlate the service water reservoir performance to the ambient weather conditions.

Heat for the tests was supplied by operation of Unit 1 and varied from about 20 to 50 million British Thermal Units per Hour. Spray temperatures were typically between 85 degrees Fahrenheit and 100 degrees Fahrenheit.

The test data, although not representative of the design basis conditions, were adequate in establishing the validity of predictive computer models. These computational models could then be used to predict the performance at the design basis conditions of heat load and adverse meteorology.

Design basis meteorological conditions necessary to establish the peak temperature and water losses of the service water reservoir were screened by means of the "coefficient of (thermal) performance" and the "coefficient of water consumption" from the 28 year record of Richmond, Virginia, about 45 miles southeast of the site.

At our request the applicant demonstrated to our satisfaction that the meteorological data base from Richmond was more conservative than that of the site for the limited span of time that both records were available simultaneously.

The maximum temperature in the service water reservoir was calculated to be 104 degrees Fahrenheit for two unit operation. On the basis of these tests, the applicant has increased the upper limit temperature from 105 degrees Fahrenheit to 110 degrees Fahrenheit for all service water. This leaves a six degree Fahrenheit margin above the maximum predicted service water reservoir temperature for two-unit operation.

Since it is anticipated that four units* will be operating at the North Anna Power Station, the applicant chose to calculate the minimum water requirements for four unit operation. The most severe water loss was for this condition calculated to be 15.1 million gallons for 30 days operation of the service water reservoir and four unit operation, which leaves a minimum quantity of 6.9 million gallons of water in the service water reservoir. This figure presumes that there is no makeup or rainfall to the service water reservoir and that it was at the minimum normal water level at the start of the transient. Since less water would be required for two unit operation, we conclude that based on the above discussion sufficient water is available for emergency conditions.

2.4.3.3 Conclusions

We have reviewed the applicant's experimental and computational modeling program for the service water reservoir. Members of the staff visited the site during portions of the test. The applicant's reports were reviewed in terms of the staff's previous experience with spray pond field tests and performance modeling.

We conclude that the applicant has performed the experimental phase of the service water reservoir test carefully and thoroughly. Furthermore, the applicant has demonstrated that the models for predicting reservoir performance, as well as the meteorological data base used, are conservative. We, therefore, conclude that the predicted design bases temperatures and water losses for two unit operation are reasonable and conservative, in accordance with Regulatory Guide 1.27, "Ultimate Heat Sinks for Nuclear Power Plants (Revision 2)." On this basis we further conclude that an adequate source of cooling water will be provided for plant operation and cooling during shutdown of Unit 2.

*Applicant is reconsidering whether to continue construction on Units 3 and 4.

3.0 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.9 Mechanical Systems and Components

3.9.4 Analysis Methods for Loss-of-Coolant Accident Loadings

In Supplement No. 7 to the Safety Evaluation Report we reported our findings with respect to the capability of the reactor vessel support system's ability to withstand the loads associated with a simultaneous safe shutdown earthquake and loss-of-coolant accident. We noted that we had reviewed and approved a set of load interaction failure curves developed by the applicant for the reactor vessel supports. We further reported that the calculated loads acting on the reactor vessel supports fell within these curves and that plastic deformation would occur only in a very small portion of the entire reactor vessel support system. We therefore concluded that the reactor vessel, its supports, and its internals would remain structurally sound under these severe loads and were acceptable.

By letter of January 31, 1979, the applicant notified us that the neutron shield tanks on Unit 2 were being modified to reduce the escape of neutrons from the reactor vessel cavity. Neutron shield tanks comprise a portion of the reactor vessel support system. A modification of the neutron shield tank therefore necessitated a reevaluation of the structural integrity of the reactor vessel supports under the loads due to a simultaneous safe shutdown earthquake and loss of coolant accident. In the letter mentioned above, the applicant submitted the results of such a reevaluation. Although the reactor vessel supports may experience slightly larger deflections than previously predicted, the newly calculated loads acting on the supports still fall within the approved load interaction failure curves. This demonstrates the structural integrity of the supports.

Therefore, we reaffirm our previous conclusion that the reactor pressure vessel support system is acceptable and that the North Anna Power Station, Unit 2 can safely operate with respect to this matter.

3.10 Seismic and Environmental Qualification of Seismic Category I Instrumentation and Electrical Equipment

3.10.3 Environmental Qualification of Westinghouse and Balance-of-Plant Seismic Category I Instrumentation and Electrical Equipment

In our Safety Evaluation supporting Amendment No. 7 to facility operating license NPF-4, North Anna Power Station, Unit 1, we required the licensee to provide preliminary results as soon as tests are completed and a final report by October 1, 1978 of the tests performed on the Barton pressure and differential pressure transmitters used for Unit 1 and 2.

On September 29, 1978, Westinghouse provided the results of the environmental qualification of Barton Models 763 and 764 Lot 1 transmitters. (Letter Report NS-TMS-1950). Our conclusions based on these tests, were that the instruments would perform their short term safety functions. However, we indicated that additional testing should be conducted to confirm their capability for longer term post accident monitoring.

On September 14, 1979, Westinghouse provided the results of these supplemental tests to confirm the capability of the transmitters to meet the acceptance criteria for longer term post-accident monitoring. In the original tests, it was attempted to demonstrate the qualification of these transmitters by subjecting them to high radiation levels corresponding to post loss-of-coolant accident conditions and subsequently exposing them to the high temperature steam conditions, typical of main steam line break accidents. This combined test was performed to circumvent the need for separate loss-of-coolant accident and main steam line break tests. This combination of high radiation and temperature while not causing the transmitters to fail, resulted in excessive instrument error.

The supplemental tests which followed were based upon radiation levels and subsequent exposure to a steam environment corresponding to loss-of-coolant accident and main steam line break conditions separately. Additional tests were also conducted to investigate the effects of radiation and temperature separately and in combination. This was done to promote an understanding of the phenomena which caused the errors and to provide a basis to support the conclusion that the transmitters are qualified to operate satisfactorily under the required service conditions. While the supplemental tests results support the conclusions that the Lot 1 instruments will function in an accident environment, we do not believe that these instruments provide a sufficient margin of safety to justify their use throughout the life of the plant. Further improvements to obtain an additional margin of safety are warranted due to the safety significance of the information provided for post accident recovery by these instruments. Accordingly, the Technical Specifications will permit the use of the Lot 1 Barton Transmitters until the second refueling outage. At that time, modified or replacement transmitters, that have been demonstrated to have a greater tolerance to harsh environments, will be required.

We questioned the adequacy of the qualification of Rosemount pressure and differential pressure transmitters to survive the extreme environmental conditions produced by high energy line breaks inside containment. Based on our review of the qualification report for these transmitters, we conclude that a sufficient basis was not provided to justify their use throughout the life of the plant. Since the test conditions to which these transmitters were subjected did not result in a failure of the transmitter to respond to changes in measured process conditions, we find that they are acceptable for use in the interim. Accordingly, the Technical Specifications will permit the use of Rosemount pressure and differential pressure transmitters until the second refueling outage. At this time, requalification of these transmitters or replacement transmitters that have been qualified will be required.

We reviewed Westinghouse Topical Report WCAP-9157 "Environmental Qualification of Safety Related Class IE Process Instrumentation" which contains the environmental

qualification results for the main coolant loop resistance temperature detectors. These temperature sensors provide data to confirm natural circulation cooling as well as data to ensure an adequate margin of subcooling to prevent steam formation in the reactor coolant system. We questioned the basis for the assessment that the normal and post accident radiation exposure would be limited to a radiation dose for which the resistance temperature detectors were qualified. The applicant provided a response to our concern which concluded that the resistance temperature detectors used for post accident monitoring are adequate if replaced after 14 years of operation. We conclude that this evaluation did not include assumptions which contained an adequate degree of conservatism. Therefore, the Technical Specifications will require the replacement of resistance temperature detectors used for post accident monitoring at each refueling outage pending requalification of the sensor to a higher radiation dose which is established based on a conservative assessment of post accident radiation levels and the normal radiation dose for their service life.

In June of 1979 Westinghouse reported a potential safety hazard under 10 CFR Part 21. This report addressed errors caused in steam generator level indication following high energy pipe breaks inside containment. High ambient temperatures due to accidents can result in a decrease in the density of water in the level instrument reference leg with a consequent increase in the indicated steam generator water level (i.e., the indicated water level exceeds actual level). We requested that the applicant evaluate the effects of such errors for all level measurement systems in containment. This evaluation led to a decision to insulate the reference legs for steam generator level measurements.

The applicant also assessed the method for establishing the low-low steam generator level trip setpoint. This setpoint is adjusted above zero-measured level by an amount which just equals the accumulation of all system errors, including temperature effects on the reference legs. We do not find this approach to evaluating errors and establishing the setpoint for safety action to be acceptable. The choice of zero-measured level, as a reference point for establishing the setpoint, does not provide an adequate margin of safety since these level transmitters do not respond to a reduction of water level below this point in the steam generators. Accordingly, the Technical Specifications will require a minimum low-low steam generator level setpoint of 18 percent (a margin of three percent in addition to identified errors of 15 percent) until such time as it can be demonstrated that this method establishes that an adequate margin of safety exists.

We have recently published staff guidance to be used in environmentally qualifying electrical equipment (see NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment"). Recognizing that the equipment qualification review for the North Anna Power Station, Unit 2 has been a long-term effort spanning several years, we recently required that the Virginia Electric and Power Company reassess their qualification documentation for equipment installed at North Anna Power, Station Unit 2 with the purpose of establishing that the qualification methods used and results obtained are in conformance with the staff positions contained in NUREG-0588. We believe that this additional review will

confirm our earlier conclusions regarding the adequacy of the qualification documentation, and therefore that it need not be completed prior to licensing North Anna Power Station, Unit 2 for low power operation. We will require that, prior to full power operations, the Virginia Electric and Power Company confirm the adequacy of qualification for all safety-related electrical equipment that could be exposed to a harsh environment.

4.0 REACTOR

4.2 Fuel Mechanical Design

As stated in Section 4.2 of our Safety Evaluation Report, the fuel for North Anna Power Station, Unit 2 is of the Westinghouse 17x17 design. This fuel design is currently operating in six plants, including North Anna Power Station, Unit 1. Three such plants have completed the first cycle of operation, and fuel inspections have been performed.

Subsequent to the issuance of our Safety Evaluation Report, Westinghouse has substantially changed their methods of fuel performance analysis and it has adopted new internal fuel rod pressure criteria. Also, at one of the operating 17x17 plants, an unexpected number of failures in two of the assembly components (grid straps and control spiders) was observed during refueling. These analytical changes and component failures and their impact on North Anna Power Station, Unit 2 are discussed and evaluated below.

Thermal Performance Analysis

The new Westinghouse fuel thermal performance code (PAD 3.3) is described in WCAP-8720, "Improved Analytical Methods Used in Westinghouse Fuel Rod Design Calculations," October 1976. This code contains a revision of an earlier fission gas release model and revised models for helium solubility, fuel swelling, and fuel densification.

The new Westinghouse code was approved with four restrictions as described in our safety evaluation of February 9, 1979 (Letter from J. Stolz, NRC to T. Anderson, Westinghouse). Three of those restrictions deal with numerical limits and have been complied with. The fourth restriction relates to use of the PAD-3.3 code for the analysis of fission gas release from uranium dioxide (UO_2) for power increasing conditions during normal operation. This restriction applies to the safety analysis of North Anna Unit 2. However, Westinghouse has stated that this restriction does not adversely affect the results of the safety analyses performed for North Anna Unit 2. Although we believe that this is essentially correct for the planned operation of North Anna Unit 2, Westinghouse has prepared and submitted a detailed evaluation of this restriction. In our previous evaluation, we agreed that the PAD-3.3 code may be used for the analysis of constant high power level conditions which conservatively bound power increasing conditions during normal operation.

For operation at five percent of full power the restriction for PAD-3.3 is not significant and the analysis as presently docketed is acceptable. We will complete our review of the Westinghouse evaluation (and the applications of the revised model) prior to authorizing operation at full power.

Internal Fuel Rod Pressure

North Anna Power Station, Unit 2 now uses the revised internal fuel rod pressure criteria as described in WCAP-8963A, "Safety Analysis For The Revised Fuel Rod Internal Pressure Design Basis", January 1979. Our evaluation and approval of these new criteria are also included in WCAP-8963A. The applicant has performed calculations for North Anna Power Station, Unit 2 with the approved Westinghouse fuel performance code (PAD 3.3, see above) and has shown that the approved internal pressure criteria as indicated in WCAP-8963A are met. Therefore, we reconfirm our previous conclusion that the internal fuel pressure analysis for the North Anna Unit 2 fuel is acceptable.

Grid Straps

During a recent refueling at a similar Westinghouse 17x17 plant (Salem Unit 1), strap damage on a number of spacer grids was observed on discharged assemblies. Similar damage has been reported previously (WCAP-8183, Rev. 1 through 8) "Operational Experience With Westinghouse Cores" but never to the extent observed at Salem Unit 1, where 31 fuel assemblies suffered some damage. The damage ranged from deformed edges and small chips to loss of full width strap pieces and was usually confined to one or two of the eight grids per assembly. A staff evaluation for Salem Unit 1 showed that such grid-strap damage was not detrimental to the operation of the reactor (see Amendment No. 20, October 1979, to the Salem Unit 1 operating license DPR-70, Docket No. 50-272). This evaluation considered thermal-hydraulics, neutronics, grid-cell deformation, flow blockage from loose pieces, and control-rod interference; the effects of all of these were found to be insignificant. We conclude that the Salem Unit 1 Evaluation regarding grid strap damage is also applicable to North Anna Unit 2 and the effects of grid-strap damage would be insignificant.

Westinghouse has recommended certain procedural changes that are designed to minimize or eliminate damage during fuel handling. These recommendations are based on the following: (1) loading sequence as to the buildup of rows and corner positions in the core, (2) offset into the open regions for vertical movement of assemblies, and (3) revised load cell limits on the refueling crane to increase the sensitivity in detecting spacer grid interference. The Virginia Electric and Power Company has agreed to follow these recommendations at North Anna 1 and 2 (letter from W. N. Thomas, VEPCO, to H. R. Denton, NRC, dated August 10, 1979). Furthermore, the fuel inspection at Unit 1 was expanded to look for grid strap damage during fuel handling. These inspections did not reveal significant strap damage. On the basis that grid strap damage is not detrimental to reactor operation and that steps will be taken to minimize its occurrence, we find that this matter is satisfactorily resolved.

Control Spiders

Another core component failure, involving control rod spiders, was also observed at Salem Unit 1. Eight alignment fingers on six spiders failed during plant operation. Thus, eight control rodlets became detached and were inserted into the core producing an observed flux tilt. This failure was traced to a manufacturing procedure that

introduced a contaminant that led to stress-corrosion cracking of the finger. This manufacturing procedure was primarily used for two lots of fingers, and the procedure has since been corrected to eliminate the problem. A complete evaluation of this problem and its safety implications is contained in Amendment 20 to the Salem Unit 1 operating license DPR-70 (October 1979, Docket No. 50-272).

The evaluation agrees with the Westinghouse conclusions that:

- (a) Failures do not represent a structural inadequacy or generic design weakness.
- (b) Failures are the result of stress corrosion cracking and were contained within the two receiving lots of outer fingers.
- (c) Elimination of all rod control clusters (RCCs) containing fingers from the suspect lots should prevent recurrence. (With respect to this item, the Virginia Electric and Power Company inspected North Anna Unit 1 after the first cycle and did not find any dropped rodlets.)

Our evaluation goes on to show that even if rodlets were dropped, the safety effects for the core would depend upon the number of dropped rodlets. A few dropped rodlets (about 10) could cause a flux tilt, but the core parameters could be maintained within the Technical Specification limits. A larger number of dropped rodlets (about 50) would be needed to cancel the excess shutdown margin or significantly affect peaking factors, but such a quantity would be easily detected and appropriate actions taken. In light of the low probability of the future occurrence of dropped rodlets and the fact that the dropping of significant numbers of rodlets would be detected, this matter is acceptably resolved. We have reviewed the Salem evaluation and have determined that it is applicable to North Anna Unit 2. Therefore, we consider this matter acceptably resolved for North Anna Unit 2.

Guide Thimble Tube Wall Wear

An unexpected degradation of guide thimble tube walls has been observed during post-irradiation examinations of irradiated fuel assemblies taken from several operating pressurized water reactors. Subsequently it has been determined that coolant flow up through the guide thimble tubes and turbulent cross flow above the fuel assemblies has been responsible for inducing vibratory motion in the normally fully withdrawn ("parked") control rods. When these vibrating rods are in contact with the inner surface of the thimble wall, a fretting wear of the thimble wall occurs. Significant wear has been found to be confined to the relatively soft Zircaloy-4 thimble tubes because the control rod claddings--stainless steel for Westinghouse nuclear steam supply systems designs--provide a relatively hard wear surface. The extent of the observed wear is both time and nuclear steam supply system design dependent and has, in some non-Westinghouse cases, been observed to extend completely through the guide thimble tube walls, thus resulting in the formation of holes.

Guide thimble tubes function principally as the main structural members of the fuel assembly and as channels to guide and decelerate control rod motion. Significant

loss of mechanical integrity due to wear or hole formation could (1) result in the inability of the guide thimble tubes to withstand their anticipated loadings for fuel handling accidents and transients, and (2) hinder scramability.

In response to our attempt to assess the susceptibility and impact of guide thimble tube wear in Westinghouse plants, Westinghouse in letters dated September 12, 1978, December 15, 1978 and June 27, 1979, and the applicant in a letter dated January 22, 1980, have submitted information on their experience and understanding of the issue. This information consisted of guide thimble tube wear measurements taken on irradiated fuel assemblies from Point Beach Units 1 and 2 (Docket Nos. 50-266 and 50-301, two-loop plants using 14x14 fuel assemblies.) Also described was a mechanistic wear model (developed from the Point Beach data) and the impact of the model's wear predictions on the safety analyses of plant designs such as those utilizing 17x17 fuel assemblies.

Westinghouse believes that its fuel designs will experience less wear than reported in other nuclear steam supply system designs because the Westinghouse designs use thinner, more flexible, control rods that have relatively more lateral support in the guide tube assembly of the upper core structure. Such construction provides the housing and guide path for the rod cluster control assemblies above the the core and thus restricts control rod vibration due to lateral exit flow. Also, Westinghouse believes that its wear model conservatively predicts guide thimble tube wear and that even with the worst anticipated wear conditions (both in the degree of wear and the location of wear) their guide thimble tubes will be able to fulfill their design functions. It is anticipated that some fuel elements will stay in the reactor vessel for a maximum of three to four years.

We have reviewed this information and conclude that the Westinghouse analysis accounts for all of the major variables that control this wear process. However, because of the complexities and uncertainties in determining (1) contact forces, (2) surface-to-surface wear rates, (3) forcing functions, and (4) extrapolations of these variables to other fuel designs (such as the 17x17 design used in North Anna), as a measure of prudence we required the applicant to make a commitment, before issuance of a full power license to submit for review a surveillance plan and schedule for the examination of guide thimble tube wear.

The specifics of such a surveillance program have not yet been determined, but since the wear phenomenon is a time-dependent process, the details of such an inspection program do not need to be specified prior to the first North Anna Unit 2 refueling outage. Furthermore, such inspection may not have to be conducted at North Anna. For example, the applicant could join in a cooperative owner's group and thereby submit applicable information derived from a similar type of plant using 17x17 fuel assemblies. For acceptability, the minimum objective of such a program should be to demonstrate that there is no occurrence of hole formation in rodged guide thimble tests.

In its letter of January 22, 1980, the applicant agreed to provide results from a surveillance program as described above. Therefore, this issue is acceptably

resolved for the first cycle of operation. This issue should be resolved for later cycles of operation when those surveillance results confirm the predictions of the analysis described above. If the surveillance results do not confirm the predictions of the analysis, we will require that the applicant take appropriate action to account for increased wear.

4.2.3 Reactor Internals

4.2.3.1 Control Rod Guide Tube Support Pins

On March 31, 1980, Westinghouse reported to the NRC that control rod guide support pins that were given a non-optimum heat treatment may be susceptible to stress corrosion cracking. This followed recent support pin inspections at a foreign plant which revealed stress corrosion cracks in Westinghouse supplied pins. The applicant has advised us that prior to zero power operation the existing guide support pins in North Anna Unit 2 internals will be replaced with new pins that have been heat treated to make them highly resistant to stress corrosion cracking. On this basis, we consider this matter resolved.

5.0 REACTOR COOLANT SYSTEM

5.2 Integrity of Reactor Coolant Boundary

5.2.2 Compliance with Codes and Code Cases

The reactor vessel for North Anna Power Station, Unit 2 was manufactured by Rotterdam Dry Dock Company of the Netherlands. However, the upper and lower pressure vessel subassemblies were subcontracted by Rotterdam Dry Dock Company to Sulzer Brothers Ltd. of Switzerland. Sulzer made all the pressure boundary welds except the final girth seam weld joining the two halves of the vessel which was made by Rotterdam. Cladding of all vessel nozzles was performed by Sulzer using a welding and heat treating process which is different from the process used by the Rotterdam Dry Dock Company on the Sequoyah vessel. Since there is limited experience with some types of underclad cracking and some uncertainty as to the cladding process used, we requested and the applicant committed to inspect the nozzle cladding prior to the issuance of an operating license to load fuel.

Ultrasonic examinations of the six reactor vessel nozzles have been completed at the North Anna Unit 2 nuclear plant. These examinations supplemented the preservice volumetric inspections required by Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code). The purpose of the supplemental examinations was to determine if cracking existed under the stainless steel cladding in the nozzle base metal, and to characterize and evaluate any cracking found.

There are two ways that underclad cracking can be produced. One is referred to as "reheat" underclad cracking, and is caused by high heat input during clad deposition. Variations in welding procedures, involving lower pre- and post-weld temperature control were developed partly to prevent underclad "reheat" cracking. It was recently discovered that this new procedure could cause "cold" cracking under the cladding, and that the depth of cracks produced by this second mechanism could be two to three times as deep as those produced by the "reheat" mechanism.

The presence of underclad reheat cracks, recognized several years ago, was previously evaluated by the staff, and was found acceptable based on extensive metallurgical and fracture mechanics analyses. The nature of the reheat cracks is described in detail in two Westinghouse topical reports, WCAP-7673-L - "Reactor Vessels Weld Cladding - Base Metal Interaction" dated April 1971 and WCAP-7673-L Addendum 1 - "Reactor Vessels Weld Cladding - Base Metal Interaction" dated August 1971. The staff's safety evaluation for the reheat cracks, "Safety Report for Sequoyah Unit 1 - Cladding Cracks" (Sequoyah Nuclear Plant Unit 1, Docket No. 50-237), was issued in April 1972. We have reviewed the earlier Westinghouse reports and our previous safety evaluation and find no new information to indicate that our earlier conclusions concerning the acceptability of reheat cracks should be modified.

Cold cracks can be produced in the base material immediately under the cladding at low temperatures (below 350 degrees Fahrenheit) during cooling subsequent to welding and is associated with three factors: (1) the presence of hydrogen in the heat affected zone of the weldment, (2) a susceptible metallurgical structure, and (3) the presence of residual stresses. Cold cracking can be avoided by pre-heating and post-weld heating the component to permit any hydrogen generated in the welding process to diffuse out of the susceptible area while the material is above the temperature range where cold cracking will occur.

The search for underclad cold cracking was initiated when information received from Westinghouse disclosed potential "cold" cracking under the cladding in vessel nozzles that had been fabricated in Europe using the low temperature cladding process. This low temperature procedure is not commonly used in the United States. The processes that are of concern are characterized by a lack of sufficient heat input to the nozzle before and after the clad layers are deposited. As this safety evaluation later discusses, the cladding procedure used for the North Anna Unit 2 reactor vessel nozzles is not expected to produce cold cracking. Nevertheless, because there was limited experience with the cold cracking phenomenon in the United States, and some uncertainty as to the cladding process used, the ultrasonic examinations were performed to provide additional information regarding the condition of the North Anna Unit 2 nozzles.

The examination results show that there are a very large number of cracks in each of the six reactor vessel nozzles. Because there are a large number of cracks, each crack could not be evaluated during the examination. Consequently, only a sample of the cracks were examined in detail and only a qualitative description of the nature of the cracking is available. The cracks are reported to be arranged in rows that form circumferential bands around the nozzle circumference. Within the circumferential bands the cracks are tightly spaced and have their lengths oriented parallel to the axial length of the nozzle. The circumferential bands of axially oriented cracks are spaced about $1\frac{1}{2}$ to 2 inches apart and extend along the entire length of the nozzles. Measurements by ultrasonic methods indicate the cracks are typically $\frac{3}{8}$ inch long with the maximum reported length being $\frac{1}{2}$ inch. Limitations on the examination methods preclude an acceptable measurement of crack depth into the base metal of the nozzle.

We have reviewed the ultrasonic examination results obtained for the North Anna Unit 2 reactor vessel nozzles and have performed an independent evaluation to determine if the cracks are acceptable for service. Our evaluation includes an assessment of the examination results, a determination of the likely cause of the cracking, an estimate of the depth of the cracks, and an assessment of the safety significance of the cracks.

The cracking pattern reported to exist in the North Anna Unit 2 reactor vessel nozzles is not typical of the underclad cold cracking associated with inadequate pre- and post-clad temperature. Instead, the reported cracking pattern is characteristic of underclad reheat cracking that results in local material degradation due to excessive heat input to the nozzle base metal during the deposition of the cladding. However,

the large number of reheat underclad cracks would likely obscure small cracks that may have been produced by other cracking mechanisms.

Although the extensive reheat underclad cracking found in the North Anna nozzles could be expected to mask detection of cold underclad cracking by the ultrasonic testing method, we believe that the welding procedures and temperature controls specified would have precluded the formation of any significant degree of cold cracking. The process used to clad the North Anna nozzles utilized the automatic gas metal arc process. A relatively high heat input was used during the application of the cladding and is associated with the observed reheat cracks. Prior to welding, the nozzle was preheated to 250 degrees Fahrenheit and then given a post-weld soak at 400 degrees Fahrenheit for two hours prior to any cool down to ambient temperatures. A post-weld heat treatment at 1150 degrees Fahrenheit was performed as a final treatment. Not only does the use of the automatic gas metal welding process minimize the generation of hydrogen in the material, but the preheat and post-weld heat treatments specified would be expected to dissipate any hydrogen that was formed; thus eliminating the major source of cold cracking.

Based on our evaluation of the inspection results and the pre- and post-clad thermal treatments, we have concluded that the flaws in the North Anna Unit 2 reactor vessel nozzles are reheat cracks. Based on our earlier review (Safety Report for Sequoyah Unit 1 - Cladding Cracks) of the reheat cracking phenomenon and the specific information provided for North Anna Unit 2, we conclude that the cracks in the North Anna Unit 2 nozzles likely are not greater than 1/8 inch deep and 1/2 inch long and are within the acceptance standards established by Section XI of the ASME Code. Compliance with Section XI of the ASME Code provides adequate assurance that the reactor vessel has sufficient margin against flaw induced fracture. To provide added assurance that adequate margins continue to be maintained during service, we will require that the North Anna Unit 2 nozzles be inspected periodically during service and that the results of the examinations be reported to the Commission. Prior to conducting the inservice examinations, we will require VEPCO to demonstrate to the staff that the examination techniques will allow reliable detection and evaluation of individual cracks, should they grow larger than the acceptance standards contained in Section XI of the ASME Code. We require that this information be supplied to us within five years.

5.2.7 Steam Generator Materials

5.2.7.1 Secondary Water Chemistry

In a letter dated November 9, 1978, the Virginia Electric and Power Company requested an amendment in the form of changes to the Technical Specifications, to Operating License No. NPF-4 for North Anna Power Station, Unit 1. The proposed changes would complete Technical Specifications 3.7.1.6 and 4.7.1.6 by specifying conductivity limits and surveillance requirements for the secondary water system.

We have reviewed the information provided by the applicant and have concluded that based on our evaluation below, that it is appropriate to remove the requirement in the Unit 1 and Unit 2 Technical Specifications for secondary water chemistry limits and surveillance.

In late 1975 we incorporated provisions into the Standard Technical Specifications (STS) that required limiting conditions for operation and surveillance requirements for secondary water chemistry parameters. The Technical Specifications for North Anna Unit 1, as well as those for all other pressurized water reactor plants that have been issued an operating license since 1974, contain either these provisions, or a requirement to establish these provisions after baseline chemistry conditions have been determined. The intent of the provisions was to provide added assurance that the operators of newly licensed plants would properly monitor and control secondary water chemistry to limit corrosion of steam generator tubes.

In a number of instances the Technical Specifications have significantly restricted the operational flexibility of some plants with little or no benefit with regard to limiting corrosion of steam generator tubes. Based on this experience and the knowledge gained in recent years, we have concluded that Technical Specification limits are not the most effective way of assuring that steam generator tube corrosion will be minimized.

Due to the complexity of the corrosion phenomena involved and the state-of-the-art as it exists today, we believe that, in lieu of specifying limiting conditions in the Technical Specifications, a more effective approach would be to institute a license condition that requires the implementation of a secondary water chemistry monitoring and control program containing appropriate procedures and administrative controls.

The required program and procedures have been developed by the applicant with input from their reactor vendor or other consultants, to more readily account for site and plant-specific factors that affect chemistry conditions in the steam generators. In our view, plant operation following such procedures would provide assurance that licensees would devote proper attention to controlling secondary water chemistry, while also providing the needed flexibility to allow them to deal more effectively with any off-normal conditions that might arise.

Consequently, we requested, in a letter dated July 31, 1979 that the applicant propose that a secondary water chemistry program which will be referenced in a condition to the license. In the letter we concluded that such a license condition, in conjunction with existing Technical Specifications on steam generator tube leakage and inservice inspection, would provide the most practical and comprehensive means of assuring that steam generator tube integrity would be maintained.

In a letter dated September 4, 1979, the applicant provided its program for monitoring the secondary water chemistry of North Anna Power Station, Units 1 and 2. The applicant's program identifies a sampling schedule for the critical parameters and of control points for these parameters. It also includes (1) identification of the procedures used to measure the value of the critical parameters, (2) identification

of process sampling points and (3) procedures defining corrective actions for off-control point chemistry conditions.

We have reviewed the applicant's program and concur with the program and agree that it meets our requirements as delineated in our letter of July 31, 1979.

However, in addition to the proposed secondary water chemistry monitoring and control program, we require monitoring of the steam condensate at the effluent of the condensate pump. The monitoring of the condensate is for the purpose of detecting condenser leakage. When condenser leakage is confirmed the applicant will be required to repair or plug the leak in accordance with MTEB Branch Technical Position MTEB 5-3 attached to Standard Review Plan 5.4.2.i. The license will be conditioned accordingly. It should be noted that the steam generators of the North Anna Power Station, Units 1 and 2 are of the Westinghouse "51" series design having carbon steel supporting plates with drilled flow holes. Steam generators of this design in operating plants have experienced denting and cracking. Although an effective secondary water chemistry control program can reduce the rate of tube degradation there is no assurance that a 40 year steam generator lifetime can be obtained.

In spite of the possibility of tube cracking, we have concluded that operation of the steam generators will not constitute an undue risk to the health and safety of the public for the following reasons:

- (1) Primary to secondary leakage rate limits, and associated surveillance requirements have been established to provide assurance that the occurrence of tube cracking during operation will be detected and appropriate corrective action, such as tube plugging, will be taken such that any individual crack present will not become unstable under normal operating, transient or accident conditions.
- (2) Inservice inspection requirements and preventative tube plugging criteria have been established to provide assurance that the great majority of degraded tubes will be identified and removed from service before leakage develops.

5.2.7.2 Steam Generator Ports

In our letter of January 21, 1980, we requested that the Virginia Electric and Power Company install inspection ports in the steam generators of the North Anna Power Station, Unit 2 prior to the start of operations. These ports were to facilitate monitoring the progression of tube denting and tube support plate degradation and to facilitate the removal of tube sections for laboratory examinations.

For some forms of steam generator degradation which have occurred, eddy current testing and tube gauging alone are not sufficient to assess and monitor tube and support plate degradation. In order to perform adequate assessment and monitoring of these areas it is necessary to install inspection ports. These ports should be installed just above the support plate and between the tubesheet and the lower support plate.

In a letter dated February 21, 1980, the Virginia Electric and Power Company concluded that installation of the inspection ports prior to the start of operation was not practical. The bases for their conclusion were that the installation of these ports would require a minimum of two months and would require a delay of start-up by at least that amount of time. On the basis that it would cost \$350,000 per day for replacement power, the Virginia Electric and Power Company stated that their consumers would be better served if the installation of these ports was delayed to some future refueling date if and when the ports would be needed. In lieu of providing the inspection ports now, the Virginia Electric and Power Company proposed to plug the first row of tubes in each steam generator, since experience has shown that the small bend radius of these tubes leads to early onset of cracking. We agree that the plugging of the first row of tubes, prior to start-up, should forestall the early need for shutdowns due to the leaking tubes since these tubes are the ones most susceptible to the development of cracks.

Under the as low as reasonably achievable (ALARA) concept we have been requesting that all possible steam generator modifications be made before the start of operations in order to minimize personnel exposure. The Virginia Electric and Power Company has informed us that, based upon their experience at Surry 1, the ports can be installed in the three steam generators at a personnel exposure of 7.5 man-rem. On this basis, we have determined that this exposure is not significant enough to justify the delay of the start-up of the plant to permit the installation of inspection ports.

However, since secondary side contamination will increase as the operating time increases, we require that these ports be installed prior to start-up after the first refueling. Accordingly, the Technical Specifications reflect this requirement.

5.2.8 Overpressure Protection

Several instances of reactor vessel overpressurization have occurred in Pressurized Water Reactors in which the technical specifications implementing Appendix G to 10 CFR Part 50 have been exceeded. The majority of cases have occurred during cold shutdown while the primary system was in a water-solid conditions. The Virginia Electric and Power Company, owner of North Anna Unit 2, was a participant in a task group of utilities to find a solution to this issue. The solution for North Anna Unit 2 includes design and administrative procedure modifications and operator training. (Discussed in letters to NRC dated April 17, April 23, and October 18, 1979). The design modifications are intended to mitigate the consequences of an overpressurization event. The modification to administrative procedures and additional operator training are intended to reduce the chance of an overpressurization event from taking place.

The overpressurization mitigation system is fully implemented and administrative procedures have been instituted which are designed to preclude overpressurization events.

We have reviewed the applicant's system for overpressure protection when the reactor coolant system is at low temperatures. The system consists of two separate trains each containing a power operated relief valve, an isolation valve, and associated circuitry. Each train contains an annunciator which sounds an alarm in the control room to alert the operator when plant conditions require enabling of the overpressure mitigation system (manually turning a key lock switch). In addition, an annunciator is provided in the control room to indicate when the overpressure transient is occurring. Indication lights are provided on the main control board to indicate power operated relief valve and power operated relief valve isolation valve position.

The power operated relief valves have multiple set points and during primary system high temperature operation are controlled by the containment instrument air. During water-solid modes of operation, a three-way solenoid is energized and the pneumatic supply is switched to bottled nitrogen. Redundant nitrogen reserve tanks are also provided in the event of a loss of bottled nitrogen supply. At primary system temperatures between 100 degrees Fahrenheit (°F) and 340 degrees Fahrenheit the staff requires overpressure protection against violation of the 10CFR50 Appendix G limits. The applicant has chosen to divide this range into three parts in order to provide this protection, i.e., (a) $320^{\circ}\text{F} < T < 340^{\circ}\text{F}$, (b) $140^{\circ}\text{F} < T < 320^{\circ}\text{F}$, and (c) $T < 140^{\circ}\text{F}$. Net positive suction head requirements for the reactor coolant pumps restrict the ability of the unit to have a low enough power operated relief valve setpoint (i.e., in order to avoid pump cavitation) to meet the requirements for primary system protection in the primary system temperature range between 320 degrees Fahrenheit and 340 degrees Fahrenheit. For North Anna Unit 2 the Appendix G pressure limit for a 320 degrees Fahrenheit primary system is 2100 pounds per square inch gauge and for 340 degrees Fahrenheit is above 2500 pounds per square inch gauge. The safety valve setpoint is 2485 pounds per square inch gauge. The applicant submitted an analysis which showed that if no operator action were taken for ten minutes after the first alarm which warns the operator of the existence of an overpressure event, the pressurizer bubble, which must be maintained at least at 943 cubic feet by Technical Specification, will provide sufficient margin to allow the operator to satisfactorily limit the consequences of the event. (a) At temperatures between 340 degrees Fahrenheit and 320 degrees Fahrenheit the pressurizer bubble and one train of the power operated relief valve system may be utilized for adequate overpressure protection. An alarm is provided to alert the operator that an overpressure transient is occurring. If operator error or equipment malfunction should occur, relief protection will be provided by the single train of the power operator relief valve system. (b) We required that at primary system temperatures below 320 degrees Fahrenheit both trains of the overpressure mitigation system will be enabled by the operation of the key lock switch. In the temperature range of 320 degrees Fahrenheit to 140 degrees Fahrenheit, the power operated relief valve circuitry will automatically select the higher of the two low temperature setpoints for the power operated relief valves. In this temperature range, the power operated relief valve setpoint will be 470 pounds per square inch gauge for train number 1 and 455 pounds per square inch gauge for train number 2. (c) At temperature below 140 degrees Fahrenheit the power operated relief valve circuitry will select the lower setpoints which correspond to 400 pounds per square inch gauge for train number 1 and 385 pounds per square inch gauge for train number 2. This multiple setpoint system allows sufficient net positive suction

head to operate the reactor coolant pumps while providing sufficient protection to prevent exceeding the 10 CFR Part 50 Appendix G limits. Technical Specifications require that all but one high head safety injection pump be isolated during water-solid conditions and that no reactor coolant pump be started with one or more reactor coolant system cold legs at or below 340 degrees Fahrenheit when the steam generator temperatures is more than 50 degrees Fahrenheit higher than the cold leg temperature. The applicant has shown that in either (a) the mass input case, for one high head safety injection pump or (b) the heat input case, from the starting of a primary coolant pump when the steam generator temperature is 50 degrees Fahrenheit higher than the cold leg, that one power operated relief valve would prevent exceeding the 10 CFR Part 50 Appendix G limits. The seismic design of the system is consistent with the staff requirement for an overpressure protection system, and adequate means for testing and calibration have been provided. We required the applicant to provide plant procedures which insure that the emergency core cooling accumulators are isolated with power removed or locked out to the isolation valves prior to proceeding to temperatures below 340 degrees Fahrenheit.

On the basis of our review as discussed above we conclude that their system meets the requirements for overpressure protection as described in Branch Technical Position RSB-5-2, "Reactor Coolant System Overpressurization Protection," and therefore is acceptable.

5.2.11 Preservice Inspection of Reactor Coolant Pressure Boundary

For nuclear power facilities whose construction permits were issued on or after January 1, 1971, but before July 1, 1974, 10 CFR 50.55a(g)(2) specifies that components shall meet the preservice examination requirements set forth in editions of Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code and Addenda in effect six months prior to the date of the issuance of the construction permit. The provisions of 10 CFR 50.55a(g)(2) also state that components (including supports) may meet the requirements set forth in subsequent editions of this code and addenda which become effective.

In a letter dated July 7, 1978 the Virginia Electric and Power Company informed us that the preservice inspection for North Anna Power Station, Unit 2, was being performed, to the extent practical, in accordance with the requirements of the American Society of Mechanical Engineers Code, Section XI, 1974 Edition, including Addenda through Summer 1975. In a letter dated December 4, 1978, Virginia Electric and Power Company requested an evaluation of certain preservice inspection requirements to demonstrate compliance with 10 CFR Part 50, paragraph 50.55a(g)(2). Some of the Section XI Code required examinations were determined to be impractical and VEPCO provided supporting information pursuant to paragraph 50.55a(a)(i) to justify deviations from these code preservice examination requirements.

Therefore, our evaluation consisted of determining if identified preservice inspection examinations are impractical and if deviations from the code requirements are justified.

As a result of our review of this information, we have determined that certain preservice examinations are impractical and performing these required examinations would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Our basis for this conclusion is discussed in the subsequent paragraphs.

5.2.11.1 Technical Evaluation Considerations

- (1) The North Anna Unit 2 construction permit was issued in February 1971. In accordance with 10 CFR 50.55a, the preservice inspection must conform with the 1970 Edition of Section XI of the American Society of Mechanical Engineers Code. The 1970 Edition of Section XI constitutes the first publication of the American Society of Mechanical Engineers inservice inspection rules. No preservice or inservice inspection requirements existed prior to that date. Since the North Anna plant system design and ordering of long lead time components were well underway by the time the Section XI rules became effective, full compliance with the exact Section XI access and inspectability requirements was not always practical.
- (2) Verification of as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the North Anna Unit 2 primary pressure boundary was fabricated contain examination and testing requirements which by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions and postulated accidents reviewed in the Final Safety Analysis Report and described in the plant design specification. As a part of these examinations all of the primary pressure boundary full penetration welds were volumetrically inspected (radiographed) and the system was subjected to hydrostatic pressure test. In addition, field pipe welds received a surface and visual examination.
- (3) The intent of a preservice examination was to establish a reference or base line prior to the initial operation of the facility. The results of subsequent inservice examination can then be compared to the original condition to determine if changes have occurred. If review of the inservice inspection results shows no change from the original condition no action is required. In the case where base line data is not available all indications must be treated as new indications and evaluated accordingly. Section XI of the ASME Code contains acceptance standards which are used as the basis for evaluating the acceptability of such indications.
- (4) Other benefits of preservice examination include providing redundant volumetric inspection of the primary pressure boundary using a test method different from that employed during the component fabrication. Successful performance of a preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using a similar test method.

- (5) In the case of North Anna Unit 2, a large portion of the code required preservice examinations were performed. In some instances where the required preservice examinations were not performed to the full extent specified by the applicable American Society of Mechanical Engineers Code, we will require that these or supplemental examinations be conducted as a part of the inservice inspection program. We have concluded that requiring these supplemental examinations to be performed at this time (before plant startup) would result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. The performance of supplemental examinations, such as surface examinations, in areas where volumetric inspection is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar Section III fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current inspection technique limitations, we will continue to evaluate the development of new or improved volumetric examination techniques. As improvements in these areas are achieved, we will require that these new techniques be made a part of the inservice examination requirements of those components or welds which received a limited preservice examination.

5.2.11.2 Evaluation of Required Examinations

We have reviewed the information submitted by the Virginia Electric and Power Company in their letters dated July 7, 1978 and December 4, 1978 related to the preservice examination of North Anna Station, Unit 2. Based on this information and our review of the design, geometry, and materials of construction of the components, certain preservice requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section XI have been determined to be impractical and would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

Therefore, pursuant to 10 CFR Part 50, paragraph 50.55a(a)(2), our conclusions that these preservice requirements are impractical is justified as follows:

(1) Reactor Vessel

(a) Item B1.18 Control Rod Drive Housings

Code Requirement: The examination areas shall include essentially 100 percent of the weld metal and base metal for one wall thickness beyond the edge of the weld in the installed peripheral control rod drive housings only.

Code Deviation Request: The Virginia Electric and Power Company requested to substitute the examination of accessible control rod drive housings in the inner region of the head for peripheral housings.

Reason for Request: Several of the peripheral housings were not accessible due to special insulation construction. Housings on the inner portion of the head which were accessible were substituted for the peripheral ones not examined.

Evaluation: We have determined that the required examinations are impractical because the installed insulation fixtures makes the examination areas inaccessible. We conclude that the examination of an equivalent total number of the housings that are accessible is acceptable and meets the code requirement to the extent practical. Based on our review of the Section XI required preservice examinations and the preservice examinations performed by the applicant, we conclude that completing the exact Section XI required examination would result in a hardship without a compensating increase in quality or safety.

(b) Item B1.3 Closure Head to Flange Weld

Code Requirement: The examination areas shall include essentially 100 percent of the head-to-flange welds.

Code Deviation Request: A deviation was requested from performing 100 percent of the code required volumetric examination.

Reason for Request: The geometric configurations of the flange limits the extent to which ultrasonic examinations can be performed for the lower side of the weld. Examination coverage was locally restricted by the head lifting lugs, which reduce examination coverage to 95 percent rather than 100 percent of the total length.

Evaluation: We have determined that part of the Section XI required examination is impractical because the existing design configuration limits the examination coverage and that completion of an estimated 95 percent of the Section XI required examination and a limited ultrasonic examination from the lower side of the weld meet the code requirement to the extent practical. Based on our review of the Section XI required preservice examinations and the preservice examinations performed by the applicant, we conclude that completing the remaining portion of the Section XI required examination would result in a hardship without a compensating increase in quality or safety.

(2) Pressurizer

(a) Item B2.2 Nozzle to Vessel Welds

Code Requirement: The examination areas shall include essentially 100 percent of the nozzle to vessel weld and adjacent areas.

Code Deviation Request: A deviation was requested from performing 100 percent of the code required volumetric examination.

Reason for Request: The weld and adjacent base material on the head side was completely examined by angle beam as required by Paragraph I-2310. The geometric configuration of the nozzle is such that no examination can be performed from the nozzle side of the weld. The Virginia Electric and Power Company estimated that 80 percent of the Section XI preservice examination requirement was performed.

Evaluation: We have determined that part of the Section XI required examination is impractical because the existing design configuration of the nozzle limits the examination coverage and that the complete examination from the head side meets the code requirement to the extent practical. Based on our review of the Section XI required preservice examinations and the preservice examinations performed by the applicant, we conclude that completing the remaining portion of the Section XI required examination would result in a hardship without a compensating increase in quality or safety.

(b) Item B2.4 Nozzle to Safe-End Welds

Code Requirement: The examination areas shall include essentially 100 percent of the dissimilar metal welds (e.g., safe-end welds) between combinations of carbon, low alloy, or high tensile steels and stainless steels, nickel-chromium-iron alloys, nickel-copper alloys. This shall include the base material for, at least, one wall thickness beyond the edge of weld.

Code Deviation Request: A deviation was requested from performing 100 percent of the code required volumetric examination.

Reason for Request: The configurations of the nozzle and safe-end are such that angle beam scan lengths are limited and the adjacent base material cannot be examined for one full wall thickness on either side. The Virginia Electric and Power Company estimated that 90 percent of the Section XI preservice examination requirement was performed.

Evaluation: We have determined that part of the Section XI required examination is impractical because the existing design configuration of the nozzle limits the examination coverage and that completion of an estimated 90 percent of the Section XI required examination meets the code requirement to the extent practical. Based on our review of the Section XI required preservice examinations and the preservice examinations performed by the applicant, we conclude that completing the remaining portion of the Section XI required examination would result in a hardship without a compensating increase in quality or safety.

(c) Item B2.8 Integrally-Welded Supports

Code Requirement: The examination areas shall include essentially 100 percent of the integrally-welded support attachment (e.g., support skirts). This includes the welds to the vessel and the base metal beneath the weld zone and along the support attachment member for a distance of two support thicknesses.

Code Deviation Request: A deviation was requested from performing 100 percent of the code required volumetric examination.

Reason for Request: The pressurizer support skirt weld could not be examined to the extent required by Section XI, Article IWB-2500, because the design of the support member results in an uninspectable region. The Virginia Electric and Power Company estimated that 92 percent of the Section XI preservice examination was performed.

Evaluation: We have determined that part of the Section XI required examination is impractical because of the existing design configuration and that completion of an estimated 92 percent of the Section XI required examination meets the code requirement to the extent practical. Based on our review of the Section XI required preservice examinations and the preservice examinations performed by the applicant, we conclude that completing the remaining portion of the Section XI required examination would result in a hardship without a compensating increase in quality or safety.

(3) Steam Generators (3), Primary Side

(a) Item B3.3 Nozzle to Safe-End Welds

Code Requirement: Same as Item B2.4.

Code Deviation: A deviation was requested from performing 100 percent of the code required volumetric examination.

Reason for Request: The reactor coolant pipe to steam generator primary nozzle safe-end weld examination is limited to the pipe side of the weld due to the design configuration of the nozzle. The Virginia Electric and Power Company estimated that 80 percent of the Section XI preservice examination was performed.

Evaluation: We have determined that part of the Section XI required examination is impractical because the existing design configuration of the nozzles limits the examination coverage and that completion of an estimated 80 percent of the Section XI required examination meets the code requirement to the extent practical. Based on our review of the Section XI required preservice examinations and the preservice examinations performed by the applicant, we conclude that completing the remaining portion of the

Section XI required examination would result in a hardship without a compensating increase in quality or safety.

(4) Reactor Coolant Pump and Valve Pressure Boundary

(a) Item B5.1 Pressure Retaining Bolting Pump Seal, Housing Bolts, In Place

Item B5.2 Pressure Retaining Bolting, Pump Bolts, When Removed

Item B6.2 Pressure Retaining Bolting, Valve Bolts, When Removed

Code Requirement: The examination areas shall include essentially 100 percent of the bolts, studs, nuts, bushings, washers, and threads in base material and flange ligaments between threaded stud holes.

Code Deviation Request: A deviation was requested from performing 100 percent of the code required volumetric examination.

Reason for Request: This examination to the extent required by Article IWB-2600 can only be performed when the pump or valve is disassembled for maintenance purposes or at the end of the 10 year interval when disassembly is undertaken for the performance of pump casing or valve body examinations.

Evaluation: We consider disassembly of the reactor coolant pumps and valves solely for the Section XI required preservice examination of the bolting to be impractical and that completing the Section XI required preservice examinations would result in a hardship without a compensating increase in quality or safety.

(5) Piping Pressure Boundary

(a) Item B4.9 Integrally-Welded Supports

Code Requirement: The examination areas shall include essentially 100 percent of the integrally-welded external support attachments. This includes the welds to the pressure-retaining boundary and the base metal beneath the weld zone and along the support attachment member for a distance of two support thicknesses.

Code Deviation Request: A deviation was requested from performing 100 percent of the code required volumetric examination.

Reason for Request: The piping system integrally welded supports are attached to the pipe by fillet welds. The configurations of such welds was such that examinations could not be performed to the extent required by Article IWB-2600 and only the base material of the pipe wall could be examined by ultrasonic techniques. Surface examinations were performed on

the internally-welded attachments in addition to the limited volumetric examinations.

Evaluation: We have determined that fillet welds for piping support attachments generally can not be examined by ultrasonic techniques to the extent required by Section XI and that the required examination is generally impractical and has been completed to the extent practical at North Anna Unit 2. Based on our review of the Section XI required preservice examinations and the preservice examinations performed by the applicant, we conclude that completing the remaining portion of the Section XI required examination would result in a hardship without a compensating increase in quality or safety.

(b) Item B4.6 Branch Pipe Connection Welds Exceeding Six Inches in Diameter

Code Requirement: The examination areas shall include essentially 100 percent of the longitudinal and circumferential welds and the base metal for one wall thickness beyond the edge of the weld. Longitudinal welds shall be examined for at least one foot from the intersection with the edge of the circumferential weld selected for examination. In the case of pipe branch connections, the areas shall include the weld metal, the base metal for one pipe wall thickness beyond the edge of the weld on the main pipe run, and at least two inches of the base metal along the branch run.

Code Deviation Request: A deviation was requested from performing 100 percent of the code required volumetric examination.

Reason for Request: The design configuration limits the ultrasonic examination of both the base metal and the weldment. Surface examinations were performed on the branch connections in addition to the limited volumetric examination.

Evaluation: We have determined that the required examination is impractical because of the design configuration of the branch connections and that the Section XI required volumetric inspection has been completed to the extent practical. Based on our review of the Section XI required preservice examinations and the preservice examinations performed by the applicant, we conclude that completing the remaining portion of the Section XI required examination would result in a hardship without a compensating increase in quality or safety.

(c) Item B4.1 Safe-End to Pipe Welds

Item B4.5 Circumferential and Longitudinal Pipe Welds

Code Requirements: Same as Item B2.4 and B4.6 respectively.

Code Deviation Request: A deviation was requested from performing 100 percent of the code required volumetric examination. The locations of the B-F and B-J welds for which deviations were requested are identified in Table 5.1. A significant number of these welds are in two inch and three inch diameter piping systems, which are difficult to examine with current ultrasonic techniques.

Reason for Request: The arrangements and details of the piping systems and components are such that some examinations as required by IWB-2600 are limited due to geometric configuration or accessibility. Generally, these limitations exist at pipe to fitting welds, where examinations can only be fully performed from the pipe side, the fitting geometry limiting or even precluding examination from the opposite side. In instances where the location of pipe supports or hangers restricts the access available for the examination of pipe welds as required by IWB-2600, examinations were performed to the extent practical unless removal of the support was permissible without unduly stressing the system.

The Virginia Electric and Power Company estimated that 88 percent of the Item B4.1 and 95 percent of the Item B4.5 Section XI preservice examinations were performed. Of the Item B4.5 circumferential and longitudinal pipe welds that did not meet the requirements of Section XI, 94 percent were due to piping configuration and fitting welds; three percent were due to nonremovable supports; and three percent were due to miscellaneous items, i.e., floor grating, etc.

Evaluation: We have evaluated the degree of accessibility and inspectability of the safe-end to pipe welds and circumferential and longitudinal pipe welds in the following table for which deviations have been requested. We have determined that part of the Section XI required examinations were impractical because of the design configuration of the piping systems and/or limitation in current ultrasonic techniques for small diameter pipe and that completion of an estimated 88 percent and 95 percent of the inspections required for Items B4.1 and B4.5, respectively meet the code requirements to the extent practical. Based on our review of the Section XI required preservice examinations and the preservice examinations performed by the applicant, we conclude that completing the remaining portion of the Section XI required examination would result in hardship without a compensating increase in quality or safety.

5.2.11.3 Conclusions

Based on the foregoing, we have determined that, pursuant to 10 CFR Part 50, paragraph 50.55a(a)(2) that certain Section XI required preservice examinations are impractical and compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

TABLE 5.1

Location of Welds in Examination Categories B-F and B-J
Preservice Inspection for North Anna Unit 2

(Drawings contained in the Virginia Electric and Power
Company Letter dated December 4, 1978)

<u>Drawing No.</u>	<u>Weld No.</u>	<u>Drawing No.</u>	<u>Weld No.</u>
VGB-1-4100	2	VGB-1-4105	31
	3		41
	8		42
	9		43
	10	VGB-1-4106	
	11		2
	12		3
	13		6
			10
			11
			16
VGB-1-4101	1		17
	3		
VGB-1-4102	1	VGB-1-4107	18
	9		
	10		
	11		
	12	VGB-1-4108	2
	13		3
	15		6
			7
		8	
VGB-1-4103	1		12
	6		13
	7		14
	10		
VGB-1-4104		VGB-1-4109	1
	1		
	2	VGB-1-4110	2
VGB-1-4105	7	VGB-1-4111	19
			3
	1		4
	3		5
	6		6
	8		7

TABLE 5.1 (Cont'd)

<u>Drawing No.</u>	<u>Weld No.</u>	<u>Drawing No.</u>	<u>Weld No.</u>
	9		10
	12		11
	19		12
	26		13
	28		14
VGB-1-4111	15	VGB-1-4205	14
	19		40
	20		41
	21		
	22	VGB-1-4206	1
	30		2
			3
VGB-1-4114	64		4
	65		5
			6
VGB-1-4200	2		7
	3		8
	8		9
	9		
	10	VGB-1-4207	1
	11		2
	12		3
	13		4
			5
VGB-1-4201	1		6
	6		7
	7		8
	14		9
	15		10
	17		11
			12
VGB-1-4202	1		13
	2		14
	5		15
			16
VGB-1-4203	1		17
	6		18
	7		19
	10		20
			21
VGB-1-4204	1		22
	2		
	3	VGB-1-4208	18
	7		

TABLE 5.1 (Cont'd)

<u>Drawing No.</u>	<u>Weld No.</u>	<u>Drawing No.</u>	<u>Weld No.</u>
		VGB-1-4209	1
VGB-1-4205	1		
	6	VGB-1-4210	19
	12		
VGB-1-4211	5	VGB-1-4304	1
	8		6
	9		7
	11		10
	12		
	13	VGB-1-4305	1
	14		2
	15		3
	16		6
	37		7
	40		
	41	VGB-1-4306	1
	42		3
			14
VGB-1-4214	63		16
			17
VGB-1-4300	2		18
	3		22
	8		23
	9		25
	10		34
	11		35
	12		36
	13		
	14	VGB-1-4307	1
			2
VGB-1-4301	1		3
	10		4
	11		5
			6
VGB-1-4302	1		7
	4		8
	5		9
	6		11
	8		12
	13		13
	14		14
	16		15

TABLE 5.1 (Cont'd)

<u>Drawing No.</u>	<u>Weld No.</u>	<u>Drawing No.</u>	<u>Weld No.</u>
			16
VGB-1-4303	1		17
	7		18
			19
VGB-1-4307	20	VGB-1-4502	1
	21		2
	22		3
	23		4
			5
VGB-1-4308	20		6
			7
VGB-1-4309	1		8
			9
VGB-1-4310	19		12
			13
VGB-1-4311	8		14
	9		15
	10		16
	11		17
	12		19
	13		20
	14		21
	15		22
			30
VGB-1-4500	1		31
	2		32
	8		33
	9		35
	10		36
	11		37
	17		38
	18		39
	19		40
	20		41
	26		42
	27		43
VGB-1-4501	1	VGB-1-4503	1
	15		6
	16		7
	17		8
	21		9
	22		11

TABLE 5.1 (Cont'd)

<u>Drawing No.</u>	<u>Weld No.</u>	<u>Drawing No.</u>	<u>Weld No.</u>
	23		12
	28		13
	29		14
VGB-1-4503	15	VGB-1-4600	36
	16		37
			39
VGB-1-4504	1		40
	24		41
	25		42
	26		43
	27		44
	30		
VGB-1-4600	1		
	3		
	4		
	6		
	7		
	9		
	10		
	11		
	12		
	13		
	14		
	15		
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	35		

Our technical evaluation has not identified any practical method by which the existing North Anna Power Station, Unit 2, can meet all the specific preservice inspection requirements of Section XI of the American Society of Mechanical Engineers Code. Requiring compliance with all the exact Section XI required inspections would delay the startup of the plant in order to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components and repeat the preservice examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are the certain steam generator nozzles, certain pressurizer provisions are the certain steam generator nozzles, certain pressurizer nozzles, and a significant number of the piping and component support systems. Even after the redesign effort, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

Based on our review and evaluation we conclude that the public interest is not served by imposing certain provisions of Section XI of the American Society Mechanical Engineers Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(2), we have allowed deviations from these requirements which are impractical to implement and would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety. We conclude that the North Anna Unit No. 2 preservice examinations meets the requirements of the 1974 Edition through Summer 1975 Addenda of Section XI of the American Society of Mechanical Engineers Code to the extent practical and is in compliance with 10 CFR 50.55a(g)(2).

5.2.12 Inservice Inspection

5.2.12.1 Inservice Testing of Pumps and Valves

By letters dated January 31, 1979 and September 4, 1979, the applicant submitted a description of its proposed inservice testing program for pumps and valves for North Anna Power Station, Unit 2. The program includes both baseline preservice testing and periodic inservice testing. It provides for both functional testing of components in the operating state and for visual inspection for leaks and other signs of degradation.

The date of the applicant's construction permit (February 19, 1971) places this plant under 10 CFR 50.55a(g)(2) which requires compliance with the 1970 edition of Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code. Since inservice testing requirements for pumps and valves were not included in the Code until the Summer 1973 addenda of the 1971 edition, the applicant has chosen to optionally meet the requirements of the 1974 edition through the Summer 1975 addenda to the extent practical and has requested relief from certain Code requirements.

In accordance with the requirements of Section 50.55a(g) of 10 CFR Part 50, and as required by Technical Specification 4.0.5, the applicant proposed that inservice testing of pumps and valves will be performed in accordance with the American Society

of Mechanical Engineers Section XI Code and applicable addenda as required by 10 CFR 50, Section 50.55a(g).

We have not completed our detailed review of the applicant's submittal. However, based on our preliminary review, we find that it is impractical within the limitations of design, geometry, and accessibility for the applicant to meet certain of the American Society of Mechanical Engineers Code requirements. Imposition of those requirements would, in our view, result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. Therefore, pursuant of 10 CFR 50.55a(g)(2) and (g)(6)(i), the relief that the applicant has requested from the pump and valve testing requirements of the American Society of Mechanical Engineers Code is granted for that portion of the initial 120 month period during which we complete our review. Since the applicant's request for relief has been granted and the applicant will comply with Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code and/or the Technical Specifications, we find the North Anna Unit 2 inservice testing program for pumps and valves acceptable.

5.4 Component and Subsystem Design

5.4.3 Residual Heat Removal System

Subsequent to the issuance of the Safety Evaluation Report, The Regulatory Requirements Review Committee approved the Branch Technical Position BTP-RSB5-1 "Residual Heat Removal System."

On March 6, 1980 a meeting was held with representatives of the Virginia Electric and Power Company and Westinghouse Electric Corporation to discuss compliance with Branch Technical Position RSB 5-1. The basis for the review was the set of general questions developed for Sequoyah, supplemented by specific questions on details of the North Anna plant by the staff present at the meeting. The Virginia Electric and Power Company representatives supplied piping and instrumentation diagrams of the various systems involved to assist in the discussion.

On the basis of the information and responses supplied by Virginia Electric and Power Company and Westinghouse Electric Corporation representatives at the meeting, it was concluded that the North Anna plant meets the requirements of Branch Technical Position 5-1 listed for Class 2 plants in Table 1 of RSB 5-1. Confirmatory documentation including a detailed written response to questions formally presented to the Virginia Electric and Power Company after the meeting is to be supplied by Virginia Electric and Power Company.

In view of the low decay heat levels associated with fuel handling and short-term operation at power levels of less than five percent, and the relative low risk associated with the fuel load and low power testing program, compared to full power long-term operations, receipt of the confirmatory documentation and its review need not be accomplished prior to fuel load and low power testing.

6.0 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

Subsequent to the issuance of the Safety Evaluation Report for North Anna, Units 1 and 2, the applicant in a letter, dated April 28, 1977, informed us that as a result of neutron streaming from the reactor cavity a higher than expected neutron dose rate was observed during a detailed radiation survey that was performed within selected areas of the North Anna Power Station, Unit 1 containment. Based on the higher than anticipated radiation levels inside the containment, the applicant has determined that, additional neutron shielding is necessary to reduce the dose rates to or below the design levels presented in Section 12 of the Final Safety Analysis Report. In a letter dated January 31, 1979 the applicant submitted his proposed design of the neutron supplementary shield. The following describes this additional shielding.

Description of the Supplemental Shield Design in the Upper Reactor Cavity

- (1) Cylindrical collar assembly: Its base rests on top of the neutron shield tank and fits around the reactor pressure vessel. The assembly consists of six segments that are fastened together by a metal strap to form the collar.
- (2) Saddle assembly: It consists of six U-shaped blankets, each blanket being made of 130 one-quarter inch wide strips of silicon based neutron attenuating material that covers each reactor pressure vessel nozzle. The saddle extends from the collar interface to the primary shield wall.
- (3) Dust cover shield blocks shaped to cover the existing dust covers on the reactor pressure vessel nozzle supports and to partially fill the space between the existing dust cover and the collar underneath each nozzle.

The supplemental shield design permits the required inservice inspection of the reactor vessel nozzle and does not require removal during refueling. The following is an evaluation of the applicant's supplemental shield design that is installed at the North Anna Power Station, Unit 2 as it affects: (1) the reactor cavity pressure transient analysis; (2) the integrity of the reactor pressure vessel supports; (3) the containment sump; and (4) missile effects.

(1) Reactor Cavity Pressure Transient Analysis

In view of the design modification that was found necessary to reduce the neutron dose rate, the applicant has redone the reactor cavity pressurization

analyses to verify the adequacy of the reactor cavity wall design. The analysis was based on a 150 square inch, limited displacement pipe rupture at the cold leg nozzle safe end. We have reviewed the reactor cavity nodalization and the input parameters used by the applicant to perform the pressurization analysis. We conclude that the analysis was done in a reasonably conservative manner. The applicant's analysis utilized the computer code RELAP4, MOD 5 to calculate the pressure-time transient. We have previously concluded, in accordance with Standard Review Plan 6.2.1.2, that the analytical model in RELAP-4 is acceptable. Therefore, we conclude that the reanalysis verifies the adequacy of the reactor cavity wall design.

Based on our review of the applicant's revised analysis, we conclude that the analysis was done in a reasonably conservative manner and is, therefore, acceptable.

(2) Reactor Pressure Vessel Support Integrity

The applicant has also calculated the asymmetric forces and moments for both the reactor pressure vessel supports and the internal structures in accordance with analytical methods approved by us as discussed in Sections 3.9.4 and 4.2.4 of Supplement No. 7 to the Safety Evaluation Report. Based on our review of the applicant's analysis, we find the forces and moments calculated by the applicant are reasonably conservative and in agreement with Task Action Plan A-2 (see Appendix B of Part I of this supplement) and therefore, acceptable.

The applicant stated that the unbalanced forces on the reactor pressure vessel and the primary shield wall were higher than those that were previously reported in the Safety Evaluation Report and found acceptable. However, as discussed in Section 3.9.4 of this report, the applicant has reported and we concur that none of the new loads exceed the structural integrity limit envelope reported in the Final Safety Analysis Report. Based on our review of this information we have determined that the design modification of the neutron shields involves no changes of design methods or criteria for the structural elements and therefore is acceptable.

(3) Effect on Containment Sump

Due to the complex and tortuous path through grating or down stairwells, any neutron shield saddle strips that may become loose due to jet forces would not be likely to be transported from the operating floor to the containment sump. In addition, the neutron shield strips have a density greater than that of water and will not float. We, therefore, agree with the applicant's conclusion that loose shield strips will not reach the containment sump.

(4) Missile Effects

The applicant has determined that the only credible missiles are the saddle strips on the nozzle of a postulated broken reactor coolant pipe. The applicant

concludes that the missile generated by the low mass with low rigidity strips will not adversely affect any safety related equipment. We agree with this conclusion and also agree with the applicant that no missiles will be generated from the collar segments or the dust covers on the supplemental shield.

Conclusion

Based on our review of the applicant's proposed design and the analyses performed to verify the integrity of the reactor cavity wall and the reactor pressure vessel supports, we conclude that the proposed design is acceptable. Matters related to the neutron attenuating material used in the collar, saddles and dust covers and its effectiveness in reducing the neutron streaming is presented in Section 12.0 of this report.

6.2.6 Containment Leakage Testing Program

In the Unit 2 Technical Specifications the applicant describes its proposed leak testing procedure for the containment airlocks, and proposes an exemption from the associated requirements of Appendix J to 10 CFR Part 50. Based on our review, we find the proposed leak testing procedures and the proposed exemption to Appendix J acceptable. The rationale for our finding acceptable, the applicant's proposed leak testing practices for the personnel airlocks and the proposed exemption from the associated requirements of Appendix J to 10 CFR 50, is discussed below.

Appendix J to 10 CFR 50 requires the containment personnel airlocks to be leak tested at six-month intervals and after each opening during such intervals (III.D.2). Appendix J further requires that the test be conducted at the peak calculated containment pressure related to the design basis accident; i.e., Pa, (III.B.2).

Considering that a full pressure airlock test is to be performed every six months, it is our judgment that testing airlocks within three days after each opening at the peak calculated containment internal pressure, will adequately demonstrate the continuing integrity of the airlock door seals such that the public health and safety will be ensured. The effect on accident consequences of testing after each opening versus testing within three days of an opening is judged to be insignificant. Furthermore, if an airlock door seal is damaged, it will be manifested during testing at the peak calculated containment internal pressure. This is an adequate demonstration of continuing airlock integrity for the period between the six-month tests.

With the approval of the exemption cited above, we conclude that the requirements of Appendix J have been met.

6.3 Emergency Core Cooling System

6.3.1 Background

Following several operational problems noted on the North Anna deep-well pumps during testing, the staff in letters, dated November 23, 1977, December 22, 1977 and February 13, 1978, required that the Virginia Electric and Power Company demonstrate

the long-term mechanical operability of the low head safety injection and recirculation spray pumps. The electrical operability of these pumps is addressed separately in the Final Safety Analysis Report and in the North Anna Power Station, Units 1 and 2 Safety Evaluation Report and its supplements.

These pumps may be required to operate for long periods of time (on the order of months) following a loss-of-coolant accident.

The basis for our acceptance of the test results is that the pump bearing wear and the amplitude of the pump vibrational frequencies remain at low, satisfactory levels when extrapolated over a period of several months.

Supplement No. 9 to the Safety Evaluation Report contains our evaluation of the previous short-term mechanical testing of the outside recirculation spray pump and low head safety injection pump. Supplement No. 9 of the Safety Evaluation Report also delineates our requirements for the mechanical testing being evaluated in this report.

6.3.2 Outside Recirculation Spray Pump Tests

The mechanical testing of the outside recirculation spray pump as delineated in Supplement No. 9 to the Safety Evaluation Report consisted of a 450-hour full-flow pump test conducted at a water temperature of approximately 130 degrees Fahrenheit. In a letter dated June 2, 1978, the Virginia Electric and Power Company submitted the results of the mechanical testing of the outside recirculation spray pump.

6.3.2.1 Test Conditions

The temperature of the water used for the outside recirculation spray pump test was maintained at 130 degrees Fahrenheit plus or minus 10 degrees Fahrenheit in order to simulate long-term post loss-of-coolant accident sump temperatures. Boron and sodium hydroxide were added to the test water to simulate post-loss-of-coolant accident sump conditions. Water samples were taken throughout the test to determine the debris concentration of the test water. Debris concentrations determined during this test were consistent with the concentrations determined during the six day test (letter from Virginia Electric and Power Company, dated March 23, 1978).

6.3.2.2 Evaluation

A review and evaluation of the outside recirculation spray pump confirmatory test data was conducted by us and by members of the Franklin Research Center who acted as consultants to us. Franklin Research Center's evaluation of the mechanical testing of the outside recirculation spray pump is contained in their report "Franklin Reserve Center Technical Report F-C5108-1" dated April 1979. We and our consultants conclude that the pump mechanical test conditions as conducted were representative of the expected post-loss-of-coolant accident sump conditions.

Measured pump vibrational frequencies were well-behaved. Measurement of the pump vibration levels indicated that the measured vibrational amplitudes were bounded and the measured frequencies agreed with those predicted by modal analyses.

The bearing and shaft wear noted at the completion of the test was very low. Based on the bearing and shaft wear measured after the six hour test, six day test, and 450 hour test, the maximum bearing and shaft wear that would be projected over the several months of operation that may be required of these pumps would be on the order of 10 mils or less. Stable bearing and mechanical pump performance is expected for wear of this magnitude.

Some minor scoring of the shaft journals and bearing surfaces was observed at the completion of the 450-hour pump test. This wear was no greater than the scoring noted at the completion of the six day pump test. The scoring did not affect pump performance.

Based on our evaluation of the pump test conditions, of the bearing and shaft wear, of the vibrational frequency response, and of the overall pump mechanical dynamic performance discussed above, we conclude that the long-term mechanical operability of the outside recirculation spray pumps is acceptable to fulfill its required safety function in the event of a loss-of-coolant accident.

6.3.3 Inside Recirculation Spray Pump

Due to the similarity in design between the outside and inside recirculation spray pumps, we did not require separate mechanical testing of the inside recirculation spray pump. We did require as discussed in Section 6.3.7.3 of Supplement No. 9 to the Safety Evaluation Report that the Virginia Electric and Power Company conduct a modal analysis of the inside recirculation spray pump. In a letter, dated April 10, 1978, the Virginia Electric and Power Company submitted this modal analysis. A review and evaluation of the modal analysis of the inside recirculation spray pump was conducted by us and by members of Franklin Research Center who acted as consultants to us. Franklin Research Center's evaluation of the modal analysis of the inside recirculation spray pump is contained in its report "Franklin Research Center Technical Report F-C5108-3" dated May 1978. The modal analysis demonstrated that the vibrational characteristics of the inside recirculation spray pumps were sufficiently similar to the vibrational characteristics of the successfully tested outside recirculation spray pump to provide a basis of comparison.

We and our consultant had questioned the advisability of the dry periodic start and stop tests of the inside recirculation spray pumps. Current surveillance testing requires monthly testing of these pumps. The Virginia Electric and Power Company had conducted discussions with the pump manufacturer concerning the dry start and stop testing of these pumps. The Virginia Electric and Power Company has indicated that the pump manufacturer had reaffirmed the pump capability to be tested in the dry mode. To provide continuing assurance of the mechanical reliability of these pumps, we require that the testing interval for the inside recirculation spray pump be increased consistent with the operational considerations for these pumps. We believe

that a test interval of once every three months is more appropriate than the current monthly test interval. In a letter, dated September 4, 1978, the Virginia Electric and Power Company agreed that the testing interval for the inside recirculating spray pumps will be changed from monthly to once every three months.

We also require that these pumps be removed and inspected at the first planned major outage. The pump bearings should be replaced if necessary.

The pumps should be optically aligned prior to reinstallation. We require a similar inspection of these pumps at least once every five years. In the letter, dated September 4, 1979, the Virginia Electric and Power Company stated that they agree to remove and inspect the inside recirculating spray pumps at the first refueling by both Units 1 and 2. They also stated that following the inspections, the pump bearings will be replaced, if necessary, and the pumps will be optically aligned prior to installation. A similar inspection of the pumps will be conducted at least once every five years thereafter. The Technical Specifications will reflect these requirements.

Based on the satisfactory results of the modal analysis, the similarity in design between the outside and the inside recirculation spray pumps, and the periodic inspections specified in this report, we conclude that the mechanical reliability of the inside recirculation spray pumps is acceptable to fulfill its required safety function in the event of a loss-of-coolant accident.

6.3.4 Low Head Safety Injection Pump Tests

The long-term mechanical testing of the low head safety injection pump consisted of a 23 day full-flow pump test conducted at a water temperature of 130 degrees Fahrenheit plus or minus 10 degrees Fahrenheit. In a letter, dated July 12, 1978, the Virginia Electric and Power Company submitted the results of the long-term mechanical test of the low head safety injection pump.

6.3.4.1 Test Conditions

The temperature of the water used for the low head safety injection pump test was maintained at 130 degrees Fahrenheit plus or minus 10 degrees Fahrenheit in order to simulate long-term post-loss-of-coolant accident sump temperatures. Boron and sodium hydroxide were added to the test water to simulate post-loss-of-coolant sump conditions. The boron concentration was to be maintained at 1800 parts per million plus or minus 100 parts per million. The initial boron concentration was within this band, but samples indicated that the boron concentration decreased throughout the test, eventually reaching about 600 parts per million. The boron concentration was maintained at a high enough level during the first few days of the test, however, to subject the pump to the test environment desired. Water samples were also taken throughout the test to determine the debris concentration of the test water.

In addition to normally installed instrumentation, accelerometers and pressure transducers were added along the pump column. Measurements of each shaft journal outside

diameter and bearing inside diameter were taken prior to and at the completion of the test run.

6.3.4.2 Evaluation

A review and evaluation of the low head safety injection pump mechanical test data was conducted by us and by members of the Franklin Research Center who acted as consultants to the staff on this matter. Franklin Research Center's evaluation of the long-term mechanical testing of the low head safety injection pump is contained in their report "Franklin Research Center Technical Report F-C5108-2" dated May 1979. We and our consultants conclude that the pump test conditions as conducted were representative of the expected post-loss-of-coolant accident sump conditions. Debris concentrations during the low head safety injection pump test were consistent with the debris concentrations determined during the outside recirculation spray pump tests, and were, therefore, acceptable. Measured vibrational frequencies were well-behaved throughout the test. The pump vibrational amplitude indicated that the pump had reached and maintained a level of stable, satisfactory dynamic operation.

The bearing wear noted at the completion of the test was very low. Based on the bearing and shaft wear measured after the test, the maximum total wear that would be projected over the several months of operation that may be required of these pumps, would be on the order of 10 mils or less. Stable bearing and pump performance is expected for wear of this magnitude.

Based on an evaluation of the pump test conditions, of the pump bearing and shaft wear, of the vibrational frequency response, and of the overall pump dynamic performance, we conclude that the long-term mechanical operability of the low head safety injection pump is acceptable to fulfill its required safety function in the event of a loss-of-coolant accident.

6.3.5 System Performance Evaluation

As a result of the performance tests conducted at the North Anna service water reservoir (see Section 2.4.3 of this report), a higher service water temperature was found for the design basis conditions at North Anna Nuclear Power Station, Units No. 1 and 2. The maximum service water temperature in the service water reservoir was calculated to be 104 degrees Fahrenheit for two unit operation. This higher service water temperature affects the net positive suction head available to the low head safety injection pump. The magnitude of the effect on the net positive suction head is limited because of the small service water temperature rise in the first few hours of an accident. In a letter, dated May 23, 1979, the Virginia Electric and Power Company provided an analysis of the effect of this service water temperature rise. The containment depressurization as given in Table 6.2-45 of the Final Safety Analysis Report is found to be unaffected, when a two degrees Fahrenheit higher service water temperature is assumed. This assumed service water temperature rise of two degrees Fahrenheit bounds the actual transient for the first six hours, well after depressurization and subatmospheric peak pressure have occurred.

The minimum available net positive suction head to the low head safety injection pumps occurs after a design basis loss-of-coolant accident with 50 degrees Fahrenheit refueling water storage tank water and 93 degrees Fahrenheit service water (see Table 6.2-42 of the Final Safety Analysis Report). This table also shows that the net positive suction head is much more dependent on a 10 degree Fahrenheit difference in refueling water storage tank temperature than a 2 degree Fahrenheit difference in service water temperature. The service water temperature and refueling water storage tank temperature are tied together as follows (1) for a service water temperature of 95 degrees Fahrenheit, the water in the refueling water storage tank cannot exceed 40 degrees Fahrenheit and (2) for a service water temperature of 93 degrees Fahrenheit the water in the refueling water storage tank cannot exceed 50 degrees Fahrenheit (Technical Specification Figure 3.6-1). Hence, the 95 degrees Fahrenheit service water temperature case has greater net positive suction head due to the 40 degree Fahrenheit refueling water storage tank water. This analysis is unchanged by the new service water transient used for design basis considerations. On the basis that, the early timing of minimum net positive suction head prevents the later rise in service water temperature from having a significant effect, we reconfirm our previous conclusion stated in Section 6.3.3 of Supplement No. 8 to the Safety Evaluation Report that the net positive suction head available for the low head safety injection pumps is acceptable.

Recently we have been reviewing fuel cladding swelling and rupture models used by vendors and applicants in their emergency core cooling system analyses. We issued a draft report "Cladding Swelling and Rupture Models for LOCA Analyses" (NUREG-0630) which proposed standards for these models. In order to assess the effects of these proposed models, letters were sent to the vendors and applicants including Westinghouse on November 8, 1979 and the Virginia Electric and Power Company on November 9, 1979. To accommodate this assessment, the Virginia Electric and Power Company first supplied new emergency core cooling system analyses applicable to both units at North Anna in a letter, dated November 29, 1979. The analyses used the currently approved Westinghouse emergency core cooling system evaluation model which is in compliance with Appendix K to 10 CFR Part 50. The analyses reflected more closely the as-built conditions for North Anna Unit 1 and are conservative for Unit 2. The analyses also used an overall peaking factor (F_q) of 2.10 compared to 2.21 used in previous analyses. The peak cladding temperature of 2088 degrees Fahrenheit for the new analysis is in compliance with the requirements of 10 CFR 50.46.

In a letter, dated December 19, 1979, the Virginia Electric and Power Company presented their assessment of the impact of using the proposed swelling and rupture models for the emergency core cooling system analyses on Units 1 and 2. An impact assessment was required for all operating reactors. The staff agrees that the methods presented in the letter, which involved incremental analysis based on a currently approved calculation are suitable for North Anna Units 1 and 2. The assessment shows that a reduction in F_q of 0.13 would be required to assure that the 2200 degrees Fahrenheit cladding temperature limit of 10 CFR 50.46 would be met, if the proposed staff cladding models were applied to the November 29, 1979 analysis.

some other Westinghouse plants would increase the permissible Fq by at least 0.15. We accept this assessment of allowable benefits. This resultant Fq increase effect more than offsets the 0.13 Fq penalty cited above, and, therefore, the Fq value of 2.10 is acceptable for this application.

Consistent with the above analyses the applicant has proposed Technical Specifications changes to lower this permissible Fq to 2.10.

A similar staff review of the proposed Technical Specification changes (our evaluation is attached to Amendment No. 16 to Operating License NPF-4, North Anna Power Station, Unit 1) for Unit 1 found them acceptable for that unit.

Based on the above considerations we conclude that loss-of-coolant accident analyses provided by the applicant justify the proposed Technical Specification changes and that a change in Fq at rated power to 2.10 is acceptable.

7.0 INSTRUMENTATION AND CONTROL

7.2 Reactor Trip System

7.2.4 Anticipated Transients Without Scram

Background

In a pressurized water reactor, the anticipated transients which require prompt action to shut down the reactor in order to avoid plant damage and possible offsite effects can be classified in two groups: those that isolate the reactor from the heat sink, and those that do not. (A list of these transients is included in Appendix IV of Volume II of NUREG-0460, April 1978.) In general, the consequences of both of these types of events are an increase in reactor power or system pressure, or both. In Section 6.3 of NUREG-0460, Volume I, potentially unacceptable consequences of anticipated transients without scram events for pressurized water reactors of designs like North Anna are indicated to include (1) pressure rises that could threaten the integrity of the reactor coolant pressure boundary, (2) loss of core cooling, and (3) leakage of radioactive material from the facility.

In NUREG-0460, we concluded that for plants which fall within the envelope of the Westinghouse generic anticipated transient without scram analyses, the anticipated transient without scram acceptance criteria will not be violated if the actuation circuitry of turbine trip and auxiliary feedwater systems which are relied upon to mitigate anticipated transient without scram consequences are sufficiently reliable and are separate and diverse from the reactor protection system. Additionally, the functionability of valves required for long-term cooling following the postulated anticipated transient without scram events has to be demonstrated.

The NRC's Regulatory Requirements Review Committee has completed its review and concurred with our approach described in Volume 3 of NUREG-0460 insofar as it applies to North Anna Unit 2. We issued requests for the industry to supply generic analyses to confirm the anticipated transient without scram mitigation capability described in Volume 3 of NUREG-0460. The staff evaluation of these reports was published as NUREG-0460, Volume 4, in March 1980.

We plan to present our recommendations on anticipated transients without scram to the Commission in May 1980, including the recommendations for modifications contained in Volume 4 of NUREG-0460. The Commission would determine required modifications to resolve anticipated transient without scram concerns as well as

the required schedule for implementation of such modifications. North Anna Unit 2 would, of course, be subject to the Commission decision in this matter. The following discusses the bases for operation of North Anna Unit 2 at power levels not exceeding five percent while final resolution of anticipated transients without scram is before the Commission.

In NUREG-0460, Volume 3, we state: "The staff has maintained since 1973 (for example, see pages 69 and 70 of WASH-1270) and reaffirms today that the present likelihood of severe consequences arising from an ATWS event is acceptably small and presently there is no undue risk to the public from ATWS. This conclusion is based on engineering judgment in view of: (a) the estimated arrival rate of anticipated transients with potentially severe consequences in the event of scram failure; (b) the favorable operating experience with current scram systems; and (c) the limited number of operating reactors."

In view of these considerations and our expectation that the necessary plant modifications will be implemented in one to four years following Commission decision on anticipated transients without scram, we have generally concluded that pressurized water plants can continue to operate because the risk from anticipated transient without scram events in this time period is acceptably small. As a prudent course, in order to further reduce the risk from anticipated transient without scram events during the interim period before completing the plant modifications determined by the Commission to be necessary, we have required that the following steps be taken:

- (1) Emergency procedures be developed to train operators to recognize an anticipated transient without scram event, including consideration of scram indicators, rod position indicators, flux monitors, pressurizer level and pressure indicators, pressurizer relief valve and safety valve indicators, and any other alarms annunciated in the control room with emphasis on alarms not processed through the electrical portion of the reactor scram system.
- (2) Operators be trained to take actions in the event of an anticipated transient without scram, including consideration of manually scrambling the reactor by using the manual scram button, prompt actuation of the auxiliary feedwater system to assure delivery of the full capacity of this system, and initiation of turbine trip. The operator should also be trained to initiate boration by actuation of the high pressure safety injection system to bring the plant to a safe shutdown condition.

We consider these procedural requirements an acceptable basis for interim operation of the North Anna Unit 2 plant based on our understanding of the plant response to postulated anticipated transient without scram events.

In response to our requirements on operator training and emergency procedures, Virginia Electric and Power Company submitted on January 10, 1980, emergency operating procedures for the postulated anticipated transient without scram (ATWS) events.

Although the proposed procedures need to be revised to be acceptable for full power operation, it is our judgment that the North Anna Unit 2 plant may be operated at low power (less than or equal to 5 percent of full power) prior to completion of procedure modifications without undue risk to the health and safety of the public. Therefore, we have concluded that the plant can be safely operated at low power prior to the completion of this effort because of the expected plant response to relevant anticipated transient without scram events at power levels not exceeding five percent (see Task Action Plan A-9).

7.9

Loss of Non-Class IE Instrumentation and Control Power System Bus During Operation

On November 30, 1979, the Office of Inspection and Enforcement issued IE Bulletin 79-27 "Loss of Non-Class IE Instrumentation and Control Power System Bus During Operation" to all power reactor facilities with an operating license and to those nearing licensing. This bulletin outlined actions to be taken to address control system malfunctions and significant loss of information to the control room operator as a potential consequence of the loss of 120 volt alternating current control power to these plant systems. Further, IE Information Notice 80-10, issued on March 7, 1980, provided information relating to the Crystal River Unit 3 event of February 26, 1980, in which a significant loss of information to the operator resulted from a loss of power to a portion of the plant instrumentation system.

At this time the Virginia Electric and Power Company has not completed their review of this matter. However, the control and instrument systems for Westinghouse plants such as North Anna Unit 2 utilize reactor protection measurements, with suitable isolation devices, for a large portion of the measurements utilized by the plant control systems. This arrangement provides an additional degree of redundancy in information available to the operator. Further, the number of control systems which would be placed in automatic control for plant operation up to five percent power would be significantly reduced under this mode of operation, and therefore operation up to five percent power is acceptable. We will require resolution of this matter before operation above five percent power.

8.0 ELECTRICAL POWER SYSTEMS

8.3 Onsite Power System

8.3.1 Alternating Current Power Distribution System

In a report made in accordance with the provisions of 10 CFR 50.55(e), dated April 27, 1979, the applicant advised us of a design deficiency related to potential overloads of the station transfer buses. To eliminate this deficiency, the applicant in Amendment No. 67 to the North Anna Power Station, Units 1 and 2 Final Safety Analysis Report, described its proposed modification to the transfer buses.

Prior to the upgrading of electrical systems, there was a potential for an overload condition on the four kilovolt station transfer buses. If Unit 1 was operating and Unit 2 was in the process of starting up, the additional load on the transfer buses if Unit 1 were to trip would result in an overload of the buses and the bus feeder breakers. The reserve station transformers are rated at 30/33.6 megavolt-amperes at 65 degrees Centigrade rise.

The power supply from reserve station service transformers for Units 1 and 2 has been upgraded by connecting the normal buses between the four kilovolt reserve station service transformers and the four kilovolt circuit breakers which act as feeder breakers for the transfer buses. The sizes of the buses and the underground cables from the reserve station service transformers to the four kilovolt transfer buses have been upgraded by running two buses per phase with a total ampacity of 7200 amperes per phase and two underground two million circular mil cables per phase with a total ampacity of 6000 amperes.

The applicant performed voltage drop calculations on the modified system which included the examination of various station contingencies. The worst case of reserve system loading that was considered in the design of the modification was: one unit in the startup mode on reserve power and the other unit at 100 percent power on station service (unit auxiliary) power and then tripping with resultant transfer to the reserve power system. Using this condition as the plant operating requirement, the emergency system was designed so that the voltage on the buses must remain above 90 percent, or it must recover to greater than 90 percent in 60 seconds, or in the case of a safety injection, within 10 seconds. Under these postulated conditions, certain non essential normal loads will be automatically shed in order to meet the voltage drop requirements and to minimize available fault currents.

The applicant has set certain pre-conditions to assure that one feedwater pump and one condensate pump will remain running in each unit after automatic load shedding has occurred.

We have reviewed and evaluated the applicant's upgraded system of the transfer buses and their associated switchgear and have found this aspect of the design is capable of carrying the design loads and is therefore acceptable.

8.3.2 Diesel Generator Reliability

The reliability of the installed diesel generators has been demonstrated by performance of the preoperational testing specified in Regulatory Guide 1.108 "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants". This includes performance of 69 consecutive start and load tests with zero failures, and a 24 hour full-load-carrying capability test. A continuing demonstration of reliability will be obtained by inclusion in the Technical Specifications of the periodic testing provision of Regulatory Guide 1.108. To provide further assurance of the long term reliability of the diesel generators, the applicant has been requested to review the design with regard to the recommendations of NUREG/CR 0660, Enhancement of Onsite Emergency Diesel Generator Reliability; and to report the conformance to or plans for implementation of these recommendations or justification for the existing design. In a letter dated January 31, 1980, the applicant provided the requested information. We will review this information prior to full power operation and require implementation of these recommendations as deemed necessary prior to the start of operation after the first refueling cycle, to assure long term reliability of the installed diesel generators.

8.6 Inoperable Conditions for the Diesel Generator and Associated Alarms for those Conditions

A review of malfunction reports on diesel-generators at operating nuclear plants uncovered that in some cases the information available to the control room operator to indicate the operational status of the diesel-generator may be imprecise and could lead to misinterpretation. This can be caused by the sharing of a single annunciator station to alarm conditions that render a diesel-generator unable to respond to an automatic emergency start signal and to also alarm abnormal, but not disabling conditions. Another cause can be the use of wording of an annunciator window that does not specifically say that a diesel is inoperable (that is, unable at the time to respond to an automatic emergency start signal) when in fact it is inoperable for that purpose.

In this regard, we requested the applicant to perform a review and provide the results of an evaluation of the alarm and control circuitry for the diesel-generators at the North Anna Power Station Unit 2 facility to determine the conditions that could render a diesel generator unable to respond to an automatic emergency start signal and if they are alarmed in the control room. These conditions are to include not only the trips that lock out diesel start and require manual reset; but also the control switch or mode switch positions that block automatic start, loss of control voltage, insufficient starting air pressure or the associated Class 1E battery voltage etc. Also, this review was to consider all aspects of possible diesel generator operational conditions, such as test conditions and operations from local control stations. In addition, we requested a tabulation of the following information:

- (1) All conditions that render the diesel inoperable of responding to an emergency start signal;
- (2) The wording of the annunciator window in the control room that is alarmed for each of the conditions identified in (1);
- (3) Any other alarm signals (not included in (1) above) that also cause the same annunciator alarm;
- (4) Any conditions that render the diesel generator incapable of responding to an automatic emergency start signal which is not alarmed in the control room; and
- (5) Any proposed modifications resulting from this evaluation.

In response to items (1) and (2) the applicant has identified ten conditions that render the diesel incapable of responding to an emergency start signal. These ten conditions are annunciated in the main control room by five annunciators. The wording on these five annunciator windows are EMER DG #1H TROUBLE, EMER DG #1J TROUBLE, EMER DIESEL GEN BATTERY VOLTAGE TROUBLE, EMER DG 1H INTLKS NOT RESET, and EMER DG 1J INTLKS NOT RESET.

Concerning item (3) the applicant has identified eighteen other conditions (for each diesel) which are provided with local annunciator alarms. It is also noted that these local annunciator alarms in turn actuate the appropriate main control room annunciator (one annunciator provided for each diesel).

With regard to item (4) the applicant has identified two conditions, these being "air start manual isolation valves closed" and "control room selector switch in MANUAL LOCAL position", which are not alarmed. For the air start manual isolation valves the applicant has documented that these valves will be key locked in the open position with the key for these locks under administrative control. Concerning the latter condition, the control room selector switch will be checked every four hours and recorded in the Diesel Log by an operator (in accordance with the plant administrative procedures). Further the status of this item will be monitored by a shift supervisor at the change of each shift.

Concerning item (5) an annunciator has been added in the control room to alarm if the local selector switch is not in the "AUTO REMOTE" position.

We have reviewed the information provided by the applicant and conclude that the applicant has taken appropriate measures related to design features with regard to inoperable conditions of the diesel generators and associated alarms augmented by appropriate administrative controls to remove a concern of this matter generated from malfunction reports at some operating reactors.

We have reviewed the applicant's design with respect to degraded grid voltage protection and the interaction of the onsite power system with the offsite power system. We have compared the North Anna 1 and 2 design to our established position on this subject as stated in our letter to the applicant dated July 28, 1978 and have reached the following conclusions. Our position is in four parts and each is separately addressed below.

Part 1 of the position requires undervoltage protection for low grid voltages. The undervoltage relays traditionally used to detect loss of offsite power at the emergency busses have had setpoints around 70-75 percent of nominal bus voltage. This protection alone does not protect the plant loads from damaging low voltages which are maintained above this setpoint. Therefore, we have required an additional protective trip at approximately 90 percent of nominal bus voltage with a time delay to avoid spurious trips due to short duration transients such as those occurring when starting larger motors. The North Anna design did not originally incorporate this degraded voltage protection. The design now incorporates this protective feature in a manner that satisfied the appropriate requirements of the Institute of Electrical Electronics Engineers Standard 279-1971 "Criteria For Protection Systems For Nuclear Power Generating Stations". We find this aspect of the design to be acceptable.

Part 2 of our position requires that the diesel generator bus load shedding feature be automatically bypassed once the diesel generator is supplying power to the bus. This is required so that the voltage drops encountered during load sequencing on the diesel generators will not interact with the load shedding feature and negate the loading sequences. Our position further requires that once the diesel generator breaker is subsequently opened the load shedding feature shall be automatically restored. The applicant's design is in full conformance with this requirement. When the diesel generator breaker is open, there is a permissive in the logic which allows load shedding (following a 2.2 second delay to allow fast transfer to a preferred offsite source) when undervoltage is detected on the emergency bus. This permissive is removed when the diesel generator breaker is in the closed position. We find this acceptable.

Part 3 of our position deals with incorporating tests and test frequencies into the Technical Specifications to assure continued adherence to this position throughout the plant lifetime. These provisions have been incorporated into the Technical Specifications proposed by the applicant and this is acceptable.

Part 4 of our position requires that the tap settings on the plant distribution transformers be optimized and verified at the preoperational testing stage by measurement. The applicant has demonstrated by analysis that the transformer tap settings have been fully evaluated and optimized. We find this aspect of the design to be acceptable. Our Office of Inspection and Enforcement will verify that the actual in-plant measurements are in agreement with the results of the applicant's analysis and that the transformer tap settings are optimized prior to full power operation. Accordingly, the Technical Specification will reflect this action.

On August 3, 1979 we issued our position requiring containment electrical penetrations to have overcurrent protection that meets the recommendations of Regulatory Guide 1.63, Revision 1 "Electric Penetration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants." We were subsequently advised that the North Anna Power Station Unit 2 design would not meet the single failure criterion and that some of the primary protective devices would not provide protection over the complete range of faults. Following further discussions with the applicant, we allowed the applicant to use the approach taken on the Diablo Canyon Nuclear Power Station, Units 1 and 2 (Docket Nos. 50-275 and 50-323) for an acceptable design.

The applicant submitted additional information that describes the installed primary overcurrent protection and the modifications to protection of the containment penetrations that carry power, control and instrumentation circuits. This information included listings of the power, control, and instrumentation circuits and their penetrations. Also, for each type of penetration, time-current heating curves that were matched with current-time operation curves for the primary protective devices were provided. A listing was provided giving the maximum available fault currents for each type of penetration. This information shows that the protective devices would operate in sufficient time even when carrying the maximum available fault currents to protect the penetrations from overheating and consequent loss of integrity. We conclude that the primary protection system for the penetrations as described in the submitted information is acceptable.

Our position also states that an acceptable design for the backup overcurrent protection system shall be submitted within six months after the date of licensing. Further, this backup system shall be installed and operational prior to startup following the first refueling outage. The applicant has agreed to comply with these requirements and we find this commitment acceptable. Accordingly, the Technical Specifications will reflect these requirements.

9.0 AUXILIARY SYSTEMS

9.2 Water Systems

9.2.1 Service Water System

In Section 2.4.3 of this report we stated that as a result of tests performed on the spray field of the service water reservoir the applicant has increased the design maximum service water temperature from 95 degrees Fahrenheit to 110 degrees Fahrenheit.

On this basis, applicant has evaluated the heat transfer capability of all essential components cooled by the service water system assuming 110 degrees Fahrenheit cooling water temperature. Based on its evaluation, the applicant has proposed to modify the charging/safety injection pump coolers and their associated service water piping and the control room air conditioning chillers to increase cooling capability to accommodate the increased 110 degrees Fahrenheit service water. We have reviewed the proposed modifications and agree with the applicant's program, as identified in his letter, dated March 8, 1979.

Based on our review, we reconfirm our conclusion stated in Section 9.2.1 of the Safety Evaluation Report that the service water system is in conformance with the requirements of General Design Criterion 44 regarding the capability of the system to transfer heat from systems and components important to safety to an ultimate heat sink and provision of suitable redundancy. We further reconfirm our conclusion that the system design meets the requirements of General Design Criteria 45 and 46 as regards to system design that allows performance of periodic inspections and testing.

9.5 Other Auxiliary Systems

9.5.1 Fire Protection Systems

In Section 18.2.8 of Supplement No. 7 to the Safety Evaluation Report we stated that "subsequent to our evaluation of the North Anna Units 1 and 2 fire protection system reported in Section 9.5.1 of the North Anna Power Station Units 1 and 2 Safety Evaluation Report, we issued revised fire protection guidelines," Appendix A to Auxiliary and Power Conversion Systems Branch Technical Position 9.5-1," dated August 23, 1976. On September 30, 1976, we transmitted Appendix A to Auxiliary and Power Conversions Systems Branch Technical Position to the applicant and requested performance of a fire hazards analysis and a reevaluation of the fire protection program, including a comparison with Appendix A. On April 1, 1977, the applicant submitted the information requested in our letter."

We have reviewed the information submitted by the applicant and also had a site visit related to this matter.

Our evaluation of the North Anna Units 1 and 2 Fire Protection Program is attached to Amendment No. 8 of the North Anna Power Station Unit 1 Facility Operating License NPF-4. In our evaluation to support Amendment No. 8, we concluded that the fire protection program for the North Anna Power Station, Units 1 and 2 is acceptable.

10.0 STEAM AND POWER CONVERSION SYSTEM

10.7 Turbine Missiles

On February 28, 1979, the Atomic Safety and Appeal Board issued an order for an evidentiary hearing regarding turbine missiles as they relate to North Anna Power Station, Units 1 and 2. A hearing regarding this matter was held on June 18, 1979. The Atomic Safety and Licensing Appeal Board still has this matter under consideration. In our testimony before the Appeal Board we concluded that the North Anna Power Station, Units 1 and 2 structures, systems and components important to safety are appropriately protected against the effects of turbine missiles and therefore that General Design Criterion 4 is satisfied.

On February 15, 1980, the Westinghouse manufactured turbine failed at the Yankee Rowe Nuclear Power Station. Because of this failure and cracks recently found in other Westinghouse turbines, the Unit 2 Technical Specifications will require that the Virginia Electric and Power Company conduct a preservice inspection of the turbine. This inspection will take place after hot functional testing and prior to exceeding five percent power. We are currently formulating the requirements for the inservice inspection of all Westinghouse manufactured turbines. When these requirements have been finalized, we will require the Virginia Electric and Power Company to take the appropriate action.

The Appeal Board has been advised of the turbine failure at the Yankee Rowe Nuclear Plant and cracking of other Westinghouse manufactured turbines.

12.0 RADIATION PROTECTION

12.2 Shielding

In a letter dated May 25, 1978, the Virginia Electric and Power Company forwarded the results of radiation measurements taken during the startup of North Anna Power Station, Unit 1. These measurements indicated that radiation fields (neutron and gamma) exceeded the design dose rates presented in the North Anna Units 1 and 2 Final Safety Analysis Report. These fields could result in excessive radiation exposure to personnel required to enter the reactor containment building during reactor operations. In order to reduce these fields, the Virginia Electric and Power Company proposed to add radiation shielding around the reactor vessel and over the reactor vessel nozzles (See Section 6.2.1 of this report). The Virginia Electric and Power Company analysis of the expected radiation field reduction from this shield is presented in a letter, dated January 31, 1979.

We have evaluated the Virginia Electric and Power Company's design of the collar/saddle shield proposed for Unit 2 and their analysis of the effectiveness of the shield to reduce radiation fields on the operating floor. This new shield is designed to reduce radiation levels in the personnel lock and that portion of the annulus area between the crane wall and the containment wall to that required in the Final Safety Analysis Report for general access to the containment. The applicant used both the COHORT-II Monte Carlo program and the MORSE Monte Carlo program to calculate the expected dose rates at representative receptor locations inside containment. These calculational methods should conservatively predict the expected dose rates and are acceptable in accordance with our Standard Review Plan criteria. The collar/saddle shielding is designed such that it does not require removal during refueling operations and can be easily removed to permit required Inservice Inspection of the reactor vessels. In addition to the collar/saddle shield around the reactor pressure vessel the Virginia Electric and Power Company plans to fill the openings in the crane wall between the personnel lock and the elevator with a three-inch thick wall of Permalloy, type JN. Such design concepts are consistent with Regulatory Guide 8.8 "Information Relevant to Ensuring that Occupational Radiation Exposure at Nuclear Power Stations Will Be As Low As Is Reasonably Achievable" Rev. 3, June 1978, to maintain occupational dose as low as is reasonably achievable and are therefore acceptable.

As indicated in the applicant's letter of May 25, 1978, the radiation fields at the equipment access hatch were expected to be approximately 2500 millirems per hour. With the addition of the collar/saddle shield described in the applicant's letter, dated January 31, 1979, these fields are calculated to be reduced to 25 to 50 millirems per hour. Even so, these reduced levels will most likely result

in dose rates immediately outside the equipment access hatch exceeding the design maximum dose rate of 0.75 millirems per hour specified in the Final Safety Analysis Report. However, as indicated in the applicant's letter dated March 1, 1979, at the outer surface of the missile shield, the dose rates will be less than the 0.75 millirems per hour criteria specified in the Final Safety Analysis Report. With the addition of this shielding, the design meets the acceptance criteria of Section 12.3 "Radiation Protection-Design Features" of the Standard Review Plan. To assure conformance with the design criteria specified in the Final Safety Analysis Report, the Virginia Electric and Power Company is required to verify the adequacy of the shield design including this modification during the startup test program radiation survey.

As indicated in the applicant's letter, dated January 31, 1979, the materials of construction for the collar, saddles and dust cover blocks is a silicon based elastomer. Such organic based materials generally have limited life in high radiation fields. We evaluated whether the encapsulated saddle material may experience radiation degradation within the life of the plant. The Virginia Electric and Power Company has authorized radiation-thermal testing of the shield material to be integrated gamma dose and neutron fluence level equivalent of 32 effective full power years of operation. Based on data from the test for the first four years of operation, no potential deterioration of the material was experienced. Following completion of the radiation-thermal testing, the Virginia Electric and Power Company will review the test data to determine whether a periodic inspection program is warranted. The Virginia Electric and Power Company will inform us of the results of that evaluation. On this basis, we have determined that this is acceptable.

Installation of the shielding has been completed on Unit 2, therefore, occupational radiation exposure is not a consideration in the installation. Based on our review of the design of the Virginia Electric and Power Company's proposed shield modification, we conclude that the design modification meets the acceptable design criteria specified in the North Anna Final Safety Analysis Report and contributes to maintaining doses to plant personnel as low as is reasonable achievable. We therefore find the Virginia Electric and Power Company's proposed shield design acceptable. If upon completion of the radiation survey at Unit 2, the applicant finds that the radiation exposure to operating personnel is still excessive, we will require that the applicant make additional appropriate modifications.

13.0 CONDUCT OF OPERATIONS

13.2 Training Programs

The Virginia Electric and Power Company has 21 operators who have applied for a license to operate the controls of North Anna Unit 2. Of this group, 14 (nine Senior Reactor Operators and five Reactor Operators) hold or have held licenses on North Anna Unit 1; the remainder (three Senior Reactor Operators and four Reactor Operators) are applying for their initial license on North Anna Units 1 and 2.

Each of the three senior applicants not previously licensed have a minimum of four years of nuclear operating experience as staff engineers with the utility. One individual has an additional eleven years of nuclear experience in the Navy.

Each individual meets or exceeds the experience requirements contained in the action plan and SECY-79-330E, Qualifications of Reactor Operators to sit for a cold examination.

The Virginia Electric and Power Company's licensed operator training program consisted of approximately 1200 hours of classroom training and assigned study. TMI related training has been incorporated into this program and the seven individuals who have been examined for a (initial) North Anna Unit 2 license have received this training. In addition, they have spent one month on shift involved in day-to-day operations and have passed a startup certification program (NRC approved) administered at the Surry Training Center Simulator.

Prior to TMI-2, the Virginia Electric and Power Company bought, installed, and commenced training operators on a nuclear simulator designed to replicate Surry Nuclear Power Station Unit 1 (Docket No. 50-280). The simulator has been used for training operators since July 1978. All senior Reactor Operators and all Reactor Operators from both Surry and North Anna Power Stations have been trained in recognizing and correcting the TMI-2 transient at the simulator. Additional simulator training for all personnel to be licensed on North Anna Unit 2 was conducted at the simulator.

All personnel licensed to operate North Anna Unit 1 and applicants scheduled to be administered Unit 2 examinations have received the following TMI-2 related training:

- (1) the TMI-2 accident and related pressure transients (conducted at the Surry Training Center Nuclear Simulator);
- (2) the differences between North Anna Unit 1 and North Anna Unit 2;

- (3) methods of hydrogen and void formation in the core;
- (4) methods of core heat removal including natural circulation flow;
- (5) training in the new vendor guidelines covering emergencies.

The Virginia Electric and Power Company administered its own examination on TMI related subjects to all operators licensed on North Anna Unit 1. All personnel received 90 percent or greater on the examination. The test has been audited and the grading certified by NRC personnel. No deficiencies were noted.

All shift personnel (licensed and nonlicensed) at North Anna Power Station are currently being trained in all the TMI related design changes which have been incorporated in the station. This training is taking place on shift and is being conducted by the Shift Technical Advisors.

NRC examinations were administered to twelve senior operator applicants and nine operator applicants during November 1979. The examinations were expanded in scope to cover thermodynamics, fluid flow and heat transfer. The passing grade was 80 percent overall and no less than 70 percent in each category. All individuals were administered oral examinations.

Ten individuals passed the senior operator examination and five individuals passed the operator examination. All of the individuals meet the new requirements for issuance of licenses enumerated in the Action Plan and SECY-79-330E, except for the administration of simulator examinations and separate categories for fluid flow, heat transfer and thermodynamics. The examinations were administered prior to the Commission's decision on SECY-79-330E.

Based on the above examination results, North Anna has the following complement for operation of Unit 1 and Unit 2.

No.	Type of License
10	Unit 1 and 2 Senior Operator Licenses
5	Unit 1 and 2 Operator Licenses
14*	Unit 1 Senior Operator Licenses
8*	Unit 1 Operator Licenses

The senior operators and operator who failed the Unit 2 examination will not perform licensed duties at Unit 1 until they have completed accelerated training in deficient areas and have been reexamined per the requirement of the North Anna licensed operator requalification program.

*Two Senior Operators and one operator licensed on Unit 1 failed the Unit 2 examination.

We conclude that the training programs of VEPCO are designed to, and progressing toward, producing operating staff personnel that satisfy the Commission's upgraded requirements.

15.0 ACCIDENT ANALYSES

15.1 Normal Operation and Anticipated Operational Transients

The analysis methods for postulated transients and accidents are normally reviewed in a generic sense. In this regard, we have received submittals from Westinghouse for the loss-of-coolant accident, main steamline break accident, feedwater line accident, and rod ejection accident. The description of the computer programs used in the analysis of these accidents have also been submitted.

The loss-of-coolant accident and rod ejection accident reviews have been completed and analysis methods were found acceptable. Our safety evaluation is documented in letters dated August 28, 1973 and May 30, 1975. The steamline and feedline break reviews are presently underway. The status of the code reviews as well as the ongoing steamline break and feedline break reviews are discussed below:

- (1) The following topical reports have been approved:
 - (a) WIT-6 (WCAP-7980 "Reactor Transient Analysis Computer Program Description") - Approved August 30, 1976
 - (b) THINC IV (WCAP-7956 "An Improved Program in Thermal and Hydraulic Analysis of Rod Bundle Cores") - Approved April 19, 1978
 - (c) PHOENIX (WCAP-7973 "Calculation of Flow Coastdown after Loss of Reactor Coolant Pump") - Approved March 31, 1977

- (2) The LOFTRAN, FACTRAN, MARVEL and BLKOUT code topical reports are currently under review by us. These analysis methods are described in WCAPs-7907 "LOFTRAN Code Description," 7908 "MARVEL - A Digital Computer Code for Transient Analysis of Multi Loop PWR System," 7909 "FACTRAN - A FACTRAN 4 Code for Thermal Transients in a UO₂ Fuel Rod," 7898 "Long Term Transient Analysis Program Pressurized Water Reactors (BLKOUT)," respectively. Our review of these topicals has progressed to the point that there is reasonable assurance that the conclusions based on these analyses will not be appreciably altered by completion of the analytical review, and therefore that there will be no effect on the decision to issue an operating license. If the final approval of these topical reports indicates that any revisions to the analyses are required, North Anna Power Station Unit 2 will be required to implement the results of such changes.

3. Main Steamline and Feedline Breaks - Westinghouse has recently submitted topical reports which present their analysis methods and sensitivity studies for postulated main steamline and feedline breaks. This information is

contained in WCAP-9226 "Reactor Core Response to Excessive Secondary Steam Releases" for steamline breaks and WCAP-9230 "Report on the Consequences of a Postulated Main Feedline Rupture" for feedline breaks. In addition, WCAP-9236 "NOTRUMP - A NODAL Transient Steam Generator and General Network Code" was submitted which discusses the NOTRUMP computer program. This code is used in the analyses of the postulated feedline breaks. Initially the review of these topical reports were scheduled for completion in late 1979. For review of the steamline break topical report, we requested additional information from Westinghouse in September 1978. Westinghouse responded with answers to some of our questions in May 1979. In response to our inquiries, Westinghouse has attributed their failure to answer the balance of our questions to higher priority TMI-2 analysis requirements.

We have previously accepted steamline and feedline break analyses described in plant applications for Pressurized Water Reactors designed by Westinghouse and other reactor vendors. It has been our position that a more detailed account of analytical methods for steamline and feedline break is required from the vendors for generic review and that the outcome of this review would be applied to licensed reactors. Our generic review includes the performance of in-house audit calculations and calculations by technical assistance contractors.

While our review is not sufficiently advanced to provide complete assurance that the North Anna Power Station, Unit 2 analysis methods are acceptable, it does provide evidence that substantial thermal margin exists under postulated steamline and feedline break accident conditions to preclude core damage leading to unacceptable consequences. Therefore, we conclude that the steamline and feedline break accident analyses for North Anna Power Station Unit 2 are acceptable while our more detailed review continues. Our approval is predicated on the assumption that our generic review can proceed on a reasonable schedule. To assure that this occurs, we will require a timely response to our outstanding questions on the topical reports discussed above and a commitment for prompt response to additional information requirements. The responses to outstanding questions and a commitment from the prompt response to additional information requirements should be provided prior to approval of a full power operating license, but it is not necessary that the staff complete its review and issue a Safety Evaluation Report on these codes and analyses prior to approval of a full power operating license.

17.0 QUALITY ASSURANCE

Our review of the quality assurance program description for the operations phase for the North Anna Power Station, Unit 2 Plant has verified that the criteria of Appendix B to 10 CFR Part 50 have been adequately addressed in Section 17.2 of the FSAR through Amendment 67. This determination of acceptability included a review of the list of safety-related structures, systems, and components (Q-list) to which the quality assurance program applies. The staff has recently developed a revised procedure for conducting the Q-list review that involves other NRR technical review branches and significantly enhances the staff's confidence in the acceptability of the Q-list. Staff re-review of the Q-list using the revised procedure is presently underway and the results will be reported in a later supplement. This re-review is not considered to be of sufficient importance to require its completion prior to granting authority to load fuel and perform low power tests.

APPENDIX A
CONTINUATION OF CHRONOLOGY OF RADIOLOGICAL REVIEW

March 17, 1978 Letter from applicant transmitting their 1977 Annual Report.

March 23, 1978 Letter to applicant concerning Conclusions of the Advisory Committee on Reactor Safeguards Concerning Monitoring of Microearthquakes in the vicinity of the North Anna Power Station.

March 23, 1978 Letter to applicant concerning the results of the 6-day testing of the outside recirculation spray pump.

March 23, 1978 Letter to applicant concerning Use of Code Case 110-USAS B 31.0-1967 "Code for Pressure Piping - Highgrade Stainless Steel Tubings".

March 27, 1978 Letter to applicant requesting additional information concerning Design Criteria.

March 29, 1978 Letter from applicant transmitting a list of potentially reportable items.

March 30, 1978 Letter from applicant requesting an Amendment to the Operating License and proposed Technical Specifications Change No. 7 concerning LOCA-ECCS reanalysis.

March 28, 1978 Letter from applicant concerning the adequacy of certain instrumentation.

March 31, 1978 Issuance of Supplement No. 9 to the North Anna Power Station, Units 1 & 2 Safety Evaluation Report.

April 1, 1978 Issuance of 100% full power operating license (2775 megawatts thermal).

April 1, 1978 Letter to applicant transmitting Amendment No. 3 to NPF-4 (100% power operating license), Supplement No. 9 to the Safety Evaluation Report and a Federal Register Notice.

April 3, 1978 Letter to applicant concerning Authorization to proceed to Operational Mode 2 (Initial Criticality).

April 5, 1978 Letter to applicant concerning Technical Specification Revision.

April 5, 1978 Letter from applicant concerning microseismic monitoring network.

April 10, 1978 Letter from applicant concerning a vibration model analysis of the inside recirculation spray pumps.

April 11, 1978 Letter to applicant concerning Completion of Item C.1 as Delineated in Attachment 1 to License NPF-4 Amendment 3.

April 12, 1978 Letter to applicant concerning the Steam Generator Water Hammer Demonstration Test.

April 12, 1978 Letter to applicant concerning Technical Specification Revision.

April 14, 1978 Letter from applicant concerning Proposed Technical Specification Change Nos. 5 and 6.

April 14, 1978 Letter from applicant concerning Emergency Procedure 1-EP-2 concerning redundant recirculation spray and safety injection pumps.

April 18, 1978 Representatives from NRC & VEPCO meet in Bethesda, Md. to discuss procedure for testing service water reservoir for two unit operation. (Summary issued April 25, 1979.)

April 18, 1978 Letter to applicant concerning Revised Intrusion Detection Systems Handbook.

April 10, 1978 Letter to all utilities with licenses and all applicants with applications for a license to operate a power reactor.

April 24, 1978 Letter to applicant concerning Long-Term Testing of Low Head Safety Injection Pump.

April 24, 1978 Letter from applicant concerning Proposed Technical Specification Change No. 9 - revision of Specification 4.5.2.f.2 (recirculation flow for the low head safety injection pumps).

April 25, 1978 Letter from applicant concerning the completion of a questionnaire of steam generator operating histories.

April 26, 1978 Letter from applicant concerning LOCA-ECCS package.

April 27, 1978 Letter from applicant concerning Evaluation of the Microearthquake Monitoring Program at the North Anna Power Station.

April 28, 1978 Letter from applicant requesting renewal of their April 14, 1978 request concerning design modification of the recirculation spray system.

May 1, 1978 Letter from applicant concerning Amendment to Operating License for North Anna Unit No. 1 - Proposed Technical Specification No. 10 - changes to 5.6.1 and 5.6.3 concerning fuel assemblies.

May 2, 1978 Letter to applicant concerning a request for additional information - Engineered Safeguards.

May 3, 1978 Letter from applicant transmitting a test program to verify the thermal and water inventory capabilities of the North Anna Power Station ultimate heat sink, the Service Water Reservoir.

May 8, 1978 Letter from applicant transmitting Amendment No. 4 to NPF-4 deleting two conditions contained in the operating license. Deletion of these conditions allow operation at 100% power at 2775 megawatts thermal.

May 5, 1978 Letter to all power reactor licensees and applicants with docketed applications to construct or operate a power reactor.

May 5, 1978 Letter from applicant requesting that condition 2.D.(3)j. be revised. This condition is contained in Amendment No. 3 to Facility Operating license NPF-4.

May 5, 1978 Letter from applicant requesting a proposed Technical Specification Change no. 11 concerning raising the heat flux hot channel factor limit.

May 5, 1978 Letter from applicant concerning NRC Staff Comments 3.76, 3.77, 3.78 and 3.79.

May 9, 1978 Letter from applicant concerning condition 2.D.(3)h of Amendment No. 3 to NPF-4 (stem mounted limit switches for the in containment isolation valves.

May 11, 1978 Representatives from VEPCO and the NRC meet in Bethesda, Md. to discuss VEPCO's proposal for final solution of the NPSH problem for the recirculation spray pumps. (Summary issued May 12, 1979.)

May 11, 1978 Letter from applicant transmitting responses to DPM questions addressing NPSH for the Recirculation Spray Pumps at North Anna Unit 1.

May 12, 1978 Letter from applicant concerning outside recirculation spray pumps.

May 12, 1978 Letter to applicant requesting additional information - Fire Protection Program.

May 15, 1978 Letter to applicant transmitting a copy of a Federal Register Notice for a proposed amendment to NPF-4 concerning an increase in the fuel storage capacity.

May 18, 1978 Letter from applicant transmitting additional information concerning proposed change No. 9 submitted by VEPCO on April 14, 1978.

May 19, 1978 Letter to applicant issuing Amendment No. 5 to NPF-4.

May 22, 1978 Letter from applicant concerning Environmental Monitoring Procedure Change Report.

May 25, 1978 Letter to applicant concerning Operating License Condition for Installation of Qualified Stem Mounted Limit Switches for the in Containment Isolation Valves.

May 31, 1978 Letter to applicant concerning Diesel Generator Alarms.

June 2, 1978 Letter from applicant concerning the value for the casing cooling pump discharge acceptance pressure.

June 5, 1978 Letter from applicant concerning contact policy with contractors participating with the construction and licensing of North Anna.

June 6, 1978 Letter to applicant concerning Manpower Requirements for Operating Reactors.

June 7, 1978 Letter from applicant concerning Barton and Foxboro model transmitters.

June 12, 1978 Letter to all power reactor licensees and applicants with applications for a license to construct or operate a power reactor.

June 13, 1978 Letter to applicant concerning request to revise Technical Specification 4.9.12.b.

June 13, 1978 Letter from applicant concerning Amendment to Operating License and proposed technical specification change for service water pump house.

June 14, 1978 Letter to applicant concerning D.C. power supplies.

June 23, 1978 Letter to applicant issuing Amendment No. 6 to NPF-4. This Amendment makes a change to Technical Specification A.

June 30, 1978 Letter to applicant requesting additional information on Technical Specification 3/4.7.12.

July 3, 1978 Letter to applicant issuing Amendment No. 7 to the North Anna operating license. This Amendment extends the time on condition of 2.D.(3)j. of Amendment No. 3 to October 1, 1978.

July 3, 1978 Letter from applicant transmitting a report concerning the submat drainage sump pumps at North Anna Unit 1.

July 7, 1978 Letter from applicant advising they intend to sell a limited part ownership in North Anna and Surry to Old Dominion Electric Cooperative and North Carolina Electric Membership Corporation.
(Letter undated
Received by NRC
7/7/78)

July 7, 1978 Letter from applicant concerning a preservice inspection summary report.

July 7, 1978 Letter from applicant concerning Diesel Generator Alarms.

July 10, 1978 Letter to all utilities with Operating plants concerning Draft Model I Technical Specifications. (Generic)

July 14, 1978 Letter from applicant referencing VEPCO letter dated June 5, 1978 concerning reporting information to NRC.

July 14, 1978 Letter from applicant advising they will respond to requests concerning settlement of the service water pump house by August 1, 1978.

July 14, 1978 Letter from applicant concerning testing of Unit 2 low head safety injection pump.

July 17, 1978 Letter to applicant concerning NUREG-0452 - Westinghouse Standard Technical Specification.

July 17, 1978 Letter to applicant concerning Technical Specification Revision.

July 18, 1978 Letter to licensees and applicants with docketed applications to construct or operate a power reactor. This letter transmits NUREG/CR-0181, "Barrier Penetration Database."

July 19, 1978 Letter to applicant requesting additional information concerning settlement of the pump house.

July 21, 1978 Letter to applicant requesting additional information regarding modifying the security plan.

July 21, 1978 Letter to applicant concerning Change of Environmental Monitoring Procedure for North Anna 1 & 2.

July 25 & 26, 1978 Representatives from NRC & VEPCO meet in Bethesda, Md. to discuss the Fire Protection Program for North Anna 1 & 2. (Summary issued August 1, 1979.)

July 26, 1978 Letter to applicant requesting additional information concerning foundation and soils - settlement of pump house.

July 27, 1978 Letter to applicant requesting additional information concerning the spent fuel storage racks.

July 28, 1978 Letter to applicant requesting additional information - staff positions on degraded electrical power grid conditions.

July 28, 1978 Letter from applicant advising they will reply to DPM's request for additional information on pressure vessel fracture toughness in late September 1978.

August 1, 1978 Letter to all power reactor licensees and applicants with applications for a license to operate or construct a power reactor. This letter transmits NUREG-0219, Nuclear Security Personnel for Power Plants, Content and Review Procedures for a Security Training and Qualification Program."

August 2, 1978 Letter from applicant transmitting responses to the stress analysis supporting VEPCO request to change the technical specification limit for settlement of the service water pump house.

August 3, 1978 Letter from applicant advising they will forward the required information on the movement of heavy loads over spent fuel by September 15, 1978.

August 8, 1978 Letter from applicant advising they will reply to DPM letter concerning changing the Technical Specification Limiting settlement of the Service Water Pump House at North Anna by September 1, 1978.

August 10, 1978 Letter to applicant concerning Standard for meteorological data on magnetic tape.

August 10, 1978 Letter from applicant advising that the responses to O. Parr's letter of July 26, 1978 concerning the settlement of the service water pump house for North Anna Units 1 & 2 will be provided by September 1, 1978.

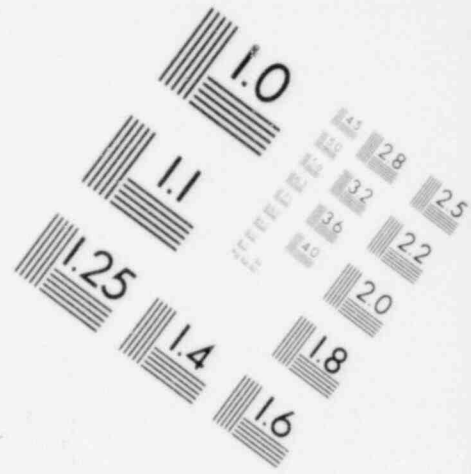
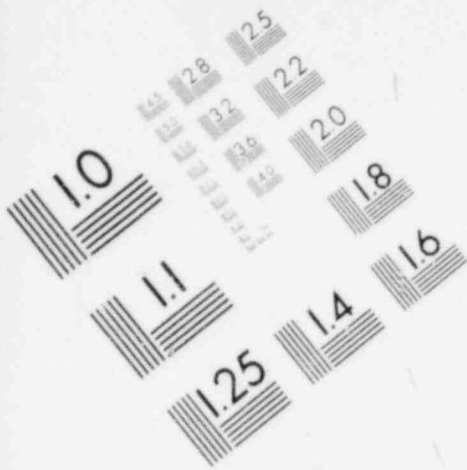
August 11, 1978 Letter from applicant transmitting responses to DPM letter of July 27, 1978 concerning expansion of spent fuel capacity.

August 14, 1978 Letter from applicant transmitting Proposed Technical Specification Change No. 13 identifying additional surveillance requirements for the diesel generator batteries.

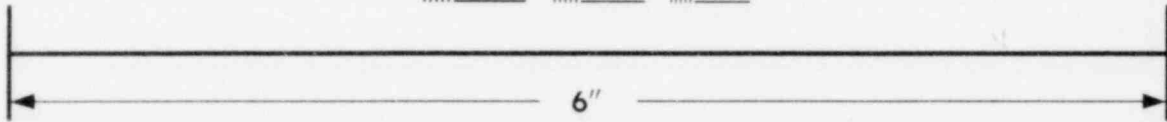
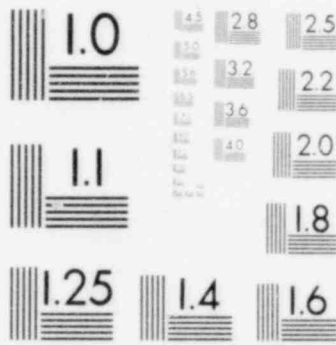
August 15, 1978 Letter to applicant concerning PWR Steam Generator Conference.

August 22, 1978 Letter to applicant concerning Fire Protection Program.

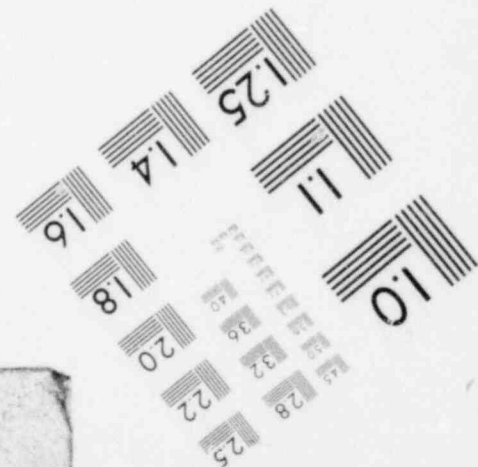
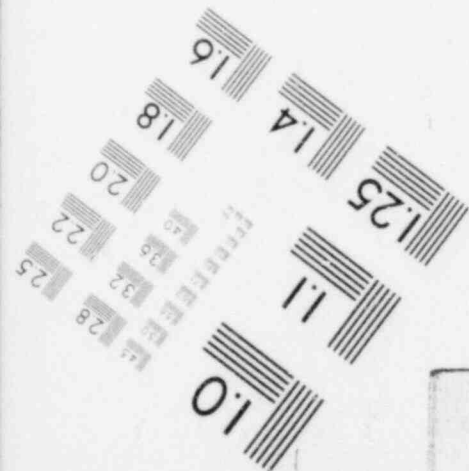
August 22, 1978 Letter from applicant transmitting test results from the generic test program on Barton pressure and differential pressure transmitters and requesting that the information be withheld from public disclosure as proprietary.



**IMAGE EVALUATION
TEST TARGET (MT-3)**



MICROCOPY RESOLUTION TEST CHART



August 28, 1978 Letter to applicant (generic) concerning upgraded guard and training requirements for Operating Plants.

August 29, 1978 Letter from applicant transmitting copies of the North Anna Power Station Environmental Radiological Monitoring Program - Quarterly Report covering the period January 1, 1978 through March 31, 1978.

August 31, 1978 Letter from applicant concerning proposed Technical Specification Change No. 14. This change reflects a reorganization of the Production Operation and Maintenance Department both onsite and offsite.

September 1, 1978 Representatives from MPA, LWR #3, I&E, Region 2 and VEPCO visit North Anna Power Station Unit 2 site to discuss matters related to the fuel loading date for Unit 2. (Summary issued September 1, 1979.)

September 1, 1978 Letter from applicant transmitting additional ownership information in accordance with request by A. Toalston, OAI.

September 8, 1978 Letter from applicant responding to requests for information concerning structural and geotechnical aspects of the limit for settlement of the Service Water Pump House at North Anna Units 1 & 2.

September 12, 1978 Letter from applicant transmitting information concerning onsite emergency power systems.

September 12, 1978 Letter to applicant transmitting a revised meeting schedule concerning a series of meetings to discuss implementation of upgraded guard qualification and training.

September 14, 1978 Letter to applicant concerning additional information on modifications to spent fuel racks.

September 19, 1978 Letter from applicant concerning Thermal Hydraulic Analysis Model.

September 20, 1978 Letter from applicant transmitting a topical report entitled "North Anna Unit 1, Cycle 1 Startup Physics Test Report."

September 22, 1978 Letter from applicant requesting additional information concerning inoperable conditions for the diesels and associated alarms for these conditions.

September 25, 1978 Letter from applicant transmitting a report on the North Anna Service Water Reservoir Test.

September 25, 1978 Letter from applicant transmitting the modified amended security plan.

September 26, 1978 Letter from applicant requesting extension of construction completion date for North Anna 2 from November 1, 1978 to December 1, 1979.

September 27, 1978 Letter to applicant concerning Protection from Degraded Grid Voltage Conditions.

September 29, 1978 Letter from applicant transmitting a report entitled "Westinghouse Reactor Protection System/Engineered Safety Features Actuation System Setpoint Methodology". This report is considered proprietary and an application and affidavit for withholding from public disclosure was enclosed.

October 13, 1978 Letter from applicant transmitting Proposed Tech. Spec. Change No. 15. This change concerns Condition D.(3)g.

October 17, 1978 Letter from applicant submitting a change in permanent piping for the demineralizer.

October 23, 1978 Letter to applicant concerning Receipt of Additional Antitrust Information. This letter forwards a copy of the Federal Register Notice and advises applicant of the names of trade journals and newspapers in which ads were placed.

October 24, 1978 Letter from applicant concerning protection for degraded grid voltage conditions.

October 25, 1978 Letter from applicant concerning Movement of Heavy Loads Near Spent Fuel.

October 27, 1978 Letter from applicant concerning inservice inspection program.

October 31, 1978 Letter from applicant transmitting a check for \$1200 and further justifying their request for an extension for Unit No. 2 of North Anna.

October 31, 1978 Letter from applicant concerning emergency diesel generator air start manual isolation valves.

November 2, 1978 Letter from applicant requesting relief from certain requirements of ASME XI for Inservice Testing of Pumps and Valves.

November 3, 1978 Letter from applicant concerning short-circuiting the Service Water Reservoir Spray System.

November 3, 1978 Letter from applicant transmitting Amendment No. 65 to the FSAR.

November 9, 1978 Letter from applicant requesting amendment to operating license concerning conductivity limits and surveillance requirements. Check for \$4000 enclosed.

November 16, 1978 Letter to applicant transmitting NUREG-0133 and Revision 1 of the Draft Radiological Effluent Technical Specifications.

November 20, 1978 Letter to all recipients of Nuclear Security Personnel for Power Plants, NUREG-0219.

November 22, 1978 Letter from applicant concerning Survey Monitoring T.S. Surveillance Requirement 4.7.12.1.

November 28, 1978 Letter from applicant transmitting the meteorological data comparison of the old and new meteorological towers located at North Anna.

November 29, 1978 Representatives from VEPCO & NRC meet in Bethesda, Md. to discuss proposed design of shielding around reactor pressure vessel. (Meeting Summary issued December 1, 1978.)

December 1, 1978 Letter to applicant requesting additional information on the North Anna Degraded Grid Voltage Protection.

December 5, 1978 Representatives from NRC & VEPCO discuss matters related to service water pumphouse settlement. (Summary of Meeting issued December 12, 1978.)

December 4, 1978 Letter from applicant concerning ASME Code.

December 6, 1978 Letter from Applicant concerning survey monitoring and Technical Specification surveillance requirements.

December 11, 1978 Letter to applicant concerning Containment Purging During Normal Plant Operation, North Anna 1.

December 11, 1978 Letter from applicant concerning Pressure Vessel Fracture Toughness Properties.

December 13, 1978 Letter from applicant concerning Replacement of A Reactor Coolant Pump Motor.

December 20, 1978 Letter from applicant concerning settlement of the service water pumphouse.

December 21, 1978 Letter from applicant concerning the Reactor Coolant System.

December 21, 1978 Letter from applicant advising they finalize the design of the degraded voltage sensing scheme by January 12, 1979.

December 26, 1978 Letter from applicant concerning a re-organization of the Production Operations Department.

December 29, 1978 Letter to applicant extending the construction completion date for North Anna Unit 2 to December 1, 1979.

January 5, 1979 Letter from applicant transmitting changes to the executive management of their nuclear power station construction & operations activities.

January 10, 1979 Letter from applicant concerning neutron flux levels.

January 12, 1979 Letter from applicant concerning Amendment 65 to the FSAR.

January 12, 1979 Letter from applicant concerning the second level of undervoltage protection.

January 12, 1979 Letter from applicant transmitting amendments to the modified amended security plan.

January 17, 1979 Letter from applicant concerning Containment Purging During Normal Plant Operation Unit No. 1.

January 18, 1979 Letter to applicant concerning Diesel Generator Alarms.

January 21, 1979 Letter to applicant concerning withholding from public disclosure - CAW-78-63 (proprietary information) on the qualification testing of Barton transmitters.

January 31, 1979 Letter to applicant transmitting five copies of the Safety Evaluation for Spent Fuel Pool.

January 31, 1979 Letter from applicant concerning Technical Specifications for North Anna Unit 2 requirements for ASME Code Class 1, 2 and 3 pumps and valves.

February 5, 1979 Letter from applicant transmitting the modified Startup Physics Testing program.

February 14, 1979 Letter to applicant concerning Contents of the Offsite Dose Calculation Manual.

February 20, 1979 Letter from applicant concerning qualification test performed on the reactor vessel bolting material for Unit No. 2.

February 22, 1979 Letter from applicant advising their letter of May 1, 1979 contained a minor typographical error.

February 23, 1979 Letter to applicant transmitting Amendment No. 9 to License NPF-4 concerning the Security Plan for Units 1 & 2 of North Anna.

March 1, 1979 Letter to applicant withholding from public disclosure as proprietary a report entitled "Westinghouse Reactor Protection System/Engineered Safety Features Actuation System Setpoint Methodology".

March 1, 1979 Letter from applicant concerning the effects of radiation-induced deterioration of the collar/saddle shield material.

March 2, 1979 Letter to applicant concerning "Summary of Operating Experience with Recirculating Steam Generators," NUREG-0523.

March 6, 1979 Letter to applicant issuing Amendment No. 8 to NPF-4 (Operating License for North Anna, Unit 1) concerning Fire Protection. Enclosures include Amendment No. 8, Safety Evaluation, Federal Register Notice and Tech. Specification pages to the license for Appendix A.

March 6, 1979 Letter from applicant concerning Amendment to Operating License Proposed Tech. Spec. Change No. 17(\$4,000 check included).

March 7, 1979 Letter from applicant concerning surveillance requirements for the preoperational test program.

March 8, 1979 Letter from applicant transmitting a supplement to proposed Technical Specification Change No. 14 reflecting a reorganization of the management of North Anna Power Station.

March 8, 1979 Representatives from VEPCO & NRC meet to discuss the Appeal Board's Decision (ALAB-529) concerning North Anna. (Meeting Summary issued March 14, 1979).

March 8, 1979 Letter from applicant concerning comprehensive test to evaluate the thermal performance and water inventory characteristics of the North Anna Service Water Reservoir and spray system. Portions of this submittal are considered proprietary by VEPCO and are requested to be withheld from public disclosure.

March 12, 1979 Letter from applicant concerning Specification 4.0.5 of the proposed Technical Specifications for North Anna 2 concerning ASME Code Class 1, 2 and 3 components.

March 13, 1979 Letter from applicant requesting an amendment to operating license exemptions to Technical Specifications and 10 CFR 50 Appendix J.

March 16, 1979 Letter from applicant concerning Modified Startup Physics Testing Program - Supplemental Information for Unit 2.

March 20, 1979 Letter from applicant concerning Protection from Degraded Grid Voltage Conditions/Interaction of Offsite and Onsite Power Systems.

March 20, 1979 Letter from applicant concerning Startup Physics Test Results - Supplemental Information - Unit 1.

March 21, 1979 Letter to applicant requesting additional information - North Anna Water Solid Overpressure.

March 23, 1979 Letter from applicant advising they have amended the security plan entitled, "Security Program, North Anna Power Station, Units 1 and 2."

March 23, 1979 Letter to applicant concerning Radioactive Waste System at North Anna Station.

March 23, 1979 Letter from applicant transmitting figures inadvertently left out of the attachment to their March 12, 1979 letter.

March 23, 1979 Letter from applicant transmitting Amendment No. 66 to the FSAR.

March 27, 1979 Letter from applicant concerning the contents of Amendment 65 to the FSAR which will be submitted shortly.

March 28, 1979 Letter to applicant requesting additional information on the inspection and surveillance of the service water reservoir and the main dam impounding Lake Anna.

March 28, 1979 Letter to applicant concerning radiological Effluent Technical Specifications for Units 1 & 2.

April 3, 1979 Letter from applicant concerning qualification testing in accordance with the 1968 Edition of the ASME Code, Section III.

April 5, 1979 Letter from applicant transmitting the 1978 Financial Annual Report.

April 5, 1979 Letter from applicant concerning Exemptions to Technical Specifications and 10 CFR 50 Appendix J - North Anna, Unit 1.

April 6, 1979 Letter from applicant advising they have amended the approved security plan for the North Anna Power Station.

April 9, 1979 Letter to applicant concerning North Anna Unit 1 Plant Staff Reorganization.

April 10, 1979 Letter from applicant concerning Modified Startup Physics Testing Program - Supplemental Information - Unit 2.

April 12, 1979 Representatives from VEPCO and NRC meet in Bethesda, Md. to discuss the North Anna Unit 2 Flow Diverter Problem. (Summary of April 12, 1979 Meeting issued April 16, 1979).

April 12, 1979 Letter from applicant concerning discovery of splitter plate 2-C cracks that had been installed in the reactor coolant system pipe elbow adjacent to the reactor coolant pump.

April 15, 1979 Letter from applicant concerning flow splitter plates discussed at a meeting held with the NRC on April 12, 1979.

April 16, 1979 Letter from applicant concerning inspection and surveillance of the North Anna Power Station service water reservoir, and the main dam impounding Lake Anna.

April 17, 1979 Letter from applicant transmitting the North Anna Power Station Environmental Radiological Monitoring Program - Quarterly Report covering the period of October 1, 1978 through December 31, 1978.

April 17, 1979 Letter from applicant concerning revision of the technical specifications for the proposed over-pressure protection system.

April 23, 1979 Letter from applicant concerning an analysis for an RHR line break at RHR cut-in temperature and pressure was being performed by the NSSS vendor for North Anna Units 1 & 2.

April 25, 1979 Letter from applicant transmitting an affidavit that service was made on Amendment No. 66 to the North Anna, Units 1 & 2 FSAR. (No cover letter.)

April 27, 1979 Letter to applicant transmitting Amendment No. 10 to NPF-4 concerning: Inservice inspection of flow splitter plates, displacement of reactor coolant pumps; and loose parts monitoring. Package consists of letter to VEPCO, Amendment with Technical Specifications page changes (Appendix A), Safety Evaluation and Federal Register Notice.

April 27, 1979 Letter from applicant advising that the modified requirements for personnel qualifications will be incorporated into an upcoming FSAR amendment.

May 1, 1979 Letter from applicant transmitting the elevations of settlement markers 15, 16, 17, and 18, located on the service water piping at the Service Water Pump house, as measured on August 3, 1978.

May 2, 1979 Letter to applicant concerning Adequacy of Station Electric Distribution Systems Voltages.

May 17, 1979 Letter from applicant supplementing information submitted on June 13, 1978 concerning settlement of Class I structures.

May 18, 1979 Letter from applicant transmitting additional information on the testing and evaluation of the North Anna Service Water Reservoir and spray system.

May 21, 1979 Letter to applicant transmitting page revisions to the security plan evaluation report.

May 23, 1979 Letter from applicant transmitting responses concerning the thermal performance test of the North Anna Service Water Reservoir.

May 23, 1979 Letter to applicant concerning Radiological Effluent Technical Specifications.

May 29, 1979 Letter from applicant responding to O. Parr's request for additional information of March 23, 1979.

May 29, 1979 Letter from applicant concerning the four corners of the Expansion Joints Enclosure of the Service Water Pump House.

May 30, 1979 Letter from applicant advising that Unit 2 is nearing completion and will be ready for fuel loading by June 26, 1979.

May 30, 1979 Letter from applicant advising that their May 18, 1979 letter was meant to be a response for North Anna Units, 1, 2, 3 & 4.

June 1, 1979 Letter to applicant concerning Instrumentation Qualification - Request for Additional Information. (Separate letters for Unit 1 and Unit 2.)

June 11, 1979 Letter from applicant concerning the Safety Evaluation Report on the fire protection program.

June 14, 1979 Letter to applicant concerning lessons learned from Three Mile Island and recommendations.

June 15, 1979 Letter to applicant concerning the issuance of an operating license for North Anna Power Station, Unit No. 2.

June 22, 1979 Letter from applicant transmitting additional information concerning "Instrument Qualification."

June 26, 1979 Letter to applicant concerning safeguards system and an inadvertent reactor scram.

June 28, 1979 Letter to applicant transmitting Amendment No. 12 to the North Anna, Unit 1 license (NPF-4) concerning settlement of the pumphouse.

June 29, 1979 Letter to applicant concerning Security Program Amendment for North Anna.

June 29, 1979 Letter from applicant concerning additional information on high density spent fuel racks.

July 5, 1979 Letter from applicant concerning electrical distribution system voltages on North Anna Unit 1.

July 6, 1979 Letter from applicant requesting technical specification changes concerning the nucleate boiling ratio.

July 9, 1979 Letter to applicant concerning Fire Protection Program.*

July 10, 1979 Letter to applicant requesting additional information on the contingency plan.

July 11, 1979 Letter to applicant concerning upgraded standard technical specifications (STS) bases program - North Anna 1.

July 12, 1979 Letter from applicant advising they are preparing a report addressing short-term and long-term recommendations for implementation on North Anna 2 as a result of the TMI-2 incident.

July 13, 1979 VEPCO Letter from applicant concerning additional instrument qualification information.

July 17, 1979 Letter from applicant transmitting "Reactor Containment Building Integrated Leak Rate Test, Type, A, B, and C", for North Anna Unit 2.

July 19, 1979 Letter from applicant concerning Failure of Solenoid Operated Valves to meet IE Bulletin 79-01.

July 23, 1979 Letter from applicant requesting an amendment to Operating License for exemptions from Tech. Specs. for North Anna 1, Appendix J, Section D.

July 23, 1979 Letter from applicant advising that the sprinkler piping for the fire protection program will be installed by August 15, 1979.

July 24, 1979 Letter from applicant transmitting a check for \$8,400.00 for review of the Safeguards Contingency Plans for Surry and North Anna.

July 25, 1979 Letter advising they will transmit the requested information on the North Anna contingency plan by August 31, 1979.

July 27, 1979 Letter from applicant concerning supplemental information on PWR feedwater lines.

July 27, 1979 Letter to applicant concerning Appendix I Technical Specifications.

July 27, 1979 Letter from applicant concerning Power Distribution Data.

July 30, 1979 Letter to applicant requesting additional information (Reactor 4.0).

July 31, 1979 Letter from applicant concerning exemptions from Tech. Specs. 10 CFR 50, Appendix J.

July 31, 1979 Letter to applicant concerning secondary water chemistry control. (2 separate letters for Units 1 & 2)

July 31, 1979 Letter from applicant concerning report on small break accident for Westinghouse NSSS System.

July 31, 1979 Letter from applicant transmitting Amendment No. 67 to FSAR which consists of a substitution or addition of pages.

August 3, 1979 Letter to applicant concerning Staff Position on Electrical Protection of Containment Penetrations for North Anna, Unit 2.

August 3, 1979 Letter to applicant transmitting Amendment No. 13 to NPF-4 concerning surveillance requirements.

August 6, 1979 Board Decisions denying intervenors' motion to amend petition to intervene and cancels the prehearing conference on Fuel Pool.

August 6, 1979 Letter from applicant requesting an amendment to the North Anna license to extend the date of the first refueling which is currently scheduled for September 15, 1979.

August 10, 1979 Letter from applicant responding to DPM questions concerning reactor fuel.

August 13, 1979 Letter from applicant concerning Electrical Protection of Containment Penetrations for North Anna 1 & 2.

August 14, 1979 Letter from applicant concerning Secondary Water Chemistry Control.

August 16, 1979 Letter from applicant concerning Station Electrical Distribution System Voltages.

August 16, 1979 Letter from applicant concerning Power Coastdown Operation for North Anna Units 1 & 2 Cycle 1.

August 17, 1979 Letter to applicant concerning Interim Actions Needed for Plant Operation Pending Final Resolution of Anticipated Transients with Failure to SCRAM (ATWS) - Unit 2.

August 17, 1979 Letter to applicant transmitting Amendment No. 14 to NPF-4 concerning an increase in fuel storage capacity from 400 to 966 fuel assemblies.

August 21, 1979 Letter from applicant concerning multiple equipment failures and unnecessary challenges to the reactor trip and the safeguards systems.

August 21, 1979 Site visit to VEPCO Headquarters in Richmond to review the North Anna Unit 1 Flux Maps as they relate to Flux Tilt Licensing Event Reports.

August 24, 1979 Letter from applicant concerning company positions on Regulatory Guides.

August 30, 1979 Letter from applicant concerning licensing North Anna Unit 2.

September 4, 1979 Letter from applicant advising they amended the security plan.

September 4, 1979 Letter from applicant concerning LHSI, ORS and IRS.

September 4, 1979 Letter from applicant concerning the contingency plan.

September 4, 1979 Letter from applicant concerning secondary water chemistry control.

September 7, 1979 Letter to applicant requesting additional information 4.0.

September 11, 1979 Letter from applicant requesting an amendment to NPF-4 to extend the date for the first refueling from September 15, 1979 to October 5, 1979.

September 11, 1979 Letter from applicant advising they will respond to IE Bulletins 79-06A and 76-06A, Revision 1 by October 15, 1979.

September 11, 1979 Letter from applicant advising they will respond to DPM request for final resolution of ATWS for Unit 2 by October 15, 1979.

September 13, 1979 Letter from applicant requesting technical specification change for refueling water storage tank.

September 14, 1979 Letter from applicant transmitting company positions on Regulatory Guide 1.59, Revision 2.

September 14, 1979 Letter to applicant issuing Amendment No. 15 to NPF-4 concerning response time testing of systems, safety injection and containment depressurization actuating testing.

September 21, 1979 Letter to applicant requesting additional information - Engineered Safeguards.

September 21, 1979 Letter from applicant concerning Guide Thimble Tube Wear.

September 21, 1979 Letter from applicant concerning Electrical Protection of Containment Penetrations for North Anna, Unit 2.

September 28, 1979 Letter to applicant concerning a request for additional information related to the September 25, 1979 event. Any actions that need to be taken are expected to be fully reflected in the design and procedures to be implemented on North Anna, Unit 2.

September 28, 1979 Letter to applicant concerning NRC Requirements for Auxiliary Feedwater Systems at North Anna Power Station, Unit 1.

September 28, 1979 Letter to applicant requesting additional information - level measurement errors due to environmental temperature effects on level instrument reference legs.

October 4, 1979 Letter from applicant concerning analysis of a potential main steam line break at North Anna 2.

October 5, 1979 Letter from applicant concerning Staff Position on Electrical Protection of Containment Penetrations for North Anna 2.

October 11, 1979 Letter to applicant concerning Environmental Qualification of Class IE Instrumentation and Electrical Equipment.

October 12, 1979 Letter from applicant concerning temperature effects on level instrument reference legs.

October 17, 1979 Letter to applicant concerning ATWS.

October 18, 1979 Letter to applicant concerning Environmental Qualification of Reactor Coolant Temperature Detectors and Containment Pressure Transmitters.

October 18, 1979 Letter from applicant concerning Anticipated Transients with Failure to Scram interim actions for North Anna 2.

October 25, 1979 Letter from applicant transmitting the response to D. Vassallo's letter of September 27, 1979.

October 31, 1979 Letter from applicant concerning Environmental Qualification of Class IE December 1, 1979 to December 1, 1980.

November 1, 1979 Letter from applicant concerning Environmental Qualification of Reactor Coolant Temperature Detectors and Containment Pressure Transmitters.

November 2, 1979 Letter from applicant concerning Environmental Qualification of Class IE Instrumentation and Electrical Equipment.

November 20, 1979 Representatives from NRC & VEPCO meet in Bethesda, Md. to discuss the environmental qualifications of electrical equipment - Rosemount Transmitters. (Summary written November 27, 1979.)

November 21, 1979 Letter to applicant concerning Upgraded Emergency Plans.

November 23, 1979 Letter to applicant concerning Proposed Revision 2 to Regulatory Guide 1.97.

November 30, 1979 DPM & VEPCO representatives meet in Bethesda, Md. to discuss matters regarding Lessons Learned Task Force Recommendations. (Summary written December 4, 1979.)

November 30, 1979 Letter to applicant Clarification of Staff Position on Electrical Protection of Containment Penetrations for North Anna 2.

December 3, 1979 Letter from applicant concerning Security Plans for Unit 2.

December 5, 1979 Letter from applicant concerning recent licensing review activity.

December 11, 1979 Letter to applicant extending the construction completion date of North Anna, Unit 2 until December 1, 1980.

December 12 & 13, 1979 Site visit by NRC employees to discuss matters related to Radiological Shielding.

December 17, 1979 Letter to applicant concerning Implementation of the Recommendations of NUREG-0660.

December 18, 1979 Letter to applicant concerning Degradation of Guide Thimble Tube Walls.

December 19, 1979 Letter from applicant transmitting information concerning environmental qualification testing conducted on Rosemount Model 1152.

December 19-20, 1979 Representatives from NRC visit the North Anna 2 Site to discuss matters regarding Lessons Learned Task Force. (Meeting Summary issued January 2, 1980.)

December 21, 1979 Letter from applicant concerning separation of electrical equipment and systems.

December 21, 1979 Letter from applicant advising they will provide us with the requested information on electrical protection of containment penetrations starting January 15, 1980 and completion by February 15, 1980.

December 21, 1979 DPM Letter to applicant concerning radiological emergency response plans.

December 26, 1979 Letter to applicant requesting for information regarding evacuation times.

January 4, 1980 Letter from applicant providing additional information on qualified life of RTDS.

January 10, 1980 Letter from applicant concerning ATWS.

January 10, 1980 Letter to applicant concerning Environmental Qualification of Rosemount Transmitters.

January 10, 1980 Letter from applicant concerning Lessons Learned Short Term Requirements.

January 11, 1980 Summary of Dec. 13, 1979 meeting to Discuss with PWR Applicants Revision 2 to Regulatory Guide 1.97.

January 14, 1980 Letter to applicant concerning Staff Position on Electrical Protection of Containment Penetrations.

January 15, 1980 Letter from applicant concerning Staff Position on Electrical Protection of Containment Penetrations.

January 21, 1980 Letter to applicant concerning Installation of Inspection Port on Steam Generators.

January 22, 1980 Letter from applicant concerning Fuel Assembly Guide Tube Thimble Wear and request withholding from public disclosure.

January 24, 1980 Letter from applicant advising that J. H. Ferguson has been elected Executive Vice-President-Power.

January 31, 1980 Letter from applicant concerning Implementation of the Recommendations of NUREG-0660 Enhancement of Onsite Emergency Diesel Generator Reliability.

February 1, 1980 Letter from applicant transmitting the final draft of the PWR near term OL group's general comments on Revision Two of Regulatory Guide. 1.97.

February 8, 1980 Summary of February 5, 1980 meeting with representatives from Pacific Gas & Electric Co., Public Service Electric & Gas Company and VEPCO to discuss the low power test program with near term operating license applicants.

February 8, 1980 Letter from applicant providing additional information on tests procedures.

February 11, 1980 Letter from applicant concerning Installation of Inspection Ports on Steam Generators.

February 15, 1980 Letter to applicant concerning withholding as proprietary information submitted by Westinghouse on the fuel assembly guide tube wear on North Anna 2, Salem 2, Sequoyah 1 & 2, McGuire 1 & 2 and Diablo Canyon 1 dockets.

February 14 & 15, 1980 Representatives from NRC visit the North Anna 2 site to discuss with VEPCO officials matters regarding outstanding TMI and non-TMI related issues.

February 15, 1980 Letter from applicant concerning Staff Position on Electrical Protection of Containment Penetrations.

February 19, 1980 Letter to applicant concerning Change in Review Procedures for Equipment Qualification Documentation for North Anna 2.

February 21, 1980 Letter to applicant concerning qualification of safety-related electrical equipment.

- March 6, 1980 Summary of meeting held on March 3, 1980 with near term operating license applicants to discuss NRC requirements.
- March 6, 1980 Representatives from NRC and VEPCO meet in Bethesda, Maryland to discuss cold shutdown of North Anna Power Station, Unit 2.
- March 7, 1980 Letter to applicant requesting additional information.

APPENDIX B

NUCLEAR REGULATORY COMMISSION
UNRESOLVED SAFETY ISSUES

B-1 Unresolved Safety Issues

The NRC staff continuously evaluates the safety requirements used in its reviews against new information as it becomes available. Information related to the safety of nuclear power plants comes from a variety of sources including experience from operating reactors, research results, NRC staff and Advisory Committee on Reactor Safeguards safety reviews, and vendor, architect/engineer and utility design reviews. Each time a new concern or safety issue is identified from one or more of these sources, the need for immediate action to assure safe operation is assessed. This assessment includes consideration of the generic implications of the issue.

In some cases, immediate action is taken to assure safety, e.g., the derating of boiling water reactors as a result of the channel box wear problems in 1975. In other cases, interim measures, such as modifications to operating procedures, may be sufficient to allow further study of the issue prior to making licensing decisions. In most cases, however, the initial assessment indicates that immediate licensing actions or changes in licensing criteria are not necessary. In any event, further study may be deemed appropriate to make judgments as to whether existing NRC staff requirements should be modified to address the issue for new plants or if backfitting is appropriate for the long-term operation of plants already under construction or in operation.

These issues are sometimes called "generic safety issues" because they are related to a particular class or type of nuclear facility rather than a specific plant. These issues have also been referred to as "unresolved safety issues." However, as discussed above, such issues are considered on a generic basis only after the staff has made an initial determination that the safety significance of the issue does not prohibit continued operation or require licensing actions while the longer-term generic review is underway.

B-2 ALAB-444 Requirements

These longer-term generic studies were the subject of a Decision by the Atomic Safety and Licensing Appeal Board of the Nuclear Regulatory Commission. The Decision was issued on November 23, 1977 (ALAB-444) in connection with the Appeal Board's consideration of the Gulf States Utility Company application for the River Bend Station, Unit Nos. 1 and 2.

In the view of the Appeal Board (pp. 25-29):

"The responsibilities of a licensing board in the radiological health and safety sphere are not confined to the consideration and disposition of those issues which may have been presented to it by a party or an "Interested State" with the required degree of specificity. To the contrary, irrespective of what matters may or may not have been properly placed in controversy, prior to authorizing the issuance of a construction permit the board must make the finding, inter alia, that there is "reasonable assurance" that "the proposed facility can be constructed and operated at the proposed location without undue risk to the health and safety of the public," 10 CFR 50.35(a)...Of necessity, this determination will entail an inquiry into whether the staff review satisfactorily has come to grips with any unresolved generic safety problems which might have an impact upon operation of the nuclear facility under consideration."

"The Safety Evaluation Report is, of course, the principal document before the licensing board which reflects the content and outcome of the staff's safety review. The board should therefore be able to look to that document to ascertain the extent to which generic unresolved safety problems which have been previously identified in a Final Safety Analysis Report item, a Task Action Plan, an ACRS report or elsewhere have been factored into the staff's analysis for the particular reactor -- and with what result. To this end, in our view, each Safety Evaluation Report should contain a summary description of those generic problems under continuing study which have both relevance to facilities of the type under review and potentially significant public safety implications."

"This summary description should include information of the kind now contained in most Task Action Plans. More specifically, there should be an indication of the investigative program which has been or will be undertaken with regard to the problem, the program's anticipated timespan, whether (and if so, what) interim measures have been devised for dealing with the problem pending the completion of the investigation, and what alternative courses of action might be available should the program not produce the envisaged result."

"In short, the board (and the public as well) should be in a position to ascertain from the Safety Evaluation Report itself -- without the need to resort to extrinsic documents -- the staff's perception of the nature and extent of the relationship between each significant unresolved generic safety question and the eventual operation of the reactor under scrutiny. Once again, this assessment might well have a direct bearing upon the ability of the licensing board to make the safety findings required of it on the construction permit level even though the generic answer to the question remains in the offing. Among other things, the furnished information would likely shed light on such alternatively important considerations as whether:

(1) the problem has already been resolved for the reactor under study; (2) there is a reasonable basis for concluding that a satisfactory solution will be obtained before the reactor is put in operation; or (3) the problem would have no safety implications until after several years of reactor operation and, should it not be resolved by then, alternative means will be available to insure that continued operation (if permitted at all) would not pose an undue risk to the public."

This appendix is specifically included to respond to the decision of the Atomic Safety and Licensing Appeal Board as enunciated in ALAB-444.

B-3 "Unresolved Safety Issues"

In a related matter, as a result of Congressional action on the Nuclear Regulatory Commission budget for Fiscal Year 1978, the Energy Reorganization Act of 1974 was amended (PL 95-209) on December 13, 1977 to include, among other things, a new Section 210 as follows:

"UNRESOLVED SAFETY ISSUES PLAN"

"SEC. 210. The Commission shall develop a plan providing for specification and analysis of unresolved safety issues relating to nuclear reactors and shall take such action as may be necessary to implement corrective measures with respect to such issues. Such plan shall be submitted to the Congress on or before January 1, 1978 and progress reports shall be included in the annual report of the Commission thereafter."

The joint Explanatory Statement of the House-Senate Conference Committee for the FY 1978 Appropriations Bill (Bill S.1131) provided the following additional information regarding the Committee's deliberations on this portion of the bill:

"SECTION 3 - UNRESOLVED SAFETY ISSUES"

"The House amendment required development of a plan to resolve generic safety issues. The conferees agreed to a requirement that the plan be submitted to the Congress on or before January 1, 1978. The conferees also expressed the intent that this plan should identify and describe those safety issues, relating to nuclear power reactors, which are unresolved on the date of enactment. It should set forth: (1) Commission actions taken directly or indirectly to develop and implement corrective measures; (2) further actions planned concerning such measures; and (3) timetables and cost estimates of such actions. The Commission should indicate the priority it has assigned to each issue, and the basis on which priorities have been assigned."

In response to the reporting requirements of the new Section 210, the NRC staff submitted to Congress on January 1, 1978, a report describing the NRC generic issues program (NUREG-0410).^{1/} The NRC program was already in place when PL 95-209

^{1/} NUREG-0410, "NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants," issued on January 1, 1978.

was enacted and is of considerably broader scope than the "Unresolved Safety Issues Plan" required by Section 210. In the letter transmitting NUREG-0410 to the Congress on December 20, 1977, the Commission indicated that "the progress reports, which are required by Section 210 to be included in future NRC annual reports, may be more useful to Congress if they focus on the specific Section 210 safety items."

It is the NRC's view that the intent of Section 210 was to assure that plans were developed and implemented on issues with potentially significant public safety implications. In 1978, the NRC undertook a review of over 130 generic issues addressed in the NRC program to determine which issues fit this description and qualify as "Unresolved Safety Issues" for reporting to the Congress. The NRC review included the development of proposals by the NRC staff and review and final approval by the NRC Commissioners.

This review is described in a report, NUREG-0510, entitled "Identification of Unresolved Safety Issues Relating to Nuclear Power Plants - A Report to Congress" dated January 1979. The report provides the following definition of an "Unresolved Safety Issue":

"An Unresolved Safety Issue is a matter affecting a number of nuclear power plants that poses important questions concerning the adequacy of existing safety requirements for which a final resolution has not yet been developed and that involves conditions not likely to be acceptable over the lifetime of the plants it affects."

Further the report indicates that in applying this definition, matters that pose "important questions concerning the adequacy of existing safety requirements" were judged to be those for which resolution is necessary to (1) compensate for a possible major reduction in the degree of protection of the public health and safety, or (2) provide a potentially significant decrease in the risk to the public health and safety. Quite simply, an "Unresolved Safety Issue" is potentially significant from a public safety standpoint and its resolution is likely to result in NRC action on the affected plants.

All of the issues addressed in the NRC program were systematically evaluated against this definition as described in NUREG-0510. As a result, 17 "Unresolved Safety Issues" addressed by 22 tasks in the NRC program were identified. The issues are listed below. Progress on these issues was discussed in the 1978 NRC Annual Report. The number(s) of the generic task(s) (e.g., A-1) in the NRC program addressing each issue is indicated in parentheses following the title.

"UNRESOLVED SAFETY ISSUES" (APPLICABLE TASK NOS.)

1. Water Hammer - (A-1)
2. Asymmetric Blowdown Loads on the Reactor Coolant System - (A-2)

3. Pressurized Water Reactor Steam Generator Tube Integrity - (A-3, A-4, A-5)
4. BWR Mark I and Mark II Pressure Containments - (A-6, A-7, A-8, A-39)
5. Anticipated Transients Without Scram - (A-9)
6. BWR Nozzle Cracking - (A-10)
7. Reactor Vessel Materials Toughness - (A-11)
8. Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports - (A-12)
9. Systems Interaction in Nuclear Power Plants - (A-17)
10. Environmental Qualification of Safety-Related Electrical Equipment - (A-24)
11. Reactor Vessel Pressure Transient Protection - (A-26)
12. Residual Heat Removal Requirements - (A-31)
13. Control of Heavy Loads Near Spent Fuel - (A-36)
14. Seismic Design Criteria - (A-40)
15. Pipe Cracks at Boiling Water Reactors - (A-42)
16. Containment Emergency Sump Reliability - (A-43)
17. Station Blackout - (A-44)

In the view of the staff, the "Unresolved Safety Issues" listed above are the substantive safety issues referred to by the Appeal Board in ALAB-444 when it spoke of "...those generic problems under continuing study which have...potentially significant public safety implications" (page 27). Eight of the 22 tasks identified with the above 17 "Unresolved Safety Issues" are not applicable to North Anna Unit 2. Six of these tasks (A-6, A-7, A-8, A-39, A-10 and A-42) are peculiar to boiling water reactors and two of the tasks (A-4 and A-5) are peculiar to pressurized water reactors with Babcock & Wilcox and Combustion Engineering nuclear steam supply systems.^{2/} With regard to the other 14 tasks that are applicable to North Anna Unit 2, the NRC staff has issued NUREG reports and other documents providing its proposed resolution of four of the issues as listed below.

<u>Task Number</u>	<u>NUREG Report and Title</u>	<u>Safety Evaluation Report/ Safety Evaluation Report Supplement Section</u>
A-12	NUREG-0577, "Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports"	Section 5.4.2 of Supplement No. 3
A-24	NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment"	Section 3.10.3 of Supplement No. 9 and of this supplement
A-26	NUREG-0224, "Reactor Vessel Pressure Transient Protection for Pressurized Water Reactors"	Section 5.2.8 of Supplement No. 7 and of this supplement
	Branch Technical Position RSB 5-2, "Reactor Coolant System Overpressurization Protection"	

^{2/} Even though Tasks A-4 and A-5 address steam generator tube problems experienced in CE and B&W plants, there are many common task elements between these tasks and Task A-3 which addresses Westinghouse steam generator tube problems. For this reason, the Task Action Plans for all three tasks have been combined into a single Task Action Plan.

<u>Task Number</u>	<u>NUREG Report and Title</u>	<u>Safety Evaluation Report/ Safety Evaluation Report Supplement Section</u>
A-31	Regulatory Guide 1.139, "Guidance for Residual Heat Removal" Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal Systems"	Section 5.4.3 of this supplement

The remaining 10 tasks that are applicable to North Anna Unit 2 are listed below.

GENERIC TASKS ADDRESSING UNRESOLVED SAFETY ISSUES
THAT ARE APPLICABLE TO THE NORTH ANNA NUCLEAR PLANT UNIT 2

1. A-1 Water Hammer
2. A-2 Asymmetric Blowdown Loads on PWR Primary Systems
3. A-3 Westinghouse Steam Generator Tube Integrity
4. A-9 ATWS
5. A-11 Reactor Vessel Materials Toughness
6. A-17 Systems Interactions in Nuclear Power Plants
7. A-36 Heavy Loads Near Spent Fuel
8. A-40 Seismic Design Criteria
9. A-43 Containment Emergency Sump Reliability
10. A-44 Station Blackout

With the exception of Tasks A-9, A-43 and A-44, Task Action Plans for the generic tasks above are included in NUREG-0649, "Task Action Plans for Unresolved Safety Issues Related to Nuclear Power Plants." The Task Action Plan for Task A-9 is currently being revised. Task Action Plans for Tasks A-43 and A-44 are currently under development. The information provided in NUREG-0649 meets most of the informational requirements of ALAB-444. Each Task Action Plan provides a description of the problem; the staff's approaches to its resolution; a general discussion of the bases upon which continued plant licensing or operation can proceed pending completion of the task; the technical organizations involved in the task and estimates of the manpower required; a description of the interactions with other NRC offices, the Advisory Committee on Reactor Safeguards and outside organizations; estimates of funding required for contractor supplied technical assistance; prospective dates for completing the task; and a description of potential problems that could alter the planned approach or schedule.

We have reviewed the 10 "Unresolved Safety Issues" listed above as they relate to North Anna Unit 2. Discussion of each of these issues including references to related discussions in the Safety Evaluation Report and its supplements are provided below in Section C-5. Based on our review of these items, we have concluded, for the reasons set forth in Section C-5, that there is reasonable assurance that North Anna Unit 2 can be operated prior to the ultimate resolution of these generic issues without endangering the health and safety of the public.

New "Unresolved Safety Issues"

No new issues have been identified in 1979 for reporting as "Unresolved Safety Issues." However, the NRC staff has not been able to perform an in-depth review to identify and evaluate new issues. NRC efforts have been concentrated on implementing new TMI-related requirements on operating plants and on identifying, defining, and scoping additional TMI-related issues and tasks. Several broad program areas where issues and tasks are being scoped will likely result in designation of new "Unresolved Safety Issues." These program areas include the following:

1. Man-machine interface and control-room design.
2. Qualification and training of operation, maintenance, and supervisory personnel.
3. Offsite emergency response, emergency planning, and action guidelines.
4. Siting policy, including compensatory design and operating provisions for plants in areas where evacuation would be difficult.
5. Systems reliability and interactions.
6. Consideration in licensing requirements of accidents involving degraded or melted fuel.

Nonetheless, the specific TMI-related requirements for licensing North Anna Unit 2 have been identified and are discussed in Part 2 of this supplement. Many of these are related to the program areas listed above. Long-term "Unresolved Safety Issue" tasks that may be undertaken in the same program areas could provide a basis for further improvements that may or may not be applicable to North Anna Unit 2.

The NRC staff also performed a cursory review of a number of candidate issues from sources other than Three Mile Island accident investigations, including a review of events reported as Abnormal Occurrences in 1979. Based on this cursory review, none were judged to be of such safety importance to require reporting to the Congress in the 1979 Annual Report as "Unresolved Safety Issues." An in-depth and systematic review of all candidate issues will be performed by the staff and the Commission in the first half of 1980. A special report will be provided to the Congress by July 1, 1980, describing the review and new issues designated as "Unresolved Safety Issues." Their applicability to all plants will be determined at that time.

Discussion of Tasks as they Relate to North Anna Unit 2A-1 Water Hammer

Water hammer events are intense pressure pulses in fluid systems caused by any one of a number of mechanisms and system conditions. Since 1971 there have been over

100 incidents involving water hammer in pressurized water reactors and boiling water reactors. The water hammers have involved steam generator feedings and piping, decay heat removal systems, emergency core cooling systems, containment spray lines, service water lines, feedwater lines and steam lines. However, the systems most frequently affected by water hammer effects are the feedwater systems. The most serious water hammer events have occurred in the steam generator feedings of pressurized water reactors. These types of water hammer events are addressed in our Safety Evaluation Report for North Anna Units 1 and 2 in Section 10.3. System design changes and testing requirements necessary to prevent this type of water hammer are discussed. In Section 10.3 of the Safety Evaluation Report and Amendment 4 to Operating License NPF-4 "North Anna Power Station Unit 1" we concluded that the preoperational test program performed on North Anna Unit 1 was acceptable, and the feedwater system and steam generator design for North Anna Units 1 and 2 with respect to this potential water hammer concern is acceptable. We will require that Unit 2 performs test to show that water hammers will not occur in the feedwater system. Accordingly, the Technical Specifications will reflect this requirement.

With regard to protection against other potential water hammer events currently provided in plants, piping design codes require consideration of impact loads. Approaches used at the design stage include: (1) increasing valve closure times, (2) piping layout to preclude water slugs in steam lines and vapor formation in water lines, (3) use of snubbers and pipe hangers, and (4) use of vents and drains. In addition, as described in Section 3.9.1 of the North Anna Power Station Units 1 and 2 Safety Evaluation Report, we require that the applicant conduct a preoperational vibration dynamic effects test program for all ASME Class 1, 2 and 3 piping systems and piping restraints during startup and initial operation. These tests will provide adequate assurance that the piping and piping restraints have been designed to withstand dynamic effects due to valve closures, pump trips, and other operating modes associated with the design operational transients.

Nonetheless, in the unlikely event that a large piping break did result from a severe water hammer event, core cooling is assured by the emergency core cooling systems described in Section 6.3 of the Safety Evaluation Report and its supplements, and protection against the dynamic effects of such pipe breaks inside and outside of containment is provided as described in Sections 3.6.1 and 3.6.2 of the Safety Evaluation Report.

Task A-1 may identify some potentially significant water hammer scenarios that have not explicitly been accounted for in the design and operation of nuclear power plants, including the North Anna unit. The task has not as yet identified the need for requiring any additional measures beyond those already required in the short term.

Based on the foregoing, we have concluded that North Anna Unit 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-2 Asymmetric Blowdown Loads on Primary Coolant Systems

In the very unlikely event of a rupture of the primary coolant piping in light water reactors, large nonuniformly distributed loads would be imposed upon the reactor vessel, reactor vessel internals, and other components in the reactor coolant system. The potential for such asymmetric loads, which result from the rapid depressurization of the reactor coolant system, was only recently identified and was not considered in the original design of some facilities. The forces associated with a postulated break in the reactor coolant piping near the reactor vessel, for example, could affect the integrity of the reactor vessel supports and reactor pressure vessel internals. A significant failure of the reactor vessel support system, besides impacting the reactor internals, has a potential for (1) damaging systems designed to cool the core following the postulated piping break, (2) affecting the capability of the control rods to function properly, (3) damaging other reactor coolant system components, and (4) causing other ruptures in the initially unbroken reactor coolant system piping loops and attached systems.

As indicated in Section 3 of the Task Action Plan for Task A-2 in NUREG-0660, we currently require that this issue be resolved prior to issuing an operating license. This issue has been acceptably resolved for the North Anna Unit 2 facility. Our evaluation and conclusions are provided in Sections 3.9.4 and 4.2.4 of the Safety Evaluation Report and in Sections 3.9.4 and 4.2.4 of Supplement No. 7 to the Safety Evaluation Report and in Sections 3.9.4 and 6.2.1 of this supplement. Accordingly, we have concluded that North Anna Unit 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-3 Westinghouse Steam Generator Tube Integrity

The primary concern is the capability of steam generator tubes to maintain their integrity during normal operation and postulated accident conditions. In addition, the requirements for increased steam generator tube inspections and repairs have resulted in significant increases in occupational exposures to workers. Corrosion resulting in steam generator tube wall thinning has been observed in several Westinghouse and Combustion Engineering plants for a number of years. Major changes in their secondary water treatment process essentially eliminated this form of degradation. Another major corrosion-related phenomenon has also been observed in a number of plants in recent years, resulting from a buildup of support plate corrosion products in the annulus between the tubes and the support plates. This buildup eventually causes a diametral reduction of the tubes, called "denting," and deformation of the tube support plates. This phenomenon has led to other problems, including stress corrosion cracking, leaks at the tube/support plate intersections, and U-bend section cracking of tubes which were highly stressed because of support plate deformation.

Specific measures such as a secondary water chemistry control and monitoring program that the applicant will employ to minimize the onset of steam generator tube problems are described in Section 5.2.7 of the North Anna Safety Evaluation Report and this supplement. In addition, Section 5.2.7 of the Safety Evaluation Report discusses provisions made by the applicant to detect such degradation. As described in these sections, the applicant has met all current requirements regarding steam generator tube integrity. The Technical Specifications will include requirements for actions to be taken in the event that steam generator tube leakage occurs during plant operation.

Task A-3 is expected to result in improvements in our current requirements for inservice inspection of steam generator tubes. These improvements will include a better statistical basis for inservice inspection program requirements and consideration of the cost/benefit of increased inspection. Pending completion of Task A-3, the measures taken at North Anna Unit 2 should minimize the steam generator tube problems encountered. Further the inservice inspection and Technical Specification requirements will assure that the applicant and the NRC staff are alerted to tube degradation should it occur. Appropriate actions such as tube plugging, increased and more frequent inspections and power derating could be taken if necessary. Since the improvements that will result from Task A-3 will be procedural, i.e., an improved inservice inspection program, they can be implemented by the applicant at North Anna Unit 2 after operation begins, if necessary.

Based on the foregoing, we have concluded that North Anna Unit 2 can be operated prior to ultimate resolution of this generic issue without undue risk to the health and safety of the public.

A-9 Anticipated Transients Without Scram (ATWS)

Nuclear plants have safety and control systems to limit the consequences of temporary abnormal operating conditions or "anticipated transients." Some deviations from normal operating conditions may be minor; others, occurring less frequently, may impose significant demands on plant equipment. In some anticipated transients, rapidly shutting down the nuclear reaction (initiating a "scram"), and thus rapidly reducing the generation of heat in the reactor core, is an important safety measure. If there were a potentially severe "anticipated transient" and the reactor shutdown system did not "scram" as desired, then an "anticipated transient without scram," or ATWS, would have occurred.

The anticipated transient without scram issue and the requirements that must be met by the applicant prior to operation of North Anna Unit 2 are discussed in Section 7.2.4 of this supplement. The requirements set forth are for the interim period pending completion of Task A-9 and implementation of additional requirements if found to be necessary.

The Virginia Electric and Power Company has submitted some proposed anticipated transient without scram procedures, which have been reviewed by the staff. The proposed procedures were not fully acceptable for full power operation, and are being modified by the Virginia Electric and Power Company. We have concluded that the plant may be safely operated at low power prior to completion of this effort, and that the Virginia Electric and Power Company can prepare adequate anticipated transient without scram procedures, in accordance with our guidance, prior to full power operation.

A-11 Reactor Vessel Materials Toughness

Resistance to brittle fracture, a rapidly propagating catastrophic failure mode for a component containing flaws, is described quantitatively by a material property generally denoted as "fracture toughness." Fracture toughness has different values and characteristics depending upon the material being considered. For steels used in nuclear reactor pressure vessels, three considerations are important. First, fracture toughness increases with increasing temperature. Second, fracture toughness decreases with increasing load rates. Third, fracture toughness decreases with neutron irradiation.

In recognition of these considerations, power reactors are operated within restrictions imposed by the Technical Specifications on the pressure during heatup and cooldown operations. These restrictions assure that the reactor vessel will not be subjected to that combination of pressure and temperature that could cause brittle fracture of the vessel if there were significant flaws in the vessel material. The effect of neutron radiation on the fracture toughness of the vessel material is accounted for in developing and revising these Technical Specification limitations over the life of the plant.

For the service times and operating conditions typical of current operating plants, reactor vessel fracture toughness for most plants provides adequate margins of safety against vessel failure under operating testing, maintenance, and anticipated transient conditions over the life of the plant. In addition, conservative analyses indicate that adequate safety margins are available during accident conditions until after many years of operation. However, results from a reactor vessel surveillance program and analyses performed using currently available methods indicate that the reactor vessels for up to 20 older operating pressurized water reactors and those for some more recent vintage plants will have marginal toughness after comparatively short periods of operation. The principal objective of Task A-11 is to develop an improved engineering method and safety criteria to allow a more precise assessment of the safety margins that are available during normal operation and transients in older reactor vessels with marginal fracture toughness and of the safety margins available during accident conditions for all plants.

Our evaluation of the reactor vessel materials fracture toughness and reactor vessel integrity requirements of Appendix G of 10 CFR Part 50 for North Anna

Unit 2 during normal operation, testing, maintenance, and anticipated transient conditions is described in Sections 5.2.3 and 5.3 of the Safety Evaluation Report and Section 5.2 of this supplement. In Section 5.2 of this supplement, we indicated that the applicant meets the fracture toughness requirements of Appendix G to 10 CFR Part 50 except that Paragraph IV.A.4 of Appendix G has not been met by the Unit 2 reactor vessel. This paragraph relates to the vessel bolting requirements. As stated in Section 5.2 of this supplement, we indicated that based on information provided by the applicant, we conclude that the exemption for this area of noncompliance to Appendix G of 10 CFR Part 50 is justified.

Results from analyses performed by PWR reactor manufacturers indicate that the integrity of some reactor vessels may not be maintained in the event that a main steam line break or a loss-of-coolant accident occurs after approximately 20 years of operation. For most plants now undergoing licensing review, materials currently used for vessel fabrication will likely maintain acceptable fracture resistance over the design life of the plant. However, some PWRs in the later stages of licensing have the potential after many years of operation to have marginal fracture toughness for these postulated accident conditions. When Task A-11 is completed and explicit fracture evaluation criteria for accident conditions are defined, all vessels will be reevaluated for acceptability over their design lives. Since Task A-11 is projected to be completed many years before North Anna Unit 2 could have advance of a vessel reaching marginal fracture resistance for the postulated accident conditions, acceptable vessel integrity will be assured until the vessel is reevaluated for long-term acceptability. Accordingly, based on the foregoing, we have concluded that North Anna Unit 2 can be operated prior to resolution of this generic issue without undue risk to the health and safety of the public.

A-17 Systems Interactions in Nuclear Power Plants

The licensing requirements and procedures used in our safety review address many different types of systems interactions. Current licensing requirements are founded on the principle of defense-in-depth. Adherence to this principle results in requirements such as physical separation and independence of redundant safety systems, and protection against events such as high energy line ruptures, missiles, high winds, flooding, seismic events, fires, operator errors, and sabotage. These design provisions supplemented by the current review procedures of the Standard Review Plan (NUREG-75/087) which require interdisciplinary reviews and which account, to a large extent, for review of potential systems interactions, provide for an adequately safe situation with respect to such interactions. The quality assurance program which is followed during the design, construction, and operational phases for each plant is expected to provide added assurance against the potential for adverse systems interactions.

In November 1974, the Advisory Committee on Reactor Safeguards requested that the NRC staff give attention to the evaluation of safety systems from a multi-

disciplinary point of view, in order to identify potentially undesirable interactions between plant systems. The concern arises because the design and analysis of systems is frequently assigned to teams with functional engineering specialties-- such as civil, electrical, mechanical, or nuclear. The question is whether the work of these functional specialists is sufficiently integrated in their design and analysis activities to enable them to identify adverse interactions between and among systems. Such adverse events might occur, for example, because designers did not assure that redundancy and independence of safety systems were provided under all conditions of operation required, which might happen if the functional teams were not adequately coordinated. Simply stated, the left hand may not know or understand what the right hand is doing in all cases where it is necessary for the hands to be coordinated.

In mid-1977, Task A-17 was initiated to confirm that present review procedures and safety criteria provide an acceptable level of redundancy and independence for systems required for safety by evaluating the potential for undesirable interactions between and among systems.

The NRC staff's current review procedures assign primary responsibility for review of various technical areas and safety systems to specific organizational units and assign secondary responsibility to other units where there is a functional or interdisciplinary relationship. Designers follow somewhat similar procedures and provide for interdisciplinary reviews and analyses of systems. Task A-17 will provide an independent investigation of safety functions--and systems required to perform these functions--in order to assess the adequacy of current review procedures. This investigation is being conducted by Sandia Laboratories under contract assistance to the NRC staff.

The contract effort, Phase I of the task, began in May 1978 and is nearing completion. The Phase I investigation is structured to identify areas where interactions are possible between and among systems and have the potential of negating or seriously degrading the performance of safety functions. The investigation will then identify where NRC review procedures may not have properly accounted for these interactions. Preliminary results of the Phase I contracted effort indicate that, within the limitations of the study, there are only a few areas where the review procedures are weak from a systems interaction standpoint. These results are being finalized by the contractor and the staff is considering whether, and if so what changes in the Standard Review Plan are needed. Finally, a follow-on Phase II of the task will be scoped based on the results of Phase I and the status and scope of other related NRC activities.

The NRC staff believes that its review procedures and acceptance criteria currently provide reasonable assurance that an acceptable level of system redundancy and independence is provided in plant designs. Although some changes to the review procedures will likely result, the preliminary results of the Phase I effort appear to confirm this belief. Therefore, we conclude that there is reasonable assurance that North Anna Unit 2 can be operated prior to the ultimate resolution of this generic issue without endangering the health and safety of the public.

A-36 Control of Heavy Loads Near Spent Fuel

Overhead cranes are used to lift heavy objects, sometimes in the vicinity of spent fuel, in both pressurized water reactors and boiling water reactors. If a heavy object, such as a spent fuel shipping cask or shielding block, were to fall or tip onto spent fuel in the storage pool or in the reactor core during refueling and damage the fuel, there could be a release of radioactivity to the environment and a potential for radiation overexposures to in-plant personnel. If the dropped object is large, and is assumed to drop on fuel containing a large amount of fission products with minimal decay time, calculated offsite doses could exceed the siting guideline values in 10 CFR Part 100.

The applicant has complied with our requirements for the safe handling of fuel and spent fuel casks as discussed in Section 9.1 of the North Anna Safety Evaluation Report, in Section 9.1 of Supplement No. 8 to the Safety Evaluation Report, and in our Safety Evaluation dated January 29, 1978 regarding the North Anna expanded spent fuel pool. In addition, the Technical Specifications will include a prohibition on the movement of loads over spent fuel in the storage pool that weigh more than the equivalent weight of a fuel assembly. These measures provide reasonable assurance that the likelihood of a load handling accident damaging enough spent fuel to cause unacceptable consequences is small for North Anna Unit 2.

Task A-36 may result in additional requirements applicable to North Anna Unit 2 to further reduce the likelihood of such accidents. These additional requirements are expected to be procedural and therefore can be implemented at North Anna Unit 2 after operation begins if found to be desirable.

In the interim period, the current design, administrative and procedural measures are acceptable as indicated above. Accordingly, we have concluded that there is reasonable assurance that North Anna Unit 2 can be operated prior to the ultimate resolution of this generic issue without endangering the health and safety of the public.

A-40 Seismic Design Criteria - Short-Term Program

NRC regulations require that nuclear power plant structures, systems and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes. Detailed requirements and guidance regarding the seismic design of nuclear plants are provided in the NRC regulations and in Regulatory Guides issued by the Commission. However, there are a number of plants with construction permits and operating licenses issued before the NRC's current regulations and regulatory guidance were in place. For this reason, rereviews of the seismic design of various plants are being undertaken to assure that these plants do not present an undue risk to the public. Task A-40 is, in effect, a compendium of short-term efforts to support such reevaluation efforts of the NRC staff,

especially those related to older operating plants. In addition, some revisions to Standard Review Plan sections and Regulatory Guides to bring them more in line with the state-of-the-art will result.

As discussed in Sections 2.5 and 3.7 of the Safety Evaluation Report and its supplements, the seismic design bases and seismic design of North Anna Unit 2 have been evaluated at the operating license stage and have been found acceptable. In addition as discussed in Section 18.2.5 of Supplement No. 7 to the Safety Evaluation Report, the Advisory Committee on Reactor Safeguards recommended that the staff assure itself that significant seismic design margins exist in all systems required to accomplish safe shutdown. We are presently conducting a seismic review program for North Anna Units 1 and 2. We stated in Section 18.2.5 that although we have concluded that the seismic design of North Anna Units 1 and 2 is acceptable, we will assure that additional safety margins exist as recommended by the ACRS. The results of Task A-40 will not affect these conclusions. Accordingly, we have concluded that North Anna Unit 2 can be operated prior to ultimate resolution of this generic issue without endangering the health and safety of the public.

A-43 Containment Emergency Sump Reliability

Following a postulated loss-of-coolant accident, i.e., a break in the reactor coolant system piping, the water flowing from the break would be collected in the emergency sump at the low point in the containment. This water would be recirculated through the reactor system by the emergency core cooling pumps to maintain core cooling. This water would also be circulated through the containment spray system to remove heat and fission products from the containment. Loss of the ability to draw water from the emergency sump could disable the emergency core cooling and containment spray systems. The consequences of the resulting inability to cool the reactor core or the containment atmosphere could be melting of the core and/or loss of containment integrity.

One postulated means of losing the ability to draw water from the emergency sump could be blockage by debris. A principal source of such debris could be the thermal insulation on the reactor coolant system piping. In the event of a piping break, the subsequent violent release of the high pressure water in the reactor coolant system could rip off the insulation in the area of the break. This debris could then be swept into the sump, potentially causing blockage.

Currently, regulatory positions regarding sump design are presented in Regulatory Guide 1.82, "Sumps for Emergency Core Cooling and Containment Spray Systems," which address debris (insulation). The Regulatory Guide recommends, in addition to providing redundant separated sumps, that two protective screens be provided. A low approach velocity in the vicinity of the sump is required to allow insulation to settle out before reaching the sump screening; and it is required that the sump remain functional assuming that one-half of the screen surface area is blocked.

A second postulated means of losing the ability to draw water from the emergency sump could be abnormal conditions in the sump or at the pump inlet such as air entrainment, vortices, or excessive pressure drops. These conditions could result in pump cavitation, reduced flow and possible damage to the pumps.

Currently, regulatory positions regarding sump testing are contained in Regulatory Guide 1.79, "Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors," which addresses the testing of the recirculation function. Both in-plant and scale model tests have been performed by applicants to demonstrate that circulation through the sump can be reliably accomplished.

As indicated in Section 6.3.4 of Supplement No. 8 to the Safety Evaluation Report, the applicant has performed out-of-plant scale model tests of the North Anna Unit 2 containment sump design. The test identified the need for several design modifications that were subsequently incorporated into the plant design. We concluded that the applicant had demonstrated that there was reasonable assurance that the sump design would perform as expected following a loss-of-coolant accident and therefore was acceptable.

Task A-43 is principally concerned with the adequacy of emergency sump performance for plants licensed to operate before current design and testing requirements were imposed. The results of Task A-43 are not expected to alter our conclusions for the North Anna Unit 2 sump. Accordingly, we have concluded that the North Anna Unit 2 can be operated prior to ultimate resolution of this generic issue without endangering the health and safety of the public.

A-44 Station Blackout

Electrical power for safety systems at nuclear power plants must be supplied by at least two redundant and independent divisions. The systems used to remove decay heat to cool the reactor core following a reactor shutdown are included among the safety systems that must meet these requirements. Each electrical division for safety systems includes an offsite alternating current (ac) power connection, a standby emergency diesel generator ac power supply, and direct current (dc) sources.

Task A-44 involves a study of whether or not nuclear power plants should be designed to accommodate a complete loss of all ac power, i.e., a loss of both the offsite and the emergency diesel generator ac power supplies. A loss of all ac for an extended period of time in pressurized water reactors accompanied by loss of the auxiliary feedwater pumps (usually one of two redundant pumps is a steam turbine driven pump that is not dependent on ac power for actuation or operation) could result in an inability to cool the reactor core, with potentially serious consequences. This particular accident sequence was a significant contributor to the overall risk associated with the PWR analyzed in the Reactor Safety Study

(WASH-1400). The steam turbine driven auxiliary feedwater pump for the PWR analyzed in WASH-1400 had no ac dependencies. If the auxiliary feedwater pumps are dependent on ac power to function, then a loss of all ac power could of itself result in an inability to cool the reactor core and, accordingly, this event sequence would be expected to be more important to the overall risk posed by the facility.

A loss of all ac power was not a design basis event for North Anna Unit 2. Nonetheless, the combination of design, operation, and testing requirements that have been imposed on the applicant will assure that these units will have substantial resistance to a loss of all ac and that even if a loss of all ac should occur there is reasonable assurance that the core will be cooled. These are discussed below.

A loss of offsite ac power involves a loss of both the preferred and backup sources of offsite power. Our review and basis for acceptance of the design, inspection, and testing provisions for the offsite power system are described in Section 2 of the North Anna Units 1 and 2 Safety Evaluation Report. In addition, the applicant conducted a grid stability analysis. Our review of this analysis is also described in Section 8.2.

If offsite ac power is lost, two independent and redundant onsite diesel generators and their associated distribution systems will deliver emergency power to safety-related equipment. Our review of the design, testing, surveillance, and maintenance provisions for North Anna Unit 2 onsite emergency diesels is described in Section 8.3.1 of the Safety Evaluation Report. Our requirements include preoperational testing to assure the reliability of the installed diesel generators in accordance with the provisions of Regulatory Guide 1.108. In addition, as discussed in Section 8.3.2 of this supplement, the applicant has to provide information regarding enhancement of diesel generator reliability to better assure the long-term reliability of the diesel generators.

Even if both offsite and onsite ac power are lost, cooling water can still be provided to the steam generators by the auxiliary feedwater system by employing a steam turbine driven pump that does not rely on ac power for operation. Our review of the auxiliary feedwater system design and operation is described in Section 10.4 of the North Anna Unit 2 Safety Evaluation Report. Additional actions by the NRC staff and the applicant to improve the reliability of the auxiliary feedwater systems for North Anna Unit 2 are described in Part II of this supplement in Section II.K.3.

In addition, we are requiring the applicant to perform analyses of accidents and transients and to develop operating guidelines, operating procedures, and conduct operator training based on these analyses as described in this supplement in Section I.C.1. These requirements will include consideration of loss of all ac

power. With regard to testing, the applicant has included a simulated loss of all ac power in its low power test program as described in Section I.G.

Based on the foregoing, we have concluded that there is reasonable assurance that North Anna Unit 2 can be operated prior to the ultimate resolution of this generic issue without endangering the health and safety of the public.

NORTH ANNA POWER STATION, UNIT 2

SAFETY EVALUATION REPORT

PART II

TMI-2 ISSUES RELATED TO FUEL LOAD AND

LOW POWER TEST PROGRAM

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PART II

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PART II

Introduction

The TMI-2-related requirements for near-term operating license (NTOL) applications were initially identified in the January 5, 1980 memorandum from the Executive Director of Operations to the Commissioners, "TMI Action Plan Prerequisites for Resumption of Licensing." On February 6, 1980, a revision of this list of requirements based on the latest draft of the Task Action Plans as of February 6, 1980 was prepared and discussed with the Commission. These requirements were listed in two categories; those required prior to fuel load and low power testing operation up to five-percent power (designated as FL) and those required prior to operation above five-percent power (designated as FP).

This supplement addresses only those TMI-2-related requirements in the February 6, 1980 list of NTOL requirements as required prior to fuel load, identified therein as FL.

These requirements were developed from all available sources such as the recommendations of the Bulletins and Orders Task Force, the Presidential Commission to Investigate TMI-2, and the NRC Special Inquiry Group, and those which resulted from the Lessons Learned Task Force Short Term Recommendations (NUREG-0578), and the Lessons Learned Task Force Final Report (NUREG-0585).

Those requirements of the February 6, 1980 list which resulted from the Lessons Learned Task Force Short Term Recommendations (NUREG-0578) and those resulting from the Advisory Committee on Reactor Safeguards (ACRS) review of that document and the additional requirements of the Director, Office of Nuclear Reactor Regulation were previously approved by the Commission. On September 27, 1979, a letter was issued transmitting these requirements to all pending operating license applicants. On November 9, 1979, a letter clarifying these requirements was issued to all pending operating license applicants to assist in their understanding of our requirements.

The response of the Virginia Electric and Power Company (Veeco) to our letters has been the subject of staff review since October 1979. Meetings were held with the Virginia Electric and Power Company in Bethesda on November 20, November 30, 1979 and February 26, 1980. Site visits were made on December 19 and 20, 1979 and February 14, 1980 to check hardware installation, review proposed support centers, and to review specific administrative procedures relating to operating personnel and accident response.

In addition, to meet the remaining items of the February 6, 1980 listing of requirements, the staff and the Virginia Electric and Power Company have had ongoing reviews and meetings concerning these requirements and the Virginia Electric and Power Company's responses to these additional items. Further site visits were held, for example, the February 20-22, 1980 visit by a team headed by an Office of Inspection and Enforcement leader and composed of the NRR licensing project manager, the Office of Inspection and Enforcement site representative, and technical members from NRR. They evaluated the onsite and offsite support centers and their staffing and the installed communications system between the plant and NRC Incident Response Center. This evaluation included the review of licensee management organization and managerial capabilities.

Each applicable FL requirement of the February 6, 1980 listing is discussed below and follows the numbering sequence utilized therein. The Table of Contents of Part II of this supplement consists of that action plan listing. Those requirements arising from the previously approved NUREG-0578 are identified by appropriate reference. The discussion of these items includes sections titled Position and Clarification which are repeated from the generic letters to operating license applicants as discussed above.

i OPERATIONAL SAFETY

I.A.1 Operating Personnel and Staffing

I.A.1.1 Shift Technical Advisor (2.2.1.b - NUREG-0578)

POSITION

Each licensee shall provide an on-shift technical advisor to the shift supervisor. The shift technical advisor (STA) may serve more than one unit at a multi-unit site if qualified to perform the advisor function for the various units.

The shift technical advisor shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The shift technical advisor shall also receive training in plant design and layout, including the capabilities of instrumentation and controls in the control room. The licensee shall assign normal duties to the Shift Technical Advisors that pertain to the engineering aspects of assuring safe operation of the plant, including the review and evaluation of operating experience.

CLARIFICATION

1. Due to the similarity in the requirements for dedication to safety, training and onsite location and the desire that the accident assessment function be performed by someone whose normal duties involve review of operating experiences, our preferred position is that the same people perform the accident and operating experience assessment functions. The performance of these two functions may be split if it can be demonstrated the persons assigned the accident assessment role are aware, on a current basis, of the work being done by those reviewing operating experience.
2. To provide assurance that the STA will be dedicated to concern for the safety of the plant, our position has been that STA's must have a clear measure of independence from duties associated with the commercial operation of the plant. This would minimize possible distractions from safety judgments by the demands of commercial operations. We have determined that, while desirable, independence from the operations staff of the plant is not necessary to provide

this assurance. It is necessary, however, to clearly emphasize the dedication to safety associated with the STA position both in the STA job description and in the personnel filling this position. It is not acceptable to assign a person, who is normally the immediate supervisor of the shift supervisor, to STA duties as defined herein.

3. It is our position that the STA should be available within 10 minutes of being summoned and therefore should be onsite. The onsite STA may be in a duty status for periods of time longer than one shift, and therefore asleep at some times, if the ten minute availability is assured. It is preferable to locate those doing the operating experience assessment onsite. The desired exposure to the operating plant and contact with the STA (if these functions are to be split) may be able to be accomplished by a group, normally stationed offsite, with frequent onsite presence. We do not intend, at this time, to specify or advocate a minimum time onsite.
4. The implementation schedule for the STA requirements is to have the STA on duty by January 1, 1980, and to have STAs, who have all completed training requirements, on duty by January 1, 1981. While minimum training requirements have not been specified for January 1, 1980, the STAs on duty by that time should enhance the accident and operating experience assessment function at the plant.

DISCUSSION AND CONCLUSIONS

Veeco has committed to provide an onshift technical advisor (STA). Veeco intends to meet this commitment by increasing shift staffing to include an additional licensed Senior Reactor Operator (SRO) or an experienced engineer who is a member of the site Safety Engineering Staff. This additional staffing began on January 1, 1980. During 1980 a portion of the station SRO's will begin an advanced training program to qualify them as shift technical advisors. During 1980, at least one SRO or engineer who is participating in this training program will be on each shift and will be designated as the shift technical advisor. In the event of an accident the STA will be dedicated to assessing plant conditions and advising the shift supervisor.

Veeco's ultimate goal is to provide training to Safety Engineering Staff engineers so that all STA's will be members of the Safety Engineering Staff.

All STA's must be fully trained by January 1, 1981. Vepco has put together training programs to meet this requirement. During 1980, all SRO's designated as STA's will complete eight weeks of mathematics, physics, thermodynamics, fluid flow, heat transfer, instrumentation and control, chemistry, materials and structural analysis. Following this, the STA's will receive two weeks of design review and five weeks of systems dynamic behaviour including transient analysis and techniques for transient identification. The training program for engineers designated as STA's will consist of 3 portions: academic training in thermodynamics, fluid flow, heat transfer and reactor theory; specific instruction in plant systems and Technical Specifications; and finally simulator training. The specifics of this training program are under development by Vepco and will be submitted for our review. Vepco has committed to provide requalification training for the STA's on an annual basis.

The STA is responsible for providing technical and operational advice in such areas as accident assessment, plant response, thermodynamics, heat transfer and fluid mechanics to the Shift Supervisor and/or Assistant Shift Supervisor during normal or emergency conditions. During normal operations, the STA is also responsible for assessment of plant operations, evaluation of operating procedures, conducting shift safety meetings, maintaining shift operator qualification and training, disseminating plant operating experiences to the shift, maintaining shift timekeeping records, and other shift administrative responsibilities.

Vepco has designated a Safety Engineering Staff onsite whose primary responsibility would be to perform the operating experience assessment function. The STA's will interface with this staff and provide a conduit for transferring operating experience to the operating shifts.

Organizationally, the SRO/STA reports to the Operations Supervisor however, on a routine shift basis he is under the functional supervision of the Shift Supervisor, as are all other persons on shift. To ensure that the STA will not be called upon to use his SRO license, ADM-1.0, "Station Organization and Responsibility," states, "The Shift Technical Advisor shall not assume command or control function nor function as the Shift Supervisor or Assistant Shift Supervisor." The engineer/STA reports through the Safety Engineering Staff to the Superintendent-Technical Services.

Based on our review of the material sub-itted, we have concluded that Vepco has met this requirement. Qualified STA's will serve on shift to perform an accident assessment role. In addition, they will provide a communication link between the shift and the individual(s) performing the operating experience assessment function. The STA's will undergo annual requalification training.

I.A.1.2 Shift Supervisor Duties (2.2.1.a - NUREG-0578)

POSITION

1. The highest level of corporate management of each licensee shall issue and periodically reissue a management directive that emphasizes the primary management responsibility of the shift supervisor for safe operation of the plant under all conditions on his shift and that clearly establishes his command duties.
2. Plant procedures shall be reviewed to assure that the duties, responsibilities, and authority of the shift supervisor and control room operators are properly defined to effect the establishment of a definite line of command and clear delineation of the command decision authority of the shift supervisor in the control room relative to other plant management personnel. Particular emphasis shall be placed on the following:
 - a. The responsibility and authority of the shift supervisor shall be to maintain the broadest perspective of operational conditions affecting the safety of the plant as a matter of highest priority at all times when on duty in the control room. The principle shall be reinforced that the shift supervisor should not become totally involved in any single operation in times of emergency when multiple operations are required in the control room.
 - b. The shift supervisor, until properly relieved, shall remain in the control room at all times during accident situations to direct the activities of control room operators. Persons authorized to relieve the shift supervisor shall be specified.
 - c. If the shift supervisor is temporarily absent from the control room during routine operations, a lead control room operator shall be designated to assume the control room command function. These temporary duties, responsibilities, and authority shall be clearly specified.
3. Training programs for shift supervisors shall emphasize and reinforce the responsibility for safe operation and the management function the shift supervisor is to provide for assuring safety.

4. The administrative duties of the shift supervisor shall be reviewed by the senior officer of each utility responsible for plant operations. Administrative functions that detract from or are subordinate to the management responsibility for assuring the safe operation of the plant shall be delegated to other operations personnel not on duty in the control room.

DISCUSSION AND CONCLUSIONS

Veeco has issued a management directive which emphasizes the assignment of primary management responsibility to the shift supervisor. The directive is signed by the Vice-President-Power Supply and Production Operations. Veeco states that the directive will be reissued on an annual basis.

Administrative Procedure ADM-1.0, "Station Organization and Responsibility" has been revised to further clarify the responsibility of the shift supervisor. This procedure delineates the command decision authority of the shift supervisor in the control room relative to other plant management personnel or onshift operations personnel. It also delineates the responsibilities of the control room operators. Both the above referenced management directive and ADM-1.0 require the shift supervisor to maintain, as a matter of highest priority, the broadest perspective of operational conditions affecting the safety of the facility. He shall not become totally involved in any single operation when multiple operations are taking place.

The shift supervisor shall remain in the control room at all times when either unit is operating in Mode 1, 2, 3 or 4, except that he may be allowed to be absent provided an individual, other than the shift technical advisor, who possesses a valid SRO license assumes the control room command function during his absence. The individual who assumes the control room command function must remain in the control room until the shift supervisor returns and reassumes the command function.

Normally, the assistant shift supervisor will assume the command function in the event the shift supervisor is absent.

The shift supervisor may only be relieved by an individual who possesses a valid SRO license. Individuals who do not possess a valid SRO license, including members of station management, may not relieve the shift supervisor, nor may they direct the licensed activities of licensed operators.

Veeco has developed a SRO Supervisory Skill training program for shift supervisors which emphasizes the responsibilities for safe operations and the management function the shift supervisor is to provide. In keeping with the clarification provided by the staff, the training program emphasizes such supervisory skills as 1) leadership; 2) interpersonal communication; 3) command responsibilities and limits; 4) motivation of personnel; 5) problem analysis; and 6) decisional analysis.

The Director of Nuclear Operations has fully participated in the review and revision of administrative procedures with specific emphasis on the delegation of miscellaneous duties to personnel other than the shift supervisor.

Veeco has met the requirements of Section 2.2.1.a of NUREG-0578. Procedures have been revised to establish the authority of the shift supervisor and delineate a clear line of succession. Administrative duties have been reviewed and, where not safety related, reassigned to other personnel. A training program emphasizing the shift supervisor's management function has been established. Control room operator responsibilities have been defined. (See Item I.C.3.)

I.A.1.3 Shift Manning

POSITION

Assure that the necessary number and availability of personnel to man the operations shifts have been designated by the licensee. Administrative procedures should be written to govern the movement of key individuals about the plant to assure that qualified individuals are readily available in the event of an abnormal or emergency situation. This should consider the recommendations on overtime in NUREG-0578. Provisions should be made for an aide to the shift supervisor to assure that, over the long term, the shift supervisor is free of routine administrative duties.

DISCUSSION AND CONCLUSION

The Virginia Electric and Power Company's shift crew composition for the operation of North Anna, Units 1 and 2 will include at least two senior licensed operators, three licensed operators, three unlicensed operators and one health physics technician. This requirement will provide the following coverage. Each unit will be supervised by a shift supervisor who is a licensed SRO on that unit, or may be a single individual if he is licensed on both units. The second senior operator licensed for each unit must be stationed in the control room area at all times when the unit is in operating modes 1 through 4; this also could be a single individual if he is appropriately licensed. In addition, a reactor operator licensed for each unit must be at the controls of that unit at all times when fuel is in the reactor. Also, a relief reactor operator licensed for each unit must be available on-shift. This could be a single individual if he is licensed for both units.

In addition, during fuel loading operations an additional licensed senior operator will be present to direct those operations.

The staff's requirement for overtime restrictions is implemented through Vepco North Anna Administrative Procedure 3.0. These restrictions include:

1. An individual should not be permitted to work more than 12 hours straight (not including shift turnover time).

2. There should be at least a 12-hour break between all work periods (shift turnover time is included in this 12-hour break).
3. An individual should not work more than 72-hours in any 7-day period.
4. An individual should not work more than 14 consecutive days without have 2 consecutive days off.

Based on the foregoing, we have concluded that the necessary number and availability of personnel to man the operating shifts will be required of the Virginia Electric and Power Company and the limitations on overtime are in place.

I.A.3.1 Revised Scope and Criteria for Licensing Examinations

Refer to Part I, Section 13.2, Training Program, for a discussion of this item.

I.B.1 Management for Operations

I.B.1.1 Organization and Management Criteria

POSITION

Corporate management of the utility-owner of a nuclear power plant shall be sufficiently involved in the operational phase activities, including plant modifications, to assure a continual understanding of plant conditions and safety considerations. Corporate management shall establish safety standards for the operation and maintenance of the nuclear power plant. To these ends, each utility-owner shall establish an organization, parts of which shall be located onsite, to: perform independent review and audits of plant activities; provide technical support to the plant staff for maintenance, modifications, operational problems, and operational analysis, and aid in the establishment of programmatic requirements for plant activities.

The licensee shall establish an integrated organizational arrangement to provide for the overall management of nuclear power plant operations. This organization shall provide for clear management control and effective lines of authority and communication between the organizational units involved in the management, technical support, and operation of the nuclear unit.

The key characteristics of a typical organization arrangement are:

Integration of all necessary functional responsibilities under a single responsible head.

The assignment of responsibility for the safe operation of the nuclear power plant(s) to an upper level executive position.

DISCUSSION AND CONCLUSIONS

On February 20 through 22, 1980, a Joint NRC team representing the Office of Nuclear Reactor Regulation and the Office of Inspection and Enforcement performed a management review of the Virginia Electric and Power Company organization for the purpose of reviewing the Virginia Electric and Power Company management organization in regards to its capability to operate the North Anna, Unit 2 Nuclear Power Station.

During the team review, we found that in the present management organization, the two top corporate officials dealing with plant operation did not have nuclear plant operations experience or formal training in nuclear engineering. The Virginia Electric and Power Company staff management currently is simultaneously responsible for fossil and nuclear operations.

However, we were presented a management reorganization plan which will take effect April 1, 1980 which will split fossil and nuclear responsibilities. The management responsible for nuclear in this new organization will have nuclear plant operations experience. Even the newly hired Executive Vice-President has hands-on experience in nuclear plant operations.

This new organization should satisfy our newly drafted criteria for both organization and personnel qualifications. This new organization will have an onsite safety assessment staff, as described in I.B.1.2. They will also have a corporate staff, to coordinate the various onsite groups from both their nuclear stations.

We also reviewed the function and operation of the current Technical Specification Offsite Safety Review Committee. Their members had no nuclear plant operations experience, and we found that their function added little to enhance the safe operation of the nuclear plants, although they do meet the requirements of the Technical Specifications. Vepco has submitted a Technical Specification change to North Anna Unit 1 operating license involving Section 6.0 - Administrative Controls. This change formalizes the new Vepco corporate and plant staff organizations as they were described in draft during our recent team inspection visit and, as such, this change is applicable to the Unit 2 license. This new organization divides the fossil and nuclear power organizations into separate groups, each with their own operations and technical staffs. This new organization places people with nuclear operations and technical training in line management. The organizational responsibility and managerial qualifications follow those outlined in the staff's draft criteria for utility management and Technical competence. And, as such, we find this new organization acceptable for an operating license.

With respect to offsite technical support to the plant staff, in the event of an emergency, support may be provided by corporate office personnel. We required that the applicant establish plans for the use of these personnel in the event they are needed. These procedures

have been recently submitted for our review. We have reviewed the procedures and have determined that the procedures are acceptable for operation at power levels not exceeding five percent.

With respect to the plant staff organization, the organization is as shown in Section 13.1 of the Final Safety Analysis Report. The shift supervisors, who are in charge of the facility during their shift, report to the operating supervisor. At the time of our audit of the Vepco organization we were advised that the operating supervisor did not hold a senior operator's license for Unit 2, nor would he have one at the time of projected fuel load for Unit 2. We required and the applicant has amended his plant staff organization such that in respect to Unit 2, the shift supervisor will report to an individual holding a senior operator's license on Unit 2. Accordingly, the Technical Specifications will reflect this requirement.

I.B.1.2 Safety Engineering Group and Onsite Evaluation Capability

POSITION

Utility management shall establish a group, independent of the plant staff, but assigned onsite, to perform independent reviews of plant operational activities.

The main functions of this group will be to evaluate the technical adequacy of all procedures and changes important to safe operation of the facility, and an evaluation and assessment of the plants' operating experience and performance.

DISCUSSION AND CONCLUSION

The applicant originally committed to having two people onsite, prior to fuel loading, in the Safety Engineering Staff (SES) to provide an independent check that the plant facilities are maintained and operated in a safe manner. The plant SES will be independent of the plant staff similar to that of the QA organization by being technically responsible to offsite management. The plant SES will combine the review functions of engineering assessment, evaluation and dissemination of plant operating experience, and the functions of the STA's. This group will consist of seven engineers, four of whom will be designated as STA's. The group will functionally report to the Superintendent of Technical Support and technically offsite to the Director, Safety Evaluation and Control.

During routine Monday through Friday day shift, it is expected that the onsite staffing would be composed of either four or five engineers (the STA's will all have both college degrees and plant experience).

The technical disciplines represented in the group are electrical, operations, mechanical, radiation protection and nuclear.

We find that this onsite safety engineer's group will satisfy our requirements for a safety engineering group and the onsite evaluation and dissemination of operating experience. As such, this group satisfies our requirement for issuance of an operating license.

Vepco also will institute a system level SES in the home office to provide a centralized review of industry operating experience applicability to Vepco's nuclear units. The systems level SES will also provide assistance to the station SES where expertise is required. It is Vepco's intention that the systems SES will eventually replace the function of the current System Nuclear Safety and Operating Committee which is detailed in the Technical Specifications.

Although the staff does not require this additional engineering group, Veeco has proposed this additional home office engineering group. We believe that this is a useful addition to its management organization.

I.B.1.4 Licensee Onsite Operating Experience Evaluation Capability

See Sections I.A.1.1 and I.B.1.2 of Part II of this report.

I.B.2.2 Resident NRC Inspector

POSITION

1. The Office of Inspection and Enforcement (IE) will implement the approved resident inspector program by recruiting, training, and assigning the resident inspectors to provide a minimum of two resident inspectors at each site where there are one or two reactors.
2. IE will place a senior resident inspector at near-term operating plants by June 1980.

DISCUSSION AND CONCLUSION

An NRC inspector with several years of nuclear plant operation and inspection experience was transferred to the North Anna Power Station as a resident inspector in July 1978. In December 1979 a second inspector, also possessing several years experience, was assigned as resident inspector. This inspector, currently in training, previously held a senior reactor operator license on an operating pressurized water reactor. At the time of his assignment, the previously assigned inspector assumed the duties of senior resident inspector.

Due to normal career progression, the current senior resident inspector will transfer to another IE office in April 1980 and will be replaced with another qualified inspector.

Placement of NRC resident inspectors at this facility has been accomplished.

I.C Procedures

I.C.1 Short-Term Effort

Analysis and Procedure Modification (2.1.9 - NUREG-0578)

POSITION

Analyses, procedures, and training addressing the following are required:

1. Small break loss-of-coolant accidents;
2. Inadequate core cooling; and
3. Transients and accidents.

Some analysis requirements for small breaks have already been specified by the Bulletins and Order Task Force. These should be completed. In addition, pretest calculations of some of the Loss of Fluid Test (LOFT) small break tests (scheduled to start in September 1979) shall be performed as means to verify the analyses performed in support of the small break emergency procedures and in support of an eventual long term verification of compliance with Appendix K of 10 CFR Part 50.

In the analysis of inadequate core cooling, the following conditions shall be analyzed using realistic (best-estimate) methods:

1. Low reactor coolant system inventory (two examples will be required - loss-of-coolant accident (LOCA) with forced flow, LOCA without forced flow).
2. Loss of natural circulation (due to loss of heat sink).

These calculations shall include the period of time during which inadequate core cooling is approached as well as the period of time during which inadequate core cooling exists. The calculations shall be carried out in real time far enough that all important phenomena and instrument indications are included. Each case should then be repeated taking credit for correct operator action. These additional cases will provide the basis for developing appropriate emergency procedures. These calculations should also provide the analytical basis for the design of any additional instrumentation needed to provide operators with an unambiguous indication of vessel water level and core cooling adequacy (see Section 2.1.3.b of NUREG-0578).

The analyses of transients and accidents shall include the design basis events specified in Section 15 of each Final Safety Analysis Report (FSAR). The analyses shall include a single active failure for each system called upon to function for a particular event. Consequential failures shall also be considered. Failures of the operators to perform required control manipulations shall be given consideration for permutations of the analyses. Operator actions that could cause the complete loss of function of a safety system shall also be considered. At present, these analyses need not address passive failures or multiple system failures in the short term. In the recent analysis of small break LOCAs, complete loss of auxiliary feedwater was considered. The complete loss of auxiliary feedwater may be added to the failures being considered in the analysis of transients and accidents if it is concluded that more is needed in operator training beyond the short-term actions to upgrade auxiliary feedwater system reliability. Similarly, in the long term, multiple failures and passive failures may be considered depending in part on staff review of the results of the short-term analyses.

The transient and accident analyses shall include event tree analyses, which are supplemented by computer calculations for those cases in which the system response to operator actions is unclear or these calculations could be used to provide important quantitative information not available from an event tree. For example, failure to initiate high-pressure injection could lead to core uncover for some transients, and a computer calculation could provide information on the amount of time available for corrective action. Reactor simulators may provide some information in defining the event trees and would be useful in studying the information available to the operators. The transient and accident analyses are to be performed for the purpose of identifying appropriate and inappropriate operator actions relating to important safety considerations such as natural circulation, prevention of core uncover, and prevention of more serious accidents.

The information derived from the preceding analyses shall be included in the plant emergency procedures and operator training. It is expected that analyses performed by the nuclear steam supply system (NSSS) vendors will be put in the form of emergency procedure guidelines and that the changes in the procedures will be implemented by each licensee or applicant.

In addition to the analyses performed by the reactor vendors, analyses of selected transients should be performed by the NRC Office of Research, using the best available computer codes, to provide the basis for comparisons with the analytical methods being used by the reactor vendors. These comparisons together with comparisons to data, including LOFT small break test data, will constitute the short-term verification effort to assure the adequacy of the analytical methods being used to generate emergency procedures.

DISCUSSION AND CONCLUSIONS

This item requires analysis, procedure guidelines, emergency procedures, and operator training related to small break loss-of-coolant accidents, inadequate core cooling, and transients and non-LOCA accidents.

Westinghouse submitted analyses for small break accidents in Topic Report WCAP-9600 "Report on Small Break Accidents for Westinghouse NSSS System"; June 1979. Emergency procedure guidelines were then developed from these analyses by the Westinghouse Plant Owners Group. These guidelines were reviewed and approved by the staff in November 1979. The staff review of these analyses and guidelines was performed by the Bulletin and Orders Task Force as is documented in their report on Westinghouse reactors, "Generic Evaluation of Feedwater Transients and Small Break Loss-of-Coolant Accidents in Westinghouse-Designed Operating Plants", NUREG-0611, January 1980 (Appendix IX, section 2.2). We have reviewed the design features of the North Anna, Unit 2 plant and we conclude that the review and approval of the small break LOCA analyses and guidelines apply in total to the North Anna, Unit 2 plant.

I&E has reviewed the small break LOCA emergency procedures for North Anna 1 and 2 and is requiring changes for the operating unit (North Anna, Unit 1). Vepco uses identical procedures for both units. NRR has identified several areas in which improvements should be made in these procedures and we will review and resolve any concerns with the upgraded procedures prior to low power testing. This is not a requirement for zero power operation.

Westinghouse submitted analyses of inadequate core cooling on October 30, 1979, "Analysis of Inadequate Core Cooling and Emergency Core Cooling Guidelines to Restore Core Cooling". The staff review of these analyses and guidelines has not been completed. Instructions on steps to be taken to restore adequate core cooling, if it should be lost during

natural circulation, have been included in the North Anna, Unit 2 emergency procedure for "Loss of Reactor Coolant Accident" (2-EP-2). The previously mentioned NRR and I&E reviews of the emergency procedure identified several areas related to inadequate core cooling which require improvement. We require that questions relating to the inadequate core cooling guidelines and procedures be resolved to the staff's satisfaction prior to low power testing. This is not a requirement for zero power operation.

The third part of this item relates to analysis, procedure guidelines, emergency procedures, and operator training for transients and accidents. The applicant has committed to providing all of the required items but has stated that it may not be possible to meet the schedule required for operating reactors, that is, analyses and guideline development due by March 31, 1980 and emergency procedures and operator training by June 30, 1980. We are continuing to discourage any delays in the established schedule. Completion of this work is not required for the low power test program.

I.C.2 Shift and Relief Turnover Procedures (2.2.1.C - NUREG-0578)

POSITION

The licensee shall review and revise as necessary the plant procedure for shift and relief turnover to assure the following:

1. A checklist shall be provided for the oncoming and offgoing control room operators and the oncoming shift supervisor to complete and sign. The following items, as a minimum, shall be included in the checklist.
 - a. Assurance that critical plant parameters are within allowable limits (parameters and allowable limits shall be listed on the checklist).
 - b. Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transients and accidents by a check of the control console. What to check and criteria for acceptable status shall be included on the checklist.
 - c. Identification systems and components that are in a degraded mode of operation permitted by the Technical Specifications. For such systems and components, the length of time in the degraded mode shall be compared with the Technical Specifications action statement (this shall be recorded as a separate entry on the checklist).
2. Checklists or logs shall be provided for completion by the offgoing and ongoing auxiliary operators and technicians. Such checklists or logs shall include any equipment under maintenance or test that by itself could degrade a system critical to the prevention and mitigation of operational transients and accidents or initiate an operational transient (what to check and criteria for acceptable status shall be included on the checklist); and
3. A system shall be established to evaluate the effectiveness of the shift and relief turnover procedure (for example, periodic independent verification of system alignments).

DISCUSSION AND CONCLUSIONS

Veeco has developed a shift relief turnover procedure, ADM-29.3, "Conduct of Operations", that will provide assurance that the oncoming shift possesses adequate knowledge of critical plant status information and system availability. Among other things, this procedure requires that a checklist shall be completed by and signed by offgoing and oncoming control room operators and shift supervisors. It further requires that other operators transfer the required information through the use of logbooks and status boards.

The Veeco Quality Assurance Department's coverage of shift relief and conduct is documented as a part of the surveillance and inspection of safety-related activities program. A pre-printed inspection report is used and is scheduled on a monthly basis.

We have reviewed the administrative procedure revised to implement this requirement and the checklist to be filled out by offgoing and oncoming control room operators. We conclude that an adequate exchange of information will take place during shift turnover. We also conclude that an adequate surveillance program exists to provide assurance that the effectiveness of the turnover procedure will be routinely evaluated.

I.C.3 Shift Personnel Responsibilities (2.2.1.a - NUREG-0578)

This item is included with I.A.1.2 Shift Supervisor Duties.

I.C.4 Control Room Access (2.2.2.a - NUREG-0578)

POSITION

The licensee shall make provisions for limiting access to the control room to those individuals responsible for the direct operation of the nuclear power plant (e.g., operations supervisor, shift supervisor, and control room operators), to technical advisors who may be requested or required to support the operation, and the predesignated NRC personnel. Provisions shall include the following:

1. Develop and implement an administrative procedure that establishes the authority and responsibility of the person in charge of the control room to limit access, and
2. Develop and implement procedures that establish a clear line of authority and responsibility in the control room in the event of an emergency. The line of succession for the person in charge of the control room shall be established and limited to persons possessing a current senior reactor operator's license. The plan shall clearly define the lines of communication and authority for plant management personnel not in direct command of operations, including those who report to stations outside of the control room.

DISCUSSION AND CONCLUSIONS

Vepco has developed an administrative procedure, ADM-6.0 "Control Room Access", that establishes specific individual authority and responsibility related to controlling personnel access during normal and accident conditions. During normal operations, individuals shall enter the control room only when specific duties require such entry. The on-duty shift supervisor has complete authority to control access to the control room during normal operations.

During emergency conditions access to the control room is limited to those individuals responsible for the direct operation of the facility, to technical advisors required to support operation, to NRC resident inspectors and to other personnel specifically requested by the shift supervisor. As soon as an emergency condition arises, the on-duty shift supervisor will direct all personnel not allowed control room access during an emergency to leave the control room. In an emergency condition, a member of the security department will assist the shift

supervisor in controlling access to the control room. He will insure that only authorized persons are in the control room and that not more than 15 persons are in the control room at any time.

Oncoming operating shift personnel reporting to the station during an emergency condition will report to the Onsite Operations Support Center, notify the shift supervisor of their presence, and await further instructions.

Although not specifically stated in ADM-6.0, the line of succession for the shift supervisors has been established. ADM-1.0, "Station Organization and Responsibility", states that the shift supervisor may be relieved by an individual who possesses a valid SRO license. Individuals who do not possess a valid SRO license, including members of station management, may not relieve the shift supervisor, nor may they direct the licensed activities of licensed operators.

EPIP-1, "Emergency Classification and Organization Formation, Notification and Communications", has been revised to clearly delineate the lines of authority and communications between the control room and various onsite and offsite support centers.

We have reviewed the applicable procedures revised to implement this staff position. We conclude that Vepco has met this requirement.

I.C.5 Licensee Dissemination of Operating Experiences

See Sections I.A.1.1 and I.B.1.2 of Part II of this report.

I.C.7 NSSS Vendor Review of Low Power Test Procedures

The applicant's low power test procedures are currently under review by the NSSS Vendor, Westinghouse. This review will be completed and documented prior to startup of the low power test program.

I.G Training During Low Power Testing

Introduction

In a letter dated December 3, 1979 to Joseph Hendrie (NRC), S. David Freeman, Chairman of the Board of TVA, proposed "pursuing certain limited activities in the case of those power plants where construction has been completed during the Commission's pause..." One of the activities proposed was a series of natural circulation tests to be performed at Unit 1 of the Sequoyah Nuclear plant at power levels up to five percent of normal full power. By letter to Steven Varga (NRC) dated December 5, 1979, Mr. C. M. Stallings of Virginia Electric and Power Company (Vepco) endorsed the idea of performing similar tests on North Anna 2. The proposed test program was further described in letters of February 8, 1980 and March 19, 1980 from Mr. Stallings to Mr. Varga.

The proposed low power test program for Vepco was reviewed by the staff using the following five criteria:

1. The tests should provide meaningful technical information beyond that obtained in the normal startup test program.
2. The tests should provide supplemental operator training.
3. The tests should not pose an undue risk to the public.
4. The risk of damage to the nuclear plant during the test program should be low.
5. The radiation levels that will exist after the low power test program is completed (including that from crud deposits) must not preclude implementation of requirements stemming from the NRR Lessons Learned Task Force, Kemeny Commission, Rogovin Commission or Task Action Plan.

The low power test program proposed by Vepco consists of nine tests, eight of which involve natural circulation in the reactor coolant system at low power conditions, but at normal, or nearly normal, operating pressures and temperatures. The test program is nearly identical to the program that had been proposed to be performed on Sequoyah 1 and reviewed by the NRC staff.

The specific tests proposed are:

1. Natural circulation test;
2. Natural circulation with simulated loss of offsite ac power;
3. Natural circulation with loss of pressurizer heaters;
4. Effect of secondary side isolation on natural circulation;
5. Natural circulation at reduced pressure;
6. Cooldown capability of the charging and letdown system;
7. Simulated loss of all onsite and offsite ac power;
8. Establishment of natural circulation from stagnant conditions; and
9. Forced circulation cooldown (part A) and boron mixing and cooldown (part B).

The tests will not necessarily be performed in this order. In general the test program will progress from relatively simple tests to those that are more complex. Members of the NRC staff will observe the performance of selected tests.

STAFF EVALUATION

The staff is in the process of evaluating the low power test program proposed by Vepco. The criteria listed above are being used as the basis of the evaluation. The status of the staff's review is described below for each of the criteria.

A. CRITERION 1

Criterion 1 states that the tests should provide meaningful technical information beyond that obtained during the normal test program. By meaningful we mean information that adds to the understanding of the capabilities of a plant to remove heat from the reactor either by natural convection circulation of reactor coolant

or by other heat transfer mechanisms considered in the analyses of small loss-of-coolant accidents. Although natural circulation tests have been performed on many reactors, they have not been done under degraded plant conditions, such as loss of electrical power or isolation of the secondary side of a steam generator.

The staff has reviewed each of the tests proposed by Vepco relative to Criterion 1. We have concluded that the test program will provide meaningful technical information.

The earlier tests in the series are only expected to confirm that natural circulation can be obtained, and to develop the techniques needed to simulate decay heat using fission heat. As the program proceeds to the more complex tests, meaningful information is expected to be obtained. This is especially true for the test in which loss of all alternating current electric power, both onsite and offsite, is simulated. This test is expected to demonstrate a design capability that has never previously been experimentally confirmed in a commercial nuclear power plant. (A similar test is planned to be performed on Sequoyah 1.) Other tests that are expected to provide significant technical information are those that demonstrate that natural circulation can be established from stagnant conditions and that determine the degree of boron mixing that can be obtained under natural circulation conditions.

It should be noted that all of the natural circulation tests proposed by Vepco will be single phase, liquid tests. That is, the tests will be initiated and conducted with the reactor coolant subcooled. Thus, the tests will not be representative of the two-phase conditions that might exist following an accident. Vepco opposes two-phase testing because they believe that the potential risk of damage to the plant outweighs the benefits to be gained. Despite the lack of two-phase tests in the proposed test program, the staff concludes that the test program will provide meaningful information and is expected to confirm the ability of the plant to perform as designed in areas that have not been previously demonstrated in commercial, light-water nuclear power plants.

B. CRITERION 2

Criterion 2 states that the tests should provide supplemental operator training. In regard to the training objectives of the

test program, Vepco plans to conduct a sufficient number of repetitions of tests one through six so that each licensed operator will participate in at least one test and observe two others. Tests seven through nine will run several times so that each operating crew will have an opportunity to gain "hands-on" experience for each of these tests. Some of the training that will be obtained during low power testing could also be provided by simulator training. However, simulator training is generally limited to operations that take place in the control room. The performance of the test program will aid in the check-out of procedures for those operations conducted outside the control room, and provide training in those operations. Therefore, the staff concludes that the proposed test program will provide valuable training not otherwise available for the North Anna operating crews.

As noted above, all of the natural circulation tests proposed to be performed on North Anna, Unit 2 will be single phase liquid tests. Unless the licensed operators are given additional training, they could be misled into believing that the single-phase natural circulation conditions they experience in performing the test program would be representative of the two-phase conditions they may encounter following an accident. Thus, in addition to the operational training to be gained by the tests, we require that the North Anna operations staff receive additional simulator and classroom training, dealing with two-phase flow phenomena that may occur following an accident.

C. CRITERION 3

Criterion 3 requires that the tests should not pose an undue risk to the public. Vepco has not submitted, for staff review, the safety analyses that demonstrate that Criterion 3 will be satisfied. Vepco intends to submit these analyses at least 4 weeks prior to the scheduled start of the low power test program. Since the proposed test program will be performed at power levels of 5 percent or less, the decay heat in the event of a reactor trip or an accident will be about comparable to heat losses at normal reactor coolant system (RCS) operating temperature. Therefore, we do not anticipate that the safety analysis to be prepared by Vepco will uncover any significant safety problems. However, review of these safety analyses by the staff along with the supporting safety evaluation report, will be required prior to beginning the test program.

We will require that Vepco prepare, and submit for staff review, any special procedures required for the low power test program. These special procedures should clearly define any special technical specifications needed to perform each test, including any changes to the safety system setpoints. The staff review of the special test procedures will concentrate on the overall approach proposed by Vepco, not the details of valve lineup and the designation of instruments to be used to record data.

Vepco has stated that overall administrative control of the low power test program will be accomplished by modification of their existing Startup Test procedures. When modified, this document should serve as a lead or master document, outlining the entire test program and defining the sequence in which the individual tests will be performed. For each individual test, the master document should specify which conditions should be established or maintained, and what orders or instructions apply during the period the test is being performed, including the applicable emergency procedures if limits are exceeded. At the conclusion of each individual test, the master document should specify that normal technical specifications and licensed plant conditions, including safety system settings, apply. The master document should also specify that the normal plant administrative procedures will be followed when tests are being conducted so there will be no doubt that the licensed senior operator has the authority and responsibility to direct the licensed operators in accordance with 10 CFR 55.4(e).

Also, Vepco should thoroughly review the special test procedure and test exemptions relative to the normal operating procedures and technical specifications to assure that there are no ambiguities that will arise during testing.

D. CRITERION 4

Criterion 4 states that the risk of damage to the nuclear power plant during the test program should be low. In this regard, Vepco has not proposed any tests that it feels represent more than a minimal risk to Unit 1 of the North Anna plant. The staff concurs in this matter. This is the major reason it has not proposed any natural circulation tests involving two-phase conditions.

E. CRITERION 5

Criterion 5 states that the radiation levels that will exist after the low power test program is completed (including that from crud deposits) must not preclude implementation of requirements stemming from the TMI-2 accident. Vepco has evaluated the expected radiation levels following the completion of the low power test program. They have stated that they do not foresee that the radiation levels created by the low power testing will prevent implementation of any requirements for physical alterations dictated by the Lessons Learned Task Force, Kemeny Commission, Rogovin Commission, or Task Action Plan as presently understood. The radiation exposure from these tests will not preclude any currently identified changes, additions, or deletions from the plant.

ADDITIONAL TESTS

The staff has requested that Vepco also obtain some baseline data regarding differential pressure across the elbow pressure taps in each reactor coolant loop for various pump combinations. Vepco has agreed to perform such tests.

These tests will be conducted with the core installed, but all control rod assemblies inserted. The reactor coolant system will be at about normal operating temperature and pressure. The tests will be performed with one pump and two pumps operating. The differential pressure data will be obtained in all three loops; that is, the loops with flow in the normal direction and the loops having flow in the reverse direction. Pump data such as motor current will also be recorded.

The purpose of the tests is to provide baseline data for an undamaged core. In the event that there is an accident sometime in the future involving core damage, similar data could be obtained and compared to the baseline data to infer the extent of the core damage.

II SITING AND DESIGN

II.B.4 Degraded Core - Training

POSITION

The staff requires that the applicant develop a program to ensure that all operating personnel are training in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged. The training program shall include the following topics.

A. Incore Instrumentation

1. Use of fixed or movable incore detectors to determine extent of core damage and geometry changes.
2. Use of thermocouples in determining peak temperatures; methods for extended range readings; methods for direct readings at terminal junctions.

B. Excore Nuclear Instrumentation (NIS)

1. Use of NIS for determination of void formation; void location basis for NIS response as a function of core temperatures and density changes.

C. Vital Instrumentation

1. Instrumentation response in an accident environment; failure sequence (time to failure, method of failure); indication reliability (actual vs indicated level).
2. Alternative methods for measuring flows, pressures, levels, and temperatures.
 - a. Determination of pressurizer level if all level transmitters fail.
 - b. Determination of letdown flow with a clogged filter (low flow).

- c. Determination of other Reactor Coolant System parameters if the primary method of measurement has failed.

D. Primary Chemistry

1. Expected chemistry results with severe core damage; consequences of transferring small quantities of liquid outside containment; importance of using leak tight systems.
2. Expected isotopic breakdown for core damage; for clad damage.
3. Corrosion effects of extended immersion in primary water; time to failure.

E. Radiation Monitoring

1. Response of Process and Area Monitors to severe damages; behavior of detectors when saturated; method for detecting radiation readings by direct measurement at detector output (overanged detector); expected accuracy of detectors at different locations; use of detectors to determine extent of core damage.
2. Methods of determining dose rate inside containment from measurements taken outside containment.

F. Gas Generation

1. Methods of H₂ generation during an accident; other sources of gas (Xe, Kr); techniques for venting or disposal of non-condensibles.
2. H₂ flammability and explosive limit; sources of O₂ in containment or Reactor Coolant System.

DISCUSSION AND CONCLUSIONS

We recently transmitted to the applicant our requirements regarding training to control or mitigate an accident in which the core is severely damaged. In a letter dated March 12, 1980, the applicant

has stated that he is developing such a program to meet our criteria. Therefore, we consider this matter resolved for the low power testing program. The applicant further states that all licensed North Anna, Unit 2 operators will receive initial training before operation at full power.

II.D.2 Relief and Safety Valve Test (2.1.2 - NUREG-0578)

POSITION

Pressurized water reactor and boiling water reactor licensees and applicants shall conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

CLARIFICATION

1. Expected operating conditions can be determined through the use of analysis of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70.
2. This testing is intended to demonstrate valve operability under various flow conditions, that is, the ability of the valve to open and shut under the various flow conditions should be demonstrated.
3. Not all valves on all plants are required to be tested. The valve testing may be conducted on a prototypical basis.
4. The effect of piping on valve operability should be included in the test conditions. Not every piping configuration is required to be tested, but the configurations that are tested should produce the appropriate feedback effects as seen by the relief or safety valve.
5. Test data should include data that would permit an evaluation of discharge piping and supports if those components are not tested directly.
6. A description of the test program and the schedule for testing should be submitted by January 1, 1980.
7. Testing shall be complete by July 1, 1981.

DISCUSSION AND CONCLUSIONS

We require that the Virginia Electric and Power Company carry out a testing program to qualify the relief and safety valves under expected

operating conditions for design basis transients and accidents as provided in NUREG-0578, Section 2.1.2, and as clarified in NRC letter to operating license applicants dated November 9, 1979. Accordingly, the low power operating license will be conditioned.

The Virginia Electric and Power Company has stated that they are actively pursuing a joint effort with other members of the utility industry which will develop requirements for a generic test facility and program for RCS relief and safety valve prototypical testing. This involves subscription to and participation in a program developed and managed by the Electric Power Research Institute (EPRI). The initial result of that joint industry effort (i.e., the EPRI "Program Plan for the Performance Verification of PWR Safety/Relief Valves and Systems") was presented to and discussed with representatives of the NRC staff at a meeting with EPRI personnel on December 17, 1979.

The staff will perform a detailed review of the generic program proposed by EPRI. On the basis of our preliminary discussions to date with EPRI regarding the feasibility of meeting the clarified valve testing requirements of NUREG-0578 (including discussions at the December 17 meeting), and on the basis of Vepco's assurance that the proposed EPRI program will be applicable to the North Anna design and consistent with the NRC position in this regard, we believe that there is adequate assurance at this point that the NUREG-0578 requirement regarding performance verification of RCS relief and safety valves will be met satisfactorily for the North Anna 2 unit. We conclude that, pending satisfactory results from the ongoing test program, this requirement places no restrictions on North Anna 2 operation through full power.

In establishing these test requirements as part of NUREG-0578, the staff concluded that the extended time for completion of the qualification testing was appropriate since this testing is considered to be confirmatory in nature.

II.D.5 Relief and Safety Valve Position (2.1.3.a - NUREG-0578)

POSITION

Reactor system relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve position detection device or a reliable indication of flow in the discharge pipe.

CLARIFICATION

1. The basic requirement is to provide the operator with unambiguous indication of valve position (open or closed) so that appropriate operator actions can be taken.
2. The valve position should be indicated in the control room. An alarm should be provided in conjunction with this indication.
3. The valve position indication should be safety grade. If the position indication is not safety-grade, a reliable single channel direct indication powered from a vital instrument bus may be provided if backup methods of determining valve position are available and are discussed in the emergency procedures as an aid to operator diagnosis and action.
4. The valve position indication should be seismically qualified consistent with the component or system to which it is attached. If the seismic qualification requirements cannot be met feasibly by January 1, 1980, a justification should be provided for less than seismic qualification and a schedule should be submitted for upgrade to the required seismic qualification.
5. The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift). If the environmental qualification program for this position indication will not be completed by January 1, 1980, a proposed schedule for completion of the environment qualification program should be provided.

DISCUSSION AND CONCLUSIONS

Two power-operated relief valves (PORV) and three safety valves, connected to the top of the pressurizer are provided in the North Anna 2 design to protect against overpressurization. Positive indication of PORV position is obtained by a direct, stem-mounted indicator which mechanically activates limit switches at the fully-open and fully-closed valve stem positions (single channel for each PORV). Vepco has installed an accelerometer similar to those employed in the noise monitoring system on the discharge piping of each safety valve (also a single channel for each valve) and in the discharge piping of each PORV. All valve positions are indicated in the main control room; and VEPco has stated that these valve position indication systems will be qualified seismically and environmentally by the vendor in a program to be established early in 1980. Vepco has also indicated that an alarm in the main control room will indicate when any valve is not in the fully-closed position.

The described design incorporates only a single channel of positive position indication for each safety valve. In accordance with the NRC position and clarification, therefore, Vepco has described backup methods of determining valve positions; these include temperature sensors downstream of each valve, pressurizer relief tank temperature/pressure/level indicators and pressurizer high pressure sensors, already installed and all indicated and alarmed in the main control room. These methods have been incorporated into the plant operating procedures.

Vepco has provided procedures for the calibration of the acoustic monitors which establish alarm set points based on the vendor's experience. The IE inspector will verify that the procedures have been utilized to calibrate the acoustic monitors. The verification should be done prior to the low power test program. Field experience may require future adjustments in calibration set points.

On the basis of Vepco's submittals to NRC describing these new systems, discussions with Vepco engineering and operating staff representatives, and an inspection tour of the North Anna facility, the Vepco approach to providing positive pressurizer relief and safety valve position indication, by use of direct stem-mounted devices on the PORVs and by use of accelerometers at the discharge of each safety valve and PORV is acceptable.

II.E.1.2 Auxiliary Feedwater Initiation and Indication

Auxiliary Feedwater Initiation (2.1.7.a - NUREG-0578)

POSITION

Consistent with satisfying the requirements of General Design Criterion 20 of Appendix A to 10 CFR Part 50 with respect to the timely initiation of the auxiliary feedwater system, the following requirements shall be implemented in the short term:

1. The design shall provide for the automatic initiation of the auxiliary feedwater system.
2. The automatic initiation signals and circuits shall be designed so that a single failure will not result in the loss of auxiliary feedwater system function.
3. Testability of the initiating signals and circuits shall be a feature of the design.
4. The initiating signals and circuits shall be powered from the emergency buses.
5. Manual capability to initiate the auxiliary feedwater system from the control room shall be retained and shall be implemented so that a single failure in the manual circuits will not result in the loss of system function.
6. The a-c motor driven pumps and valves in the auxiliary feedwater system shall be included in the automatic actuation (simultaneous and/or sequential) of the loads onto the emergency buses.
7. The automatic initiating signals and circuits shall be designed so that their failure will not result in the loss of manual capability to initiate the AFWs from the control room.

In the long term, the automatic initiation signals and circuits shall be upgraded in accordance with safety-grade requirements.

CLARIFICATION

Control Grade (Short-Term)

1. Provide automatic/manual initiation of AFWS.
2. Testability of the initiating signals and circuits is required.
3. Initiating signals and circuits shall be powered from the emergency buses.
4. Necessary pumps and valves shall be included in the automatic sequence of the loads to the emergency buses. Verify that the addition of these loads does not compromise the emergency diesel generating capacity.
5. Failure in the automatic circuits shall not result in the loss of manual capability to initiate the AFWS from the control room.
6. Other Considerations
 - a. For those designs where instrument air is needed for operation, the electric power supply requirement should be capable of being manually connected to emergency power sources.

DISCUSSION AND CONCLUSIONS

The auxiliary feedwater system (AFW) for North Anna was designed as a safety-related system, aside and apart from any TMI-related requirements imposed subsequently by NRC. Consistent with that design intent, and as described in Vepco's submittals to NRC and in discussions with Vepco personnel in connection with this NUREG-0578 position, the AFW initiating circuitry for North Anna Unit 2 incorporates both automatic and manual system start capability, including manual initiation of the system from the main control room. Manual initiation capability is provided independent of automatic initiation, and the design of the automatic initiation circuitry is such that a single-failure cannot result in total loss of the AFW system function. Further, the North Anna 2 design incorporates on-line testability, and the system is powered from reliable emergency buses as specified in NUREG-0578 (including automatic actuation of a-c motor driven pumps and valve loads onto the emergency buses).

The North Anna Unit 2 AFW initiation circuitry design meets NUREG-0578 requirements.

Auxiliary Feedwater Indication (2.1.7.b - NUREG-0578)

POSITION

Consistent with satisfying the requirements set forth in General Design Criterion 13 to provide the capability in the control room to ascertain the actual performance of the AFW when it is called to perform its intended function, the following requirements shall be implemented:

1. Safety-grade indication of auxiliary feedwater flow to each steam generator shall be provided in the control room.
2. The auxiliary feedwater flow instrument channels shall be powered from the emergency buses consistent with satisfying the emergency power diversity requirements of the auxiliary feedwater system set forth in Auxiliary Systems Branch Technical Position 10-1 of the Standard Review Plan, Section 10.4.9.

CLARIFICATION

A. Control Grade (Short-Term)

1. Auxiliary feedwater flow indication to each steam generator shall satisfy the single failure criterion.
2. Testability of the auxiliary feedwater flow indication channels shall be a feature of the design.
3. Auxiliary feedwater flow instrument channels shall be powered from the vital instrument buses.

B. Safety-Grade (Long-Term)

1. Auxiliary feedwater flow indication to each steam generator shall satisfy safety-grade requirements.

C. Other

1. For the short-term the flow indication channels should by themselves satisfy the single failure criterion for each steam generator. As a fall-back position, one auxiliary feedwater flow channel may be backed up by a steam generator level channel.
2. Each auxiliary feedwater channel should provide an indication of feed flow with an accuracy on the order of ± 10 percent.

DISCUSSION AND CONCLUSIONS

Auxiliary feedwater flow indication for North Anna Unit 2 is provided by a single flow indicating element (channel) in the individual AFW feed lines to each of the three steam generators. These flow channels are powered from the vital buses (battery-backed).

Veeco has noted that the direct flow indication arrangement provided is backed by safety grade steam generator water level indication. Taken together then, the combined (direct and indirect) AFW flow indication capability does satisfy the single failure criterion. Further, the direct flow indication channels provide indication with an accuracy of approximately ± 10 percent; and testability of all channels is a feature of design. The flow indication and water level instrument power supplies for a steam generator are fed by separate vital buses.

The direct AFW flow indication arrangements provided for the North Anna 2 unit satisfy the "control grade" requirements specified in the NUREG-0578 position and clarifications and therefore, are acceptable.

II.E.4.1 Containment Penetrations

(2.1.5.a - NUREG-0578)

POSITION

Plants using external recombiners or purge systems for post-accident combustible gas control of the containment atmosphere should provide containment isolation systems for external recombiner or purge systems that are dedicated to that service only, that satisfy the redundancy and single failure requirements of General Design Criterion 54 and 56 of Appendix A to 10 CFR Part 50, and that are sized to satisfy the flow requirements of the recombiner or purge system.

CLARIFICATION

1. This requirement is only applicable to those plants whose licensing basis includes requirements for external recombiners or purge systems for post-accident combustible gas control of the containment atmosphere.
2. An acceptable alternative to the dedicated penetration is a combined design that is single-failure proof for containment isolation purposes and single-failure proof for operation of the recombiner or purge system.
3. The dedicated penetration or the combined single-failure proof alternative should be sized such that the flow requirements for the use of the recombiner or purge system are satisfied.
4. Components necessitated by this requirement should be safety grade.
5. A description of required design changes and a schedule for accomplishing these changes should be provided by January 1, 1980. Design changes should be completed by January 1, 1981.

DISCUSSION AND CONCLUSIONS

The North Anna, Unit 2 design uses external hydrogen recombiners. The hydrogen recombiner line takes suction from the same penetration used for the suction of the containment vacuum pumps, the hydrogen

purge lines and the hydrogen analyzer. Each of these lines has the suction intake downstream of two containment isolation valves located outside of containment. Since radioactive gases could be flowing through these pipes during the post-accident mode, these systems become extensions of containment. Therefore, we have required that adequate provisions be installed for containment isolation.

The applicant has committed to install redundant, remote-manual actuated valves in series to isolate the containment vacuum pumps from the combustible gas control system. This provides a single failure proof design to isolate the containment vacuum pumps thus dedicating the penetration to the combustible gas control system.

The backup hydrogen purge system is presently isolated from the hydrogen analyzers and recombiners by an administratively locked closed valve. This system is not operated during normal plant operations. Its use would only be contemplated if both hydrogen recombiners fail. The applicant has been required to evaluate the radiological consequences to personnel manually opening this valve with a substantial radiation source in the containment building. If the analysis shows that remote manual operators are necessary to actuate this valve the staff will require redundant valves in series receiving diverse power supplies so that a spurious electrical signal could not open the recombiner system to the plant's vent stack.

The applicant has committed to convert the manual valves in the hydrogen recombiner piping to remote manual actuation. This is in response to evaluating the personnel exposures that might occur if these valves required manual opening.

The applicant is also evaluating the radiological consequences to personnel opening the administratively locked closed valves of the hydrogen analyzers. This evaluation may conclude that these valves should be administratively locked open. Since these valves are located downstream of the redundant containment isolation valves and the hydrogen analyzer piping constitutes a closed system outside of containment, we find opening these valves acceptable.

The discharge line from the hydrogen recombiner shares the same penetration with the discharge line from the hydrogen analyzer. Containment isolation is provided by a check valve inside containment and a remote manual valve outside containment. The combined hydrogen

recombiner suction and discharge line is sized such that the flow requirements for the use of the combustible gas control system are satisfied. The applicant has committed to complete all plant modifications by January 1, 1981.

The applicant has committed to comply with recommendation 2.1.5.a. The conceptual design and implementation schedule satisfy our requirements for this item. Therefore, we conclude that the applicant's response to date concerning this item is acceptable, and that it is in compliance with the staff's requirements.

Containment Penetrations

(2.1.5.c - NUREG-0578)

POSITION

1. All licensees of light water reactor plants shall have the capability to obtain and install recombiners in their plants within a few days following an accident if containment access is impaired and if such a system is needed for long-term post-accident combustible gas control.
2. The procedures and bases upon which the recombiners would be used on all plants should be the subject of a review by the licensees in considering shielding requirements and personnel exposure limitations as demonstrated to be necessary in the case of TMI-2.

CLARIFICATION

1. This requirement applied only to those plants that included Hydrogen Recombiners as a design basis for licensing.
2. The shielding and associated personnel exposure limitations associated with recombiner use should be evaluated as part of licensee response to requirement 2.1.6.b, "Design Review for Plant Shielding."
3. Each licensee should review and upgrade, as necessary, those criteria and procedures dealing with recombiner use. Action taken on this requirement should be submitted by January 1, 1980.

DISCUSSION AND CONCLUSIONS

There are two external recombiners at the North Anna Power Station, Units 1 and 2. Each recombiner system is capable of serving either unit. As discussed in Section 2.1.5.a, remote manual actions are required of the operator to isolate the containment vacuum pumps and align the hydrogen recombiners. As also discussed in Section 2.1.5.a, manual action may be necessary to align the hydrogen analyzer and hydrogen purge system. However, if manual actions are required, sufficient physical separation exists between the Units 1 and 2 piping systems to preclude improper alignment of the valves.

The applicant has committed to comply with recommendation 2.1.5.c. The conceptual design and implementation schedule satisfy the requirements for this item. Therefore, we conclude that the applicant's response on this item is acceptable.

II.F.1 Additional Accident Monitoring Instrumentation (2.1.8.b - NUREG-0578)

POSITION

The requirements associated with this recommendation should be considered as advanced implementation of certain requirements to be included in a revision to Regulatory Guide 1.97, "Instrumentation to Follow the Course of an Accident," which has already been initiated, and in other Regulatory Guides, which will be promulgated in the near-term.

1. Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions; multiple monitors are considered to be necessary to cover the ranges of interest.
 - a. Noble gas effluent monitors with an upper range capacity of 10^5 $\mu\text{Ci/cc}$ (Xe-133) are considered to be practical and should be installed in all operating plants.
 - b. Noble gas effluent monitoring shall be provided for the total range of concentration extending from normal condition (ALARA) concentrations to a maximum of 10^5 $\mu\text{Ci/cc}$ (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of 10.
2. Since iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.
3. In-containment radiation level monitors with a maximum range of 10^8 rad/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be designed and qualified to function in an accident environment.

CLARIFICATION

The January 1, 1980 requirements were specifically added by the Commission and were not included in NUREG-0578. The purpose of the

interim January 1, 1980 requirement is to assure that licensees have methods of quantifying radioactivity releases should the existing effluent instrumentation go off-scale.

1. Radiological Noble Gas Effluent Monitors

A. January 1, 1980 Requirements

Until final implementation in January 1, 1981, all operating reactors must provide, by January 1, 1980, an interim method for quantifying high-level releases which meets the requirements of Table 2.1.8.b.1. This method is to serve only as a provisional fix with the more detailed, exact methods to follow. Methods are to be developed to quantify release rates of up to 10,000 Ci/sec for noble gases from all potential release points (e.g., auxiliary building, radwaste building, fuel handling building, reactor building, waste gas decay tank releases, main condenser air ejector, BWR main condenser vacuum pump exhaust, PWR steam safety valves and atmosphere steam dump valves and BWR turbine buildings) and any other areas that communicate directly with systems which may contain primary coolant or containment gases (e.g., letdown and emergency core cooling systems and external recombiners). Measurements/analysis capabilities of the effluents at the final release point (e.g., stack) should be such that measurements of individual sources which contribute to a common release point may not be necessary. For assessing radioiodine and particulate releases, special procedures must be developed for the removal and analysis of the radioiodine/particulate sampling media (i.e., charcoal canister/filter paper). Existing sampling locations are expected to be adequate; however, special procedures for retrieval and analysis of the sampling media under accident conditions (e.g., high air and surface contamination and direct radiation levels) are needed.

It is intended that the monitoring capabilities called for in the interim can be accomplished with existing instrumentation or readily available instrumentation. For noble gases, modifications to existing monitoring systems, such as the use of portable high-range survey instruments, set in shielded collimators so that they "see" small sections of sampling lines is an acceptable method for meeting the intent of this requirement. Conversion of the measured dose rate (mR/hr) into concentration ($\mu\text{Ci/cc}$) can be performed

using standard volume source calculations. A method must be developed with sufficient accuracy to quantify the iodine releases in the presence of high background radiation from noble gases collected on charcoal filters. Seismically qualified equipment and equipment meeting IEEE 279 is not required.

The licensee shall provide the following information on his methods to quantify gaseous releases of radioactivity from the plant during an accident.

TABLE 2.1.8.b.1

INTERIM PROCEDURES FOR QUANTIFYING

HIGH-LEVEL ACCIDENTAL RADIOACTIVITY RELEASES

Licensees are to implement procedures for estimating noble gas and radioiodine release rates if the existing effluent instrumentation goes off-scale.

Examples of major elements of a highly radioactive effluent release special procedures (noble gas).

- Preselected location to measure radiation from the exhaust air, e.g., exhaust duct or sample line.
- Provide shielding to minimize background interference.
- Use of an installed monitor (preferable) or dedicated portable monitor (acceptable) to measure the radiation.
- Predetermined calculational method of convert the radiation level to radioactive effluent release rate.

1. Noble Gas Effluents

a. System/method description, including:

- i. Instrumentation to be used including range or sensitivity, energy dependence, and calibration frequency and technique.
- ii. Monitoring/sampling locations, including methods to assure representative measurements and background radiation correction.
- iii. A description of method to be employed to facilitate access to radiation readings. For January 1, 1980, control room readout is preferred; however, if impractical, in situ readings by an individual with verbal communication with the control room is acceptable based on iv., below.
- iv. Capability to obtain radiation readings at least every 15 minutes during an accident.
- v. Source of power to be used. If normal ac power is used, an alternate backup power supply should be provided. If dc power is used, the source should be capable of providing continuous readout for 7 consecutive days.

b. Procedures for conducting all aspects of the measurement/analysis, including:

- i. Procedures for minimizing occupational exposures.
- ii. Calculational methods for converting instrument readings to release rates based on exhaust air flow and taking into consideration radionuclide spectrum distribution as function of time after shutdown.
- iii. Procedures for dissemination of information.
- iv. Procedures for calibration.

TABLE 2.1.8.b.2

HIGH RANGE EFFLUENT MONITOR

Noble gases only

Range (overlap with normal effluent instrument range):

- Undiluted containment exhaust	10^{+5} μ Ci/cc
- Diluted (> 10: 1) containment exhaust	10^{+4} μ Ci/cc
- Mark I BWR reactor building exhaust	10^{+4} μ Ci/cc
- PWR secondary containment exhaust	10^{+4} μ Ci/cc
- Buildings with systems containing primary coolant or gases	10^{+3} μ Ci/cc
- Other buildings (e.g., radwaste)	10^{+2} μ Ci/cc

- Not redundant - one per normal release point
- Seismic - no
- Power - vital instrument bus
- Specifications - per Regulatory Guide 1.97 and ANSI N320-1979
- Display*; continuous and recording with readouts in the technical support center (TSC) and emergency operations center (EOC)

Qualifications - no

*Although not a present requirement, it is likely that this information may have to be transmitted to the NRC. Consequently, consideration should be given to this possible future requirement when designing the display interfaces.

2. Radioiodine and Particulate Effluents

A. For January 1, 1980 the licensee should provide the following:

1. System/method description, including:

- a. Instrumentation to be used for analysis of the sampling media with discussion on methods used to correct for potentially interfering background levels of radioactivity.
- b. Monitoring/sampling location.
- c. Method to be used for retrieval and handling of sampling media to minimize occupational exposure.
- d. Method to be used for data analysis of individual radio-nuclides in the presence of high levels of radioactive noble gases.
- e. If normal ac power is used for sampling collection and analysis equipment, an alternate backup power supply should be provided. If dc power is used, the source should be capable of providing continuous readout for 7 consecutive days.

2. Procedures for conducting all aspects of the measurement analysis, including:

- a. Minimizing occupational exposure.
- b. Calculational methods for determining release rates.
- c. Procedures for dissemination of information.
- d. Calibration frequency and technique.

DISCUSSION AND CONCLUSIONS

Monitors for radioactive effluents currently installed at North Anna 2 are designed to detect and measure releases associated with normal reactor operations and anticipated operational occurrences. Such monitors are required to operate in radioactivity concentrations

approaching the minimum concentration detectable with "state-of-the-art" sample collection and detection methods. These monitors comply with the criteria of Regulatory Guide 1.21 with respect to releases from normal operations and anticipated operational occurrences.

Radioactive gaseous effluent monitors designed to operate under conditions of normal operation and anticipated operational occurrences do not have sufficient dynamic range to function under release conditions associated with certain types of accident. General Design Criterion 64 of Appendix A to 10 CFR Part 50 requires that effluent discharge paths be monitored for radioactivity that may be released from postulated accidents.

The potential gaseous effluent release points at North Anna, Unit 2, consist of the process vent, ventilation stacks A and B, and the main steam safety valve discharge pipes.

As an interim measure for the determination of high level noble gas releases, North Anna, Unit 2, will use gamma radiation area monitors located near the various effluent discharge pipes, vents, or stacks to measure the gamma radiation produced during passage of noble gases during accidents. The applicant has provided procedures relating the observed monitor readings, calculated noble gas concentrations in the discharge path for a given monitor reading and the observed air volume flow rate to provide an estimate of gross radioactivity release rates. The applicant's procedures have been reviewed and were found to be acceptable.

Interim procedures for monitoring high level radioiodine and radioactive particulates in gaseous effluents have been provided to the staff. The applicants procedures have been reviewed and were found to be acceptable.

The equipment and procedures described by the applicant meet our position in NUREG-0578 and are, therefore, acceptable.

II.F.2 Inadequate Core Cooling (2.1.3.b - NUREG-0578)

SUBCOOLING METER

POSITION

Licensees shall develop procedures to be used by the operator to recognize inadequate core cooling with currently available instrumentation. The licensee shall provide a description of the existing instrumentation for the operators to use to recognize these conditions. A detailed description of the analyses needed to form the basis for operator training and procedure development shall be provided pursuant to another short-term requirement, "Analysis of Off-Normal Conditions, Including Natural Circulation" (See Section 2.1.9 of NUREG-0578).

In addition, each PWR shall install a primary coolant saturation meter to provide on-line indication of coolant saturation condition. Operator instruction as to use of this meter shall include consideration that is not to be used exclusive of other related plant parameters.

CLARIFICATION

1. The analysis and procedures addressed in paragraph one above will be reviewed and should be submitted to the NRC "Bulletins and Orders Task Force" for review.
2. The purpose of the subcooling meter is to provide a continuous indication of margin to saturated conditions. This is an important diagnostic tool for the reactor operators.
3. Redundant safety grade temperature input from each hot leg (or use of multiple core exit in T/C's) are required.
4. Redundant safety grade system pressure measures should be provided.
5. Continuous display of the primary coolant saturation conditions should be provided.
6. Each PWR should have: (A) Safety grade calculational devices and display (minimum of two meters) or (B) a highly reliable single channel environmentally qualified, and testable system plus a backup procedure for use of steam tables. If the plant computer is to be used, its availability must be documented.

7. In the long term, the instrumentation qualifications must be required to be upgraded to meet the requirements of Regulatory Guide 1.97 (Instrumentation for Light Water Cooled Nuclear Plants to Assess Plant Conditions During and Following an Accident) which is under development.
8. In all cases appropriate steps (electrical, isolation, etc.) must be taken to assure that the addition of the subcooling meter does not adversely impact the reactor protection or engineered safety features systems.
9. The attachment provides a definition of information required on the subcooling meter.

INFORMATION REQUIRED ON THE SUBCOOLING METER

Display

Information Displayed (T-Tsat, Tsat, Press, etc.) _____
Display Type (Analog, Digital, CRT) _____
Continuous or on Demand _____
Single or Redundant Display _____
Location of Display _____
Alarms (include setpoints) _____
Overall uncertainty (°F, PSI) _____
Range of Display _____
Qualifications (seismic, environmental IEEE 323) _____

Calculator

Type (process computer, dedicated digital or analog calc.) _____
If process computer is used specify availability, (%of time) _____
Single or redundant calculators _____
Selection Logic (highest T., lowest press) _____
Qualifications (seismic, environmental, IEEE 323) _____
Calculational Technique (Steam Table , Functional Fit, ranges) _____

Input

Temperature (RTD's or T/C's) _____
Temperature (number of sensors and locations) _____
Range of temperature sensors _____
Uncertainty of temperature sensors (°F at 1) _____
Qualifications (seismic, environmental IEEE 323) _____

Backup Capability

Availability of Temp & Press _____
Availability of Steam Tables, etc. _____
Training of operators _____
Procedures _____

*Uncertainties must address conditions of forced flow and natural circulation

ADDITIONAL INSTRUMENTATION

POSITION

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement those devices cited in the preceding section giving an unambiguous, easy-to-interpret indication of inadequate core cooling. A description of the functional design requirements for the system shall also be included. A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

CLARIFICATION

1. Design of new instrumentation should provide an unambiguous indication of inadequate core cooling. This may require new measurements to or a synthesis of existing measurements which meet safety-grade criteria.
2. The evaluation is to include reactor water level indication.
3. A commitment to provide the necessary analysis and to study advantages of various instruments to monitor water level core cooling is required in the response to the September 13, 1979 letter.
4. The indication of inadequate core cooling must be unambiguous, in that, it should have the following properties:
 - a. it must indicate the existence of inadequate core cooling caused by various phenomena (i.e., high void fraction pumped flow as well as stagnant boil off).
 - b. it must not erroneously indicate inadequate core cooling because of the presence of an unrelated phenomenon.
5. The indication must give advanced warning of the approach of inadequate core cooling.

6. The indication must cover the full range from normal operation to complete core uncovering. For example, if water level is chosen as the unambiguous indication, then the range of the instrument (or instruments) must cover the full range from normal water level to the bottom of the core.

DISCUSSION AND CONCLUSIONS

This item requires: the addition of a subcooling meter; procedures and training related to the use of existing instrumentation to detect inadequate core cooling and new instrumentation and procedures to provide an unambiguous indication of inadequate core cooling.

North Anna 2 has installed a subcooling meter and provided a description of the system in the November 26, 1979 submittal; "Lessons Learned Short Term Requirements, Surry Power Station, Units 1 and 2, North Anna Station Units 1 and 2." This system has temperature inputs for each of the hot legs and from twenty selected core exit thermocouples. Pressure inputs are taken from both the Reactor Coolant System and the pressurizer. The subcooling meter display consists of two analog meters mounted on the main control board. Additional information is displayed on the front of the electronics drawers for the subcooling meter. A graphic, three color 15 lamp display of the incore thermocouple and a 6 lamp display of the hot leg resistance temperature detectors (RTDs), is also provided on each of the two electronics drawers. The lamp color (green, amber or red) indicates the margin to saturation in the region being monitored.

We find that this system of monitoring reactors cooling system subcooling meets all of our requirements; and in fact, significantly exceeds our requirements in the area of information display.

Procedures and training related to the use of existing instrumentation to detect inadequate core cooling are discussed in Section I.C.1.

In terms of new instrumentation to provide an unambiguous indication of inadequate core cooling, Vepco has proposed to install a system of reactor vessel pressure drop measurement to be used in combination with the existing core exit thermocouples and the installed subcooling meter. Vepco has proposed to measure differential pressure between the top of the reactor vessel and the bottom of the reactor vessel on two narrow range and two wide range instruments. The system is intended to function

as follows: with the reactor coolant pumps off, the pressure drop between the top and the bottom of the vessel would indicate the collapsed liquid level (the equivalent liquid level without voids in the two-phase region) in the vessel. This would be read on the narrow range instrument in terms of feet of liquid. With the reactor coolant pumps running, the pressure drop from the top to the bottom of the vessel would provide an approximate indication of the void fraction in the vessel. This would be read on the wide range instrument as percent of full flow ΔP with the vessel filled with water.

The relationship between vessel differential pressure and core cooling involves complex phenomena, especially with one or more reactor coolant pumps operating. The adequacy of the system to indicate core cooling has not been demonstrated for conditions including: level swell, two-phased pumped flow; flow blockage; system dynamics (including blowdown). Vepco has met our requirement to provide a commitment to install instrumentation to detect inadequate core cooling and our requirement to provide a system design before fuel loading. The staff will continue to review the Vepco design and will complete its review in sufficient time to allow for installation of an acceptable system by January 1981. The analyses and procedures related to the use of the new instrumentation must also be submitted and approved by NRC prior to January 1, 1981 which is the implementation date for the installation of the new instrumentation. We conclude that this requirement places no restrictions on North Anna Unit 2 operation through full power.

II.G Emergency Power For Pressurizer Equipment (2.1.1 - NUREG-0578)

POSITION

Consistent with satisfying the requirements of General Design Criteria 10, 14, 15, 17 and 30 of Appendix A to 10 CFR Part 50 for the event of loss of offsite power, the following positions shall be implemented:

1. Motive and control components of the power-operated relief valves (PORVs) shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.
2. Motive and control components associated with the PORV block valves shall be capable of being supplied from either the offsite power source or the emergency power source when the offsite power is not available.
3. Motive and control power connections to the emergency buses for the PORVs and their associated block valves shall be through devices that have been qualified in accordance with safety-grade requirements.
4. The pressurizer level indication instrument channels shall be powered from the vital instrument buses. The buses shall have the capability of being supplied from either the offsite power source or the emergency power source when offsite power is not available.

CLARIFICATION

1. While the prevalent consideration from TMI Lessons Learned is being able to close the PORV/block valves, the design should retain, to the extent practicable, the capability to open these valves.
2. The motive and control power for the block valve should be supplied from an emergency power bus different from that which supplies the PORV.
3. Any changeover of the PORV and block valve motive and control power from the normal offsite power to the emergency onsite power is to be accomplished manually in the control room.

4. For those designs where instrument air is needed for operation, the electrical power supply requirement should be capable of being manually connected to the emergency power sources.

DISCUSSION AND CONCLUSIONS

We have reviewed the applicants submittal of the emergency power design and discussed the design details with them. We find the current North Anna Unit 2 emergency power supply design for pressurizer level and relief and block valves to be in conformance with all requirements and clarifications of Lessons Learned Item 2.1.1 and is, therefore, acceptable.

II.K.1 IE Bulletins on Measures to Mitigate Small Break LOCA's and Loss of Feedwater

INTRODUCTION

By letters dated April 14 and April 18, 1979, we transmitted our Office of Inspection and Enforcement (IE) Bulletins No. 79-06A and 79-06A(Revision 1) respectively, to Virginia Electric and Power Company (Veeco or the licensee). These bulletins specified actions to be taken by the licensees of operating reactors to avoid occurrence of an event similar to that which occurred on March 28, 1979 at Three Mile Island, Unit No. 2 (TMI-2). By letter dated April 26, 1979, Veeco provided its response to the aforementioned bulletins for North Anna Power Station, Units 1 and 2 (North Anna 1 and 2). Veeco supplemented its response by letter dated June 29, 1979, providing clarification and elaboration of certain of the Bulletin Action Items in response to our expressed concerns. Following our review of the two Veeco submittals, we requested additional information regarding Veeco's responses in our August 23, 1979 letter. By letter dated October 15, 1979, Veeco provided the requested information. Our evaluation of Veeco's responses, as supplemented, is given below.

EVALUATION

In Bulletin Action Item No. 1, licensees were requested to review the description of circumstances described in Enclosure 1 of IE Bulletin 79-05 (issued to all licensees with Babcock & Wilcox (B&W)-designed plants for action, and to all other licensees for information) and the preliminary chronology of the TMI-2 accident included in Enclosure 1 to IE Bulletin 79-05A (same distribution as IE Bulletin 79-05).

- (a) This review should be directed toward understanding: (1) the extreme seriousness and consequences of the simultaneous blocking of both auxiliary feedwater trains at the Three Mile Island Unit 2 plant and other actions taken during the early phases of the accident; (2) the apparent operational errors which led to the eventual core damage; (3) that the potential exists, under certain accident or transient conditions, to have a water level in the pressurizer simultaneously with the reactor vessel not full of water; and (4) the necessity to systematically analyze plant conditions and parameters and take appropriate corrective actions.

- (b) Operational personnel should be instructed to: (1) not override automatic action of engineered safety features unless continued operation of engineered safety features will result in unsafe plant conditions (see Section 7a.); and (2) not make operational decisions based solely on a single plant parameter indication when one or more confirmatory indications are available.

- (c) All licensed operators and plant management and supervisors with operational responsibilities were to participate in this review and such participation was to be documented in plant records.

On April 21, 1979, an NRC briefing team provided a detailed review of the circumstances described in Enclosure 1 of IE Bulletin 79-05 and the preliminary chronology of the TMI-2 accident included in Enclosure 1 of IE Bulletin 79-05A to a majority of the licensed operators and plant management. The briefing team consisted of an IE Section Leader, an Operator Licensing Branch (OLB/NRR) representative, and the facility Principal/Resident Inspector. Attendance was documented and the briefing was videotaped for later presentation to any absentees at a briefing by the NRC Principal/Resident Inspector. The NRC briefing also provided a detailed review of Items 1.a and 1.b of IE Bulletin 79-36A. We consider the NRC briefing to be an acceptable response to Bulletin Action Item No. 1.

Action Item 2 of the Bulletin requested licensees to review actions required by operating procedures for coping with transients and accidents, with particular attention to (a) recognition of the possibility for forming voids large enough to compromise core cooling capability, (b) action required to prevent the formation of such voids, and (c) action required to enhance core cooling in the event such voids are formed. Emphasis in (a) was placed on natural circulation capability.

In its October 15, 1979 supplemental response, Vepco stated that a chart with saturation and 50 Fahrenheit degrees subcooling curves has been placed in the Control Room. Training of operators on the natural circulation mode of operation has been carried out and documented. Also an engineering review has been conducted to determine a mechanism which will warn the operator that he is losing the margin to saturation. This method would provide the operator with the ability to trend this information. These activities represent part of the Vepco response to the requirements of Item 2.1.3.b of NUREG-0578.

Vepco also identified the instrumentation which is currently available to the operator for recognition of void formation and to determine whether core cooling is being achieved by the natural circulation mode in the event of total loss of forced reactor coolant flow.

Vepco has changed the plant emergency procedure regarding loss of reactor coolant flow to provide the operator with the indication and actions to be taken to establish and maintain natural circulation in case that total forced reactor coolant flow is lost.

The emergency procedures dealing with a LOCA, loss of secondary coolant, and deteriorating pressure conditions were changed to incorporate the reactor coolant pump trip requirements specified by IE Bulletin 79-06C.

Vepco revised the emergency procedure for loss of reactor coolant flow to provide the operator with guidance to enhance core cooling by natural circulation. This procedure instructs the operator on methods to be used in feeding and bleeding the steam generators and the instruments to be used to verify that core cooling by natural circulation has been established.

In addition, Vepco participated, as a member of the Westinghouse Owners Group, in the effort to develop generic guidelines for emergency procedures. In our November 5 and December 6, 1979 letters to the Owners Group, we approved the Westinghouse generic guidelines regarding small break LOCAs for implementation by licensees with Westinghouse-designed reactors. The Owners Group, in conjunction with Westinghouse, has also developed generic guidelines for emergency procedures regarding natural circulation. These generic guidelines were submitted on December 28, 1979, as part of the Owners Group response to the requirements of Item 2.1.9 of NUREG-0578 regarding inadequate core cooling. In order to satisfy NUREG-0578 requirements, Vepco should have incorporated the guidelines into the North Anna 1 procedures (small break LOCA guidelines by January 1, 1980 and inadequate core cooling guidelines by January 31, 1980). Our evaluation of inadequate core cooling may be found in Section I.C.1 of this supplement. Procedures based on these generic guidelines represent an acceptable method of complying with Bulletin Action Item No. 2.

We find that Vepco has provided an acceptable response to Bulletin Action Item No. 2.

Bulletin Action Item No. 3 requested that licensees with facilities that used pressurizer water level coincident with pressurizer pressure for automatic initiation of safety injection into the reactor coolant system trip the low pressurizer level setpoint bistables such that, when the pressurizer pressure reached the low setpoint, safety injection would be initiated regardless of the pressurizer level. The pressurizer level bistables could be returned to their normal operating positions during the pressurizer pressure channel functional surveillance tests.

In its June 29, 1979 response, Vepco stated that the pressurizer level bistables which input to safety injection initiation had been placed in the trip mode at North Anna Unit 1. Trip status lights on the control board confirmed that the action had been completed. Subsequently, in July 1979, operating procedures were revised to include verification that these bistables were in the trip mode before placing the plant in operation. A standing order was issued requiring the North Anna Unit 1 operators to manually initiate safety injection when the primary system pressure is below the actuation setpoint. On December 28, 1979 we issued Amendment 16 to the North Anna, Unit 1 operating license. The license amendment approved the design change in the safety injection initiation logic. This design change consisted of modifying the safety injection initiation system logic so that safety injection will be initiated on a two-out-of-three low pressurizer pressure condition regardless of the pressure level. This modification has also been made on Unit 2. We consider Vepco's response to Bulletin Action Item No. 3 acceptable.

Bulletin Action Item No. 4 requested that licensees review the containment isolation initiation design and procedures, and implement all changes necessary to permit containment isolation, whether manual or automatic, of all lines whose isolation would not degrade needed safety features or cooling capability, upon automatic initiation of safety injection.

The North Anna Unit 2 design provides for automatic initiation of containment isolation upon safety injection actuation, as called for in the bulletin. This aspect of Vepco's response is therefore, acceptable.

Containment isolation consists of a Phase A and a Phase B isolation. Phase A involves closure of automatic valves in all non-essential process lines; Phase B isolates all remaining process lines, except for those related to engineered safety features. The reactor coolant pump seal water return line is isolated upon a Phase A signal. The seal water supply is not provided with isolation valves. The component cooling water supply and return lines for the reactor coolant pumps are isolated by a Phase B signal. The reactor coolant pumps do not trip automatically on either isolation signal. Therefore, the pumps must be manually tripped following a Phase B isolation, since component cooling water to the motor coolers and thermal barriers is lost.

We find that the North Anna Unit 2 design adequately addresses the concerns expressed in Bulletin Action Item No. 4.

In Bulletin Action Item No. 5, licensees with facilities at which the auxiliary feedwater system is not automatically initiated were requested to prepare and implement immediately procedures which required the stationing of an individual (with no other assigned duties and in direct and continuous communication with the control room) to promptly initiate adequate auxiliary feedwater to the steam generator(s) for those transients or accidents the consequences of which could be limited by such action.

The auxiliary feedwater system at North Anna Unit 2 is automatically initiated, with no operator action required in order to ensure adequate flow. Therefore, Bulletin Action Item No. 5 does not apply to this plant.

Bulletin Action Item No. 6 requested that licensees prepare and implement immediately procedures which:

- (a) Identified those plant indications (such as valve discharge piping temperature, valve position indication, or valve discharge relief tank temperature or pressure indication) which plant operators could utilize to determine that the pressurizer power operated relief valve(s) are open, and
- (b) Directed the plant operators to manually close the power-operated relief block valve(s) when reactor coolant system pressure was reduced to below the setpoint for normal automatic

closure of the power-operated relief valve(s) and the valve(s) remain in the stuck open position.

Veeco reviewed the applicable North Anna Unit 1 procedures and determined that no changes or revisions were needed to comply with Bulletin Action Item No. 6.a.

In response to Action Item No. 6.b, Veeco issued a Standing Order to the operators to ensure compliance with the requirements. In May 1979, the plant procedures were revised to implement Action Item No. 6.b. The North Anna, Unit 2 procedures reflect these changes. Based on our review, we find that Veeco's response to Bulletin Action Item No. 6 is acceptable.

In Bulletin Action Item No. 7, licensees were requested to review the action directed by the operating procedures and training instructions to ensure that: XXXXXXXXXX

- (a) Operators do not override automatic actions of engineered safety features, unless continued operation of engineered safety features would result in unsafe plant conditions. For example, if continued operation of engineered safety features would threaten reactor vessel integrity, the high pressure injection (HPI) should be secured (as noted in b(2) below).
- (b) Operating procedures currently, or are revised to, specify that, HPI system had been automatically actuated because of a low pressure condition, it must remain in operation until either:
 - (1) Both low pressure injection (LPI) pumps are in operation and flowing for 20 minutes or longer; at a rate which would assure stable plant behavior; or
 - (2) The HPI system has been in operation for 20 minutes, and all hot and cold leg temperatures are at least 50 degrees Fahrenheit below the saturation temperature for the existing RCS pressure. If 50 degrees subcooling cannot be maintained after HPI cutoff, the HPI shall be reactivated. The degree of subcooling beyond 50 degrees and the length of time HPI has been in operation shall be limited by the pressure/temperature considerations for the vessel integrity.

- (c) Operating procedures currently, or are revised to, specify that, in the event of HPI initiation with reactor coolant pumps (RCP) operating, at least one RCP shall remain operating for two-loop plants and at least two RCPs shall remain operating for 3 or 4 loop plants, as long as the pump(s) is providing forced flow.
- (d) Operators are provided additional information and instructions to not rely upon pressurizer level indication alone, but to also examine pressurizer pressure and other plant parameter indications in evaluating plant conditions, e.g., water, inventory in the reactor primary system.

In response to Bulletin Action Item No. 7.a, Vepco revised the applicable North Anna 1 plant procedures in May 1979 to prohibit overriding engineered safety features unless continued operation of engineered safety features would result in unsafe conditions. The North Anna Unit 2 procedures incorporate this change. This constitutes an acceptable response to Bulletin Action Item No. 7.a.

In response to Bulletin Action Item No. 7.b, Vepco participated in the effort by the Westinghouse Owners Group, in conjunction with Westinghouse, to develop generic guidelines for emergency procedures. In our November 5, and December 6, 1979 letters to the Owners Group, we approved generic guidelines for emergency procedures regarding small break LOCAs for implementation by licensees with Westinghouse-designed operating plants. These approved guidelines include the following criteria (taken from our letter of December 27, 1979) for termination of safety injection:

- (1) The reactor coolant system pressure is greater than 2000 psig and increasing, and
- (2) The pressurizer water level is greater than the programmed no-load water level, and
- (3) The reactor coolant indicated subcooling is greater than (insert plant-specific value, which is the sum of the errors for the temperature measurement system used and the pressure measurement system translated into temperature using the saturation tables), and

- (4) The water level in at least one steam generator is stable and increasing, as verified by auxiliary feedwater flow to that unit. Auxiliary feedwater flow to the unaffected steam generator should be greater than (a value in gpm sufficient to remove decay heat after 20 minutes following reactor trip) until the indicated level is returned to within the narrow range level instrument.

Details of our evaluation of this issue are included in the report (NUREG-0611) of our generic review of Westinghouse-designed operating plants.

The Office of Inspection and Enforcement (IE) will verify that the approved Westinghouse generic safety injection termination criteria have been properly incorporated in the North Anna Unit 2 plant procedures. Pending such verification, we find that the licensee's actions with regard to this bulletin action item are acceptable.

Another issue on which the Westinghouse Owners Group, in conjunction with Westinghouse, worked to achieve resolution with the staff was the matter of reactor coolant pump operation following a small break LOCA (Bulletin Action Item No. 7.c). On July 26, 1979, IE Bulletin 79-06C superseded Action Item No. 7.c of Bulletin 79-06A. Bulletin 79-06C required that, as a short-term action, licensees were to trip all reactor coolant pumps after initiation of safety injection caused by low reactor coolant system pressure. In its August 31, 1979 response to Bulletin 79-06C, Vepco stated its conformance with this requirement. This action was to remain in effect until the results of analyses specified in Bulletin 79-06C had been used to develop new guidelines for operator action.

We have completed our review of the reactor coolant pump trip issue with the Owners Group. The generic guidelines for emergency procedures regarding small break LOCAs, which we approved in our November 5 and December 6, 1979 letters to the Owners Group, contain the approved pump trip criteria for Westinghouse-designed operating plants. Basically, they are as follows:

- (1) Stop all reactor coolant pumps after high pressure safety injection pump operation has been verified, and when the wide

range reactor pressure is at (plant-specific pressure derived from secondary system relief capacity, primary-to-secondary system pressure difference, and instrument inaccuracies).

Appropriate cautions have been included in the guidelines regarding isolation of component cooling water to the reactor coolant pumps and maintaining seal injection flow to preclude pump damage due to inadequate cooling. The details of our review of the pump trip issue are reported in NUREG-0623.

Pending IE confirmation that Vepco has incorporated the pump trip criteria as specified in the approved Westinghouse generic guidelines into the North Anna Units 1 and 2 plant procedures, we find Vepco's response to Bulletin Action Item No. 7.c acceptable.

In response to Bulletin Action Item No. 7.d, Vepco issued a Standing Order to North Anna 1 operations personnel, which cautioned against overreliance on pressurizer level indication, and recommended examination of other plant parameters in assessing water inventory and plant conditions. In addition, the concern expressed in this bulletin action item was incorporated in the licensee's operator training program. In its June 29, 1979 letter, Vepco supplemented its original response to identify the specific plant parameters to be used in assessing water inventory and plant conditions. Vepco also stated that the applicable procedures were revised to reflect the above mentioned considerations. The North Anna, Unit 2 procedures reflect these revisions. We find these actions to be an acceptable response to Bulletin Action Item No. 7.d.

Bulletin Action Item No. 8 required that licensees review alignment requirements and controls for all safety-related valves necessary for proper operation of engineered safety features. In response, Vepco stated that the required review was conducted by reviewing valve positions concurrently with the procedures that check or manipulate the valves. In its October 15, 1979 supplemental response, Vepco added that valve lineups on safety-related systems are completed after every refueling. Locked valves on safety-related systems are verified and documented with respect to their proper position. Safety-related valves that have position indication in the control room are verified to be in their positions on a shift turnover check list, which has been implemented to meet the requirements of Item 2.2.1.c of NUREG-0578, "Shift and Relief Turnover Procedures".

We find Vepco's response to Bulletin Action Item No. 8 acceptable.

In Bulletin Action Item No. 9, licensees were requested to review their procedures to assure that radioactivity will not be inadvertently released from containment. Particular emphasis was placed on the resetting of engineered safety features (ESFs) and the effects of this action on valves controlling the release of radioactivity.

In its October 15, 1979 supplemental response, Vepco listed all systems which are designed to transfer potentially radioactive fluids from containment, indicated those systems for which high radiation interlocks exist, and identified the means by which the operability of each system listed is assured. Information pertaining to the resetting of ESFs and its effect on valves controlling the release of radioactivity was provided in Vepco's October 24, 1979 response to Item 2.1.4 of NUREG-0578. In brief, once Phase A Containment Isolation has been initiated by a safety injection signal, the automatic isolation valves can be opened only upon manual reset of the actuating signal and deliberate remote manual operation of the individual valve.

We find that Vepco has adequately addressed the concerns expressed in Bulletin Action Item No. 9.

The staff's implementation of Item 2.1.4 of NUREG-0578 provides further assurance that the inadvertent release of radioactivity from containment upon resetting of ESFs will be precluded. Any review of Item 2.1.4 is contained in Section II and 4 of this report.

Action Item No. 10 of Bulletin 79-06A required that licensees review and modify, as necessary, maintenance and test procedures for safety-related systems to ensure that they require that: (a) redundant systems are operable before a system is taken out of service, (b) systems are operable when returned to service, and (c) operators are made aware of the status of these systems.

In its October 15, 1979 supplemental response, Vepco provided additional information regarding this bulletin action item. The North Anna Unit 2 Technical Specifications specify the surveillance requirements that must be completed to confirm the operability of safety-related systems. A subsystem or equipment is removed

from service for preventive or corrective maintenance according to maintenance operating procedures. When a subsystem fails or is removed from service, this event is entered in an Action Statement Log to ensure that Technical Specification requirements are met. When maintenance has been completed, the controlling procedure ensures that testing of the subsystem/equipment is performed to determine operability.

Maintenance operating procedures will test the redundant subsystem/train before removal of a portion of the other subsystem/train, if it does not isolate it from performing its safety function while testing. In the case of subsystems which are made inoperable for testing, it is verified that the redundant train of the system to be removed from service is not listed in the Action Statement Log and that it has passed its last scheduled periodic test. The redundant train is visually inspected and its power supply is verified as being operable and not listed in the Action Statement Log. These steps are taken and documented in the maintenance operating procedure before the system is removed from service.

Operability of a redundant emergency diesel is tested by the maintenance operation procedure in accordance with the Technical Specifications. The procedures require verification that safety-related systems powered from the redundant diesel are operable from a review of the Action Statement Log.

Vepco conducted a detailed review of periodic tests to ensure that the operability of a system is determined when equipment is returned to service following testing. This review also identified equipment which is made inoperable for testing purpose.

The transfer of information about the status of safety-related systems at shift change will be accomplished according to the requirements of Item 2.2.1.c of NUREG-0578.

Based on our review, we find that Vepco's response to Bulletin Action Item No. 10 is acceptable.

Bulletin Action Item No. 11 requested licensees to review their prompt reporting procedures for NRC notification to assure that the NRC is notified within one hour of the time the reactor is not in a controlled or expected condition of operation. Further, at that time, an open, continuous communication channel shall be established and maintained with the NRC.

The existing North Anna Unit 2 notification procedures were revised on April 30, 1979 to specify that the NRC be notified within one hour of the time the reactor is not in a controlled or expected condition of operating. Provisions are included for establishing and maintaining a continuous open channel of communication with the NRC using the dedicated telephone line established for this purpose. The North Anna Unit 2 procedures also contain these requirements. These reporting requirements have been posted on a bakelite sign within view of the Shift Supervisor's desk. We find Vepco's action in response to Bulletin Action Item No. 11 acceptable.

In Bulletin Action Item No. 12, licensees were requested to review operating modes and procedures to deal with significant amounts of hydrogen gas that may be generated during a transient or other accident, that would either remain inside the primary system or be released to the containment.

In response to this Bulletin action item, Vepco reviewed the existing North Anna Unit 2 procedures regarding removal of hydrogen gas from the containment using the two recombiners, purge blowers and associated analyzers and piping provided for this purpose. This review emphasized the accessibility, shielding, operability, sampling, and maintenance of the recombiner system.

In addition, in its October 15, 1979 supplemental response, Vepco identified the various methods covered by existing procedures for removing hydrogen gas from the reactor coolant system. The North Anna Unit 2 procedures also contain the aforementioned provision.

Based on our review, we find that Vepco has provided an adequate response to Bulletin Action Item No. 12.

This bulletin action item requested licensees to propose changes, as required, to those plant Technical Specifications which had to be modified as a result of implementing Bulletin Action Item Nos. 1 through 12 and to identify design changes necessary in order to effect long-term resolution of these items.

In its October 15, 1979 supplemental response, Vepco identified the one change to the North Anna Unit 2 Technical Specifications necessitated by actions required by this bulletin. This change was required to implement two-out-of-three low-low pressurizer pressure safety injection actuation (from Bulletin Action Item No. 3).

We find Vepco's response to Bulletin Action Item No. 13 acceptable.

IE Bulletin 79-06C was issued to all licensees with Westinghouse-designed operating plants on July 26, 1979. This bulletin, which is applicable to all operating PWRs, revised one of the positions in IE Bulletin 79-06A and introduced supplemental requirements. The most salient feature of this bulletin is that it reversed the requirement in the previous TMI-2-related bulletins regarding the operation of the reactor coolant pumps during a small-break LOCA. This bulletin requires that the reactor coolant pumps be tripped upon a small-break LOCA, whereas the previous bulletins required that some of the reactor coolant pumps be kept running.

IE Bulletin 79-06C contained five short-term actions and one long-term action to be implemented by licensees. In its August 31, 1979 letter, C. M. Stallings to James P. O'Reilly, Vepco provided responses to Bulletin 79-06C for North Anna Units 1 and 2. Our evaluation of Vepco's responses is summarized below.

Short-Term Actions:

Item No. 1 required (a) that all operating reactor coolant pumps be tripped upon reactor trip and initiation of high pressure injection caused by low reactor coolant system pressure, and (b) that two licensed operators be in the control room at all times (three in the case of dual control rooms) to accomplish the above action and any required supplemental actions.

In response to Item No. 1.a, Vepco issued a Standing Order to the North Anna operators which implemented the required actions. We find Vepco's response to Item No. 1.a acceptable.

In response to Item No. 1.b, Vepco stated its conformance to the bulletin requirements for both one and two unit operation. We find that Vepco's response to Item No. 1.b acceptable.

Items No. 2 and No. 3 required that licensees perform analyses of a range of small break LOCAs and a range of time lapses between reactor trip and pump trip (Item No. 2), and that were reported in NUREG-0623, published in November 1979. Implementation of the recommendations, contained in NUREG-0623 will be carried out under Item II.K.3 of the NRC TMI-2 Action Plan. The work of the Westinghouse Owners Group represents an acceptable response to Item No. 2 of Bulletin 79-06C.

Item No. 3 required that licensees develop new guidelines for operator action, for both LOCA and non-LOCA transients that consider the impact of reactor coolant pump trip requirements. In response to this item, Vepco referenced the Owners Group effort in developing revised guidelines for operators for both LOCA and non-LOCA transients. These revised guidelines were contained in the report WCAP-9600 which was submitted for staff review in June 1979. By letters dated November 5 and December 6, 1979, D. F. Ross, Jr. to Cordell Reed (and modified by our December 27, 1979 letter), we approved the Westinghouse generic guidelines for emergency operating procedures regarding guidelines for operator action for both LOCA and non-LOCA transients be developed (Item No. 3) based on the reactor coolant pump trip requirements originating from the analyses required by Item No. 2.

In its response to these items, Vepco referenced the work of the Westinghouse Owners Group (Vepco is a participating member). The Owners Group submitted the Westinghouse report WCAP-9584, "Analysis of Delayed Reactor Coolant Pump Trip During Small Loss-of-Coolant Accident for Westinghouse Nuclear Steam Supply Systems", as a generic response to Items No. 2 and No. 3. Since the generic guidelines for emergency operating procedures originally submitted in the small break LOCA analysis report, WCAP-9600, "Report on Small Break Accidents for Westinghouse NSSS System", were considered consistent with the pump trip guidance, additional guidelines were not proposed. By letters dated November 5, December 6 and December 27, 1979, D. R. Ross, Jr. to Cordell Reed, we approved the generic guidelines for emergency operating procedures regarding small break LOCAs for all operating Westinghouse-designed plants. Our evaluation of the Westinghouse analyses pertaining to reactor coolant pump trip is contained in NUREG-0623. The effort of the Westinghouse Owners Group represents an acceptable method of meeting the requirements of Items No. 2 and No. 3. On this basis, we find Vepco's response to these items acceptable.

Item No. 4 required that emergency procedures, based on the guidelines developed under Item No. 3 above, be developed by licensees and that all licensed reactor operators and senior reactor operators be retrained as required. The small break LOCA procedures were required (by Item 2.1.9.a of NUREG-0578) to be implemented by January 1, 1980. Our evaluation of Vepco's implementation of Item 2.1.9.a of NUREG-0578 is contained in Section I.C.1 of this SER Supplement.

Item No. 5 was related to inadequate core cooling (as specified in Item 2.1.9.b of NUREG-0578). This item required that licensees perform analyses of inadequate core cooling, develop guidelines for emergency procedures based on these analyses, and implement procedures based on the above-mentioned guidelines. In response to this item, Vepco referenced the work of the Westinghouse Owners Group. By letter dated October 30, 1979, the Owners Group submitted a document, "Westinghouse Inadequate Core Cooling Analysis Performed to Meet the Requirements Set Forth in NUREG-0578", which addressed this item. The procedures associated with this item were to have been implemented by January 31, 1980. Our evaluation of Item 2.1.9.b of NUREG-0578 (inadequate core cooling) is contained in Section I.C.1 of this supplement.

Long-Term Action:

Item No. 1 pertained to the design of circuitry which would provide for automatic tripping of the operating reactor coolant pumps under all circumstances in which such action was considered necessary. In its response to this item, Vepco stated that it did not believe that the automatic tripping of the reactor coolant pumps should be a required function. Our evaluation of this item is contained in NUREG-0623 along with corresponding recommendations. Implementation of the NUREG-0623 recommendations as licensing requirements will be carried out by the staff upon approval by the Director of the Office of Nuclear Reactor Regulation within the scope of Item II.K.3 of the NRC's TMI-2 Action Plan (NUREG-0660).

II.K.3 Generic Review Matters - Small Break LOCAs and Loss of Feedwater Transients

As part of its generic review of small break LOCAs and feedwater transients in Westinghouse-designed operating plants, the NRC's Bulletins and Orders Task Force (B&OTF) performed a review of the North Anna, Unit 1 auxiliary feedwater system. The B&OTF generic review is described in NUREG-0611, "Generic Review of Feedwater Transients and Small Break Loss of Coolant Accidents in Westinghouse-Designed Operating Plants".

By letter dated September 28, 1979, D. Eisenhut to W. L. Proffitt, the NRC staff transmitted the licensing requirements for the North Anna Unit 1 auxiliary feedwater system resulting from the above-mentioned review to Vepco. Vepco provided its response to these requirements in its November 2, 1979 letter, C. M. Stallings to Harold R. Denton. Our review of Vepco's response is currently in progress.

Since the North Anna Unit 2 auxiliary feedwater system is essentially identical to that at North Anna Unit 1, this evaluation is also applicable to North Anna Unit 2. Completion of the auxiliary feedwater system reliability analysis and appropriate system modifications is classified as a requirement for full power operation for near term operating license applications in Appendix A of the NRC TMI-2 Action Plan (NUREG-0660) and is not necessary for low power testing. Hence, we will report the results of the implementation of the B&OTF auxiliary feedwater system requirements in another supplement to this Safety Evaluation Report prior to full power operation of North Anna Unit 2.

Our review of small break LOCAs for North Anna Unit 2 is discussed in Section I.C.1 of this report.

The remainder of the recommendations identified in NUREG-0611 will be implemented with an appropriate implementation schedule in the NRC TMI-2 Action Plan.

III Emergency Preparations and Radiation Protection

Emergency Preparedness Short-Term

III.A.1.2(a) Technical Support Center (2.2.2.b - NUREG-0578)

POSITION

Each operating nuclear power plant shall maintain an onsite technical support center (TSC) separate from and in close proximity to the control room that has the capability to display and transmit plant status to those individuals who are knowledgeable of and responsible for engineering and management support of reactor operations in the event of an accident. The center shall be habitable to the same degree as the control room for postulated accident conditions. The licensee shall revise his emergency plans as necessary to incorporate the role and location of the technical support center. Records that pertain to the as-built conditions and layout of structures, systems and components shall be readily available to personnel in the TSC.

CLARIFICATION

1. By January 1, 1980, the licensee shall meet the items that follow.
 - a. Establish a TSC and provide a complete description.
 - b. Provide plans and procedures for engineering/management support and staffing of the TSC.
 - c. Install dedicated communications between the TSC and the control room, near site emergency operations center, and the NRC.
 - d. Provide monitoring (either portable or permanent) for both direct radiation and airborne radioactive contaminants. The monitors should provide warning if the radiation levels in the support center are reaching potentially dangerous levels. The licensee should designate action levels to define when protective measures should be taken (such as using breathing apparatus and potassium iodide tablets, or evacuation to the control room).

- e. Assimilate or ensure access to Technical Data, including the licensee's best effort to have direct display of plant parameters, necessary for assessment in the TSC.
- f. Develop procedures for performing this accident assessment function from the control room should the TSC become uninhabitable, and
- g. Submit to the NRC a longer range plan for upgrading the TSC to meet all requirements.

Each licensee is encouraged to provide additional upgrading of the TSC as soon as practical, but no later than January 1, 1981.

It is recommended that the TSC be located onsite in close proximity to the control room.

The TSC should be large enough to house 25 persons.

The center should be activated in accordance with the "Alert" level as defined in the NRC document "Draft Emergency Action Level Guidelines, NUREG-0610", dated September, 1979.

The instrumentation to be located in the TSC should be qualitatively comparable to that in the control room.

The power supply to the TSC instrumentation should be reliable and of a quality compatible with the TSC instrumentation requirements.

Each licensee should establish the technical data requirements for the TSC. As a minimum, data should be available to permit the assessment of:

- Plant Safety Systems Parameters
- In-Plant Radiological Parameters
- Offsite Radiological Parameters

Each licensee should review current technology as regards transmission of those parameters identified for TSC display.

The center should be well built in accordance with sound engineering practice. However, in the event that access to the center is prevented, each licensee should prepare a backup plan for responding to an emergency from the control room.

The licensee should provide protection for the technical support center personnel from radiological hazards.

DISCUSSION AND CONCLUSIONS

A temporary onsite Technical Support Center (OTSC) has been established in the Records Building, a two story building inside the Protected Area security fence adjacent to the main facility. The first level of the building contains the record storage area. Technical information such as general arrangement drawings, piping isometrics, electrical drawings, system specifications, and plant procedures that might be needed during an emergency are accessible here.

The second level contains an assembly area for technical personnel. Adequate space is provided for 25 persons. Communications equipment has been installed in this area. Dedicated lines have been installed between the OTSC and 1) Control Room, 2) Offsite Emergency Operations Center and 3) NRC Emergency Response Center. Additional lines allow communications with Vepco headquarters, NRC Region II headquarters, Vepco System Operator, and the Westinghouse Emergency Response Center, as well as various locations within the station.

EPIP 1, "Emergency Classification and Organization Formation, Notification and Communications," has been revised to incorporate activation of the OTSC. This procedure identifies the personnel who will report to and make up the OTSC staff if the Emergency Plan is implemented. Procedures have been revised to cover performance of the accident assessment function from the Control Room in the event the OTSC becomes uninhabitable.

A typewriter, paralleled with the Control Room computer typewriter, has been installed in the OTSC assembly area to allow direct display of plant parameters necessary for evaluation and assessment. Vepco is investigating a more versatile permanent data link for the OTSC.

Procedures have been revised to provide for the installation of portable radiation and airborne radioactivity monitoring equipment in the OTSC when it is activated.

Vepco has determined it will be necessary to construct a new building in order to meet all long term requirements for the OTSC. Vepco has provided a preliminary description of the permanent OTSC and a tentative construction schedule which calls for completion by December 15, 1980.

Vepco has met this requirement. An OTSC has been established with adequate communications links and access to plant parameter data and technical information. Appropriate procedural revisions have been made to establish and man the OTSC at the outset of an emergency. Plans for a permanent OTSC, although preliminary at this time, provide reasonable assurance that long term requirements will also be met.

III.A.1.2(b) Onsite Operational Support Center (2.2.2.c - NUREG-0578)

POSITION

An area to be designated as the onsite operational support center shall be established. It shall be separate from the control room and shall be the place to which the operations support personnel will report in the emergency situation. Communications with the control room shall be provided. The emergency plan shall be revised to reflect the existence of the center and to establish the methods and lines of communication and management.

DISCUSSION AND CONCLUSIONS

Veeco has established an onsite operational support center (OOSC) in the plant assembly room. Communications with the control room by telephone and public address system have been established.

The Emergency Plan Implementing Procedure (EPIP-1) has been revised to require 1) operators not required for plant operation, 2) fire brigade members, and 3) first aid team members to report to the OOSC in the event of a Station Emergency, Site Emergency or General Emergency. Operators reporting to the station to relieve the shift during an emergency report to the OOSC and standby until instructed by the Emergency Director to relieve the shift.

Other support groups such as health physics, instrument technicians, and maintenance personnel report to their respective work areas.

Veeco has met this requirement.

III.A.3 Improving NRC Emergency Preparedness

III.A.3.3 Communications

POSITION

Direct dedicated telephone lines (OPX) have been installed at each operating power plant and selected fuel facilities; these lines are for immediate notification and continuous communication with NRC concerning facility status. A second direct and dedicated network for health physics and environmental information is to be installed by February 1980.

DISCUSSION AND CONCLUSIONS

Direct dedicated telephones have been installed at the North Anna Units 1 and 2 control rooms, the NRC resident inspector's office, and the site technical support center. A second network for health physics and environmental information has been installed with extensions in the control room, health physics supervisor's office, technical support center, and the plant visitors center. A functional check of these phones was performed after installation. This task is complete.

III.B Emergency Preparedness of State and Local Governments

III.B.1 Near-Term Actions

We have reviewed the applicant's emergency plan for a fuel load and low power license. For this license, we require that the combined applicant, State and Local emergency plans must meet:

- a. Current Regulatory Requirements at 10 CFR Part 50, Appendix E.
- b. Regulatory Position Statements in Regulatory Guide 1.101 (March 1977).
- c. Essential planning elements in NUREG 75/111 and Supplement 1 thereto.
- d. Additional requirements based on NRC review against interim upgraded criteria, as necessary on a site specific basis.

We have reviewed the combined applicant, State and local emergency plans and find that they met the above criteria. The basis for this finding is summarized below.

The applicant submitted a plan for coping with emergencies at North Anna Power Station Units 1 and 2. We reported on the applicant's emergency plan in the Safety Evaluation Report and Supplement No. 2 to the report. We determined that the applicant's emergency plan met the requirements of Appendix E to 10 CFR Part 50 and provided an adequate basis for an acceptable state of emergency preparedness.

The applicant's emergency plan includes provisions for coping with emergencies within the boundary of the plant site and in the environs of the plant site. Responsibility for planning and implementing all emergency measures within the site boundaries rests with the licensee. The planning and implementation of measures to cope with plant-related emergencies outside the site boundary are a coordinated effort involving the applicant and local, State and Federal agencies having emergency responsibilities. The emergency plan describes the coordination of the arrangements and agreements between the licensee and these agencies. Provisions have been made for an annual review of the emergency plan and for periodic testing, updating, and improving procedures based on training, drills, and exercises. The scope and content of the applicant's emergency plan is substantially equivalent to that recommended in Annex A, "Organization and Content of Emergency Plans for Nuclear Power Plants", to Regulatory Guide 1.101.

Based on our review of the applicant's emergency plan, we conclude that it meets the regulatory position statements of Regulatory Guide 1.101.

The Virginia Radiological Emergency Response Plan (COVREP) updated October 1979, was reviewed against the guideline standards of the Nuclear Regulatory Commission's "Guide and Checklist for Development and Evaluation of State and Local Government Radiological Emergency Response Plans in Support of Fixed Nuclear Facilities," (NUREG-75/111) including Supplement No. 1 to that publication dated March 15, 1977, which identifies those items essential for NRC's concurrence in a State plan. As a result of this review, and in accordance with the provisions of the Federal Register Notice (Volume 40, No. 248, December 24, 1975) the NRC concurred formally in the COVREP on October 24, 1979. The Federal Emergency Management Agency (FEMA), which participated actively in the review of Virginia's plan joined in the recommendation for concurrence.

As a result of the Commission's action plan for Promptly Upgrading Emergency Preparedness at Power Reactors (SECY 79-450), the Emergency Planning Review Team conducted a site visit and technical meeting with the applicant, State and local officials. In response to our visit, the applicant has submitted on December 10, 1979 a proposed revision to the North Anna Power Station Emergency Plan. This proposed revised plan is under review by the staff. We will report on the results of our review of the proposed revision prior to granting a full power license.

With regard to the fuel load and low power license, we have reviewed the applicant's current plan and the proposed revised plan and have concluded that further requirements on a case-by-case basis are not necessary to grant a fuel load and low power license.

In summary, based on our review of the combined applicant, State and local emergency plans, we conclude that the current plan provides an acceptable state of emergency preparedness for a fuel load and low power license. In addition attached is the NRC/FEMA statement with regard to low power testing.

DEFICIENCIES TO BE CORRECTED FOR A FULL POWER LICENSE

Current efforts by the staff, the Commission and FEMA to upgrade rules and guidance in the area of emergency planning should result in definitive and uniform acceptance criteria in the near future. The proposed revision to Appendix E to 10 CFR Part 50 will include implementation schedules for applicants and licensees. In the meantime, the NRR staff has informed light water reactor applicants and licensees of its new requirements in the emergency planning area via various letters and orders. Highlights of these current staff requirements yet to be accommodated in the emergency plans for the applicant are:

1. Demonstration of preparedness to cope with a full spectrum of accidents as outlined in NUREG-0396.
2. Provisions of means to notify the public within 10 miles of the station in an expeditious fashion (i.e., within 15 minutes) in the event of a serious accident.
3. Establishment of a near-site emergency operations facility, including all required appointments.
4. Adoption of the predetermined emergency detection/classification/notification/immediate action scheme in NUREG-0610, and provision of corresponding emergency action levels correspondingly.
5. Implementation of an acceptable public information program.
6. Provision of analyses of times required for evacuation of populations within 10 miles of the site with and without means for prompt warning of the people.
7. Improve the State and local emergency plans for the site considering upgraded joint NRC/FEMA criteria.

FEMA/NRC INTERIM AGREEMENT ON CRITERIA FOR LOW
POWER TESTING AT NEW COMMERCIAL NUCLEAR FACILITIES

The FEMA/NRC Steering Committee has agreed that for the purposes of low power testing (up to 5% power) at new commercial nuclear facilities that the public health and safety is adequately protected if such facility is located in a State which had received a concurrence under the previous voluntary concurrence program, administered by the NRC and based on evaluation by a multi-agency Federal Regional Advisory Committee. In addition, operator plans at individual sites must be consistent with both the existing NRC Appendix E to 10 CFR Part 50 and NRC Regulatory Guide 1.101 in order to assure adequate protection of the public health and safety prior to low power testing.

NRC and FEMA agree that State, local and nuclear facility operator plans must be adequate when judged against the criteria contained in NUREG-0654 and FEMA/REP-1 prior to full scale commercial operation.

This agreement is based on the considerations discussed in the exchange of letters between H. Denton, NRC and J. McConnell, FEMA, both dated February 14, 1980.

The parties note that the North Anna, Salem and Diablo Canyon sites are located in Virginia, New Jersey and California respectively, all of which have received prior NRC concurrence in State Plans. The Salem facility is located near the Delaware border; the radiological emergency plan of the State of Delaware has also received prior NRC concurrence. NRC stipulates that individual nuclear facility operator plans at these plants are in compliance with Appendix E and are consistent with Regulatory Guide 1.101.

III.D.3 Worker Radiation Protection Improvements

III.D.3.3 In-Plant Radiation Monitoring (Partial) (2.1.8.c - NUREG-0578)

POSITION

Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

CLARIFICATION

Use of Portable versus Stationary Monitoring Equipment

Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments for the following reasons:

- a. The physical size of the auxiliary/fuel handling building precludes locating stationary monitoring instrumentation at all areas where airborne iodine concentration data might be required.
- b. Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.
- c. Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.
- d. The time required to retrieve samples after an accident may result in high personnel exposures if these filters are located in high dose rate areas.

Iodine Filters and Measurement Techniques

- A. The following are short-term recommendations and shall be implemented by the licensee by January 1, 1980. The licensee shall have the capability to accurately detect the presence of iodine in the region of interest following an accident. This can be accomplished by using a portable or cart-mounted iodine sampler with attached single channel analyzer (SCA). The SCA window should be

calibrated to the 365 keV of ^{131}I . A representative air sample shall be taken and then counted for ^{131}I using the SCA. This will give an initial conservative estimate of presence of iodine and can be used to determine if respiratory protection is required. Care must be taken to assure that the counting system is not saturated as a result of too much activity collected on the sampling cartridge.

- B. By January 1, 1981, the licensee shall have the capability to remove the sampling cartridge to a low background, low contamination area for further analysis. This area should be ventilated with clean air containing no airborne radionuclides which may contribute to inaccuracies in analyzing the sample. Here, the sample should first be purged of any entrapped noble gases using nitrogen gas or clean air free of noble bases. The licensee shall have the capability to measure accurately the iodine concentrations present on these samples and effluent charcoal samples under accident conditions.

DISCUSSION AND CONCLUSIONS

The applicant states that North Anna Unit 2 has portable low volume air samplers equipped with silver Zeolite adsorbers. Collected samples are analyzed by gamma radiation spectrum analysis using Ge(Li) counting systems.

10 CFR Part 20 provides criteria for control of exposures of individuals to radiation in restricted areas, including airborne iodine. Since iodine concentrates in the thyroid gland, airborne concentrations must be known in order to evaluate the potential dose to the thyroid. If the airborne iodine concentration is overestimated, plant personnel may be required to perform operational functions while wearing respiratory protective equipment which may result in diminished personnel performance during an accident. The purpose of this recommendation is to improve the validity of measurement of airborne iodine concentrations within nuclear power plants.

Under normal operating conditions, air samples are collected on charcoal adsorbers; under accident conditions, supplies of silver zeolite cartridges will be used. Samples are analyzed in the radiochemical laboratory using a Ge(Li) detector. In addition to the in-plant analytical capability, a similar capability exists at the nearby Surry Power Station. Procedures

for sampling and analysis of in-plant air samples have been specifically designed to permit plant personnel to discriminate between valid radioiodine analysis and false readings resulting from noble gas retention in radioiodine sampling media.

The equipment and procedures described by the applicant meet our position in NUREG-0578 and are, therefore, acceptable.

IV Recommendation of NRC Special Inquiry Group

Item 1 Control Room Design Review

As a part of the staff actions following the TMI-2 accident, we will require that all licensees and applicants for operating licenses conduct a detailed control room design review. We expect those reviews to be initiated within the next several months and require over a year to complete. As an interim measure, Vepco was required to perform a preliminary design assessment of the Unit 2 control room to identify significant human factors deficiencies and instrumentation problems. Our contractor, the Essex Corporation, audited the Vepco assessment and concluded that, while the Vepco study uncovered some problem areas, many others were overlooked.

To better establish the acceptability of the North Anna Unit 2 control room design, the NRC staff, together with our consultants, conducted a 5 day on-site review of the Unit 2 control room. NRC staff members participating in the review included instrumentation and control, operator licensing, and reactor systems engineers. The review included the assessment of control and display panel layout, annunciator design, labeling of panel components, and the usability and completeness of selected emergency procedures. The review was performed by means of detailed inspection of the control panels, interviews with operators, and observation and videotaping of operators as they walked through selected emergency procedures.

Our review identified numerous human factors deficiencies. In general, the control room was not designed to promote effective and efficient operator action. We found that control devices and associated parameter displays were not grouped together in a logical fashion and that meters and recorders were difficult to read. The annunciator system was not designed to promote early operator recognition of abnormal conditions. The noise level in the control room was so high that communication between operators was difficult. Procedures which are well written and clearly understood by the operator can compensate for many of the control room deficiencies we identified. However, we judged the procedures at North Anna Unit 2 to be in need of some revisions. Further, the operators' knowledge of these procedures needed considerable improvement. Finally, we noted a number of deficiencies, which by themselves are minor, but which we believe indicate a need for better attention to detail by the management at North Anna.

Deficiencies Identified During the Control Room Review

Significant human factors related control room design deficiencies identified by the review team were:

1. Control-Display and General Control Room Organization - controls and displays have poor functional grouping, and appeared to confuse the operator while he demonstrated the use of emergency procedures for the review team. In many cases, displays are not located near the controls with which they are associated.

Most of the safety related system controls and indicators are located on vertical panels behind the main control console. Some of these are not visible to the operator normally stationed at the console.

2. Meter Displays - vertical meters, used extensively on the vertical panels behind the main control console, are difficult to locate and read by the operator at the console because identical meters are mounted together in strings or clusters of five or more. In addition, an inconsistency in the numerical coding on labels for controls and associated meters impedes quick location and identification.
3. Annunciators - there is no indication of priority or significance of a particular annunciator. Safety and non-safety alarms are intermingled throughout the annunciator panel and are characterized by display windows of the same size and color. Operators must visually search the annunciator panels for the priority alarms.

Further, when an alarm condition is cleared the alarm display window extinguishes without providing the operator with an audible indication.

4. Control Room Noise Level - the control room is fairly compact which, by itself, should enhance communications. However, a ventilation duct which exhausts battery room air into one end of the Unit 2 control room generates continuous high level noise. To this is added high level periodic announcements over the public address system. The speaker for the PA system is mounted in the ceiling directly over the control console. Therefore, communication is difficult and essential messages could easily go unheard or be misinterpreted.

5. Safety Injection System Status Monitoring - there is no system level indication of safety injection system status. In addition, no system level indication is available to the operator to verify normal S. I. operation after automatic initiation. In both cases, status information is obtained by visually checking displays, none of which are located on the main control console.
6. Core Cooling Monitors - Redundant core cooling monitors which indicate subcooling margin have meter displays which are installed on the vertical panels behind the main control console. The meter readings are subject to error due to significant parallex problems. In addition, the scale on the meters cannot be read from the operator's normal position in front of the main control console.

For precise readings, the operators we consulted indicated that they rely on digital outputs displayed on the front of these same monitors which are located at one end of the control room and are accessible only through the use of a ladder.

7. Strip Chart Recorders - we found that on some strip chart recorders, pen positions and trend lines were obscured; some charts lacked labeling and pen labeling; others were installed a few feet off the floor making reading and interpretation of information very difficult; and other had scale increments which were inconsistent with increments on the chart paper.
8. Lamp Test - most illuminated displays cannot be tested for burned out lamps.
9. Procedures - abnormal procedures are not tabbed for easy and quick identification and access by operators. Other significant deficiencies relating to procedures in general are: operator action steps are contained within other steps, general notes, warnings, and cautionary statements; some instructions are vague, ambiguous, and contained in extremely long sentences; some instructions require overly precise control settings beyond the capability of the operator and the controller; little feedback information is provided to the operator with regard to system response to operator actions taken; and procedural steps have been overlooked or omitted. We observed that at least one abnormal procedure could not be performed to completion by an operator because the

instructions were not sufficiently clear. Emergency and abnormal procedures have not been verified by walkthroughs on the Unit 2 control panel by a full complement of operators.

10. Violation of Design Conventions - some design conventions established by the applicant which were violated include: switch positions for open-close, off-on, lower-raise; indicators which are arranged in a C-B-A order contrary to stereo typical and plant convention; and plant color conventions where the color "red" had several meanings.

11. Process Computer - the process computer system does not provide a cross referencing index system which would enable easy and quick operator access to important sensor information.

In addition, there is no formal procedure for logging or documenting computer alarm setpoints which may be changed from time to time by operators or programmers.

12. Process Controller - some Hagan process controllers do not give the operator positive indication of valve operation, but only indicate that the initiating or control signal has been transmitted. In addition, the operation of certain Hagan controllers violate sterotype and convention where the control is increased to cause a decrease in the controlled parameter.

13. General Maintenance - a lack of general maintenance of the control room was exhibited by: use of paper with the wrong scale in at least one recorder; ink and pen colors differing in at least two recorders; incorrect labeling on the main control panel; several non-operating lamps in the emergency lighting system; a vertical meter with no function identification but with a penciled in scale; an air pact (breathing appartus) which was not functioning properly; lamps in several displays not operating; and step ladders and other maintenance equipment obstructing passage around the control room.

14. Labeling - some print on labels have poor contrast with background. In other cases, label coding nomenclature is not consistent with or related to associated control identification.

15. Protective Equipment - the number of air packs available in the control room is not sufficient to accommodate the minimum number of operators. The time necessary to don the air pack (breathing apparatus) was unusually long. Protective clothing for operators in the control room is not provided. Communications between operators wearing air packs was extremely limited.
16. Exposed Controls - the applicant has provided protection for certain exposed controls in high traffic areas, however, there are several other switches and controls in these areas which also should be protected against inadvertent actuation.
17. Number of Personnel in the Control Room - large numbers of personnel were observed in the control room in and around primary operating areas during the day shift operation.
18. Emergency Lighting - a requested demonstration of emergency lighting in the control room was not accomplished; however, emergency lights were turned on while normal lighting was maintained. We observed that some emergency lamps did not illuminate.
19. Emergency Operations - walkthroughs of emergency procedures by control room operators indicated that, at times, it was necessary to monitor and control systems from up to four different stations in the control room.

Corrective Actions

We believe that many of the deficiencies identified could cause the operator to take erroneous actions under stressful conditions. These actions could initiate a transient or could exacerbate his response to an abnormal event already underway. Therefore, we have concluded that sufficient corrective actions must be taken prior to operation at power to substantially reduce the likelihood of operator error. Several of these actions can be implemented quickly and this will be reflected in our requirements. However, we believe that, because the consequences of accidents initiated at 5 percent power (or below) are very low, most of the corrective measures need not be implemented until Vepco is prepared to escalate power above 5 percent.

Specifically, we will require that the following corrective actions be implemented prior to Mode 2 operation (operation at critical):

- o Significantly improve labeling and instrumentation and control demarcation.
- o Color code annunciator windows as an aid in identifying high priority alarms.
- o Review, and improve where necessary administrative controls used to ensure proper safety injection status.
- o Correct problems associated with general maintenance and implement measures to prevent their recurrence.
- o Institute controls to limit control room access.
- o Test the adequacy of emergency lighting.

These corrective actions are not required prior to Mode 2 operations because there is little or no risk involved in the safe operation of the plant.

Prior to operation above 5 percent of rated power the following actions must be taken:

- o Correct the control room noise problem.
- o Improve operator accessibility to Core Cooling Monitor displays.
- o Correct deficiencies associated with the strip chart recorders. Commit to purchasing and installing as soon as possible, data recording and logging equipment in the control room.
- o Install equipment for testing lamps on safeguards panels and establish a mechanism for testing other lamps important to safety.
- o Review all emergency and abnormal operating procedures and correct deficiencies. Perform sufficient procedure walkthroughs to ensure that all operators are familiar with and understand these procedures.
- o Correct violations of design convention.
- o Correct deficiencies in operator procedures for utilizing plant computer outputs.

- o Correct operational problems associated with the Hagan controllers.
- o Procure sufficient emergency air packs to supply all operators required to be in the control room during emergencies. Ensure that sufficient replacement air is available when needed. Train all operators to use the air packs.
- o Install sufficient protective guards to prevent inadvertent operation of J-handle switches located in the control room.
- o Assess control room staffing requirements during emergency operation.

The staff will review all changes to be made by Vepco prior to escalation above 5 percent power.

These corrective actions, when implemented, will serve to substantially improve operator effectiveness during emergencies. However, we believe that, in the longer term, other control room modifications should be made. For example, some rearrangement of controls and displays are needed and annunciator and status monitoring systems should be upgraded. To ensure that these additional modifications are made in the most efficient and effective manner, we will not require their implementation until Vepco has completed the detailed control room design review to be required of all operating reactor licensees. We presently expect that this review will be completed and most corrective actions implemented early in 1982. It is our judgment that the control room improvements to be made in the near term are sufficient to reduce the risk of operator error to an acceptable level for this interim period.

Item 2 Power Ascension Test Schedule

POSITION

The Office of Inspection and Enforcement should increase scrutiny of the power ascension test program to prevent any compromising of safety in view of the proposed expansion of startup test programs and the economic incentives to achieve the already delayed commercial operation of new plants.

DISCUSSION AND CONCLUSIONS

The licensee committed by letters dated December 5, 1979 and February 8, 1980 to perform special tests involving verification of natural circulation core cooling capability as part of the Unit 2 low power test program. (See Section I.g of Part II of this report.) The senior resident inspector will witness the initial performance of these tests and as much of the normal startup tests as practicable. This effort will be augmented by IE Region II inspectors as necessary.

NRC FORM 335 (7-77)		U.S. NUCLEAR REGULATORY COMMISSION BIBLIOGRAPHIC DATA SHEET		1. REPORT NUMBER (Assigned by DDC) NUREG-0053 Suppl. 10	
4. TITLE AND SUBTITLE (Add Volume No., if appropriate) Supplement No. 10 to the North Anna Power Station, Unit 2 Safety Evaluation Report				2. (Leave blank)	
7. AUTHOR(S)				3. RECIPIENT'S ACCESSION NO.	
9. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code) U. S. Nuclear Regulatory Commission Washington, D.C. 20555				5. DATE REPORT COMPLETED MONTH April YEAR 1980	
12. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)				6. (Leave blank)	
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15. SUPPLEMENTARY NOTES Docket No. 50-339				8. (Leave blank)	
16. ABSTRACT (200 words or less) <p>On June 4, 1976, the Nuclear Regulatory Commission issued its Safety Evaluation regarding the application for licenses to operate the North Anna Power Station, Units 1 & 2. The application was filed by the Virginia Electric and Power Company. Supplement No. 1 to the Safety Evaluation Report was issued on June 30, 1976; Supplement No. 2 was issued on August 2, 1976; Supplement No. 3 was issued on September 15, 1976; Supplement No. 4 was issued on December 8, 1976; Supplement No. 5 was issued on December 29, 1976; Supplement No. 6 was issued on February 2, 1977; Supplement No. 7 was issued on August 18, 1977; Supplement No. 8 was issued on December 14, 1977; and Supplement No. 9 was issued on March 31, 1978. Supplements 1 through 9 to the Safety Evaluation Report documented the resolution of several outstanding items. Since the time that Unit 1 was permitted to operate at 100 percent power, during April 1978, there have been changes in the NRC requirements and new licensing guidance has been put into effect. This supplement addresses the requirements for fuel loading and conducting low power testing of North Anna Unit 2 up to a power level of five percent of full power.</p>				10. PROJECT/TASK/WORK UNIT NO.	
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